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APPLICATION OF SPECIFIC ENERGY FOR BIT SELECTION HASSI-MESSAOUD OMG-501

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Besides our supervisor, we would like to thank the rest of our thesis

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DEDICATION

We are very thankful to ALLAH that he enabled us to finish this work after years of education;

We want to dedicate our work in the first place, to our dear parents for their sacrifices, patients and encouragement, during the whole period of studies;

We also dedicate this work to our brothers and sisters, friends and all family and who contributed from near or far.

ملخص : تناقش هذه الأطروحة تطبيق تقنيات تحسين الطاقة الميكانيكية في خفض التكاليف من خلال التنبؤ بمعدلات الخرق المثلى باستخدام بيانات معلمات الحفر في الوقت الفعلي وبيانات بنية الطبقات الارضية تم الحصول عليها أثناء عملية الحفر الفعلية ، وأيضًا كيفية اختيار أداة الحفر. في الحقول التي توجد فيها بيانات متوفرة لعدة ابيار ، يمكن إنشاء معيار دقيق لمعدل تغلغل الحقل مما يساعد في تحسين التكلفة. في الآونة الأخيرة ، ارتفع عدد الآبار التي تم حفرها في حقل حاسي مسعود مع سعر النفط ، ولكن هذا الارتفاع غير مكتمل والإنفاق الفعلي على الآبار يرتفع بسرعة. زيادة الإنفاق على تأثيرات تكلفة الحفر على الأداء الأساسي واستدامة أعمال الانتاج و الاستكشاف. لذلك ، أصبحت الحاجة إلى تحسين الأداء مثل مبادرات خفض التكاليف التشغيلية هدفًا بالغ الأهمية في هذا المجال... **كلمات مفتاحية :** ألطاقة النوعية, اداة الحفر, معدل الاختراق, الاداء .

Abstract:

This thesis examines the application of mechanical specific energy optimisation techniques in cost reduction through prediction of optimum ROP using real-time drilling parameters data and intrinsic formation data acquired during the actual drilling process, also how drill bits could be chosen. In fields where offset well data exist accurate field penetration rate benchmark can be established aiding cost optimisation. In recent times, the number of wells drilled in HMD has risen with the oil price, however growth is patchy and the actual spending on wells is rising rapidly. Spending surge on drilling cost impacts on the bottom-line performance and sustainability of E&P business. Therefore, the need for drilling performance improvement as operational cost reduction initiatives has become a critical industry goal.

Key-words: Specific energy, drill bit, rate of penetration model, performance

Résumé :

Cette thèse examine l'application des techniques d'optimisation d'énergie spécifique à la mécanique dans la réduction des coûts grâce à la prévision de la ROP optimale à l'aide des données des paramètres de forage en temps réel et des données de formation intrinsèque acquises au cours du processus de forage, ainsi que du choix du l'outil de forage. Dans les champs où il existe des données de puits décalées, il est possible d'établir un repère précis du taux de pénétration du champ, ce qui facilite l'optimisation des coûts. Récemment, le nombre des puits forés à HMD a augmenté avec le prix du pétrole, mais la croissance est inégale et les dépenses réelles en puits augmentent rapidement. La hausse des dépenses en coûts de forage a une incidence sur les résultats nets et la durabilité des activités d'énergie et production. Par conséquent, la nécessité d'améliorer les performances de forage au fur et à mesure que les initiatives de réduction des coûts opérationnels est devenue un objectif essentiel de l'industrie.

Mots-clés : l'énergie spécifique, l'outil de forage, modèle de vitesse d'avancement, performance.

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NOMENCLATURE

$A_{b:}$ Area (section) in^2

D_b: bit diameter

ROP: Rate of penetration

PDC: Polycrystalline diamond compact

TSP: thermally stable polycrystalline

UCS: Uniaxial Compressive Strength

PV: Plastic viscosity

YP: Yield point

SPP: stand pipe pressure

Q: Flow rate

HP_B: Horse power

G_p: Equivalent mud weight

AAPE: Average absolute percentage error

WOB: Weight on bit

RPM: Rate per minute

N: Rotary speed

T, T_{bit}: Bit torque

MSE : Mechanical specific energy

DSE: Drilling specific energy

IADC: International Association of Drilling Contractors

MD: Mud Density

C_f: Drilling cost per foot;

C_b: Bit cost;

C_r: Hourly rig rate;

t_t: Trip time;

t_c: Connection time;

t_b: Drilling time;

Δh: Footage drilled.

GENERAL INTRODUCTION

Drilling operation summarily is defined as operation of making a hole, to connect the reservoir to the surface facilities. the main objectives are the realization of a hole, in the best technical and safety conditions and at a minimal cost.

Generally, the drilling price is a function of the time taken to reach the objective, which is therefore a function of the drilling techniques used. Most of these time-related costs are related to the deepening work, and therefore to the different factors that affect the speed of advancement of a drilling bit, these different factors are called drilling parameters.

The concept of specific energy is equivalent to the proportion of all the input energy to the bit to output penetration rate. By using this parameter, it can be used to optimize drilling performance, the performance of bit and minimize wellbore instability. By analyzing these parameters, the costs of drilling operations by increasing the rotational speed of drilling equipment, maximizing bit life, and will be reduced.

The objective of this thesis is to give an approach to drilling bit selection using specific energy with both mechanical and drilling form in order to obtain maximum ROP, which is most considerable parameter for identification of bit performance.

This thesis is divided on five chapters:

The first and second chapter presents the rotary drilling bits, also gave the drilling parameters either mechanicals and hydraulics.

The third chapter contains general information about specific energy and ROP models.

The fourth chapter comprise the case study by applying the MSE & DSE and modelled ROP in well OMG501, then generate the calculation by offset wells concept over other two well in same field OMG503 and OMK573, also includes results discussion and concluded ideas.

CHAPTER.I: ROTARY DRILLING BITS

I.1. Introduction

Demand for oil and gas is still rising. Meanwhile, production from existing reserves seems to be plateauing. The new and unconventional sources of oil and gas are expecting to fill the gaps. These are ultra-deepwater reserves, tight oil and gas in shale rock and hydrocarbons in the far north.

Growing demand for hydrocarbons, and thus increase in their price has caused rapid development of drilling technology. For this reason also, wells are being drilled in an increasingly demanding geological conditions. All these factors contribute to the decreased cost of drilling operations and the need to reduce the duration of drilling.

It entailed intense competition among the major manufacturers bringing continuous development in drill bit technology. Drilling in a deeper in more harsh conditions well requires a more advanced drilling technology and equipment.

Therefore, the efficiency of drilling tools is increased by improving their quality, allows a further increase in rate of penetration. This is particularly important when drilling deep wells, especially in the case of drilling in hard formations [1].

The drill bit is the main tool of the drilling process, positioned at the end of the drill string. Its rotation cuts and the weight on bit indents, resulting in penetration of the formation. Drilling fluid circulates through the bit to decrease bit wear by cooling, and to help the penetration rate by removing cuttings. There is a great selection of bits available, where rotary drilling has two main groups of bits in which we find numerous varieties of bit designs. These are roller-cone bits and fixed-cutter or diamond bit [2].

I.2.Types of drilling bits

There are three main types of drilling bits used in the oil well drilling:

• roller cone bits (rock bits)

• polycrystalline diamond (PDC) compact bits

• natural or thermally stable diamond bits

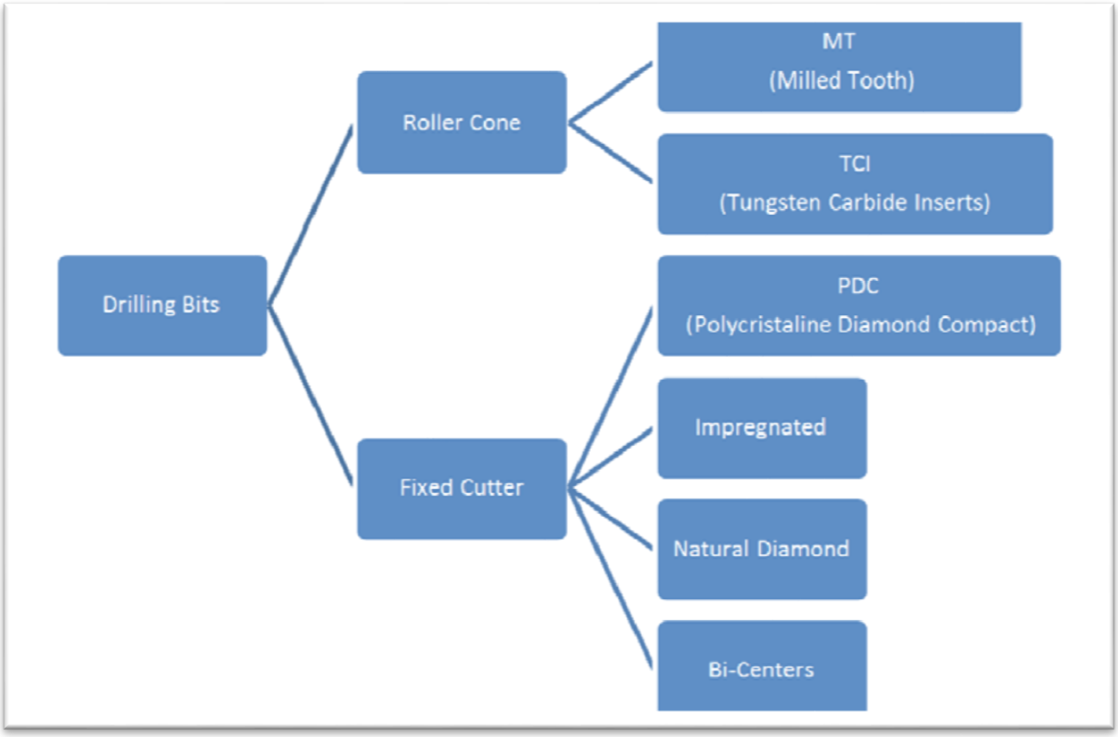


Figure I.1: Development paths for today's drill bits.

I.2.1. Roller cone drill bits

Roller cone bits are the most commonly used type of rotary drilling bits. The first such constructions have been made in the beginning of 20th century. They have undergone several improvements since then so are still very useful tools. This comprehensive bit type is accessible with wide variety of tooth design and bearing types. Thus, is suitable for drilling various types of rock formations. The drill bit design depends on the rock formation properties and the hole diameter. Taking into consideration diversification of drillability of the rocks, roller cones bits are produced in many different configurations. The crushing comes from the high weight utilized driving the teeth into the rock as the cones and the bit rotate.

A roller cone bit consists of three major elements: the cones, the bearings and the body of the bit. Roller cone bits can have one, two, three or even four cones. Three equal – sized cones solution is the most often applicable form. Each cone has teeth sticking out of them in the rows that collaborate and fit into the teeth from adjacent cones. The cones are fixed on bearings which operate on a pin that are a part of the leg of the bit. The body is forged and welded object consisting of three legs.

The body is forged from a nickel-chrome-molybdenum steel alloy and is then treated. Cones are forged too from a nickel-molybdenum alloy steel and treated. Nozzles and Tungsten Carbide Insert teeth are made of sintered tungsten carbide. The bearings are made of suitable tool-steelgrade alloy. Figure I.2shows a typical roller cone drilling bit (Tungsten Carbide Insert bit) [1].

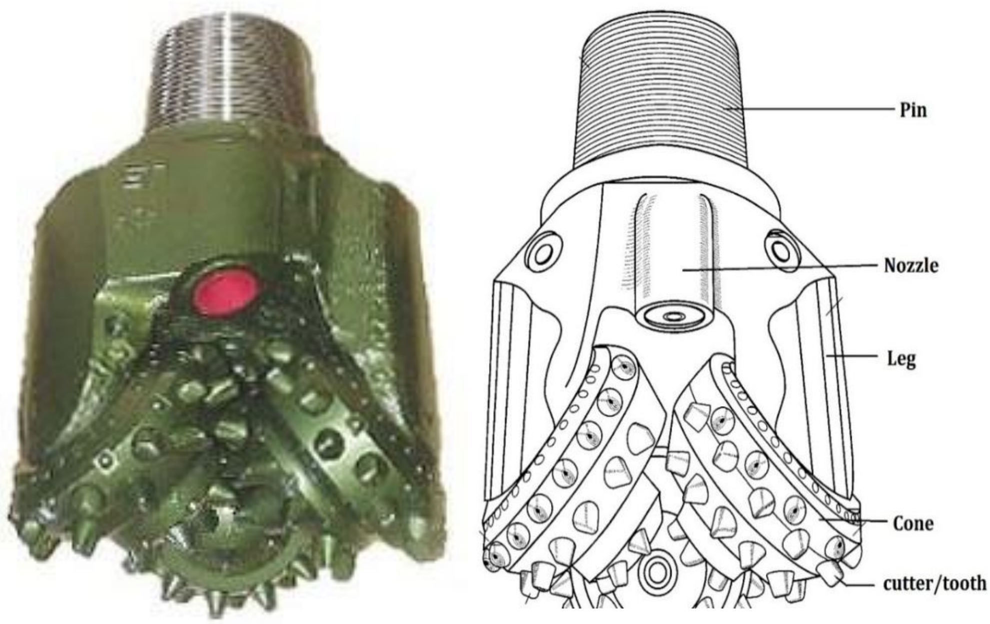


Figure I.2: Roller cone drilling bit (Tricone bit).

I.2.1.1. Cone offset

Percussion with a tooth penetration in the formation, and to have a better progress so it is logical the more the ground is soft that the hard ground, the more the tooth will have to be big.

The sliding (shifting) of the cones on themselves produces a tearing of the chips of terrain; therefore, on each cone, It is necessary to make a shift of the rows of teeth.

This pulling is done by the effect of sliding or shifting, the axis of each cone and the axis of rotation of the bit are not in the same direction, they are offset. This shifting is called "offset". It is even larger than the bit used on soft terrain, on the other hand it becomes zero for the bits to use on hard terrain in which the chip removal is no longer possible and the sliding effect would be harmful to teeth of the bit [3].

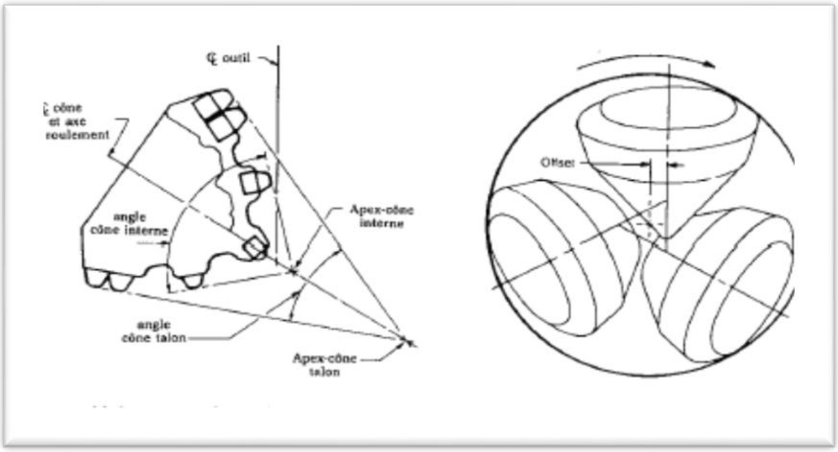


Figure I.3: Offset in soft formation (ENSPM)

I.2.1.2. Bearings system

Characteristic feature of the roller cone bits is the presence of bearings. Bearings are a device used to allow constrained relative motion between the pin and the cone. They play an important role in maintaining operational reliability and the effectiveness of the bit. They are placed on the pin and allow to rotate the cone while exploiting the rock.

Bearing arrangement can vary. It depends on the forces that will be subjected to and dimensions of the roller cone. Heavy-duty bearings consist of two journal bearings and ball bearings. Bearings meet one more very important role. There are a lock that keeps the cone on the pin. Balls are inserted through special passage which is then closed in order to prevent from falling balls.

There are three main types of bearings:

- Unsealed roller bearings
- Sealed roller bearings
- Sealed journal bearings

Figure I.4 shows non sealed and sealed bearing.

The unsealed, conventional roller bearing is originally filled with grease and subjected to mud during drilling. Drilling fluid serves to lubricate and cool the bearings. On the other hand sand and other particles from drilling mud cause excessive abrasive wear.
Currently are used in bits for spudding in a well where trip time is short, in soft formations and in the case when foam, air or gas are used as a drilling mud.

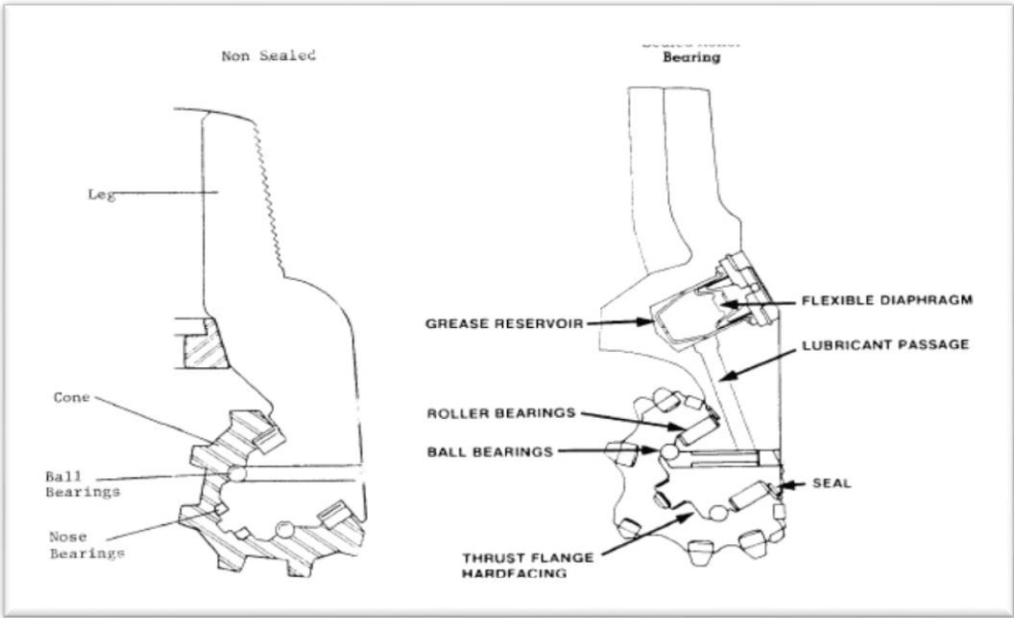


Figure I.4: Non-Sealed and Sealed Bearing

Nowadays the vast majority of drilling bits are equipped with sealed and lubricated bearings. As a result their resistance has been increased to provide longer suitability in demanding conditions.
In case of the sealed roller bearings the detrimental effect of drilling mud has been eliminated as long as the seal is working properly. However, component wear still exists. The major cause of bearing breakage is journal spalling, which results, in the long run, in permanent failure. At present sealed roller bearings are used mainly on milled tooth bits and their resistance often exceeds that of the cutters.
The most efficient solution currently used is journal bearing. The bearing consists of no moving parts, but is just a journal pin fitted to the inside coated surface of the cone. The main advantage is much bigger contact area at the critical, improved distribution of the load. Therefore it can better withstand high rotary speeds and weights. As a result

lifetime has been extended, allowing their use in carbide cutters. To ensure proper seal between the cone and the journal metal seals have been incorporated [4].

I.2.1.3. Lubricating system

In order to improve the work of the bearings, and thus lengthen the working time at the bottom hole, the lubricators are placed in each leg, of which lubricant is supplied to the bearings. The driving force causing the flow of lubricant to the bearing is mud pressure that by acting on the diaphragm pushes the grease towards bearings. Some leakage of the grease may take place due to sudden pressure variations [1].

I.2.1.4. Bit hydraulics

I.2.1.4.1. Conventional bit

The conventional bit is replaced by chucks of tungsten carbide, but the flow is important enough at the bottom of the well for which turbulence occurs which pushes back and up instantly the cutting at the surface through the annular space. As a result, there was better bottom cleaning and avoided regrinding of the cuttings [5].

I.2.1.4.2. Jet bit

The nozzle bit has interchangeable tungsten carbide chucks that are placed between the knurls to improve cleaning and to allow rock destruction in soft ground. The choke joint has a shape of "O" ring to ensure tightness, so When mounting do not forget to put this seal and never use twice the same "O" ring during successive reassembles.
The nozzles are attached to the bit by circlips or threaded rings, depending on the bit manufacturers [5].

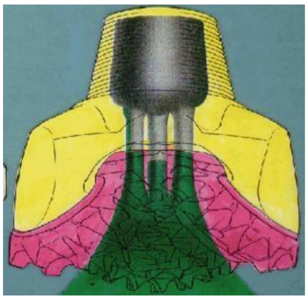


Figure I.5: conventional bit (IADC)

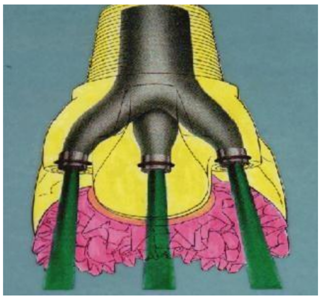


Figure I.6: Jet bit (IADC)

I.2.1.5. Cutting structure

There are two main kind of roller cone bits:

- Steel tooth bits – the cutting structure is milled out of a steel cone body.
- Tungsten carbide insert bits – are manufactured by fitting tungsten carbide inserts into the cones.

I.2.1.5.1. Milled tooth (MT)

Steel tooth bits are also known as mill tooth bits. These tools are resistant, solid and can withstand harsh downhole conditions but due to relatively rapid wear in some cases (hard formations) are not used in deep wells where tripping time is a major factor. Arrangement, hardfacing and angle of teeth are primary design features incorporated in steel tooth bits construction. These features are strongly conditioned by the type of rock to be drilled[2].

Soft formation – in this case the strength of the components may be lower, bearings are smaller, more thin legs and cone shells are used. Teeth are broadly spaced and their number is low. Therefore, there is more space for long thin cutters with small angles (39°to 42°).

Medium formation - strength of the teeth is a value intermediate between soft and hard bits. The inner and gouge rows are hardfaced, with moderate tooth angles (43°to 46°)

Hard formation - bits are characterized by increased strength, components must withstand high loads. As evidenced by that the bit body is more durable, bearings are bigger. Teeth are brief, dull and are near positioned. This type contains many rows arranged close to each other. Tooth angle is (46°to 50°) [1].

I.2.1.5.2. Tungsten carbide insert (TCI)

Tungsten carbide insert (TCI) bits have revolutionized tricone bits. The cutting structure of insert bit is composed of tungsten carbide inserts which are machined into a holes in the cone of the bit. TCI bits are able to drill long sections until the fatigue occurs, however are sensitive to shock loadings. Diamond shell may make them even more durable, which is particularly suitable in abrasive formations for gauge protection. Generally, tungsten carbide inserts bits of similar construction as mill tooth bits are more expensive. Insert bits main purpose is to drill medium and harder formations, using journal bearings to ensure longer work at the bottom hole. Numerous design features in the milled tooth bits have been introduced for carbide insert bits.

For medium and soft rock formations chisel shapes inserts are used to maximize penetration through scraping and gouging operation.

The ovoid rounded shape inserts are the most robust. By crushing and chipping action they exploit hard, abrasive formations [1].

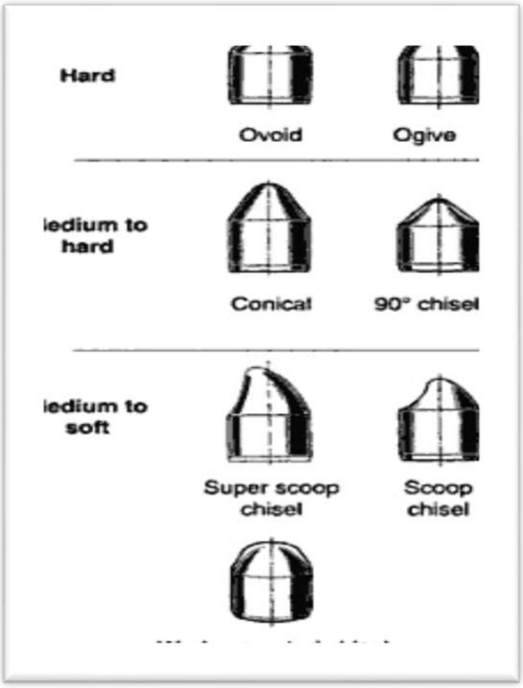


Figure I.7 Teeth shapes.

I.2.2. Fixed cutter drill bit

Cutter bits do not have rotating elements, they are monobloc tools such as natural and synthetic diamonds that are used for their manufacture. The work of natural diamond tools work as a file while that of synthetic diamond bits work as a planer.

I.2.2.1. Natural diamond drill bits

Diamond bits have been applied in oilfield industry since the first half of the twentieth century. They are produced both as drilling or coring bits. Important feature is the lack of moving parts, which contributes to increased reliability. The bit consist of three main parts: diamonds, matrix and shank.

Diamonds are mounted in predrilled holes in matrix which is connected to the shank. The matrix is coated with a powdered mixture of bonding material and tungsten carbide. The shank made of steel ensures structural solidity and by means of machined thread allows to connect with drill string.

The diamond bits are made by hand. This allows you to adapt them to specific drilling conditions. This is achieved by selecting the optimum sizes and shapes of diamonds, and through appropriate arrangement on the surface of the matrix.

The design of diamond drill can be varied by changing the shape of the matrix and the diameter of the drill, the number and configuration of waterways. While drilling soft formations, that require less load, large diamonds are used. It results in larger cuttings and leaves more space to remove them. In case of hard formations drilled with low ROP, small diamonds are used to maximize contact on the working face. The bit hydraulic should be optimized to ensure proper cooling and sufficient hole cleaning [1].

Diamond bit selection should be preceded by a detailed economic analysis to justify its use. Field experience has shown that these are the following situations:

- When the roller cone bits lifetime is limited by too rapid wear on the components.
- When the ROP is very low as a result of high mud density or insufficient rig hydraulic system.
- Deep, small diameter holes. Due to limited space for bearings, roller cones bits are inefficient.
- In directional drilling, diamond bits support hole inclination.
- When WOB isrestricted.
- Application of diamond bits for coring ensure good quality cores.

There some specific conditions in which you should avoid using diamond bits:

- Hard, fractured formations where the bit could be subjected to shocks.

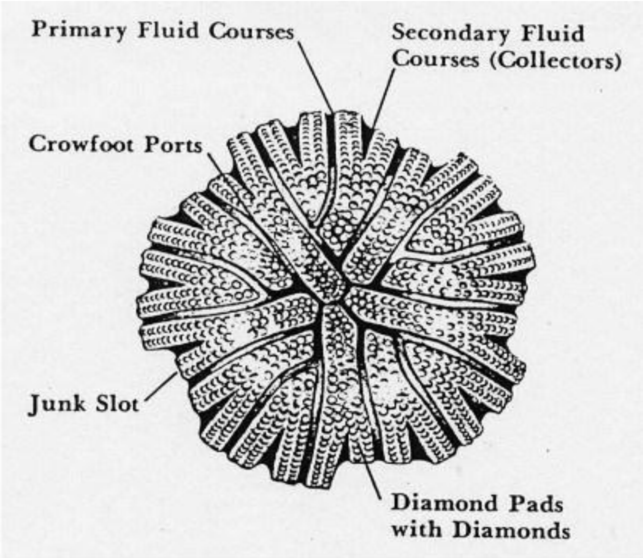


Figure I.8 Typical natural diamond bit.

I.2.2.2. Diamond impregnated drill bits

The bit body is made of tungsten carbide matrix, impregnated with synthetic diamonds inside. Abrasive structure is resistant to high pressures and temperatures, and therefore impregnated bits were applied at drilling very hard formations with low drillability of rock and high abrasiveness. Due to the small size of the impregnated synthetic diamonds, obtained ROP of this type of tools is very low. Figure 3.3 shows Diamond impregnated bits.

Figure I.9 Diamond impregnated bits.

The selection of the impregnated bit should be done with special attention paid to proper selection of the matrix hardness, to ensure that it is uniformly wear as diamond blades. The harder the rock, the softer matrix should be used. This is due to the fact that during the drilling very abrasive and hard rocks, new not yet worn stones should be allowed to unveil [1].

I.2.2.3. Thermally stable PDC (TSP)

A major achievement in enhancing the thermal resistance of polycrystalline diamond cutter was to produce diamond drills PDC types of heat-resistant blades (TSP) in which the space between the grains of diamond inclusions were etched cobalt. These blades have a hard sintered pads, so there are no foreign materials reduce thermal resistance. Thermal resistance drills with cutting TSP is 1148 K (875^{0}C). Due to the increased thermal resistance of the blades TSP bits can be used to drill hard and abrasive formations, in which the operation of a conventional diamond PDC bit is ineffective. TSP is used often in combination with turbines due to their enhanced heat resistance.
TSP bits should be used in rotation within 120-160 rpm for medium-hard rocks and 150-200 rpm for soft rocks. Axial thrust should be between 25-30% of the load exerted on roller cone bits of the same diameter [1].

Figure I.10: TSP bit.

I.2.2.4. Polycrystalline diamond compact bit (PDC)

Inventing and adapting to the needs of industry the diamond compacts made from a polycrystalline very thin layer represent a milestone in the development of bits design.

The diamond , self – sharpening blanks are assembled on a tungsten carbide slug that is press – fitted into the previously prepared spaces in the bit body. A PDC bits don't employ moving parts like bearings and cones which makes them more reliable. Rocks are cut in shear action like lathe operation. This requires less energy and therefore lower WOB is necessary. Therefore results in longer service life of the rig and drillstring.
PDC plates are sensitive to mechanical shock, causing detachment of the polycrystalline diamond layer from the tungsten carbide substructure. Modernization process currently underway are aimed at increasing the mechanical resistance of PDC cutter. One of the new technology introduces an additional layer forming a compact blade PDC. The task of the third layer is to absorb mechanical shocks, and is located between a polycrystalline layer and tungsten carbide layer. What is more PDC cutting structure cannot withstand temperatures exceeding 800 ^{0}C. Therefore proper hole cleaning is crucial to ensure efficient operation [1].

Figure I.11: PDC bit (A) and PDC cutters (B).

I.2.2.4.1. Cutting structure

Number of cutters is closely related to rock formation strength. Fewer blades are used in soft formation, and their amount increases with increasing rock hardness. Cutters shape is usually circular and the final form depends on specific application and manufacturer. Large cutters are utilized in soft formation in order to produce larger cuttings which improves hole cleaning and prevents from bit balling. Smaller blades size ensures longer bit life in more demanding geological conditions.
The cutters arrangement is determined by back rake and side rake angles.

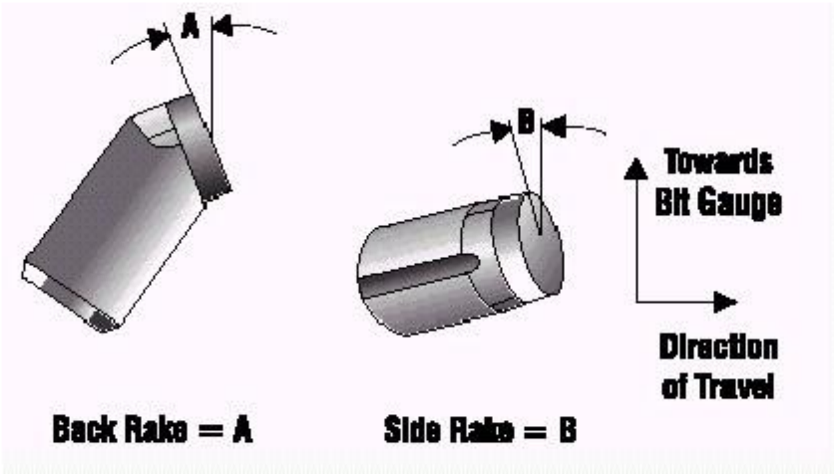


Figure I.12: Back rake, Side rake angles.

The back rake angle influences ROP and the pace of cutters wear. Back rake magnitude ranges between 15^0 to 45^0 and has different values across bit. With its increasing the robustness increases and the rate of penetration decreases.

The side rake angle is the determinant of the orientation of the cutting structure from left to right. Its role is to support the bottom hole cleaning by leading borings straight to annulus. In general, side rake angle has small values [1].

I.2.2.4.2. Bit design

Polycrystalline Diamond Compact bits bodies may have body milled from steel or formed from tungsten carbide (matrix bit). The bit has an elongated gauge with wear pads to ensure proper hole diameter. This also contributes to stable operation and good directional control.

PDC bit for soft formation has big junk slots in order to remove large amount of cuttings. Whilst PDC bit for hard formation is equipped with many small cutters and respectively smaller junk slots. PDC bits can be effectively used for drilling soft to medium rock formations. PDC bits selection also depends on the number of segments, blades or cutters (the more the harder rock) and their height (the lower the harder rock).

Figure I.13. The design of PDC bits depending on the hardness of the rocks (from soft A to hard D).

Bit profile is important for the cleaning and control of the direction of drilling. The most common profiles are double cone and shallow cone. The first type ensures better maintenance of hole diameter and good directional control. Whereas the second type allows for greater ROP. The principle is that the bit with deeper cone the better stability of operation.

Also, the length of the tool has an impact on steerability. The shorter the tool, the easier it is to change the direction of action.

As already mentioned, the important aspect is to maintain the proper hole diameter. Potential reaming takes additional time and is expensive. Therefore the PDC bits are equipped with additional cutters at the gouge area.

PDC bits are relatively expensive and require proper treatment, but due to its parameters and resistance well suited in the following circumstances [4]:

- Applied for offshore drilling and long sections where tripping time is an important factor.
- Drilling with oil based mud and water based mud in non hydrating formations.
- In directional drilling with high RPM using turbines and positive displacement motors.
- When the economic efficiency of the drilling process strongly depends on the high ROP.

Application of PDC is associated with certain limitations and risks. These tools are sensitive for lost junk in bore hole, require proper hole cleaning. Moreover, fractured and fragile geological formations are the threat to the sustainability of the bit. Excessive reaming should be avoided, because of significant reduction in bit life [1].

I.2.2.4.3. The profile: there are mainly three deferential PDC bit profiles:

I.2.2.4.3.1. Flat profile or with a weak inner cone:

The angle of the cone is weak and less than 15°. In this type of profile, the weight is distributed evenly over the cutters, but the number of these is limited and their wear is integral due to the stability of the tool. Tools with this profile are used for soft ground and are not very favorable for fast advancement. They are more economical in consolidated land.

I.2.2.4.3.2. Double cone profile: the inner cone is very pronounced. The cutters are increasingly distributed to the periphery, improving stability and directional accuracy. Tools withthis profile are used for hard terrain.

I.2.2.4.3.3. Parabolic: profile Short or long, this type of profile has a large surface on which a large number of cutting is fixed. The short or medium profile has the advantage of reducing the resistance torque during drilling, which makes it possible to apply more weight to the tool and, consequently, to increase the forward speed. In addition, the parabolic profile is easier to steer with a bottom motor in a deviated well [6].

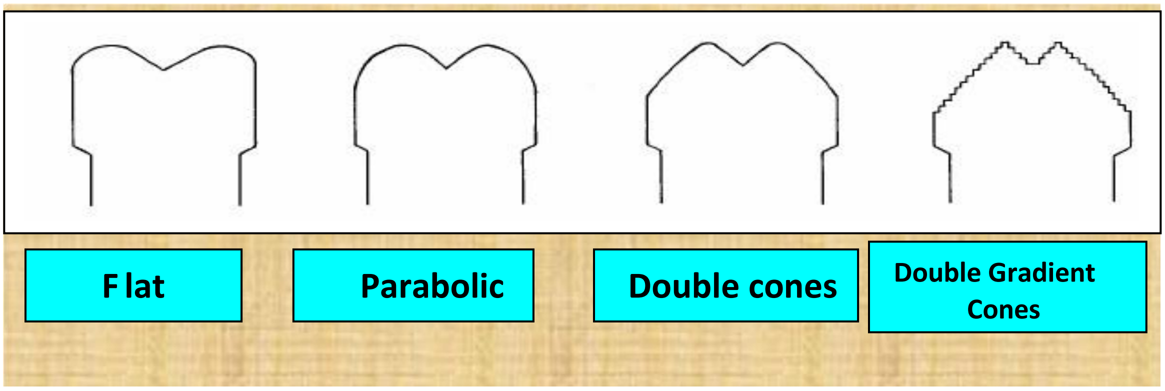


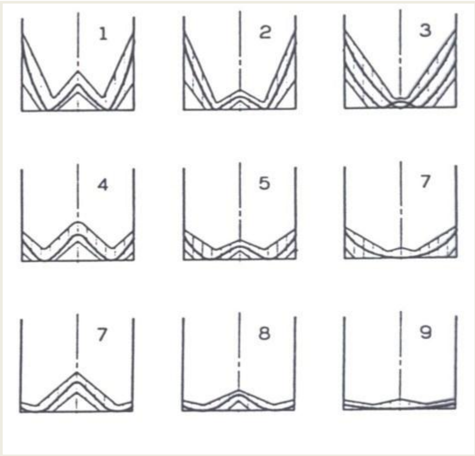
Figure I.14: Different types of PDC profiles.

I.2.2.4.4. IADC fixed cutter classification system

IADC (International Association of Drilling Contractors) in 1981 created a classification of the drills. This classification includes both rock properties and structural peculiarities. Also takes into account some special cases of application of drilling tools. Designation of each bit consists of 4 characters. The first is the type of cutting structure and matrix material. The second defines the profile of the drill. The third sign is characterized by hydraulic solutions. The fourth describes the size and density of the blades [7].

First sign. The characters D, M, S, T and O define the type of cutting structure and the body material.
D: Natural diamond matrix body

M: Matrix body PDC
S: Steel body PDC
T: TSP matrix body
O: Other



[1].

Second sign. The numbers 1 to 9 define the bit profile, where G feature gauge height and C cone height in that order.
1: G high, C high
2: G high, C medium
3: G high, C low
4: G medium, C high
5: G medium, C medium
6: G medium, C low 7: G low, C high
8: G low, C medium
9: G low, C low
Third sign. The numbers 1 to 9 define the bit hydraulic.
1: changeable jets, bladed
2: fixed ports, bladed
3: open throat, bladed
4: changeable jets, ribbed
5: fixed ports, ribbed
6: open throat, ribbed
7: changeable jets, open faced
8: fixed ports, open face
9: open throat, open face
The letters R, X and O can substitute the numbers 6 or 9. R – mud channels arranged radially
X – mud channels positioned transversely
O – other
Fourth sign. The numbers **0** to **9** denote the cutter size and density.
0: impregnated
1: density light, size large
2: density medium, size large
3: density heavy, size large
4: density light, size medium
5: density medium, size medium
6: density heavy, size medium
7: density light, size small
8: density medium, size small
9: density heavy, size small

I.2.2.4.5. Attack of drill bit by the rock

I.2.2.4.5.1. Reactions of the rock on drill bit

At a given moment the bit is in equilibrium under the action of the external forces constituted by the load and the engine torque and under the action of the reaction system that the rock opposes to the bit.

The knowledge of these reactions is necessary for the determination of the stresses to which the various elements constituting the bit are subjected; the knowledge of these constraints is itself very useful for the choice of shapes and dimensions, and the mechanical characteristics of the different parts of the bit. Any percussion provoked voluntarily to better destroy the rock must be able to be supported by the part of the bit which transmits it.

In particular roller cone bit, which include bearings, will have to withstand fatigue phenomena, which are involved in the operation of the rolling blocks due to the periodic variation of loads and stresses [3].

I.2.2.4.5.2.Wear of the active parts of the bit

As already indicated, the contact under load and a relative movement of the rock and the bit cause wear by abrasion and friction of the active parts of this one.

Other wear may intervene fiat maintain in contact with the active parts of the bit with the cuttings, previously detached from the virgin rock; these wears thus depend on the conditions of evacuation and recovery of cuttings. The drilling mud can itself erode parts of the bit [3].

I.2.2.4.6. Determination of toolwear

I.2.2.4.6.1. Wear of the milled teeth and insert bits

This wear is due to abrasion by the rock. It is expressed in 1/8 of the height of the tooth. The symbol T (Tooth; Teeth) is used.

0: no loss; T1: 1/8 of the height of the tooth is worn, T2, T3 ......, T8:

all the tooth is worn. For a broken tooth, BT (Brocken Teeth) is noted. The wear of the insert bit is due to the loss of the cutting elements either by breaking or by heating [8].

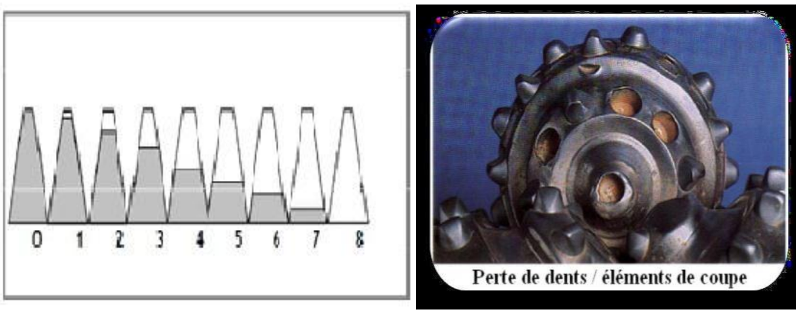


Figure I.15: the height of the teeth/picot (IADC)

I.2.2.4.6.2. Wear of fixed cutter bits PDC

-Analysis of the wear of the PDC: During the ascent of the Bit, the bit man (specialist of the bits) inspects it and makes an analysis of the wear of the bit according to the codification IADC (International Association of Drilling Contractors). It is a very difficult operation because it is subjective; it differs from one person to another.

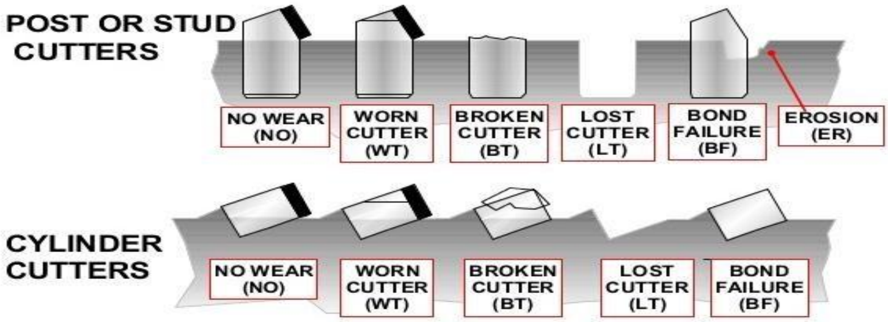


Figure I.16: fixed cutter main characteristic (IADC)

.This wear is due to the loss of the cutting elements either by breaking or by heating

0:no loss

1; 2; ...; 8: all stakes are lost.

This wear leads to the formation of a conical hole. The symbol O or I is used.

- Wear detection

objective determination is very important because it will serve to:

• Select the bit best suited to the type of training to be drilled;

The old way of accounting for bit wear only considered the overall wear of the cutting elements, the condition of the bearings and the diameter of the bit. Currently, the method used introduced in 1987 is more complete. It applies to both roller cone bits and diamond bits. there are eight (08) columns of information are used to report bit wear (see table below).

The first 4 columns relate to the cutting structure.

TableI.1: information for bit evaluation wear

Cutting Structure				B/S	G	Remarks	
Inside rows	**Outsiderows**	**Characteristic of the wear**	**location**	**Bearings / seals**	**Calibration** 1/16 in	**Otherfeatures**	**Reason for theascent**
1	2	3	4	5	6	7	8

- **The first column** indicates by a number from 0 to 8 the wear of the cutting elements of the inner rows (ie 2/3 inside the cutting elements).

  For diamond bits, 0 indicates that the bit has not lost height and 8 indicates a total loss of available height.
- **The second column** also indicates by a number from 0 to 8, the wear of the cutting elements of the outer rows (outer 1/3 of the cutting elements).
- **The third column** uses a two-letter code to indicate the main characteristics of the wear of the cutting structures. (see table).

TableI.2: Codification of cutters wear

BC: Cone broken.	**LN: Loss of chess.**
BT: Broken teeth.	**LT: Loss of teeth.**
BU: Tool blocked.	**OC: Eccentric wear.**
CC: cracked cone.	**PB: Pinch tool.**
CD: Cone blocked.	**PN: Duse blocked.**
CI: Interference between cones	**RG: Peripheral wear.**
CR: Torus tool.	**RO: Damaged seal.**
CT: Chipped teeth.	**SD: Arm Damage (cone)**
ER: Erosion.	**SS: Wear with auto sharpening.**
FC: Flattened teeth.	**TR: Wear between teeth.**
HC: Warming up.	**WO: Whistled tool.**
JD: Damage by	**WT: Used teeth (SS / FC).**
	NO:without wear.

- **The fourth column** uses a letter or number to indicate the location of the wear reported in the 3rd column
- **The fifth column** uses a letter or number (depending on the type of bearing) to indicate the state of the bearings.
  X: Is used for bits without bearings (PDC, diamond, ... etc).
- **The sixth column** indicates diameter loss in 1/16 inch.
  I: indicates that there is no loss of diameter.
- **The seventh column** is used to support any additional wear, in addition to that reported in column This column is not limited to cutting structures only. It uses the same codes as the Column 3.
- **The eighth column** indicates the cause of the ascent of the bit.(tab 4)

Table I.3: reason of pulling

BHA: BHA change.	**FM: formation change.**
DMF: Engine failure of the bottom.	**HP: Trouble drilling.**
	HR: Number of hours.
DSF: BHA problem.	**PP: Pump pressure.**
DST: Drill stem test.	**PR: rate of penetration.**
DTF: Problem bit background.	**TD: Final depth / casing installation.**
LOG: Electrical logs.	
RIG: Repairing the ADF.	**TQ: Couple.**
CM: Mud reconditioning.	**TW: Unscrewing string.**
CP: Beginning of coring.	**WC: Weather problem.**
DP: Drilling a plug.	**WO: BHA whistling.**

I.3.Bit optimization

The most important factor affecting the drilling rate is considered by the industry to be the bit selection. Importance of the drill bit in the overall drilling cost is seen in the cost equation [*], which expresses the significance of drill bit optimization. During the planning phase, the primary analysis is drill bit optimization.

$$C_f = \frac{(t_r+t_t+t_c)C_r+t_rC_m+C_b}{\Delta D} \tag{I.1}$$

Where C_f is drilling cost [$/ft], t_r: the drilling time [hr], t_t: the trip time [hr], t_c: the connection time [hr], C_r: the rig cost [$/hr], C_m: the downhole motor cost [$/hr], C_b: the cost of bit [hr], and ΔD is the formation drilled, in [ft].

Drill bits have been continuously developed and improved since the introduction of the drill bit. They are designed and optimized to produce low cost drilling, increase operational time of the bit to minimize tripping, and to provide stable and safe operations. All these aspects result in lower drilling costs, in accordance with cost equation [*]; and minimizing drilling risks.

The selection of bit is foremost dependent on the formation type being drilled. There are many operating factors affecting the performance of the drill bit, mainly the WOB, RPM, mud properties, hydraulic efficiency and formation properties. The drill bit elements affecting the drilling rate are bit diameter, bit weight, bit wear and bit hydraulic. Bit selection for specific conditions are often based on mathematical predictions from models, rule of thumb, trial and error, or a combination of these. While roller-cone bits have a more complex geometry than diamond bits, the diamond bits have a very wide selection in bit and cutter design. The result is a much greater variation of bit performance for diamond bits [2].

I.4.Characteristics of principal drill bit type:

TableI.2: Characteristics of principal drill bit type

Roller cone bit characteristics	Fixed cutter bit characteristics
- Used for short radius profiles - Roller cones limited by their function period. - High performance with better directionel control. - Easy control of tool face. - Roller cones with short teeth for minimum torque, because roller cones doesn't work with high torque. - Weak resistance against high abrasives formations (sand…). .	- Prefer with long section drilling. - High bit-life time, suitable better with drilling parameters. - Choice of shorts gauge for better tool face control. -High torque counterbalanced by limited cutter size. -Adapted with hard and abrasive formations (PDC). - High penetration in directional drilling (horizontal).

I.5.Conclusion

Proper selection of drill bits and use of appropriate drilling parameters play crucial role in drilling operation, its costs and duration. Optimizing and streamlining the process during planning phase is very important.

The constructers present a whole range of different types of bits which are important to know the particular characteristics. It is also important to bear in mind that a poor bit choice can lead, at the same time as a less good rock attack, to a faster or accidental destruction of the rock by the bit.

CHAPTER.II: DRILLING PARAMETERS

II. 1. Introduction

Oil and gas companies have played a major role in the energy sector, and constantly try to develop technology to maximize their overall revenue. However, as the wells continue to get drilled farther, the drilling wells cost continue to rise. Many researchers have worked for optimizing constant operational parameters. However, these parameters lead to wasted time and money for the operators if they are not well estimated. This is because they constantly change throughout the drilling process. Therefore, it is required to know widely the behavior and the influence of the several parameters, usually known as drilling variables, on the system drilling quality, among these variables we notice: weight on bit (WOB), rotation of the bit (rotation per minute (RPM)) and drilling mud flow (DMF). Especially, determining the optimal rate of penetration (ROP) has been always one of the main concepts of drilling engineering.

In this chapter, we will introduce, classify and define the drilling variables, and other hydraulic parameters.

II. 2. Drilling Principles

The wide variations in drilling conditions encountered under field conditions make it difficult to develop general rules of operation for maximum drilling efficiency. Field experience usually provides the basis for operations in a particular area, but testing often is too costly and experience too late. Consequently, a method for determining optimum drilling techniques and parameters for any particular drilling condition, with a minimum of engineering effort and drilling experience is greatly needed [9]. The drilling parameters, or variables, associated with rotary drilling have been analyze and divided in two groups as independent and dependent parameters as shown in Figure II.1. The independent variables are those which can be directly controlled by the drilling rig operator and dependent variables are those which represent the response of the drilling system to the drilling operation. There are, of course, many factors other than those discussed here that effect drilling efficiency and footage cost. These include such factors as formation hardness, abrasiveness of formation and well depth. As these items cannot be conveniently controlled, their influence on costs must simply be accepted [10].

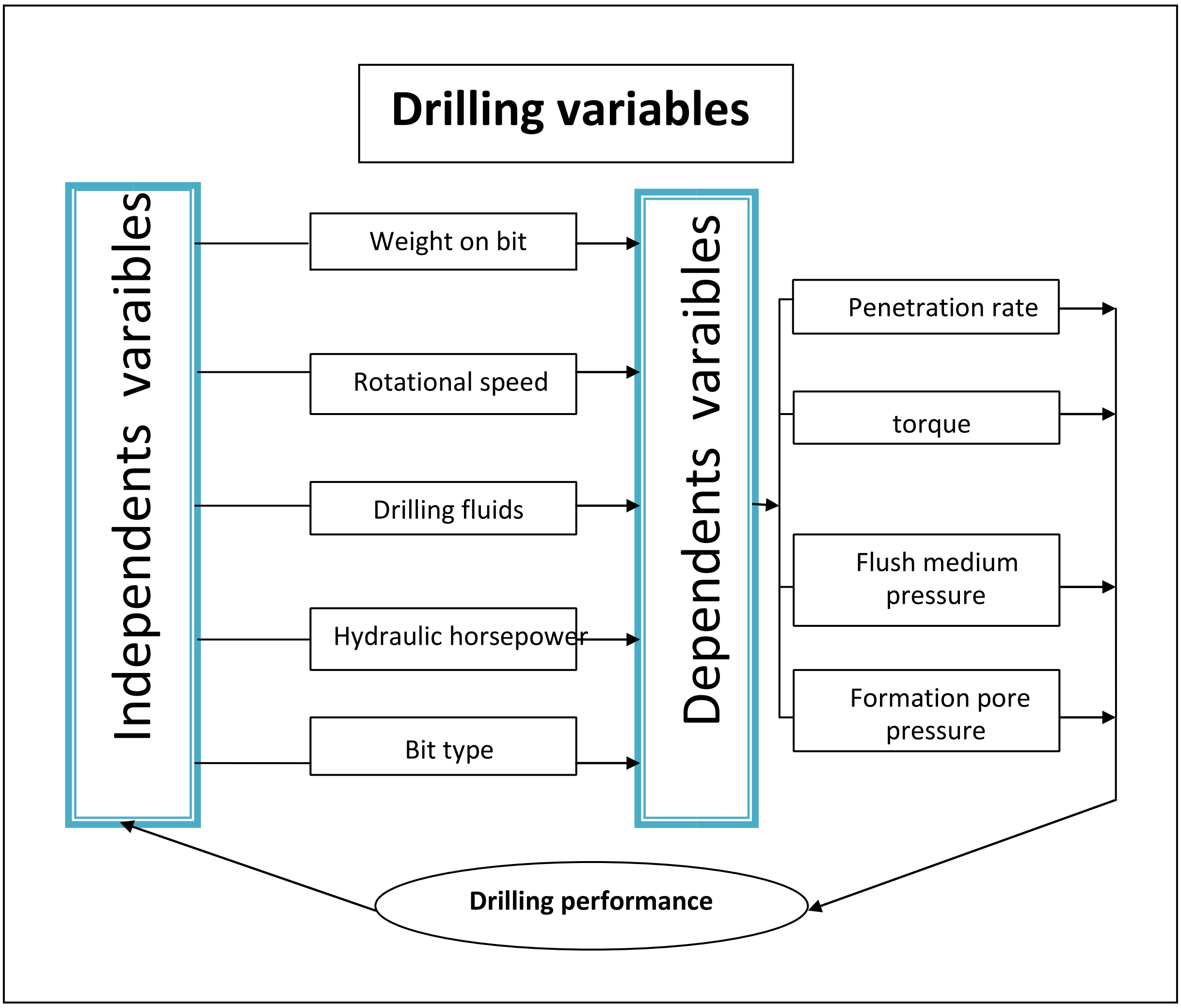


Figure II.1. Drilling variables associated with rotary drilling.

II. 2. 1. Dependent Variables

The dependent variables associated with rotary drilling represent the response of the drilling system to the imposed conditions and are the penetration rate of the bit, the torque and the flush medium pressure and formation pore pressure [10].

II. 2 .1. 1.Rate of Penetration (ROP)

The rate of penetration (ROP), also known as drill rate, is the speed at which a drill bit breaks the rock under it to deepen the borehole. It is normally measured in feet per minute or meters per hour. This parameter is the most important parameter, since all the calculations in this study are based on estimations of ROP in the drilling industry[11].

The factors which effect on rate of penetration are listed under two general classifications such as controllable and environmental. Controllable factors are the factors which can be instantly changed such as weight on bit, bit rotary speed, hydraulics. Environmental factors on the other hand are not controllable such as formation properties and drilling fluids requirements. The reason that drilling fluid is considered to be an environmental factor is due to the fact that a certain amount of density is required in order to obtain certain objectives such as having enough overpressure to avoid flow of formation fluids. Another important factor is the effect of the overall hydraulics to the whole drilling operation which is under the effect of many factors such as lithology, type of the bit, downhole pressure and temperature conditions, drilling parameters and mainly the rheological properties of the drilling fluid. It has been observed that the drilling rate of penetration generally increases with decreased Equivalent Circulating Density (ECD). Another important term controlling the rate of penetration is the cuttings transport. It was concluded that average annular fluid velocity is the dominating parameter on cuttings transport, the more the flow rate is high the less cuttings bed is developed [11].

II. 2 .1. 2. Torque

Torque is a rotational force and it can be described as the ability to overcome resistance to rotation. Its magnitude is measured by multiplying the perpendicular component of the force applied by the distance between the axis of rotation and the point where the force is applied. In drilling applications this distance would of course be the drill pipe radius. It is measured by means of Top Drive System (TDS) systems. Previously the readings for this parameter were relative. This parameter is going to be significantly important for inclined and highly deviated wells, which is also related with the wellbore cleaning issues [10].

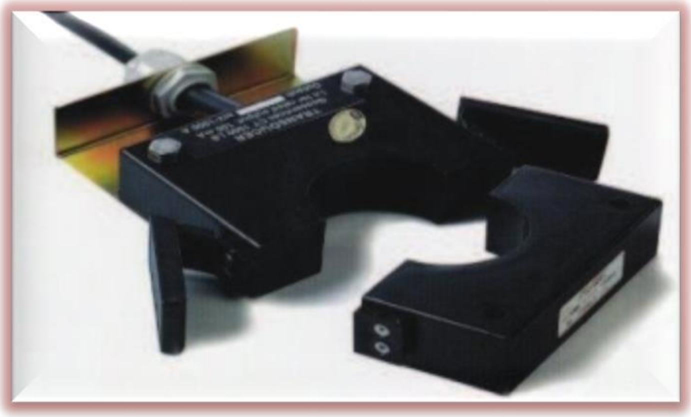


Figure II.2. frequency sensor of torque (T) [34]

Frequency sensor of torque is a sensor with Hall affect, installed around a current conductor, witch measure electric current consumption by rotary table motor, and provide following information:

- Drill bit state, especially ball bearing.
- Lithology changement
- Cone wedged
- Torque transmission while back-off
- Effort needed for unstuck the string

II. 2 .1. 3. Flush Medium Pressure

Drilling fluids in the wellbore can be in either a static or dynamic state. The static system occurs when the fluid stands idle in the well. The dynamic state occurs when the fluid is in motion, resulting from pumping or pipe movement. The static pressure of a column of fluid pressure is known as "hydrostatic pressure" which is an essential feature in maintaining control of well and preventing kicks or blowouts. The hydrostatic pressure of a fluid column is a function of the mud weight or density and the true vertical well depth.

The ROP obtained while a well is drilled generally shows a steady decline as well depth increases. The causes of the reduction in ROP with depth can be divided into two categories:

1) Processes that affects the unbroken rock;

2) Processes that act on the rock once it is broken into chips.

II. 2 .1. 4. Formation Pore Pressure

Formation pore pressure can be major factor affecting drilling operations especially in deep wells. An operator planning a well needs some knowledge of overburden and formation fluid pressure in order to select the necessary hydrostatic or drilling fluid pressure. If this pressure is not properly evaluated, it can cause drilling problems such as lost circulation, blowouts or kicks, stuck pipes, hole instability and excessive costs.

The Formation fluid or pore pressures are usually categorized as normal, subnormal and abnormal or over pressured. When formation pore pressure is approximately equal to hydrostatic pressure of drilling fluid for a given vertical depth, formation pressure is described to be normal. When the formation is opened to the atmosphere during drilling, a column of drilling fluid from the ground surface down to the formation depth (hydrostatic pressure) would balance the formation pressure. If the formation pressure is less than that of the hydrostatic pressure, then it is called subnormal formation pressure. Formations with pressure higher than hydrostatic are encountered at various depth in many areas. These formations are referred to as being abnormally pressured or over pressured. Generally, abnormal pore pressures are associated with fluids trapped within the pore spaces of rocks by low permeability barriers such as salt domes, folds or faults. Numerous authors have demonstrated the severe reduction in ROP with different rotary bits as the borehole pressure increases [10].

II. 2. 2. Independent Variables

The independent variables are the drilling fluids, weight on bit, the bit rotational speed, bit type and the hydraulics horse power.

II. 2. 2. 1. Weight On Bit (WOB)

It represents the amount of weight applied onto the bit, that is then transferred to the formation which in turn is the energy created together with string speed that advances drill string.

This amount of downward force exerted on the drill bit provided by thick-walled tubular pieces in the drilling assembly that are known as drill collars.

It is an essential part of drilling optimization to ensure that the well deepens as drilling moves forward. Finding the right amount of WOB per application is crucial to drilling operations. If the WOB is greater than the optimum value, the drill bit has a higher chance of wear or damage and there is even a chance for the drill string to buckle. [10].

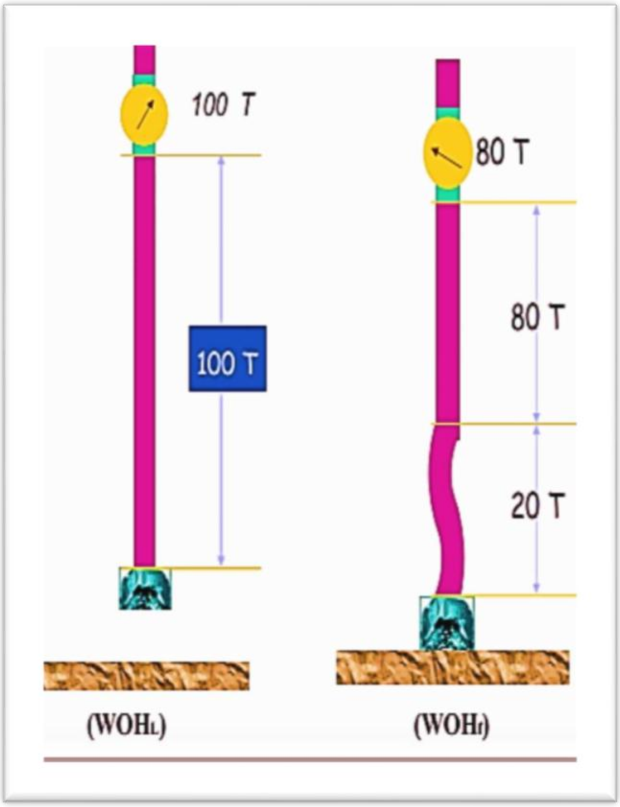


Figure II.3. weight on the bit (WOB) [34]

The weight on bit (WOB) parameter is calculated according to physical principle, considering the weight of drillstring up the soil (WOBl), and the weight while drilling (WOBd):

$$WOB = WOBl - WOBd$$

Hole charge of drill-string is supported by the bit body applied against formations, resulting decreased bit-life. The charge get bigger in front hard formation.

II. 2. 2. 2. Revolution Per Minute (RPM)

The definition of RPM is a measure of frequency of rotations performed by an equipment in one minute. It is a technical term which is associated with any equipment that conducts its operations by performing rotations over a fixed axis. It is an

International System (IS) unit of rotations and is abbreviated by many other common terms such as rpm/RPM (or rotations per minute) or rev/minute.

Some of the examples of equipment used in drilling sector that consists of revolutions per minutes include: top drive, drilling mud motor, compressor reciprocating pumps and motors downhole, motor internal combustion engine [11].

Figure II.4. frequency sensor of RPM [34]

Revolution per minute increases with increased formation strength and torque parameter, it’s limited by vibration which affect drill string (resonance phenomenon; witch causes fatigue and shearing).

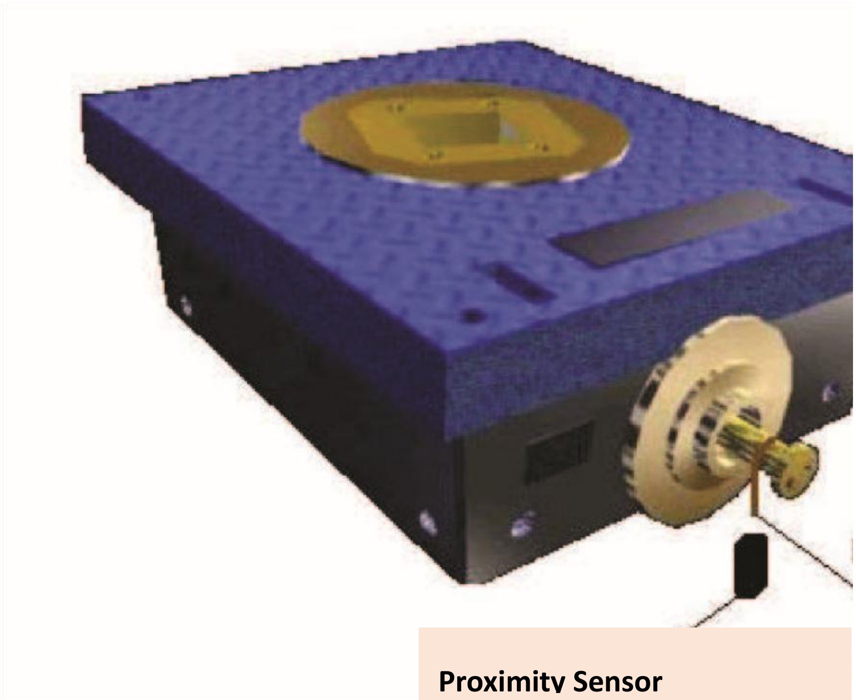


Figure II.5 : sensor position in rotary table

II. 2. 2. 3. Drilling Fluids

The bottom hole must be always cleaned, so we have to remove the cuttings from the borehole. This one obtained by using drilling fluids with sufficient flow flushing medium that can be air, water, oil, oil/water emulsion, mud or foam. Drilling rate is proved to be faster and bit life longer with air as compared to water or mud. Drilling was originally performed with air or water as a drilling medium used to cool the bit and flush away the drill cuttings. As these two media were usually, easily available, cheap and satisfactory for the shallow boreholes and hard formations being drilled at that time. Through the years many additional requirements have been placed on the drilling fluid. To satisfy these demands, as boreholes began to be drilled deeper, and especially with the rapid development of oil well drilling in soft and often caving sedimentary formation, the composition has been modified greatly from the air or water that was originally used. A drilling fluid called mud was developed, consisting of water and bentonite clay to overcome problems such as borehole instability, Mud has a number of properties such as its caking ability, its higher density, viscosity and its thixotropic properties, which make it particularly suitable for drilling deep and soft formations that would otherwise prove difficult to drill. However, The selection of the type of drilling fluid is largely determined by the expected hole conditions. The adjustment of drilling fluid properties is intimately related to the well depth, casing program and the drilling equipment [10].

II. 2. 2. 4. Hydraulic Horse Power

Hydraulics has long been recognized as one of the most important considerations in the design of drilling programs. Improved bottom hole cleaning afforded by jet rock bits and high levels of bit hydraulic horsepower permit the use of the most effective combination of weight and rotary speed and minimizes the risk of bit fouling. These benefits became apparent during the early days of jet bit drilling as contractors began to search for ways to maximize the effectiveness of their hydraulic systems. The results are extended bit life and faster penetration rates. An increasing number of commercial bits are becoming available with interchangeable nozzles, providing the flexibility of rig-site hydraulics optimization. With these interchangeable nozzles, the hydraulic power of the drilling fluid that is dissipated across the bit face can be adjusted to match that portion of the rig's hydraulic power that is available for the bit after other system losses have been considered. The degree to which drilling rate was affected by bit hydraulic horsepower depends on the rock/drilling-fluid combination [10].

II. 2. 2. 4.1. For roller cone bits

a) Drilling flow rate:

The phenomenon of carrying out the cuttings is more directly proportional to the link between penetration and weight is called balling up or stuffing point of the bit. Beyond this point the flow is no longer sufficient to evacuate all the cuttings as they are produced by the teeth of the bit and a portion of the weight placed on the bit is supported by the cuttings.

We can delay the appearance of balling up by increasing the speed to the chokes, which allows a better cleaning of the face of size. The flow therefore has an influence on the progress but up to a certain limit value beyond which it no longer improves the progress and on the contrary risks being harmful by the formation of cellars (turbulence through the joints bits and drill collar), the erosion to the right of the drill collars where the rate of the mud is all the higher as one uses oversized drill collar.

The flow is calculated according to the rate of rise of the cuttings. This rate is greater in soft terrain than in hard terrain. Some prefer to use lower flow rates but focus on the jet bit rate.

The fact of wanting to delay the appearance of the balling up should not however lead to use a flow such that:

- in soft terrain there is risk of formation of cellars,
- in poorly consolidated terrain, erosion of the walls,
- increased losses circulation in the annulus producing at the bit the same effect as an increase in density, resulting in reduced progress, and causing traffic losses.

b) Minimum rate through jet of the bit

The mud jet has the effect of cleaning the bottom of the well and inducing sufficient turbulence to wash the teeth of the bit. Before the nozzle, the pressure must be high and the speed is low. In contrast, after the nozzle, the pressure is low and the speed must be high.

c) Influence of jet (nozzle) of the bit

• Slightly open: little flow and little cleaning ability

• Properly open: firm and directed flow and best cleaning

• Too open: flow without force and no cleaning

II. 2. 2. 4.2. For diamonds and PDCs

To properly cool the diamonds and PDC bits and avoid "burning" them, it is important to have a high flow rate.

The respect of a high flow rate is preponderant for this type of bit firstly to cool the cutters and then to clean the face of size [6].

II. 3. Conclusion:

Efficiency during drilling is an important part of cost saving measures. Drilling for petroleum purposes is a complex system, and relies on many different factors such as bit size, bit efficiency, torque, WOB, RPM, flowrate, mud rheology and formation hardness, etc. This makes the task of achieving and maintaining high ROP a challenging task, requiring more than just supplying the drill string with sufficient power, but also a significant analysis of the drill bit parameters, the case of his specific energy.

CHAPTER.III: SPECIFIC ENERGY & ROP MODELS

III. 1. Background

Drilling after hydrocarbon resources generally occur deep down in the ground through various layers of rocks. The essentials in drilling are breakage, crushing and cutting of fragments out of the rock surface to reach deeper into the ground. Rotary drilling is the standard penetration method for oil and gas wells. Teale [12] described rotary drilling as a combination of two actions: cutting and indention. The rotating movement cuts the rock, simultaneously as it pushes into the rock to indent. The work done or required energy to excavate a unit volume of rock was introduced by Teale as specific energy or mechanical specific energy (MSE) [12]. The speed of the drilling process is given in rate of penetration (ROP), presenting the drilling in feet drilled per hour.

The concept of mechanical specific energy has been used effectively in lab environment to evaluate the drilling efficiency of bits. Mechanical specific energy is a calculated value equal to the ratio of the input energy to the drill rate. Because of given volume of a specific rock requires a given amount of energy to destroy; this ratio should be relatively constant. Any significant increase in the mechanical specific energy ratio is taken as an indication that energy is being lost and the system has become less efficient. Specific energy allows the optimum operating parameters to be identified easily and more or less continuously for each foot of hole drilled, secondly, it provides quantitative data needed to cost-justify changes in areas such as well control practices, bit selection, directional target sizing and further more usefulness (Fred and William 2005) [13].

The specific energy was used to calculate the rotary drill process and it is defined as the work done in cutting a unit volume or mass of rock, and it provides a measure of the drilling efficiency (Yinghui and Brian 2004) [14].

The drilling specific energy SE_d is a very significant measure of drilling performance. It is directly compatible with cost/meter, because it relates the amount of energy required to penetrate rock .SE_d can also be used to quantify the efficiency of rock working processes and rock hardness during drilling .This relationships between drilling specific energy, drilling rate and the main mechanical rock character (Erosey 2003) [15] . Drilling data is summarized in a common format to provide a direct comparison of drilling efficiency, jet pressure and hydraulic power (Kolle 1999) [16].It is not easy to make any logical interpretation of raw data i.e., [bit load , rate of penetration , flushing pressure, rotary speed and rotation pressure] and they represent a rather confusing picture. If however, these five parameters are combined in a formula, describing the energy from the drill bit acting on the soil. This formula represents specific energy needed to penetrate one cubic meter of the soil and the different layers of soft and hard soil are clearly visible (Swedish geotechnical institute 1996) [17].

Another definition for this energy is the energy required to remove a unit volume of rock, namely the specific energy (SE) , is a critical rock property data that can be used to determine both the technical and economic feasibility of well drilling .The most efficient rock removal mechanism would be the one that requires the minimum energy to remove a unit volume of rock(Xu , Reed , Konercki , Gahan , Batarseh , Figueroa and Skinner 2003) [18] .

The petroleum industry is a high grossing industry, but also a high cost industry. Therefore, there has always been a focus on cutting costs and increasing efficiency. Given the recent unexpected drop in oil prices and the subsequent rise in uncertainty related to future price levels, the focus on cost reduction and efficiency considerations have increased dramatically. One of the most costly aspect of the industry is exploration and drilling, and therefore has a lot of potential for optimization and reducing costs. Planning and predicting future drilling operations based on controllable variables will be essential in order to realize these efficiency gains. This may be aided by ROP modelling and analysis.

III. 2. Specific energy

III. 2. 1. Mechanical specific energy (MSE)

Teale (1965) introduced the concept of MSE. Specific energy, or energy density is defined to be a measure of the work done to remove one unit volume of material. The purpose of this method is to properly present information regarding the efficiency of the drilling process. While there has been a lot of research on the subject since then, the concept was not properly introduced to the market until ExxonMobil implemented a trial run in 2005 to improve their operation efficiency (Dupriest 2005). The outcome exceeded their expectations. By use of MSE on six of their rigs over a period of three months, the ROP was increased by 133 percent, and new field records were established on 10 of 11 wells. After one year, the concept was implemented in the entire global organisation. This resulted in several positive outcomes, substantial cost-savings for global operations being among those. During the next year the organisation reported to have saved $54 million, sat 50 new drilling records, while one of the most solid safety records in the industry was preserved (Hamrick 2011) [19].

III. 2. 1. 1. The model

MSE quantifies the ratio between the mechanical energy input from the rig, and the responding ROP. The formula derived by Teal is given as:

$$MSE = \frac{\text{Input energy}}{\text{Output ROP}} \qquad (1)$$

From Eq. 1, one can conclude that a low MSE value is preferred, as it means that a large volume of rock is removed per unit energy input, something that indicates an efficient operation. The mechanical input energy consist of two forces, the axial force and the rotational force. By definition, rotational work is given as torque, times the rotation angle, while the axial work is given as force, times distance. For the drilling process, the axial force is given as the WOB that pushes the cutting edges of the bit into the rock, and the rotational force that creates a circular motion that breaks free fragments of the rock of varying sizes. The volume removed per unit time may be expressed as the cross-sectional area of the bit times the ROP. Formulated in Eqs. 2 and 3 (Hamrick 2011):

$$\text{MSE} = \frac{\text{Vertical energy input per time}}{\text{Volume removed per time}} + \frac{\text{Rotational energy input per time}}{\text{volume removed per time}} \quad (2)$$

Inserting expressions for all of the terms yields:

$$\text{MSE} = \frac{\text{WOB} \cdot \Delta h}{\text{Area} \cdot \Delta h} + \frac{2\pi \cdot \text{Torque} \cdot \text{\#Rotations per time}}{\text{Area} \cdot \Delta h} \quad (3)$$

Where Δh is change in measured depth per time.

Teale then derived the following formula based on commonly available real-time drilling data.

$$\text{MSE} = \frac{\text{WOB}}{\text{Area}} + \frac{2\pi \cdot \text{Torque} \cdot \text{RPM}}{\text{Area} \cdot \text{ROP}} \quad (4)$$

Other methods have also been presented. Based on the assumption that the parameters WOB, torque and ROP are interrelated to each other, and that the relationship between WOB and torque can be described as linear in a normal processing range, Hamrick (2011) worked on a theory of expressing MSE based solely on WOB and constants [19].

III. 2. 1. 2. MSE efficiency formula

During drilling, much energy will be lost in the transaction between bit and formation. Even under perfect conditions, the bit will only be able to deliver 30-40 percent of the input energy into further progress (Dupriest 2005), illustrated in Fig. III. 1. This was also tested by (Pessier and Fear 1992), where comparing different bits in a full scale simulator proved that while a PDC-bit can drill with less WOB due to three to five times greater sliding friction than the roller cone bit, it experiences the same magnitude additional torque, and they both end up with an efficiency of close to 30 percent. Other reasons for this high loss of energy, are factors like friction between the bit components and unnecessary torque.

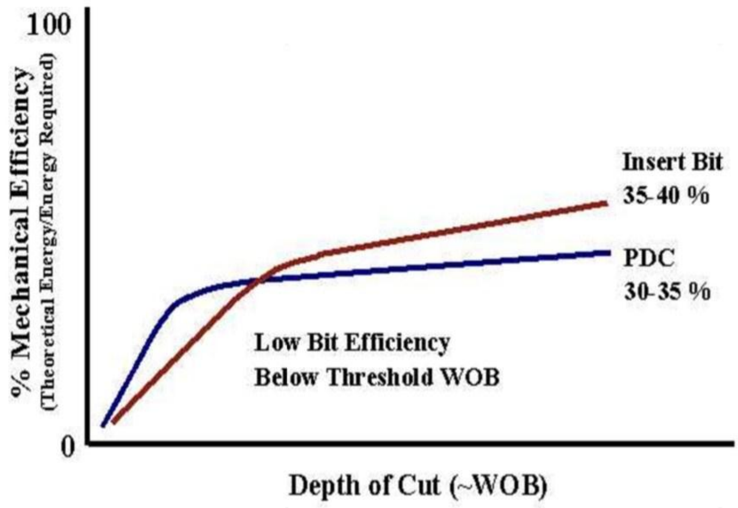


Figure III. 1: Bit efficiency vs Depth of cut (Dupriest 2005).

Even though the bit efficiency factor is known to vary between 30 and 40 percent, the standardization is set to 35 percent for most operations. The MSE-efficient formula then becomes:

$$MSE = \text{Bit efficiency factor} \cdot \frac{WOB}{Area} + \frac{2\pi \cdot Torque \cdot RPM}{Area \cdot ROP} \tag{5}$$

While downhole data during drilling has become more common, the majority of drilling data is still measured from surface. This means that the energy delivered at the bit is not of the same scale as the energy supplied and measured. Common transmission losses are illustrated in Fig. III. 2.

Energy lost along the drillstring is usually approximated by simply adding an additional efficiency factor, i.e. a Loss efficiency factor. This factor is set on a scale from 0 to 1, and is meant to exclude the lost energy due to transmission losses along the well path, such as drag and vibrations. The MSE-efficient formula then becomes

$$MSE = \text{Total efficiency factor} \cdot \frac{WOB}{Area} + \frac{2\pi \cdot Torque \cdot RPM}{Area \cdot ROP} \tag{6}$$

Total efficiency is the product of Bit efficiency and Loss efficiency [19].

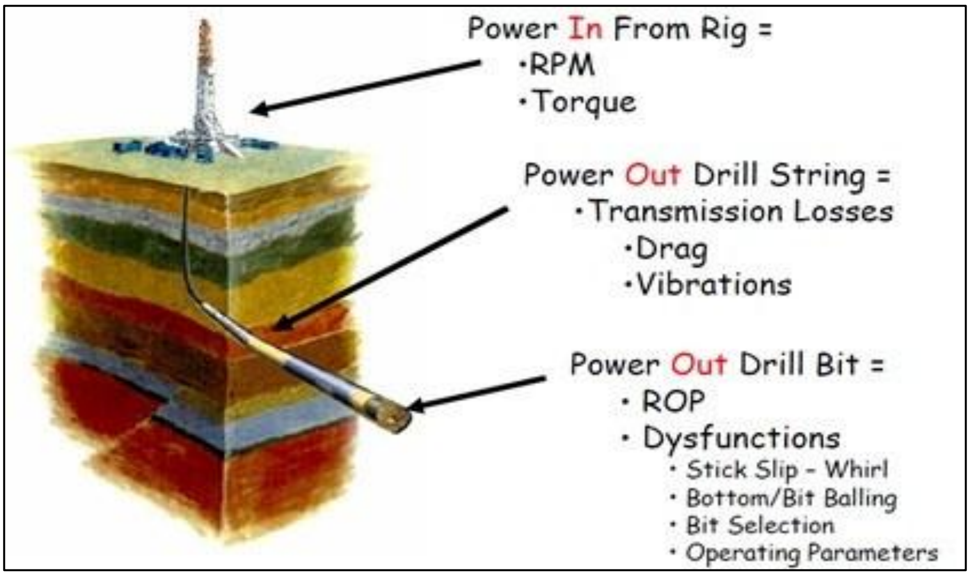


Figure III. 2: Transmission losses along the drillstring (Abbott 2014).

III. 2. 1. 3. Application of MSE during operation

MSE is primarily used as a trending tool. This means that the specific value of the MSE curve is of less importance than the trend. As mentioned earlier, each section often starts with a drill-off test to identify the optimal parameters for this formation in combination with this drillstring setup. From this information, the driller can calculate the new-bit-MSE (Guerrero 2007). The new-bit-MSE is the optimal MSE available for this system, and should be identified at the start of the section. This is because, at this point, the bit is still sharp, and should be able to achieve optimal performance. The new-bit-MSE will then be the lowest possible MSE for this system, and all future drilling should be evaluated against this value.

When new-bit-MSE is identified, a trend-line should be established. The trend-line is assumed to increase linearly with elapsed time, as illustrated in Fig. III. 3. The need of higher mechanical input energy is mainly caused by three factors; bit dullness, formation compaction and additional drag due to increased well depth.

The driller should work to keep the MSE as close to the trend-line as possible, as this should be the optimal performance. If the MSE increases above this line, the problem needs to be identified and proper measures needs to be implemented. To identify the reason behind the occurring founder, all the parameters need to be evaluated. As mentioned in section 2.1.3, different causes of inefficiency affect different parameters, making it possible to diagnose the problem to a certain degree. In most cases, this problem may be solved by simply adjusting input parameters. Table 1 represent four different scenarios of inefficiency, where changes in different parameters are indications of specific problems. Suggested counter-measures are also listed.

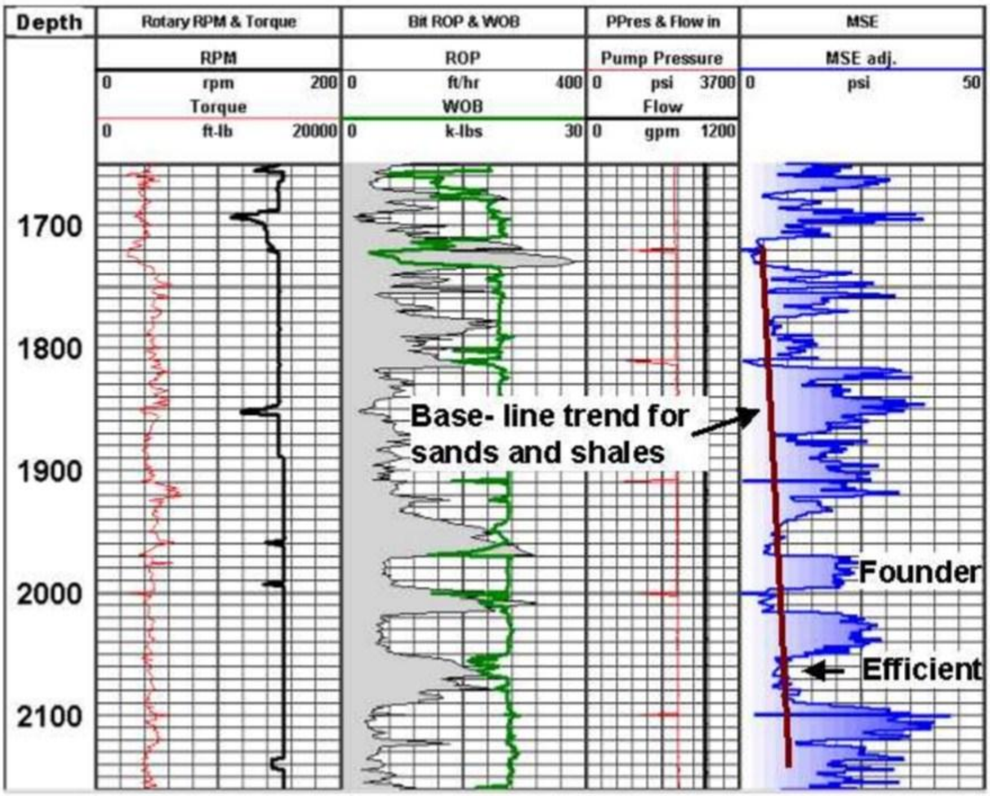


Figure III. 3: MSE vs. depth. New-bit trend-line indicated with red (Dupriest 2005).

Still, during optimal performance by the driller, ROP may not be as high as expected, and an increase of ROP is required. As explained in section 2.1.3, optimal ROP is not always possible to obtain through altering the input values of energy. If this problem arises, the entire system needs to be re-evaluated according to the identified cause. Re-evaluation should be done according to a cost-benefit evaluation, to determine if the lost time and resources to recomplete the system is worth the expected increase in ROP for the remaining part of the current section [19].

III. 2. 1. 4. Input data for MSE

Since MSE mainly is a new way of displaying information based on already existing data, different parameters need to be available for use of this concept. During later years, a number of different MSE-methods have been derived to include different types of parameters. For the most common concept, the following parameters are required:

WOB	Weight On Bit [lbf]
RPM	Revolutions Per Minute [min^{-1}]
Torque	Rotational torque [in-lb] or [ft-lb]
Area	Cross-sectional area of bit [in^2] or [ft^2]
ROP	Rate Of Penetration [in/h] or [ft/h]

These are all the parameters needed to compute MSE. Still additional info should be available to take proper use of the method. Data regarding bit dulling and bit efficiency could help improve the accuracy of the bit efficiency factor. For evaluating loss along the drill-string, parameters like mud weight, downhole vibrations and friction should be available, or the problem could be avoided by measuring values downhole. At the start of each section, a drill-off test should be conducted. This provides vital information regarding the current optimal parameters, and could be used to set a trending curve for the rest of the operation as mentioned in the previous subchapter [19].

III. 2. 1. 5. Founder point

As seen from Fig. III. 4, the curves at different RPMs follow a specific pattern consisting of three regions. At low values of WOB, the curve tends to be flat. At this point, the ROP does not respond to the additional energy input from increasing the WOB. The threshold compression strength of the formation has yet to be reached, and only rock fines and powder are produced (Pessier and Fear 1992). The second region is identified by a linear increase in ROP. In this region, the bit works at its maximum efficiency, and

an increase in input energy results in proportional increase in ROP. All systems exhibit this type of curve, and every system has its limit. At one point, the curve
starts to flatten out, and the increase in input energy no longer increases the ROP. This is known as the founder point of the system.

The founder point indicates that the system has reached its limit, and that increased input energy is hindered from being transferred to the formation by one of many factors. The founder point also indicates that the system has reached the highest possible ROP, and further increasing the input energy will bring the operation into region three; a region of drilling inefficiency.

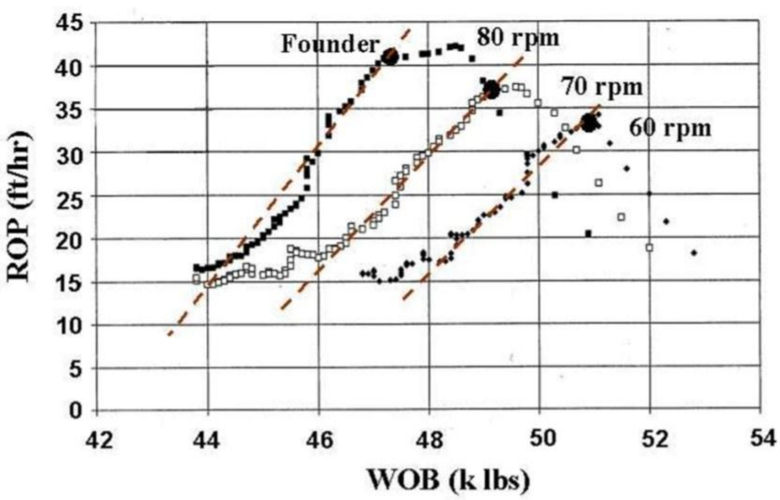


Figure III. 4: ROP vs. WOB on the resulting plot of a drill-off-test. The characterizing curves are shown for 80, 70 and 60 rpm (Dupriest and Koederitz 2005).

At this point, the driller needs to embrace this speed of progress as acceptable, or identify the cause of founder and recomplete the system accordingly. The most common reasons of founder are vibrations, bit balling and bottom hole balling.

It is important to understand that every system has its point of founder. By identifying and re-completing the limiting factor, the point at which the founder occurs will increase only until the next limiter appears. It is therefore important to identify not only the current cause of founder, but also the probable increase in efficiency that could be achieved by changing the system. Then evaluate the cost of recompleting the system versus the benefit of probable time saved. Fig. III. 5 illustrates how recompleting the system can affect the point of founder [19].

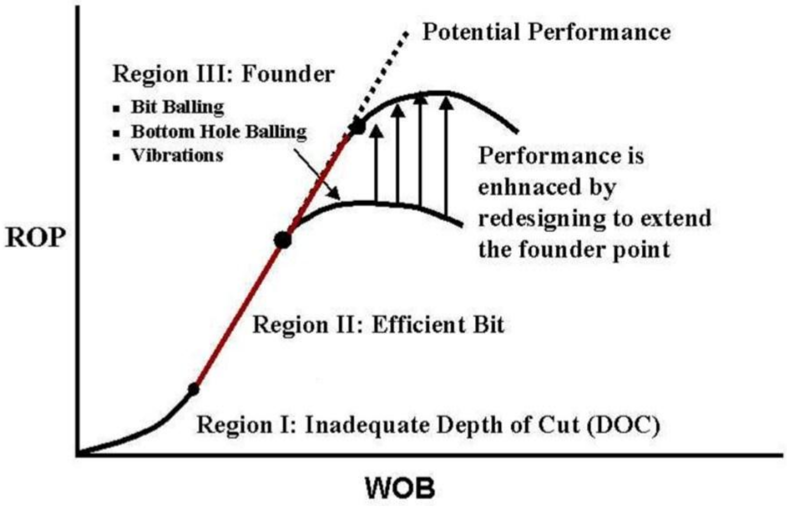


Figure III. 5: The three regions of efficiency during drilling (Dupriest and Koederitz 2005).

III. 2. 2. Drilling Specific Energy

The concept of mechanical specific energy (MSE) – the original equation developed by Teal has been modified by Miguel Armenta (Miguel 2008) to include a bit hydraulic related term on the (MSE) correlation. DSE can be calculated as shown in Eq. 7.

$$DSE = \frac{WOB}{A_B} + \frac{120\pi * RPM * T}{A_B * ROP} - \frac{1{,}980{,}000 * \lambda * HP_B}{A_B * ROP} \quad \textbf{(7)}$$

The first two terms on the right-hand side of Eq. 7 are similar to those on Teal's original equation. However, the third term represents the bit hydraulic related term. The number 1,980,000 is a unit conversion factor. The parameter Lambda (λ) is a dimensionless bit hydraulic factor depending on the bit diameter.

HP_B and bit area (HP_B/A_B) is the bit Hydraulic power per square inch HSI (hp/in^2). The (DSE) concept was evaluated by applying Eq. 7 and the relationship of DSE and ROP was investigated for different drilling parameters (WOB, and HSI). DSE vs. ROP for different WOB values for all the experiments shows grouping of curves according to the WOB Fig. III. 7. A good agreement between the experimental data and the DSE model was observed. All the curves have similar pattern showing three main regions: (1) High DSE and low ROP indicating inefficient drilling; (2) low DSE and high ROP which indicate efficient drilling; (3) A transition zone from region 1 to region 2 in between these two regions. (Miguel 2008) [20].

Field data was used to calculate DSE using Eq. 7 to identify inefficient drilling condition.

The DSE and ROP both were plotted first against depth to identify any particular pattern. After that, the drilling parameters WOB, RPM, Torque and HIS were also plotted vs. depth in order to explain the observed pattern Fig. III. 7.

In order to show the effect of the hydraulic term or the HSI, again DSE was plotted vs. ROP but this time the data is grouped according to the HSI. The WOB curves are kept on the plot to make a connection with Fig. III. 6. It was shown in Fig. III. 8. that all the data with HSI between 0.5 hp/in^2 and 1.7 hp/in^2 are located on the inefficient drilling region (Region 1: high DSE and low ROP) for their particular WOB. On the other hand all the data with HSI between 5.8 hp/in^2 and 7.9 hp/in^2 are on the efficient drilling region (Region 2: low DSE and high ROP). It is revealed from Fig. III. 8. that the bit hydraulic is the driver to move from inefficient drilling when the WOB is constant. When increasing HSI not only are the cutting removed faster underneath the bit, but also the bit cutting structure is kept clean to break new rock more effectively [21].

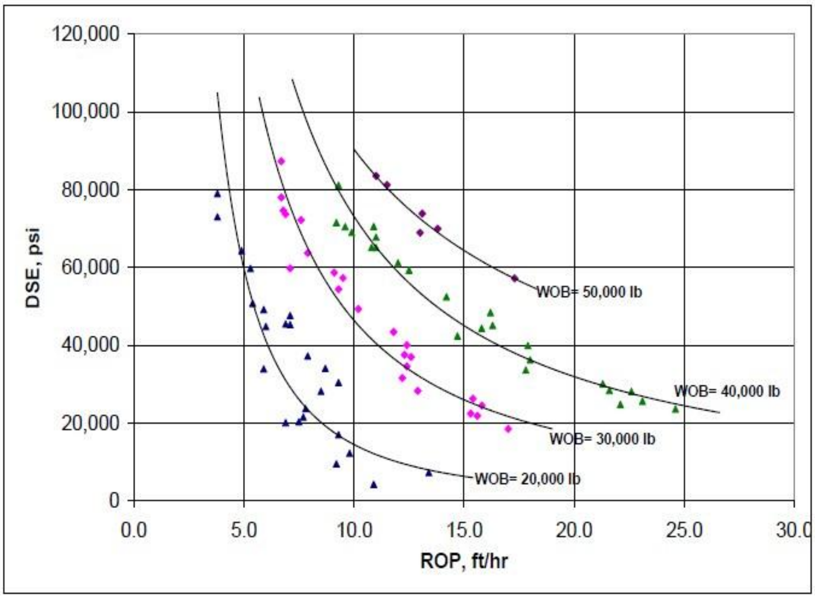


Figure III. 6: DSE vs. ROP with experimental data grouped according to the WOB (Miguel Armenta 2008)

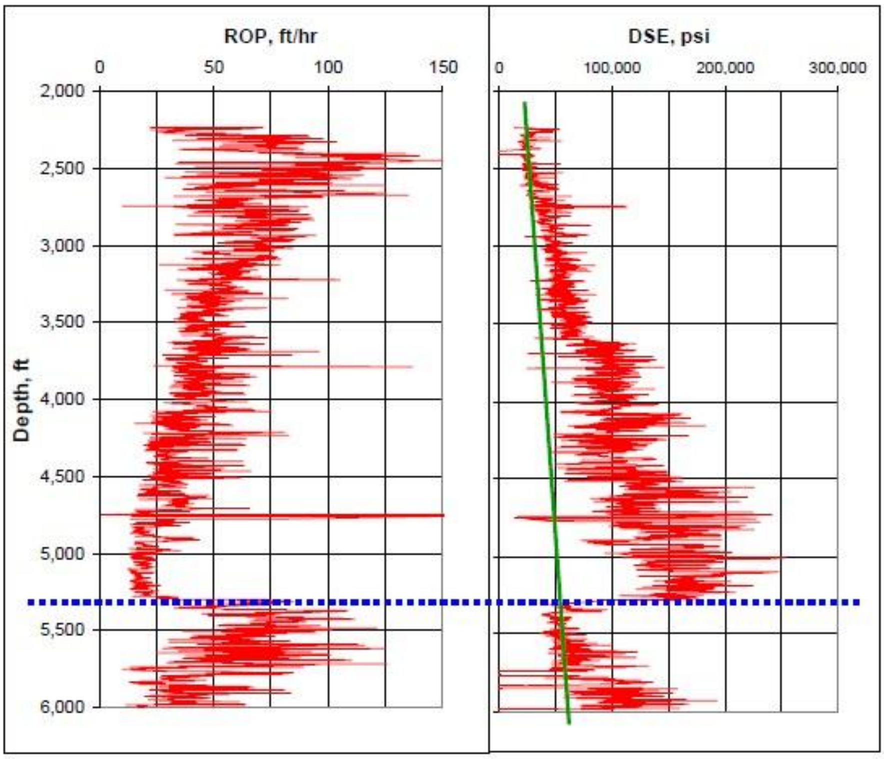


Figure III. 7: ROP and DSE vs. depth for field data (Miguel Armenta 2008)

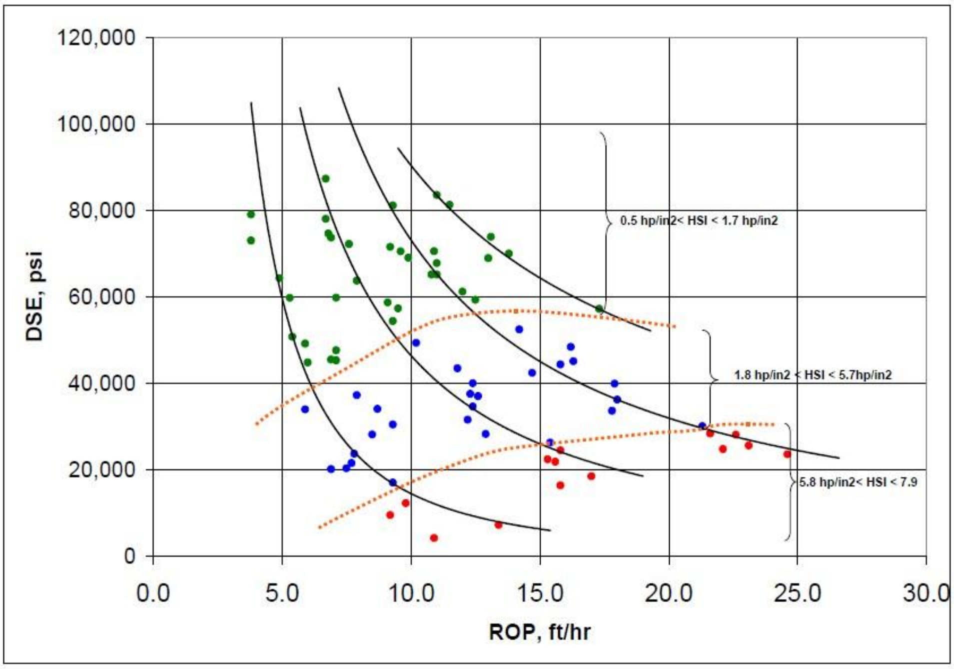


Figure III. 8: DSE vs. ROP with experimental data grouped according to the HIS (Miguel Armenta 2008)

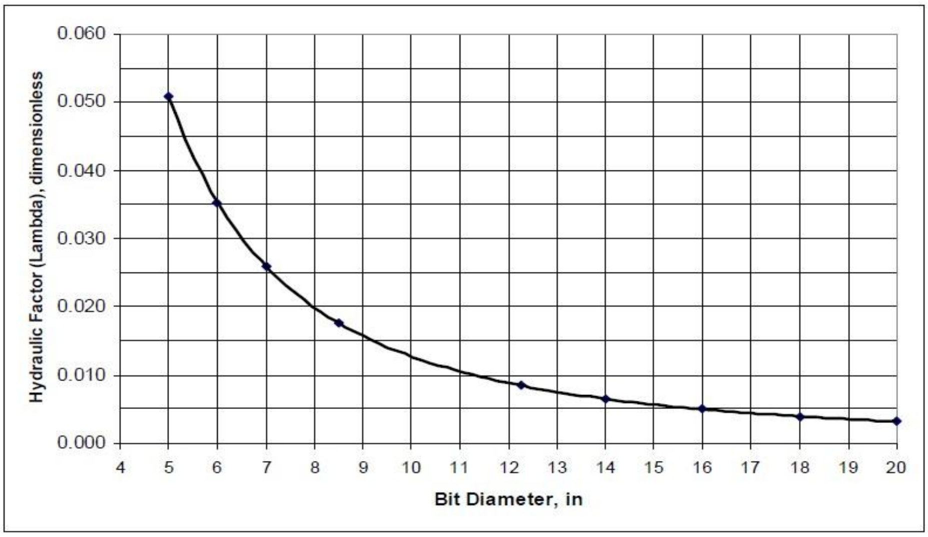


Figure III. 9: Hydraulic Factor (λ) (Miguel Armenta 2008)

III. 2. 2. 1. ROP models:

ROP measures the progress and the performance of the drilling bit in ft/hr. High ROP is considered good signs since they accelerate reaching the target in less time and cost. However, too high ROP may affect the hole geometry and cause poor hole cleaning. ROP is affected by many factors, some of them are controllable while others are uncontrollable. Drilling parameters such as; RPM, WOB, Q, T, and SPP are independent and controllable parameters. drilling fluid type and density, bit size, and mud rheological properties are uncontrollable parameters, which cannot be changed easily and highly dependent on each other. Due to the complexity of the drilling operation and overlap of different parameters, it is difficult to define the effect of only one parameter on ROP. The main parameters required to create a wellbore and have access to it are WOB, RPM and Q. Many correlations were developed to model the effect of drilling parameters on ROP [22].

There are three very common general drilling rate of penetration models in the industry, they are: Maurer, Galle and Woods and Bourgoyne & Young theories.

III. 2. 2. 1. 1. Maurer's Method

Maurer's method was developed based on a theoretical penetration equation for roller cone bits as a function of WOB, RPM, bit size and rock strength. The developed equation was based on observations such as the amount the crater cutter can create, rock strength related considerations [23].

$$ROP = k \frac{RPM * WOB^{2}}{d^{2} * UCS^{2}} \tag{8}$$

Where ROP is the rate of penetration (ft/hr), k is drillability constant, RPM is revolutions per minute, WOB is weight on bit (Klb_f), d is bit diameter (in) and UCS is the drillability strength of the rock.

III. 2. 2. 1. 2. Galle & Woods' Method

Galle and Woods investigated the best selection effect of WOB and RPM. They presented graphs for the best selection of the drilling parameters combination.
They demonstrated that drilling costs are reduced in case of using their method [24].

$$ROP = C_f . \frac{WOB^{k1} N^{k2}}{(0.93h^2 + 6h + 1)^p} \tag{9}$$

Where ROP is the rate of penetration (ft/hr), k is drillability constant, N is rotary speed, WOB is weight on bit (Klb_f), bit tooth dullness, drilling bit price.

III. 2. 2. 1. 3. Bourgoyne and Youngs' Method

Initial drilling models proposed for drilling optimization were largely established upon limited data and imprecise results. Bourgoyne & Young introduced an ROP model that is considered the most suitable for real-time drilling optimization and an essential optimization method as it is based on statistical past drilling values. The modeling is done by a multiple regression analysis of the past drilling data, including effects of variables, to produce the rate of penetration. Effects on ROP included in the model are formation strength, formation depth, formation compaction, pressure differential (bottom hole), bit weight and diameter, rotary speed, bit wear, and bit hydraulics [25].
This rate of penetration model predicts the effect of the included eight drilling variables (x_j) on the penetration rate (dD/dt). In a given formation, the modeling is done by determining the eight constants (a_j). The model is mathematically given by [2]:

$$\frac{dD}{dt} = \exp(a_1 + \sum_{j=2}^{8} a_j x_j) \quad (10.1)$$

The model can also be expressed clearer, with the exponential function integrated:

$$ROP = f_1 * f_2 * f_3 * f_4 * f_5 * f_6 * f_7 * f_8 \quad (10.2)$$

where f_{1-8} represents the various normalized effects on ROP.

Effect of formation strength or rock drillability is represented by the a_1 constant and x_1, or $f_1 = \exp(2.303\ a_1)$. Constant a_1 is proportional to the inversed natural logarithm of the squared drillability strength parameter mentioned by Maurer.

Effect of formation depth (D [ft]) is denoted by the a_2 constant, where x_2 is given by:

$$x_2 = 10000{,}0 - D \quad (10.3)$$

$f_2 = \exp(2.303\ a_2(10000 - D))$.

Therefore in a normal compacted formation, the ROP decreases exponentially with depth. This trend was found in Murray's micro-bit and field data, as well as Combs' field data.

Effect of formation compaction or pore pressure is represented by the a_3 constant and x_3. The ROP is assumed to exponentially increase with the pore pressure gradient of the formation (g_p [lb/gal]). The effect of under-compaction on ROP was suggested by compaction theory, thus x_3 is defined by equation 2.9 and $f3 = e2.303\ a3D0{,}69(gp-9)$.

$$x3 = D0{,}69(gp - 9{,}0) \quad (10{,}4)$$

Effect of differential pressure is represented by constant a_4 and x_4. It is assumed an exponential decrease in ROP with increasing bottom-hole-pressure, based on indications from field data and laboratory data. Therefore, the x_4 is given by:

$$x_4 = D(g_p - \rho_c) \quad (10.5)$$

Here ρ_c is the ECD at the bottom of the hole [lb/gal]. Whereas $f_4 = e^{2.303\ a4D(gp-Pc)}$.

Effect of bit diameter (d [in]) and bit weight (w [lb]) (w/d) is expressed by constant a_5 and x_5. Indications from several sources assume the ROP as directly proportional to the term $(\frac{W}{d})^{a_5}$. The normalized e^{a5x5} term is equal to 1.0 for 4000 lb/in bit. Consequently, x_5 is determined by:

$$x_5 = \ln\left(\frac{\frac{w}{d}-\left(\frac{w}{d}\right)_t}{4.0-\left(\frac{w}{d}\right)_t}\right) \tag{10.6}$$

Drill-off tests are used to estimate threshold bit weight $\left(\frac{W}{d}\right)_t$. Bit weight exponent values

have been reported ranging from 0.6 $- 2.0.\ f_5 = \left(\frac{\frac{w}{d}-\left(\frac{w}{d}\right)_t}{4.0-\left(\frac{w}{d}\right)_t}\right)^{a_5}$.

Effect of rotary speed (N) is represented by constant a_6 and x_6. Sources indicate that the ROP should be assumed directly proportional to N^{a6}. The normalized e^{a6x6} term is equal to 1.0 for 100 RPM, giving x_6 as:

$$x_6 = \ln\left(\frac{N}{100}\right) \tag{10.7}$$

Rotary speed exponent values have been reported ranging from 0.4 – 0.9 (from very hard formations to very soft formations). The f_6 term is: $f_6 = \left(\frac{N}{60}\right)^{a_6}$.

Effect of tooth wear (h) is represented by constant a_7 and x_7. Tooth wear has been modeled by various sources with complex terms. However, for multiple regression a simpler approach is more suitable. Fractional worn away tooth height (h) is used to determine x_7 in

equation 2.13. While $f_7 = e^{-a7*h}$.

$$x_7 = -h \tag{10.8}$$

Effect of bit hydraulics is denoted by the constant a_8 and x_8, and based on Eckel's microbit experiments. Eckel discovered that the ROP was proportional to Reynolds number group

$\left(\frac{\rho q}{\mu\, d_n}\right)^{0,5}$. Here ρ is mud density [lb/gal], q is flow rate [gal/min], μ is the apparent viscosity

[cp], and d_n is the bit nozzle diameter [in]. Giving x_8 by equation 2.14.

$$x_8 = \frac{\rho q}{350\, \mu d_n} \tag{10.9}$$

Apparent viscosity is not measured regularly and therefore estimated by: $\mu = \mu_p + \frac{\tau_y}{20}$

The f_8 term with jet impact force (F_j [klb_f]) is $f_8 = \left(\frac{F_j}{1000}\right)^{a_8}$

III. 2. 2. 1. 4. New ROP model (study 2018)

Development of the ROP Model

Based on the relationship of ROP with mechanical parameters and mud properties, the following equations can be drawn:

$$\text{ROP} \propto (\text{WOB} \times \text{RPM} \times \text{T} \times \text{SPP} \times \text{Q}) \qquad (11)$$

$$\text{ROP} \propto \frac{1}{\text{p} \times \text{PV}} \qquad (7)$$

The next step is to bring all parameters to be in field units, for example:

$$\text{Q} = \frac{Gallons}{min} = 0.1336\,\frac{ft^3}{min} \qquad (12)$$

$$\text{SPP} = \text{UCS} = \text{psi} = \frac{lb}{in^2} \qquad (13)$$

$$\text{HSI} = \frac{SPP \times Q}{1740} \qquad (14)$$

$$\text{PV} = \text{cP} = 2.42\,\frac{lb}{ft \times hr} \qquad (15)$$

This yields to a conversion factor of 16.96 which will be multiplied by the equation. Moving further, all parameters will be assigned to an unknown exponent. Formation unconfined compressive strength and bit are included in Eq. 16 since they are crucial parameters for any ROP model. In Eq. 16, a total of seven exponents are to be defined using non-linear regression. To define the effect of each individual parameter on ROP, one parameter at a time was assigned to observe its maximal effect on ROP.

$$\text{ROP} \propto \frac{\text{WOB}^a \times \text{RPM}^b \times \text{T}^c \times \text{SPP}^d \times \text{Q}^e}{d^2 \times p^f \times PV^g \times UCS^h} \qquad (16)$$

A statistical software was used to perform the nonlinear regression. The results showed most parameters having exponent ranging from 0.9 to 1.1 which can be assumed to be 1.0 in the equation. Only WOB and UCS showed exponents values of 0.396 and 1.608, respectively which gauges the high effectiveness of two parameters in the equation.

$$\text{ROP} = 16.96 \times \frac{\text{WOB}^{0,85} \times \text{RPM} \times \text{T} \times \text{SPP} \times \text{Q}}{d^2 \times p \times PV \times UCS^{1,16}} \qquad (17)$$

To calculate ‘a’ and ‘b’, nonlinear regression calculations were performed. The values of an and b were found to be 0.85 and 1.16 respectively. The developed model (Eq. 17) is then evaluated using the field data from well-1. Table 1 lists the statistical parameters for the available data. The new model predicted the ROP for well-1 with an average absolute percentage error of 20% and a correlation coefficient of 0.22. In the following section, clustering effect of the uniaxial compressive strength is performed to increase the accuracy of the proposed model [22].

III. 2. 2. 1. 5. Curry et’al (2005) model

Equation of Teal is composed of two parts; The Thrust force or weight on bit component and the Rotary speed component. The concept of specific energy, introduced efficiency to the calculation, which led to the subsequent definition of the minimum specific energy, at which energy is reduced to compressive strength of the rock being drilled which will be equivalent to efficiency of 1.

$$\text{Mechanical efficiency} = \text{Rock UCS}/\text{Es min}$$

Maximum efficiency occurs when the ratio of minimum specific energy to rock UCS approaches to 1 Curry et’al (2005) defined a technical limit specific energy equation for performance drilling as shown below;

$$ROP = (2538*W)/(MSEmin*Dia^2)$$

Bit efficiency factor used in calculating surface MSE is 0.125

III. 3. Conclusion

In this chapter, we have mentioned two major categories of specific energy which are mechanical specific energy MSE and drilling specific energy DSE; the first focuses on mechanical drilling parameters only, while the second included hydraulic drilling parameters, also we classified principles rate of penetration models and their equations, the old models and their developments, going to a new model (2018).

In the next chapter, we will see bit efficiency applying mechanical specific energy, and optimizing drilling performance by optimizing drilling parameters in order to get high rate of penetration using real data of three neighbors three wells from HMD field.

CHAPTER.IV: DATA ACQUISITION: FIELD HMD

IV. 1. Presentation of hassi-messaoud field

IV.1.1. Geographic location

The field of Hassi-Messaoud is 850km southeast of Algeria, 280 km south of the gas condensate field of Hassi R'Mel and 350km from the Tunisian border, its location in coordinated Lambert south Algeria is the following one:

X = 790000 - 840000 Y = 110000-150000

IV.1.2. Geological situation

The field of Hassi-Messaoud occupies the part the province of Triassic Province by its area and reserves. It is the largest oil field in Algeria and extends on about 2200km² of surface it is limited:

To the northwest by the Ourgla deposit [Gellale, Benkahla, Haoud-Berkaoui].

Southeast by the field of [ARhourd Elbagual, Masdar].

Geologically, it is limited by: in the West by depression from Oude M'ya, to the South by the mole of Amguid El Biad, to the North by the Djamaa structure, Touggourt, in the East by the high Sahar's background, Rhourd El Bagual.

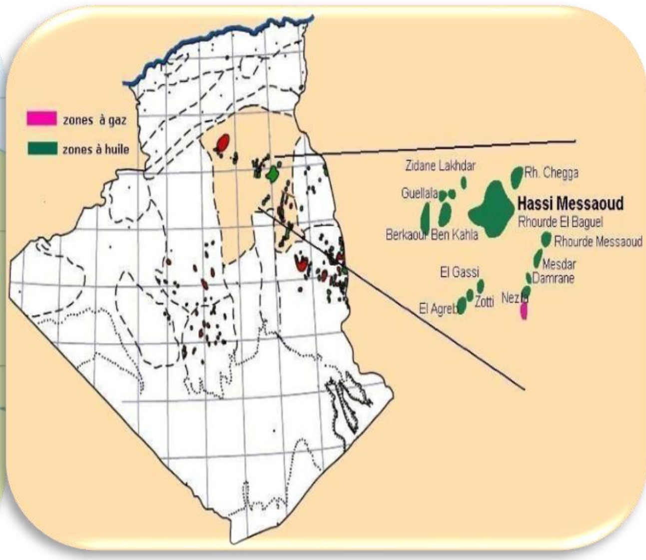


Figure **IV**.1: Geographic location of HMD Figure **IV**.2: Geological situation of HMD

IV.1.3. Reservoir characteristics

Hassi Messaoud deposit is characterized by its COMBRO ORDOVICIEN formation, its depth between 3361 to 3473 m.

The lightness of its oil (API = 54.5) and its high initial pressure (482 Kg / cm2) for a bubble point between 140 and 200 Kg / cm2.

ERE	SYST	ETAGES		Ep moy	DESCRIPTION
CENO-ZOIQUE	NEOGENE		MIO-PLIOCENE discordance alpine	240	Sable, calcaire, marne sableuse
			EOCENE	120	Sable, calcaire à silex
MESOZOIQUE	CRETACE	SENONIEN	CARBONATE	107	Calcaire, dolomie, anhydrite
			ANHYDRITIQUE	219	Anhydrite, marne, dolomie
			SALIFERE	140	Sel massif et traces d'anhydrite
			TURONIEN	90	Calcaire crayeux avec quelques niveaux argileux
			CENOMANIEN	145	Anhydrite, marne, dolomie
			ALBIEN	350	Grés, sable avec intercalations d'argile silteuse
			APTIEN	25	Dolomie cristalline avec niveau argileux, calcaire
			BARREMIEN	280	Argile, grés, dolomie
			NEOCOMIEN	180	Argile, marne, dolomie, grés
	JURASSIQUE		MALM	225	Argile, marne, calcaire, grés et traces d'anhydrite
		DOGGER	ARGILEUX	105	Argile silteuse, marne dolomitique avec fines passées de grés
			LAGUNAIRE	210	Anhydrite, marne dolomitique, marne grise
		LIAS	L.D 1	65	Dolomie, anhydrite, argile
			L.S 1	90	Alternances sel, anhydrite et argile
			L.D 2	55	Anhydrite et dolomie cristalline
			L.S 2	60	Alternances sel et argile
			L.D 3	30	Alternances de dolomie et de marne
	TRIAS	SALIFERE	TS 1	46	Alternances de sel, d'anhydrite et de dolomie
			TS 2	189	Sel massif à intercalations d'anhydrite et argile gypsifère
			TS 3	202	Sel massif et traces d'argile
			ARGILEUX	113	Argile rouge dolomitique ou silteuse injectée de sel et d'anhydrite
			GRESEUX	35	Grés, argile
			ERUPTIF discordance hercynienne	0-92	Andésites altérées
PALEOZOIQUE	ORDOVICIEN		QUARTZITES D'EL HAMRA	75	Quartzites fines avec traces de tigillites
			GRES D'EL ATCHANE	25	Grés fins à ciment argileux, bitumineux
			ARGILES D'EL GASSI	50	Argiles schisteuses, vertes ou noires, glauconieuses à graptolithes
			ZONE DES ALTERNANCES	20	Alternance de grés et argile. Présence de tigillites
	CAMBRIEN		Ri	50	Grés isométriques, fins, silteux
			Ra	120	Grés à grés quartzitiques anisométriques à niveaux de silts
			R2	100	Grés moyens à grossiers à ciment argileux illitique
			R3	300	Grés grossier à ciment argileux, argile silteuse
	INFRA-CAMBRIEN			45	Grés argileux rouges
SOCLE					Granite porphyroïde rose

Figure **IV**.3: Stratigraphy of Hassi Messaoud field.

IV.2. Well description

OMG501 is a vertical development oil producer well which is implemented in the zone Upside north of hassi-Messaoud field. **OMG501** will be drilled across the Cambrian reservoir (Ra ID, D1 & R2ab) to a total depth of ±3459m. The estimated reservoir pressure is around 220-240 kg/cm2.

IV.2.1. Well data

Table **IV**.1: OMG501 well data

<table>
<tr><td>Well Name</td><td colspan="2">OMG501</td></tr>
<tr><td>Field</td><td colspan="2">HASSI MESSAOUD</td></tr>
<tr><td>Well Classification</td><td colspan="2">Development</td></tr>
<tr><td>Operator</td><td colspan="2">SONATRACH</td></tr>
<tr><td>Drilling Contractor</td><td colspan="2">ENTP</td></tr>
<tr><td>Drilling Rig</td><td colspan="2">TP160</td></tr>
<tr><td rowspan="5">Surface Location</td><td>LSA</td><td>X = 815311.46, Y = 150141.42</td></tr>
<tr><td>Latitude</td><td>31° 54' 07.32" N</td></tr>
<tr><td>Longitude</td><td>6° 01' 57.46" E</td></tr>
<tr><td rowspan="2">UTM Zone 31</td><td>X = 786 820.978 m</td></tr>
<tr><td>Y = 3 533 321.012 m</td></tr>
<tr><td>Well Located in coordinate system</td><td colspan="2">UTM Zone 31, Clarke1880
(This system will be used as reference in all documents)</td></tr>
<tr><td rowspan="3">Elevations</td><td>Ground Level</td><td>144.308 m Above Mean Sea Level (AMSL)</td></tr>
<tr><td>Rotary Table Elevation</td><td>7.67 m Above Ground Level (AGL)</td></tr>
<tr><td>Rotary Table Elevation</td><td>151.978m Above Mean Sea Level (AMSL)</td></tr>
<tr><td>Well TD</td><td>TVD</td><td>3459m TVD/TMD</td></tr>
</table>

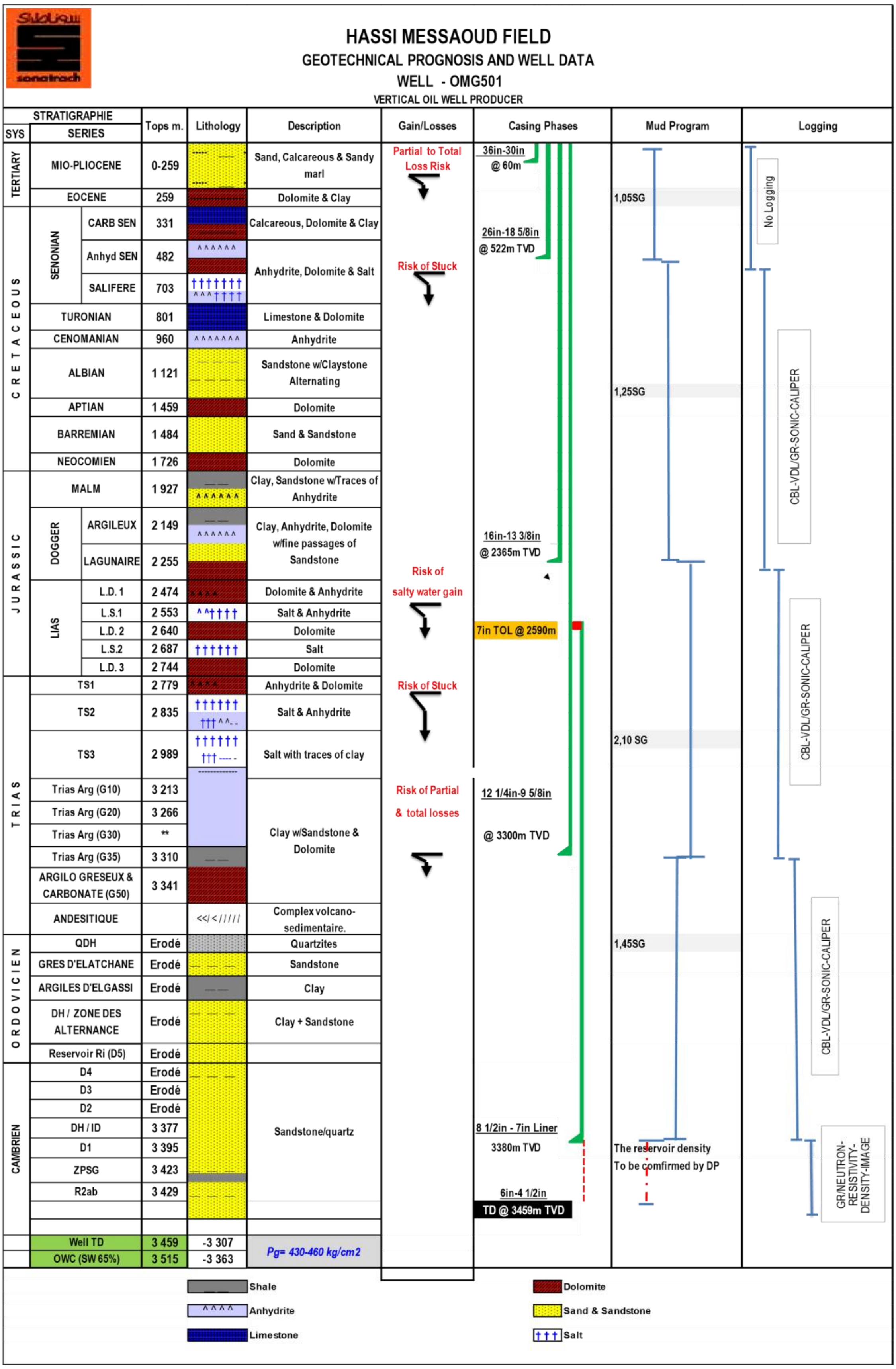


Figure **IV**.4: OMG501 well program

IV.2.2. Well location:

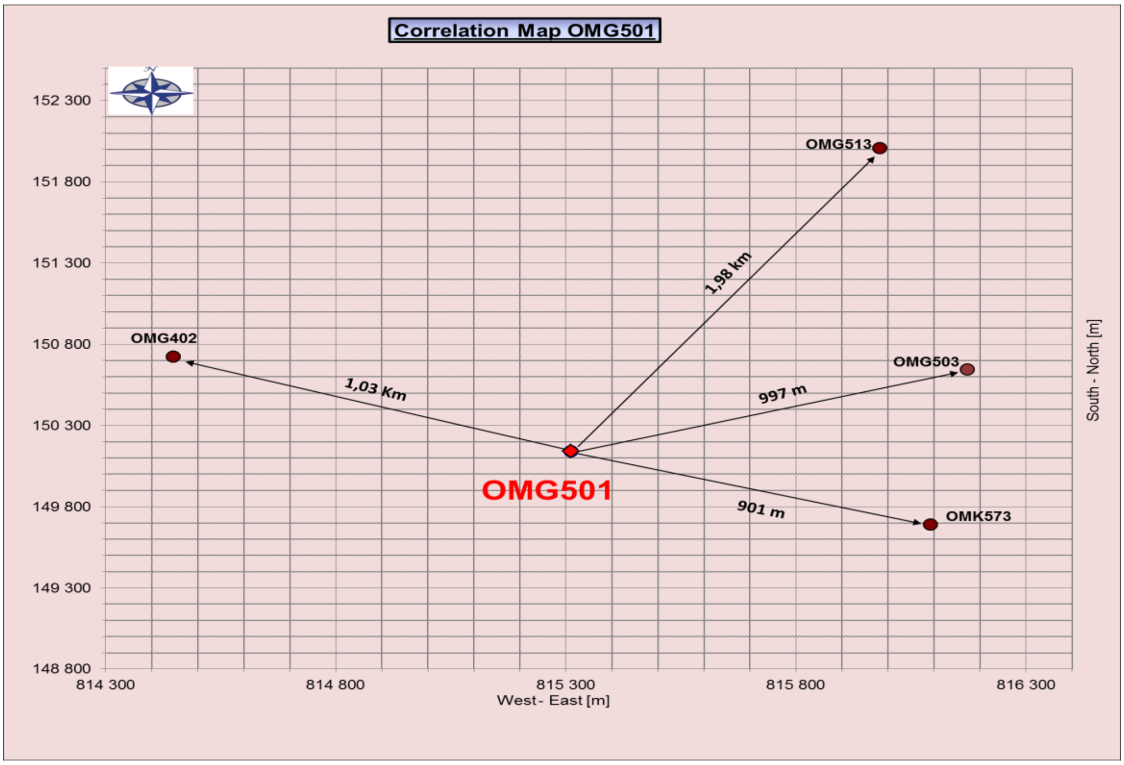


Figure **IV**.5: OMG501 well location

IV.2.3. Well data presentation

IV.2.3.1. Presentation of well data

Phase 16 " is the longest phase in the drilling, which represents 40% of total drilling time, which generates additional costs and a high meter-drilled price, for which we have to optimize the drilling parameters in order to reduces his cost.

IV.2.3.2. Bit references

Table **IV**.2: Bit references of phase 16” well OMG501

BIT TYPE	MANUFACTURED	MODEL
TFF913S	NOV	PDC
STATE	IADC	NOZZLLES
NEW	S432	9 X12

Table **IV**.3: Drilling parameters of phase 16" well OMG501

	WOB.max	WOB.min	WOB.avg	RPM.max	RPM.min	RPM.avg	Tq.max	Tq.min	Tq.avg	ROP
Formation	**Klbf**	**klbf**	**Klbf**	**rpm**	**rpm**	**rpm**	**klbf-ft**	**klbf-ft**	**lbf*ft**	**ft/h**
SENONIEN-ANH	17,28	2,66	11,413	151	69	126,983	11303	2940	7,171	77,46376
SENONIEN-SAL	16,67	7,12	11,591	142	122	135,159	12263	4941	8,507	65,10144
TYRONIEN	16,82	4,93	9,085	143	93	135,96	11250	3763	8,839	78,09024
CENOMANIEN	17,29	8,37	14,085	139	127	135,859	11033	5183	8,291	57,19992
ALBIEN	20,14	4,23	9,93	142	97	133,82	13257	3274	8,581	170,52
APTIEN	21,01	18,96	19,911	143	119	124,333	9251	5850	7,448	13,32336
BARREMIEN	19,89	4,88	13,58	133	77	127,346	12997	4397	9,066	126,7195
NEOCOMIEN	18,93	10,39	14,449	152	72	138,281	13256	7356	10,487	93,36192
MALM	22,12	10,2	15,678	152	119	137,292	13482	6983	9,748	67,15144
DOGGER-ARG	20,07	5,23	15,734	155	115	146,942	12989	6251	10,16	54,47096
DOGGER-LAG	22,53	13,95	19,651	153	135	142,454	12845	7275	9,374	25,944

IV.3. Calculated mechanical specific energy MSE

The concept of mechanical Specific energy (MSE) was first introduced by Teale (1964), it is based on the principles which quantify the amounts of energy required to destroy a given volume of rock. This has proven to be a more objective assessment of drilling efficiency in both homogenous and heterogeneous formations. If we consider a drillstring, with rotary speed N, work done per minute of rotation of the drillstring can be expressed as follows

$$\text{MSE} = \frac{\text{WOB}}{\text{Area}} + \frac{120.\ \pi\ .\ \text{Torque}\ .\ \text{RPM}}{\text{Area}\ .\ \text{ROP}}$$

Equation above is composed of two parts; The Thrust force or weight on bit component and the Rotary speed component. The concept of specific energy, introduced efficiency to the calculation, which led to the subsequent definition of the minimum specific energy, at which energy is reduced to compressive strength of the rock being drilled which will be equivalent to efficiency of 1.

Mechanical efficiency = Rock UCS/Es min

Maximum efficiency occurs when the ratio of minimum specific energy to rock UCS approaches to 1 Curry et'al (2005) defined a technical limit specific energy equation for performance drilling as shown below;

ROP = (2538*W)/(MSEmin*Dia^2)

Bit efficiency factor used in calculating surface MSE is 0.125

Applying Teal equation in phase 16", results obtained are:

Calculation,graphical representation and trend analysis (EXCEL OFFICE):

To establish relationship and pattern recognition, ROP, Lateral vibration and Ideal ROP were plotted against depth using excel spreadsheet. Similarly, UCS and MSE calculated using surface drilling parameters were plotted against depth using the same interval. The idea is to compare the MSE with UCS and investigate the effect on penetration rates and lateral vibration with a goal of establishing at what rate an optimum penetration could be achieved across the heterogenous formations. Thus, providing useful insight in validating the mathematical model for optimum rate of penetration using rock compressive strength. The benefits are in drilling rate improvement which when applied in real-time, results in enhanced drilling parameter management which is helpful in reduction of premature bit trip and improving overall drilling performance.

IV.3.1. MSE with observed ROP:

Table IV. 4: Calculated MSE with drilling parameters.

Depth	W	WOB	A	RPM	T	ROP	MSE
ft	Klbf	Lbf	inch^2	rpm	ft*lbf	ft/h	psi
1712,16	7,94271	7942,71	200,96	111,125	6859,79	73,6469	19447
1869,6	13,8392	13839,2	200,96	129,458	9494,58	71,9529	32099
2023,76	14,1238	14123,8	200,96	134,208	8598,58	62,7293	34563,8
2177,92	12,6269	12626,9	200,96	136,75	7705,67	82,3834	24045,6
2332,08	11,8921	11892,1	200,96	135,271	8601,1	85,9251	25447,8
2486,24	14,7729	14772,9	200,96	133,563	9236,92	74,3603	31181,5
2794,56	12,2767	12276,7	200,96	136,646	8267,67	49,459	42889,8
2948,72	14,5196	14519,6	200,96	135,542	8710,4	73,4897	30194,4
3102,88	14,8887	14888,7	200,96	137,083	7908,48	77,0274	26463,7
3257,04	14,9692	14969,2	200,96	135,25	8584,77	72,6028	30060,2
3411,2	12,476	12476	200,96	133,063	8718,65	128,067	17047,2
3565,36	11,5673	11567,3	200,96	135,896	9899,54	204,704	12380
3719,52	15,6985	15698,5	200,96	136,938	10214,2	133,377	19741
3873,68	16,5333	16533,3	200,96	135,979	7727,52	56,8599	34732,6
4027,84	10,9027	10902,7	200,96	138,708	10841,6	106,3	26579,9
4182	11,6929	11692,9	200,96	138,521	9330,17	94,5341	25692,2
4336,16	13,5448	13544,8	200,96	139,896	8870,71	132,63	17611,2
4490,32	12,0779	12077,9	200,96	132,146	9942,29	117,864	20960,8
4644,48	17,4565	17456,5	200,96	123,667	8818,44	76,5907	26784,3
4798,64	17,1992	17199,2	200,96	127,208	11572,7	142,047	19517,8
4952,8	12,4006	12400,6	200,96	128,938	8019,5	131,592	14795
5106,96	17,1583	17158,3	200,96	136,75	12505,1	102,718	31300,7
5261,12	16,4554	16455,4	200,96	125,479	9356,98	104,065	21236,5
5415,28	15,4088	15408,8	200,96	128,292	10803,5	109,281	23857,3
5569,44	15,2317	15231,7	200,96	135,813	9369,98	49,9243	47869,1
5723,6	14,1694	14169,4	200,96	132,021	10515,7	91,2107	28609,3
5877,76	14,6998	14699,8	200,96	142,063	10717	87,5453	32680,8
6031,92	14,9452	14945,2	200,96	142,188	11133	138,524	21500,8
6186,08	15,3792	15379,2	200,96	147,542	11230,4	113,24	27511,8
6340,24	16,7848	16784,8	200,96	145,979	10089,9	87,384	31688
6494,4	17,3458	17345,8	200,96	143,938	10381,3	81,5873	34426,8
6648,56	16,5648	16564,8	200,96	140,521	10104,3	59,2143	45041,8
6802,72	14,2404	14240,4	200,96	145,875	9537,19	32,9415	79258,9
6956,88	14,6275	14627,5	200,96	146,375	10412	60,2721	47484,8
7111,04	17,6181	17618,1	200,96	146,875	10055	48,0766	57684,5
7265,2	19,7175	19717,5	200,96	142,75	9306,42	24,8159	100474
7419,36	15,986	15986	200,96	142,56	9771,6	122,151	21462,5

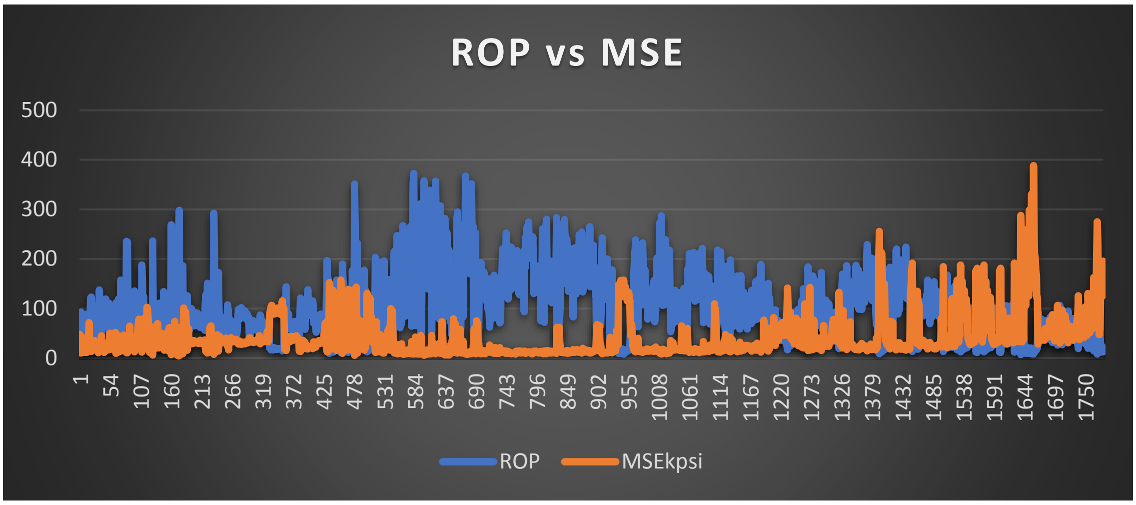


Figure **IV**.6: MSE vs observed ROP

IV.3.2. MSE with predicted ROP model:

IV.3.2.1 Used data: Available data for six formation of 16” phase from Aptien (F1) to Dogger-lagunaire (F6).

IV.3.2.1.1 Rock strength analysis

the hardness of the rock represents the load at which the rock reaches the stage of rupture. the maximum compressive strength of rocks in the wild is less than 200,000 psi and less than 5,000 psi for sedimentary rocks encountered in oil drilling.
the hardness of the rock can be measured from the cores or estimated from the electrical logging, it depends on the nature of the rock, the porosity of the rock and other factors such as the cementing of the grains.

IV.3.2.1.2 Lateral vibration:

RICHARD (2001) has discussed some of the limitations of the pure torsion approach. Like others, the author finds experimentally that the mechanical response of PDC tools depends on their speed of rotation. For this, he is interested in two energy quantities defined on the scale of the drilling tool: the specific energy, E, which is proportional to the cutting energy required to cut down a unit of rock volume and expresses as a function of the torque to the tool TOB, the radius of the tool R and the advancement per revolution DOC; and the drill resistance, S, which is proportional to the bearing energy required to cut one unit of rock volume and is expressed as a function of the weight on the WOB tool and the revolution feed. These two sizes express themselves [20]:

E = 2*TOB/TOB*DOC; S = WOB/R*DOC·

DOC: drill bit penetration per rotation, mm/tr.

TOB : bit torque, daN.m.

Depth	WOB	RPM	Tq	L.VIB	ROPo	UCS Max	UCS Min	UCS Mean	ROPo	ROP p
ft	tons	rpm	lb*ft	RMS	ft/h	KPsi	KPsi	KPsi	ft/h	ft/h
4667,44	15,853	122,7805	10,614	0,973936	62,4728	5,2-8,1	1,1-2,7	6	62,4728	179,6276
4801,92	6,327	123,439	7,329	0,126469	79,3448				79,3448	71,69353
4936,4	6,945	123,1707	9,553	0,235773	50,16				50,16	78,69624
5070,88	8,324	130,2683	10,799	0,343177	47,196				47,196	94,32384
5205,36	9,279	133,7805	9,370	0,490499	41,5872				41,5872	105,1402
5339,84	5,697	129,9268	7,657	0,397646	25,4248				25,4248	64,55816
5474,32	9,77	135,439	7,978	2,100291	63,524				63,524	110,7031
5608,8	12,499	135,4146	10,173	0,637075	45,3944	26-42	24-32	40	45,3944	141,6184
5743,28	15,384	130,1463	13,559	0,405566	71,5808	12,00-26	14-19	25	71,5808	174,3134
5877,76	15,806	133,439	13,101	0,499324	68,4648				68,4648	179,0915
6012,24	14,404	133,4634	12,974	0,439326	69,8152				69,8152	163,2096
6146,72	14,668	127,561	12,114	0,934059	81,296				81,296	166,197
6281,2	15,107	123,7073	13,502	0,483092	103,7696				103,7696	171,1741
6415,68	13,574	131,7073	14,243	0,536401	77,6296	17-25	11-125	21	77,6296	153,7999
6550,16	13,160	131,6829	14,438	0,231486	99,4832	31-36,5	19-22	36	99,4832	149,1103
6684,64	14,190	127,1707	14,631	0,548339	67,7608	33-41	21-33	4	67,7608	160,7861
6819,12	13,251	120,2439	12,128	0,566352	55,4504	5-8,00	2,3-4,6	7,5	55,4504	150,141
6953,6	15,592	128,1951	12,379	1,095928	52,3008	12,00-22	8,7-12	16	52,3008	176,6679
7088,08	15,620	134,5366	15,985	0,482863	77,376	25-33	22-29	32	77,376	176,9829
7222,56	14,114	132,7073	15,669	0,362178	80,2096	23-41	20-22	40	80,2096	159,9211
7357,04	18,150	139,8049	12,697	1,648062	30,5576				30,5576	205,6515
7557,11	19,225	141,7857	11,720	1,924701	25,35987				25,35987	217,8369

IV.4. Application of MSE in HMD field:

$$MSE = \frac{4\,WOB}{1000\,\pi\,D^2} + \frac{480\,RPM\,T}{1000\,ROP\,D^2}$$

Equation above is used as the basis to develop a technique in this thesis to use MSE values from a close-by well to compute ROP. It is assumed that the work or energy required to drill a certain amount of rock is correlative within close-by wells. The MSE values are calculated for a well, with the use of equation 3.11 as shown in figure 17. These MSE values are then implemented and used in the close-by wells. Equation above is developed into equation below, to be able to produce ROP values from MSE computed values from neighboring wells as shown in figure 18. The MSE technique procedure is shown in figure 19.

The close-by wells are OMG503 and OMK573.

Equation 3.11 → $MSE * 1000\ D^2 = \frac{4\ WOB}{\pi} + \frac{480\ RPM\ T}{ROP}$

→ $\frac{480\ RPM\ T}{ROP} = MSE\ 1000\ D^2 - \frac{4\ WOB}{\pi}$ → $\frac{1}{ROP} = \frac{MSE\ 1000\ D^2 - \frac{4\ WOB}{\pi}}{480\ RPM\ T}$ →

$$ROP = \left[\frac{MSE\ 1000\ D^2 - \frac{4\ WOB}{\pi}}{480\ RPM\ T}\right]^{-1}$$

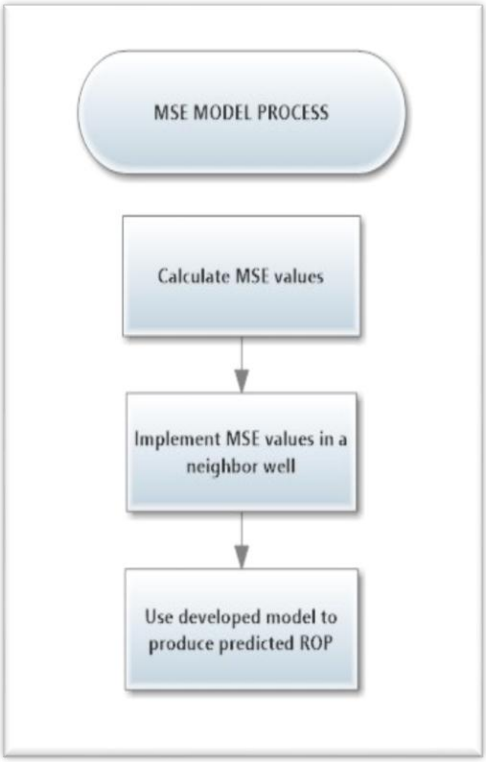


Figure **IV**.7: MSE model procedure flowchart

Table IV.6: Drilling parameters of phase 16" well OMK573

	WOB.max	WOB.min	WOB.avg	RPM.max	RPM.min	RPM.avg	Tq.max	Tq.min	Tq.avg	ROP
Formation	**Klbf**	**klbf**	**Klbf**	**rpm**	**rpm**	**rpm**	**klbf-ft**	**klbf-ft**	**lbf*ft**	**ft/h**
SENONIEN-ANH	14,31	0,76	9,06273	132	71	119,401	11921	2619	8079,84	103,87693
SENONIEN-SAL	15,82	1,04	9,4004	143	117	125,087	11348	1597	7790,79	95,778678
TYRONIEN	16,82	3,89	9,88147	144	113	133,809	18019	3851	10415,4	103,6856
CENOMANIEN	16,32	1,55	7,99757	138	117	126,766	15490	1464	8606,47	135,09441
ALBIEN	16,36	0,58	8,08666	142	107	136,262	16368	1440	10032,6	192,73847
APTIEN	10,94	6,74	8,92	140	136	139,444	13065	7343	10451,1	126,37709
BARREMIEN	20,28	1,95	9,41786	147	77	123,737	15340	2596	9878,45	106,55716
NEOCOMIEN	18,82	2,06	11,0928	146	105	132,8	16472	2342	10030,2	73,262878
MALM	20,15	6,31	14,4182	140	89	130,231	18271	5984	13419,4	79,689203
DOGGER-ARG	19,89	10,7	14,3298	146	107	124,482	18401	5811	12919	61,758636
DOGGER-LAG	20,91	11,15	15,4751	176	102	134,793	18690	9694	15149,1	62,216707

Table IV.7: Drilling parameters of phase 16" well OMG503

	WOB.max	WOB.min	WOB.avg	RPM.max	RPM.min	RPM.avg	Tq.max	Tq.min	Tq.avg	ROP
Formation	**Klbf**	**klbf**	**Klbf**	**rpm**	**rpm**	**rpm**	**klbf-ft**	**klbf-ft**	**lbf*ft**	**ft/h**
SENONIEN-ANH	18	0	12	166	28	128	14845	-461	9130	68,13933
SENONIEN-SAL	17	2	12	156	27	121	21086	-2498	15700	48,48692
TYRONIEN	15	2	7	157	69	129	23267	7999	18657	68,17986
CENOMANIEN	18	1	10	150	87	138	21444	3399	13434	63,50938
ALBIEN	18	1	8	149	18	143	21060	1458	14510	155,4432
APTIEN	23	5	19	138	94	127	19197	10536	16794	182,5818
BARREMIEN	15	4	10	144	79	128	20627	5409	13398	59,8817
NEOCOMIEN	19	3	10	158	79	138	20464	7081	14883	57,67775
MALM	22	6	11	184	72	158	19681	7886	15391	82,50427
DOGGER-ARG	20	6	12	179	134	173	19248	7910	15529	59,53922
DOGGER-LAG	24	7	15	188	85	164	20247	11450	15753	71,08888

IV.4.1 Applying MSE of well OMG501 in neighboring wells

The two figures below represent predicted rate of penetration for neighboring wells, the first OMK573 and the second OMG503, obtained by MSE of OMG501:

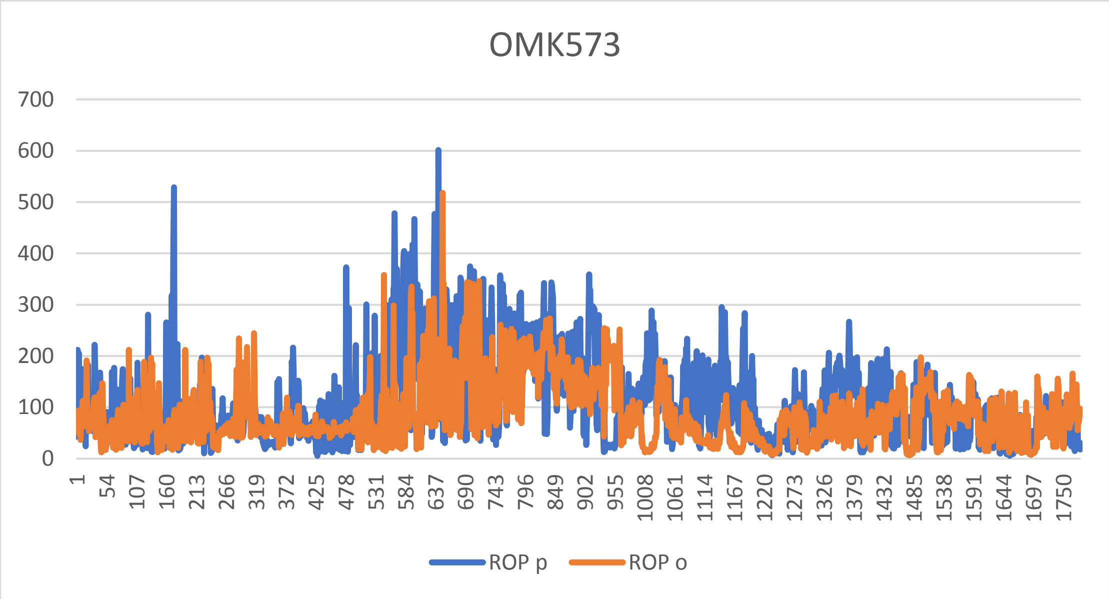


Figure **IV.** 8: Predicted ROP OMK573 with MSE of OMG501

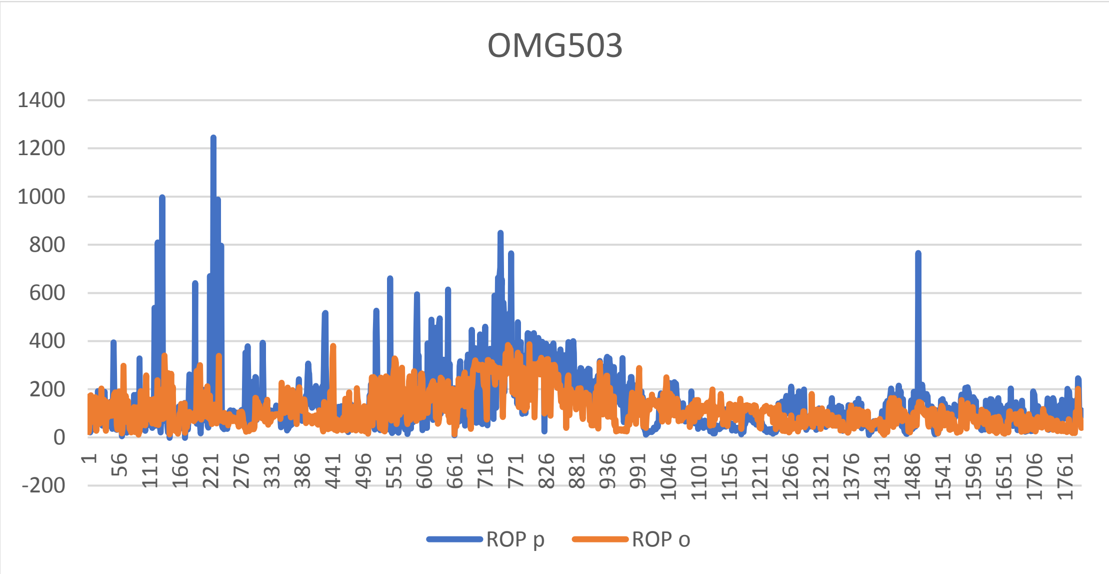


Figure **IV.** 9: Predicted ROP OMG503 with MSE of OMG501

IV.4.2 Time saving according to predicted ROP

Table IV.8: Predicted and actual operational bit time for well OMG503.

	WELL OMG503					
Formations	PREDICTED ROP (ft/h)	ACTUAL ROP (ft/h)	THICK (m)	TOP (m)	POB	AOB
SENONIEN -AN	82,71742	68,13933	171	493	6,78068	8,23137
SENONIEN-SAL	74,27361	48,48692	125	664	5,52013	8,45589
TURONIEN	69,08991	68,17986	135	790	6,40904	6,49459
CENOMANIEN	78,98101	63,50938	106	926	4,40207	5,47447
ALBIEN	205,7102	155,4432	388	1033	6,18657	8,18717
APTIEN	164,07759	182,5818	26	1422	0,51975	0,46708
BARREMIEN	121,5657	59,8817	265	1449	7,15004	14,5153
NEOCOMIEN	94,1453	57,67775	170	1715	5,92276	9,66751
MALM	89,49011	82,50427	237	1886	8,68655	9,42206
DOGGER-ARG	55,99368	59,53922	109	2124	6,38501	6,00478
DOGGER-LAG	52,12996	71,08888	110	2234	6,92116	5,07534
DRILLING TIME					64,8838	81,9955
GAIN					18,11177056	

Table IV.9: Predicted and actual operational bit time for well OMK573.

	WELL OMK573					
Formations	PREDICTED ROP (ft/h)	ACTUAL ROP (ft/h)	THICK (m)	TOP (m)	POB	AOB
SENONIEN -AN	132,26418	103,87693	196	480	4,86058	6,18886
SENONIEN-SAL	151,16392	95,778678	146	676	3,16795	4,99986
TURONIEN	134,91003	103,6856	122	822	2,96612	3,85936
CENOMANIEN	124,51052	135,09441	152	944	4,00416	3,69046
ALBIEN	259,16403	192,73847	375	1096	4,74603	6,3817
APTIEN	54,638481	126,37709	24	1471	1,44074	0,6229
BARREMIEN	83,226457	106,55716	267	1495	10,5226	8,21869
NEOCOMIEN	84,910102	73,262878	188	1762	7,26227	8,41681
MALM	117,60426	79,689203	232	1950	6,47051	9,5491
DOGGER-ARG	87,550463	61,758636	121	2182	4,53316	6,42631
DOGGER-LAG	91,22768	62,216707	115	2303	4,13471	6,06268
DRILLING TIME					54,1088	64,4167
GAIN					12,30787879	

IV.4.3. Correlation of three wells

Applying drilling parameters of OMG503 and OMK573 in well OMG501, give the results below:

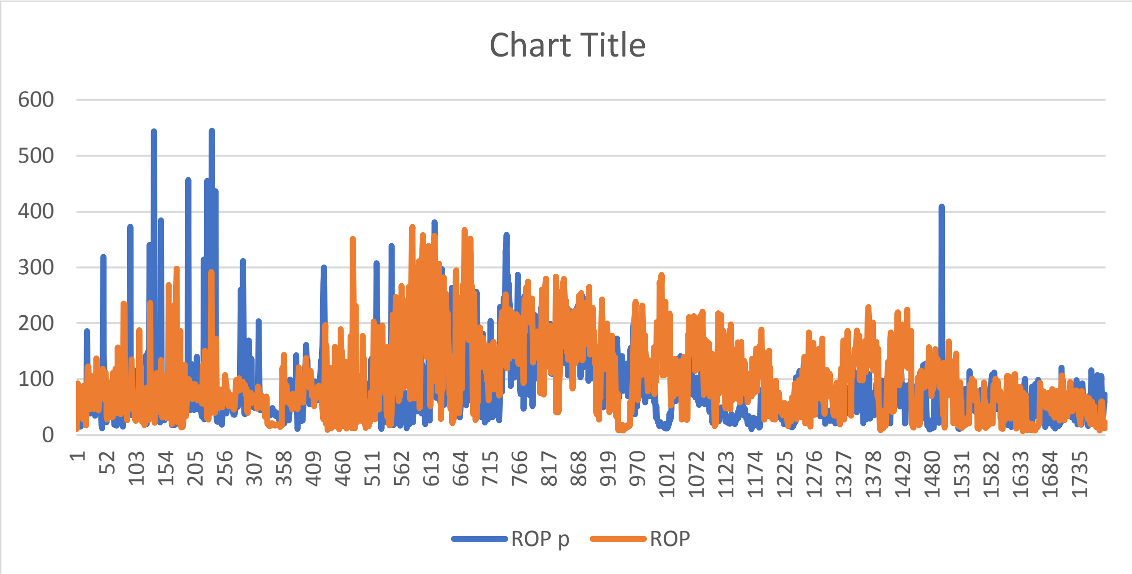


Figure IV .10: Predicted ROP OMK501 with MSE of OMG503

DRILLING TIME	**99,0011**	**88,9828**
GAIN	**-10,01823097**	

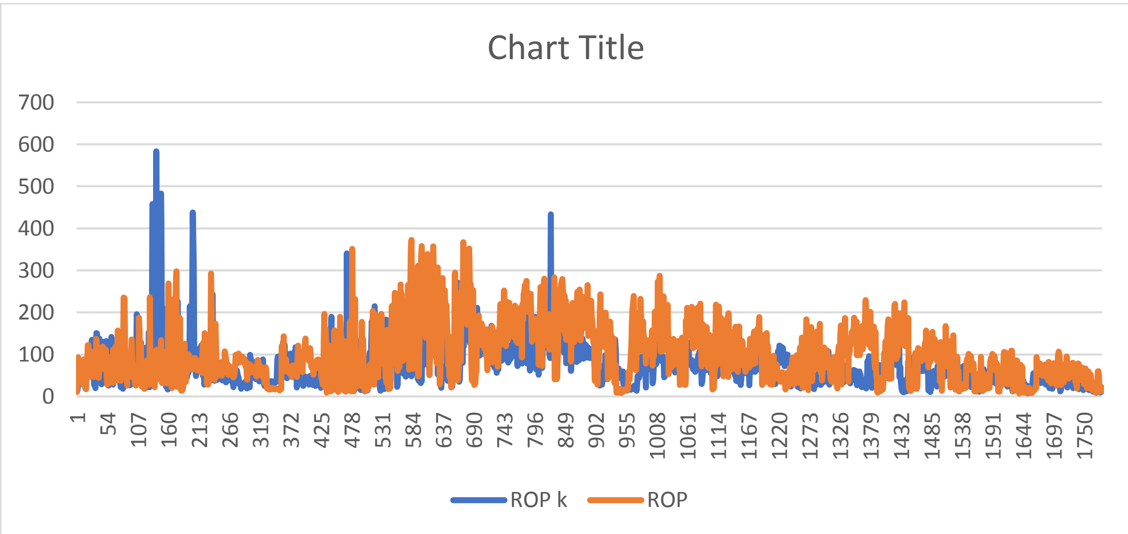


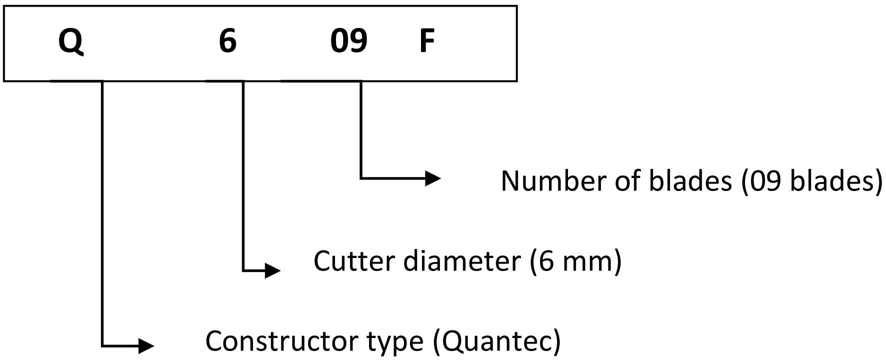
Figure IV. 11: Predicted ROP OMG501 with MSE of OMK573

DRILLING TIME	**81,781**	**78,8958**
GAIN	**-3,885240229**	

IV.4.4. Presentation of bit type for three wells:

Table IV. 10: Type of three wells drill bits.

WELL	BIT NUMBER	BIT TYPE	N/S	NOZZEL	DIAMETER
OMG501	3	TFF913S	E251135	9*12/32"	16"
OMK573	3	Q609F	E241384	9*12/32"	16"
OMG503	3	MSI916LVPX	E251135	9*12/32"	16"



IV.5 Comparing MSE & DSE, ALBIAN formation as sample study:

IV.5.1. Calculated DSE:

MSE or SE equation has been modified by Miguel Armenta (Miguel 2008) to include a bit hydraulic related term on the (MSE) correlation. DSE can be calculated as shown:

$$\text{DSE} = \frac{\text{WOB}}{\text{Area}} + \frac{120\pi\,.\ \text{RPM}\,.\ \text{T}}{\text{Area}\,.\ \text{ROP}} - \frac{1{,}980{,}000\,.\ \lambda\,.\ \text{HPb}}{\text{Area}\,.\ \text{ROP}}$$

IV.5.2. Needed data

IV.5.2.1. Hydraulic Factor (λ):

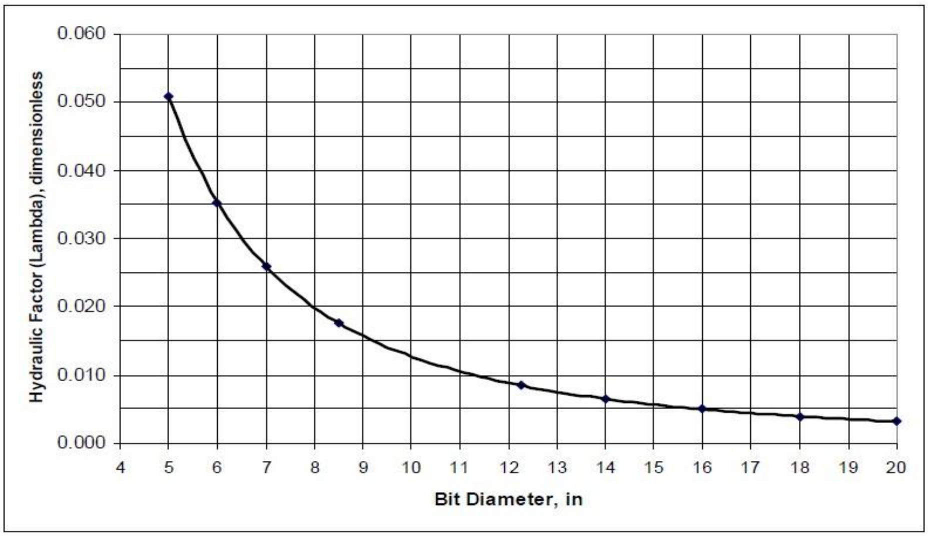


Figure **IV**.11: Hydraulic Factor (λ) (Miguel Armenta 2008)

Table **IV**.11: Hydraulic Factor (λ) for different bit diameter

Bit diameter	Hydraulic factor	Bit diameter	Hydraulic factor
5.48	0.0421	11.85	0.0089
5.72	0.0388	12.26	0.0083
6.01	0.0351	12.72	0.0078
6.28	0.0323	13.23	0.0073
6.59	0.0290	13.85	0.0067
6.91	0.0265	14.53	0.0062
7.29	0.0240	15.20	0.0055
7.68	0.0216	16.00	0.0050
8.04	0.0194	16.84	0.0044
8.47	0.0177	17.54	0.0044
9.01	0.0156	18.02	0.0039
9.58	0.0139	18.60	0.0038
10.14	0.0123	19.06	0.0038
10.74	0.0111	19.47	0.0036
11.32	0.0098	20.00	0.0030

IV.5.2.2. Hydraulic power: The ratio of bit hydraulic power HP_B and bit area (HP_B/A_B) is the bit Hydraulic power per square inch HSI (hp/in^2).

$$\text{HSI} = \frac{Pco \times Q}{35140 \times D^2} \qquad ; \ P_{co} = \frac{d \times Q^2}{2959{,}41 \times C^2 \times A^2}$$

P_{co}= bit losses (Kpa) C = 0,95 for PDC bit

d = mud weight (Kg/l) D = bit diameter (inch)

Q = mud flow (l/min) A = TFA (inch)

Table **IV**.12: Obtained DSE of phase 16” + DSE of deep phase

Depth Ft	A Inch^2	C	Q lpm	Pco Kpa	HSI HP/Inch^2	MSE Psi	DES Psi	DSE d Psi
1712,16	0,994	0,95	2834,792	3783,674	1,192321	19515,34	19414,32	14735,85
1869,6	0,994	0,95	2819,646	3743,35	1,173311	32222,48	32120,73	27408,46
2023,76	0,994	0,95	2782,75	3646,025	1,127852	34718,63	34606,44	29410,71
2177,92	0,994	0,95	2798,417	3687,195	1,147009	24136,04	24049,16	20025,77
2332,08	0,994	0,95	2816,625	3735,333	1,169544	25527,05	25442,11	21508,78
2486,24	0,994	0,95	2824,167	3755,364	1,178964	31306,63	31207,7	26626,02
2640,4	0,994	0,95	2818,688	3740,807	1,172116	36913,3	36792,66	31205,56
2794,56	0,994	0,95	2981,667	4185,907	1,387417	43076,96	42901,91	34795,54
2948,72	0,994	0,95	2818,208	3739,533	1,171517	30319,71	30220,23	25613,56
3102,88	0,994	0,95	2785,042	3652,034	1,130641	26582,94	26491,34	22249,6
3257,04	0,994	0,95	2801,396	3695,05	1,150676	30191,86	30092,96	25512,97
3411,2	0,994	0,95	2799,188	3689,227	1,147957	17082,56	17026,62	14436,3
3565,36	0,994	0,95	2723,813	3493,219	1,057697	24201,72	24138,68	21219,49
3719,52	0,994	0,95	2816,479	3734,946	1,169362	19780,57	19725,86	17192,29
3873,68	0,994	0,95	2605,771	3197,008	0,926058	34941,14	34839,51	30133,02
4027,84	0,994	0,95	2633,604	3265,669	0,956051	26628,16	26572,04	23972,99
4182	0,994	0,95	2924,646	4027,336	1,309331	25757,74	25671,31	21668,86
4336,16	0,994	0,95	2895,271	3946,842	1,270273	17645,9	17586,14	14818,43
4490,32	0,994	0,95	2606	3197,57	0,926302	21003,2	20954,16	18683,05
4644,48	0,994	0,95	2592,771	3165,189	0,912267	26925,35	26851,03	23409,03
4798,64	0,994	0,95	2713,729	3467,402	1,045993	19553,27	19507,32	17379,36
4952,8	0,994	0,95	2617,75	3226,47	0,938889	14827,52	14783	12721,18
5106,96	0,994	0,95	2716,313	3474,009	1,048984	31382,38	31318,66	28367,55
5261,12	0,994	0,95	2890,708	3934,411	1,264277	21312,75	21236,94	17726,16
5415,28	0,994	0,95	2975,771	4169,369	1,379203	23921,59	23842,83	20195,72
5569,44	0,994	0,95	2788,167	3660,234	1,134451	48098,45	47956,65	41390,08
5723,6	0,994	0,95	2823,479	3753,534	1,178103	28694,15	28613,55	24881,03
5877,76	0,994	0,95	2826,875	3762,569	1,182359	32775,57	32691,3	28788,45
6031,92	0,994	0,95	2823,417	3753,37	1,178025	21534,32	21481,26	19023,75
6186,08	0,994	0,95	2819,292	3742,41	1,17287	27571,1	27506,47	24513,41
6340,24	0,994	0,95	2804,854	3704,178	1,154942	31796,52	31714,05	27894,66
6494,4	0,994	0,95	2794,625	3677,209	1,142353	34553,04	34465,67	30419,51
6648,56	0,994	0,95	2815,104	3731,3	1,167651	45239,14	45116,09	39417,71
6802,72	0,994	0,95	2814,479	3729,643	1,166873	79620,32	79399,28	69162,93
6956,88	0,994	0,95	2808,646	3714,2	1,159633	47654,65	47534,59	41974,66
7111,04	0,994	0,95	2807,813	3711,997	1,158602	57963,26	57812,88	50848,78
7265,2	0,994	0,95	2816,667	3735,445	1,169597	101170,4	100876,3	87256,54
7419,36	0,994	0,95	2807,661	3711,595	1,158413	21513,82	21454,64	18714,13

CHAPTER.V: RESULTS DISCUSSION

V.1. Introduction

Optimisation techniques are used to reduce well construction cost by reducing operational time, and since most drilling cost are time-dependent, large saving in time and money could be achieved by reducing the drilling time. Raising rate is a significant factor in operational time reduction. Penetration rate is influenced by severable variables such as; well complexity, borehole size, rig capability, formation properties, type of drill bit and operational drilling parameters (Akgun 2002). The Prediction of optimum rate of penetration is an important part of drilling optimisation which requires the development of a drilling model. Drilling model is a mathematical relationship which relates the rate of penetration and the parameters which affects it significantly. Wee and Kologerakin (1989) noted that mathematical models which describe these processes can greatly facilitate the optimization procedure when correctly setup.

V.2. Interpretation of MSE in well OMG501:

V.2.1 Calculation of model parameters

Field drilling data were used to calculate MSE using Teal equation at every foot interval from 4667,44ft to 7557,12ft. Equation Curry et'al was used to predict the optimum or ideal penetration rate across various formations. Table 2(in appendix) shows the predicted ideal penetration rate across the various formations labelled F1, F2, F3, F4, F5 and F6.

Since maximum drilling efficiency occurs at minimum MSE values which is usually close to the unconfined compressive strength of the various lithologies.

Teale (1964) laboratory experiment showed that MSE is numerically close to the UCS of the formation at maximum drilling efficiency. Although observed field result of MSE differs slightly from the actual compressive strength of the rock due to bit efficiency factor and greater rock strength at rock bit interface as a result of differential pressure between borehole and formation fluid pressure. In this study actual drilling parameters were used to MSE and compared with formation UCS.

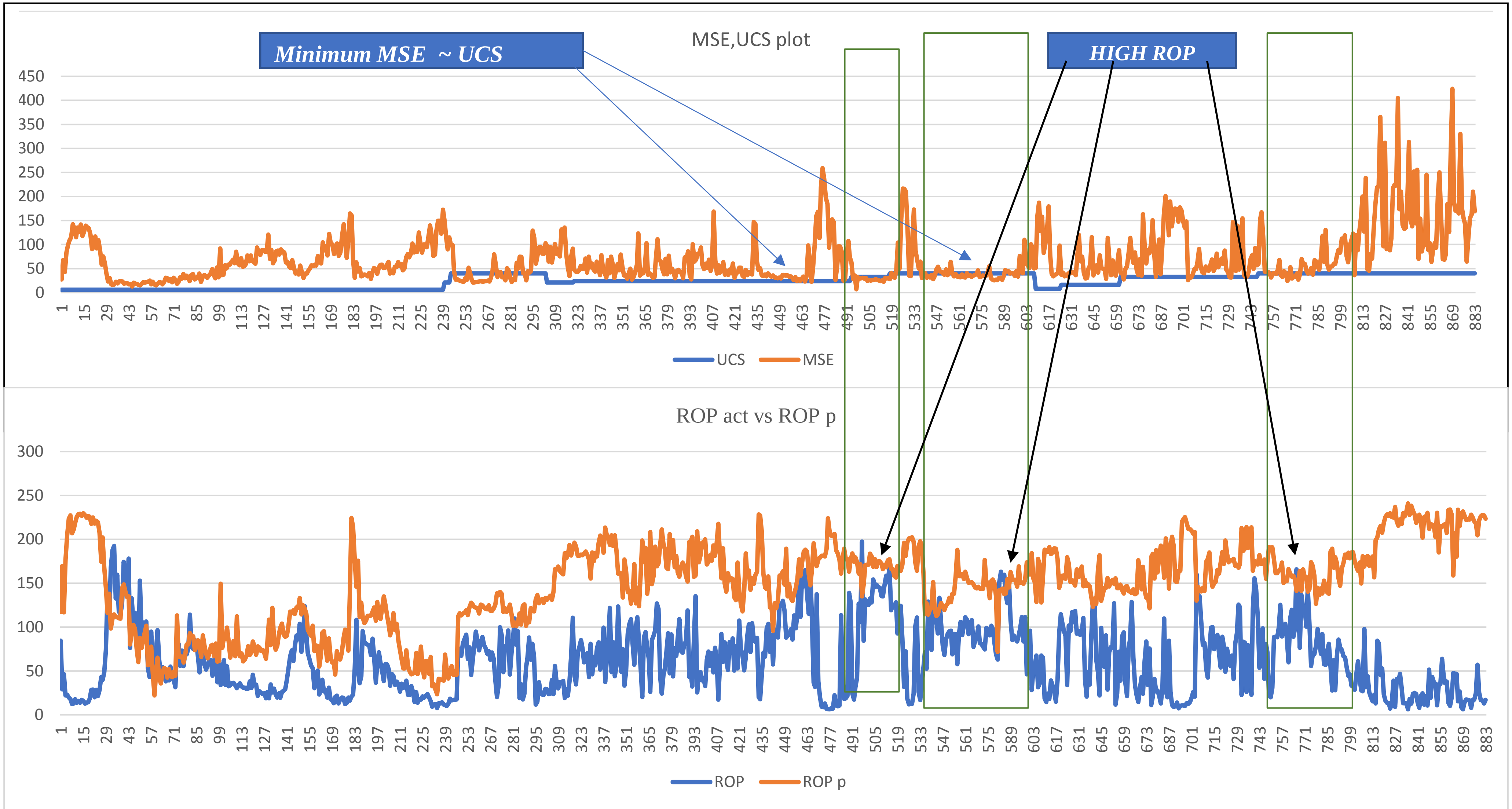


Figure **V** 1 –Plot of the Penetration rate across the different lithologies compared with UCS and MSE

V.2.2 Determination of optimum rate of penetration

Figure **V1.** shows the plot of penetration rate, lateral vibration, and MSE and UCS curve across six lithologies of varying compressive strength from 4667,44ft to 7557,12ft; the formations are: Aptien, Barremien, Neocomien, Malm, Dogger-argieux & Lagunaire.

Optimum penetration rate at the various lithologies were estimated using the model using equation of Curry et'al (2005. Investigating sections where the calculated mechanical specific energy from the drilling parameter data matches the unconfined compressive strength of the formation. Lowest value of MSE is a measure of the maximum mechanical efficiency of the drilling system with resultant highest penetration rate and less energy losses due to vibration. Efforts are geared to vary drilling parameter to achieve minimum MSE to achieve optimum penetration rate, as formation strength are reasonable uniform within the same formation interval, the corresponding values of the MSE is expected to approximately uniform. MSE values tends to increase across formation tops and spurious spike are often times observed across connection due to light weight while re- establishing the bottom hole pattern, these are disregarded unless they persist for over a long interval. Effective management of the strategy reduces the overall drill time and could result in tremendous cost saving.

V.2.3 Identification of drilling efficiency

Figure **V**.2 shows the MSE and UCS curve trend using the same actual drilling dataset, in this case a remarkable departure between the MSE and UCS curve and the resultant reduction in penetration rate with increase in downhole drilling dysfunction. Increase in MSE is an indication of inefficient drilling which may be caused by shock and vibration, high stickslip, bit balling and bit wear. Real-time indication of this condition will enable informed decision to manage the processes and reduce invisible lost time and damage to drilling system components.

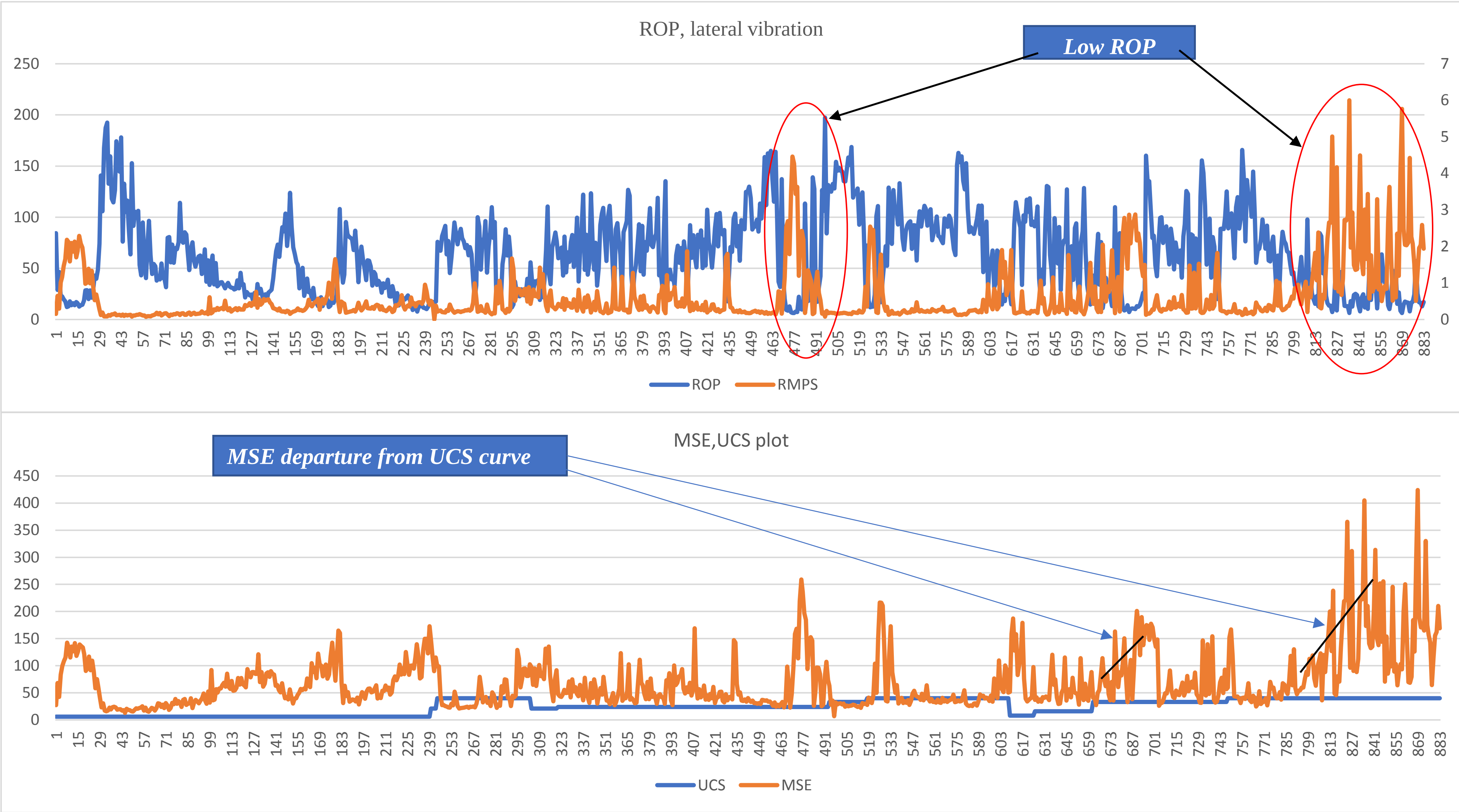


Figure **V** 2 –Analysis plot showing periods where the MSE deviates from the UCS curve.

V.2.4 Drilling Parameter Management

Specific energy decreases with increase in rotary speed and weight on bit, while penetration rate increases with increase in rotary speed and weight on bit. Figure 3 shows that upon the reduction in the penetration rate, drilling parameters were varied by reducing the weight on bit (WOB) from 15T to 5T. The change in weight on bit resulted to severe vibration with further reduction in drilling rate associated with RPM, ROP decreased from 100ft/h to 25 ft/hr, the MSE declined in response to the adjustment and the system started using less energy per unit volume of rock with corresponding increase in penetration rate.

V.2.5 Drilling Improvement

Using a baseline penetration rate during optimum efficiency at across the different lithologies, estimation of the expected improvement over the current field performance was performed. Figure 9 shows that penetration rate improvement cross the formation F1 to F6. The best performance was recorded in formation 4 and 5.

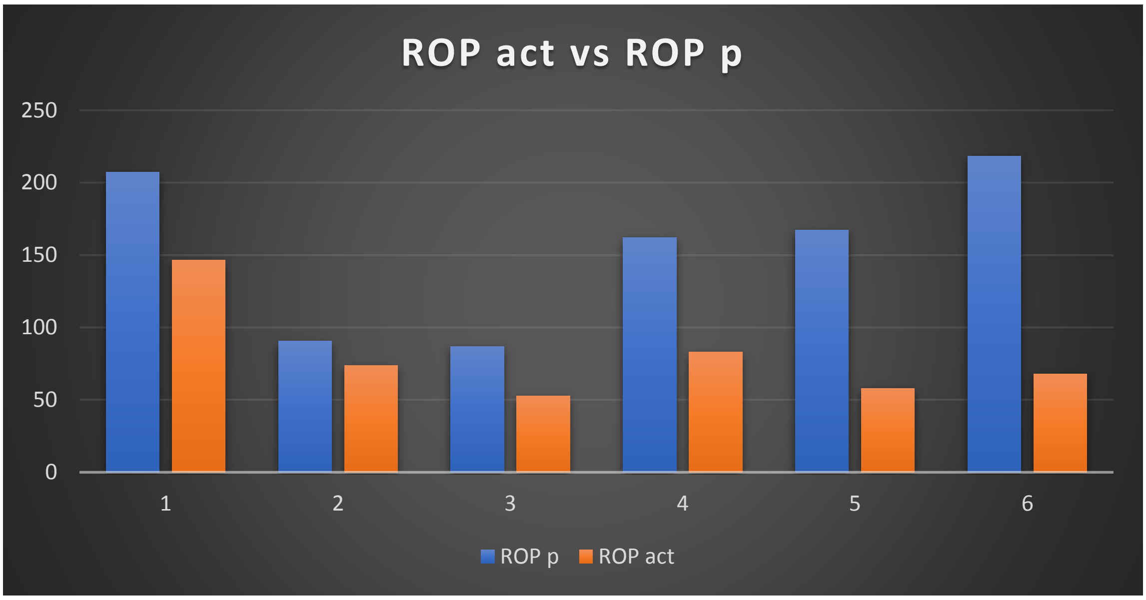
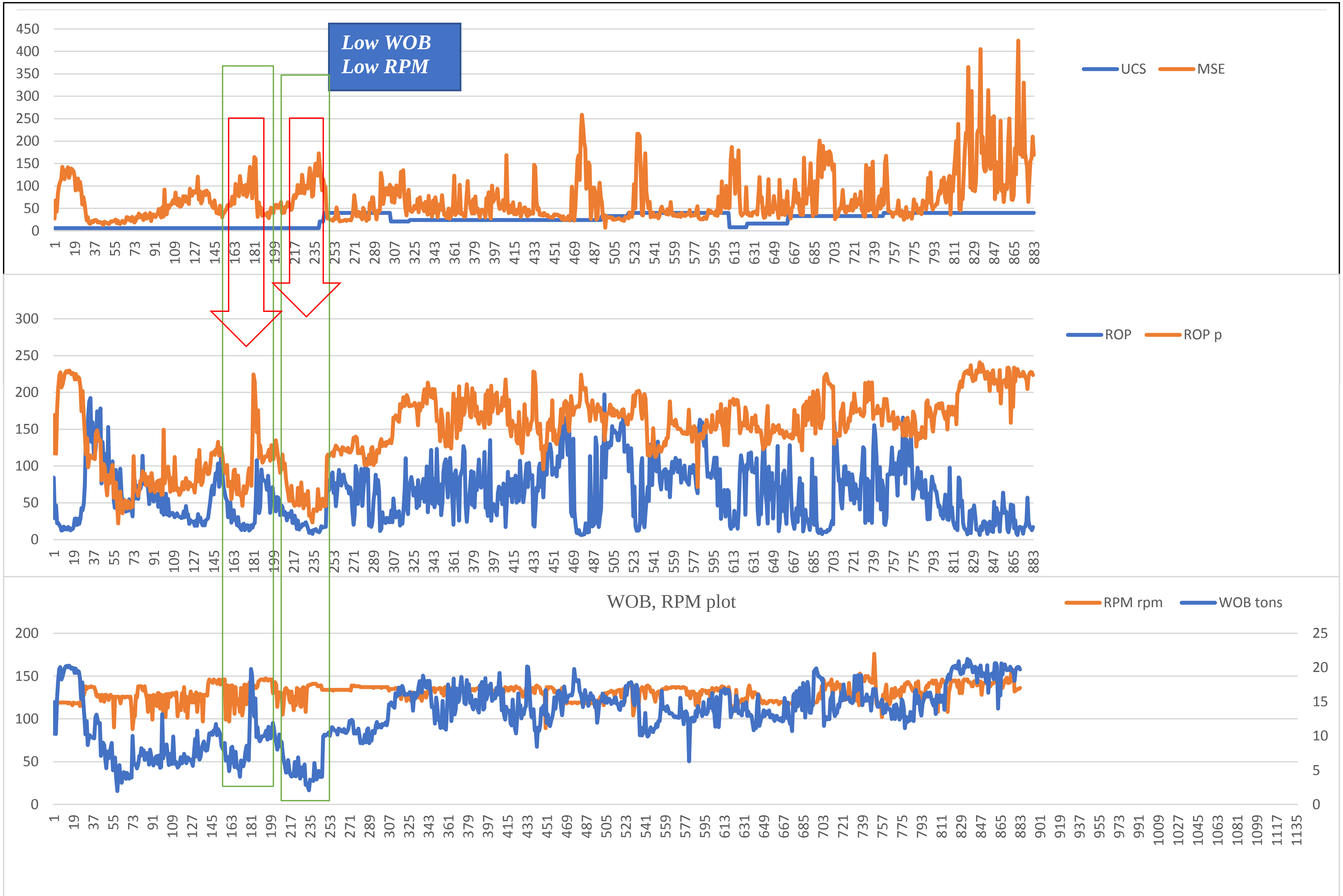


Figure **V** 3–Estimated penetration rate improvement through the application of MSE.

Figure **V** 4-Impact of drilling parameters management in optimizing the penetration rate.



Low WOB
Low RPM
UCS
MSE
450 400 350 300 250 200 150 100 50 0
ROP
ROP p
300 250 200 150 100 50 0
WOB, RPM plot
RPM rpm
WOB tons
200 150 100 50 0
25 20 15 10 5 0

V.3. Application of MSE in HMD field:

Similar lithology and conditions make it possible to correlate with respect to computing the ROP with close-by wells. As formation properties has a major impact on drillability, MSE and drilling variables effects, it also affects the ROP. The use of coefficients and values from closeby wells with the techniques introduced in this thesis to give a predicted ROP has produced promising results. Most of the modelled ROP plots appear to correlate close to the actual ROP. That said these are still modelled predictions and, in some cases, deviate significantly from the actual data.

V.3.1. Results discussion:

According to the results of the previous three wells, the bit of well OMG501 performed an average ROP of 24.3 m / h while with the new model the ROP becomes 27.6 m / h;
The bit of well OMK573 performed a ROP of 25.4 m / h while with the MSE of well OMG501 the ROP becomes 30.16 m / h;
The bit of well OMG503 performed a ROP of 31.62 ft / h while with the MSE of well OMG501 the ROP becomes 36.61 m / h;
Among the three cases, the optimum drilling parameters for a high ROP are OMG501 drilling parameters in form of MSE;
According to the bits, using the same parameters, only the bit of well OMG503 "MSI916LVPX" which was the best performing with average ROP up to 36.61.

Figure V.5: Drill-bit "MSI916LVPX" for well OMG503.

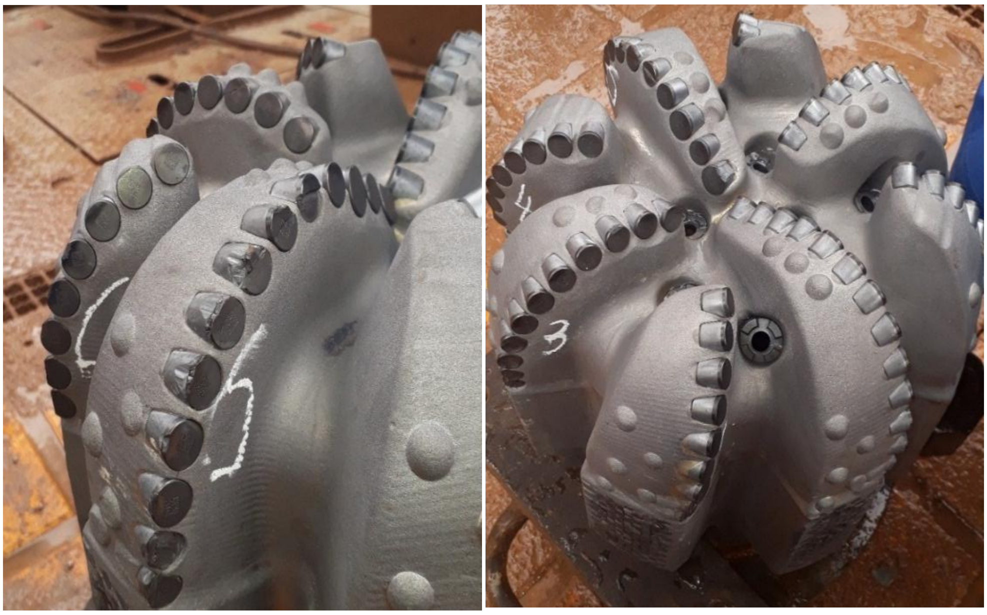


Figure V.6: Dull-grading of "MSI916LVPX" for well OMG503.

Table V.1: Presentation dull-grading of "MSI916LVPX" for well OMG503.

	Blade 1				Blade 1 Backup			
Cutter No	Cutter Size mm	Wear (0-8)	Major Wear Code	Minor Wear Code	Cutter Size mm	Wear (0-8)	Major Wear Code	Minor Wear Code
1	16	0	NO					
2	16	2	WT					
3	16	0	NO					
4	16	2	BT					
5	16	0	NO					
6	16	0	NO					
7	16	0	NO					
8	16	7	BT					
9	16	2	WT					
10	16	4	BT					
11	16	5	BT					
12	16	3	BT		16			
13	16	1	WT		16			
14	16	1	WT		16			
15	16	0	NO		16			

V.3.2. Correlation of three wells

According to correlation results, it seems that OMG501 well drilling parameters or mechanical specific energy required (MSE) wich were optimized with new ROP model are the optimum parameters between the three wells, therefore, it is recommended to take the following data obtained from OMG501 as reference of optimum penetration in region;

WOB (Klbf)	RPM (rpm)	Tq (ft*lbf)
9-10	**115-125**	**8000-9050**

V.4 Comparing MSE & DSE, ALBIAN formation as sample study:

The figure below represents the difference of energy supplied between DSE and MSE which is estimated between 20 to 2000psi, and it is shown more clearly in last 100 ft, it depends on the hydraulic parameter introduced, this provides the ability to detect changes in the efficiency of the drilling systems, more or less continuously.

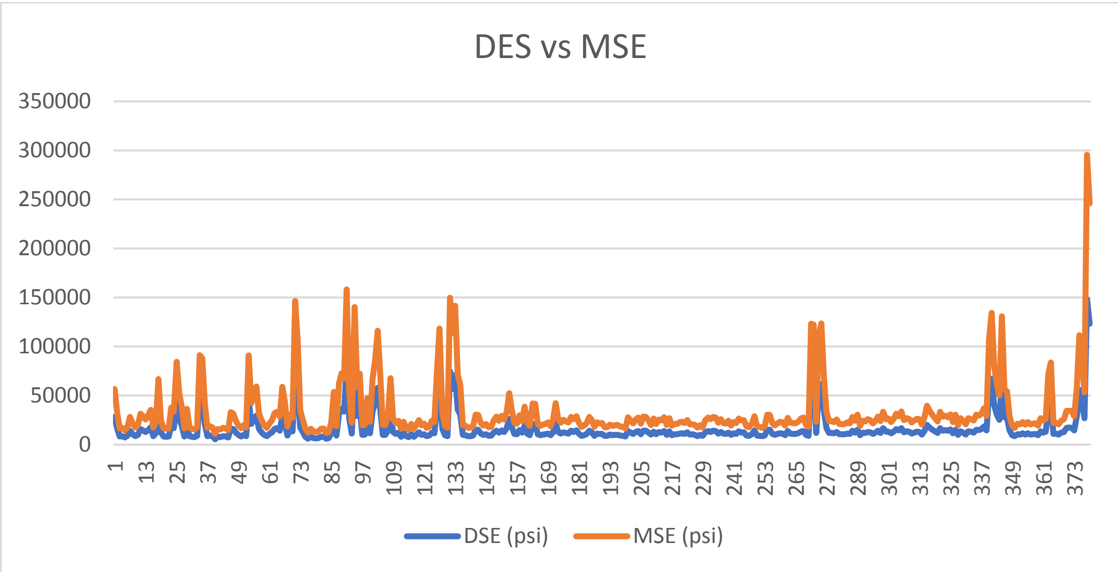


Figure V. 7: Comparing MSE & DSE, ALBIAN formation

That difference get more and more bigger and goes from 2-200 Kpsi only with real deep depth where the diameter gets lower so hydraulic power get higher.

ROP was directly proportional and had a strong relationship with rotational speed, weight on bit, mud circulation rate, torque, standpipe pressure, and rock unconfined compressive strength.

GENERAL CONCLUSION

Conclusions

This thesis looked at drilling performance improvement strategy as a means of drilling cost reduction through improving drilling efficiency using the drilling mechanical specific energy. The following conclusion can be made from the study.

Real-time analysis of the drilling parameter data and comparison of real-time MSE acquired from downhole together with geological properties of the rock drilled provides timely understanding of drilling mechanics and efficiency. The mechanical specific energy is proven as an efficient modeling drill rate management and can be computed on continuous basis and used for identification of drilling inefficiencies in a timely manner. It could also serve as a veritable tool in the selection of optimum drilling parameters to optimize penetration rate. Selection of drilling parameters which yields minimum MSE values approximately to UCS values resulted in a more productive drilling with highest penetration rate. The degree of drilling inefficiency increased with increasing MSE values which coincede with period of high shock and vibration. The opportunity for efficiency improvement in drilling using real-time MSE create substantial saving in cost reduction and improves project economics.

Several techniques are developed to model ROP for a new well. The techniques attain coefficients or specific values from a close-by already drilled well. Using these and drilling parameters, the proposed method predicts ROP for the new well.

The techniques are tested by comparison with three wells; three close-by wells from Hassi-Messaoud field. Thereby each well may be tested with each technique with coefficients or values from two different close-by wells. The results display both the actual ROP and modelled ROP plots for comparison.

RECOMMENDATION

The proposed model can estimate rate of penetration as a function of many drilling variables such as weight on bit, rotary speed, flow rate, formation parameters, drilling fluid density and viscosity.

To increase the accuracy of model, it is necessary to use data from more than a single well. Also, these data should be from a variable formation.

Furthermore, the ROP optimized value can be reach as maximum by considering the other effects such are hydraulic (pressure and flow rate), bit type, bit wear and BHA type, the modelling part can be more effective, and high demand of specific energy.

Using drilling specific energy rather then mechanical would also give promise results especially plotting several well (well offset) in same region

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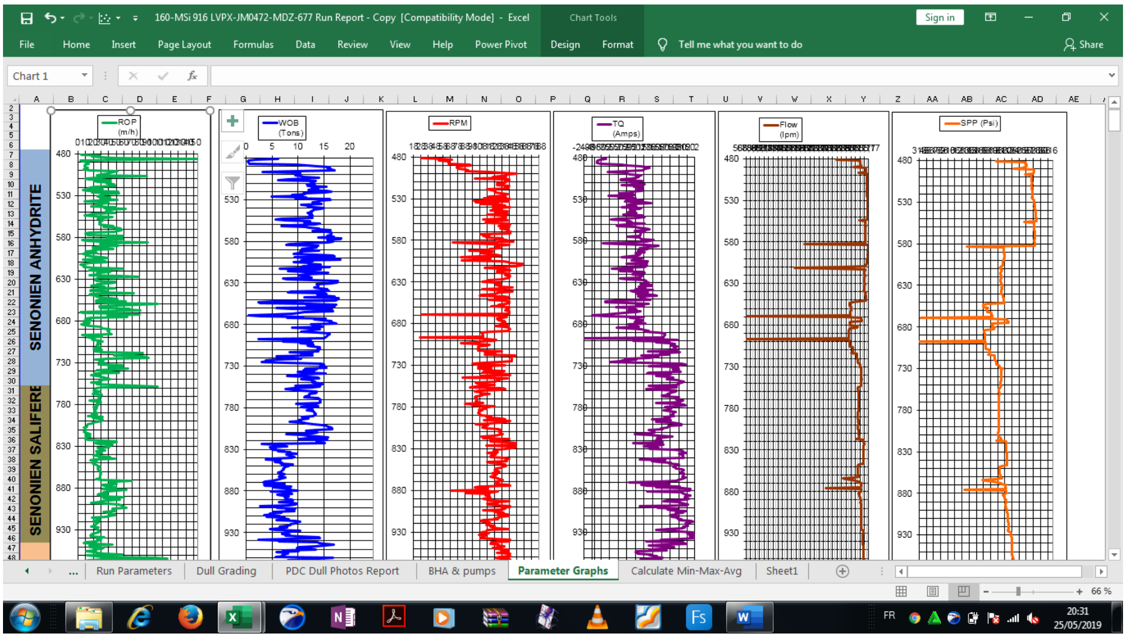
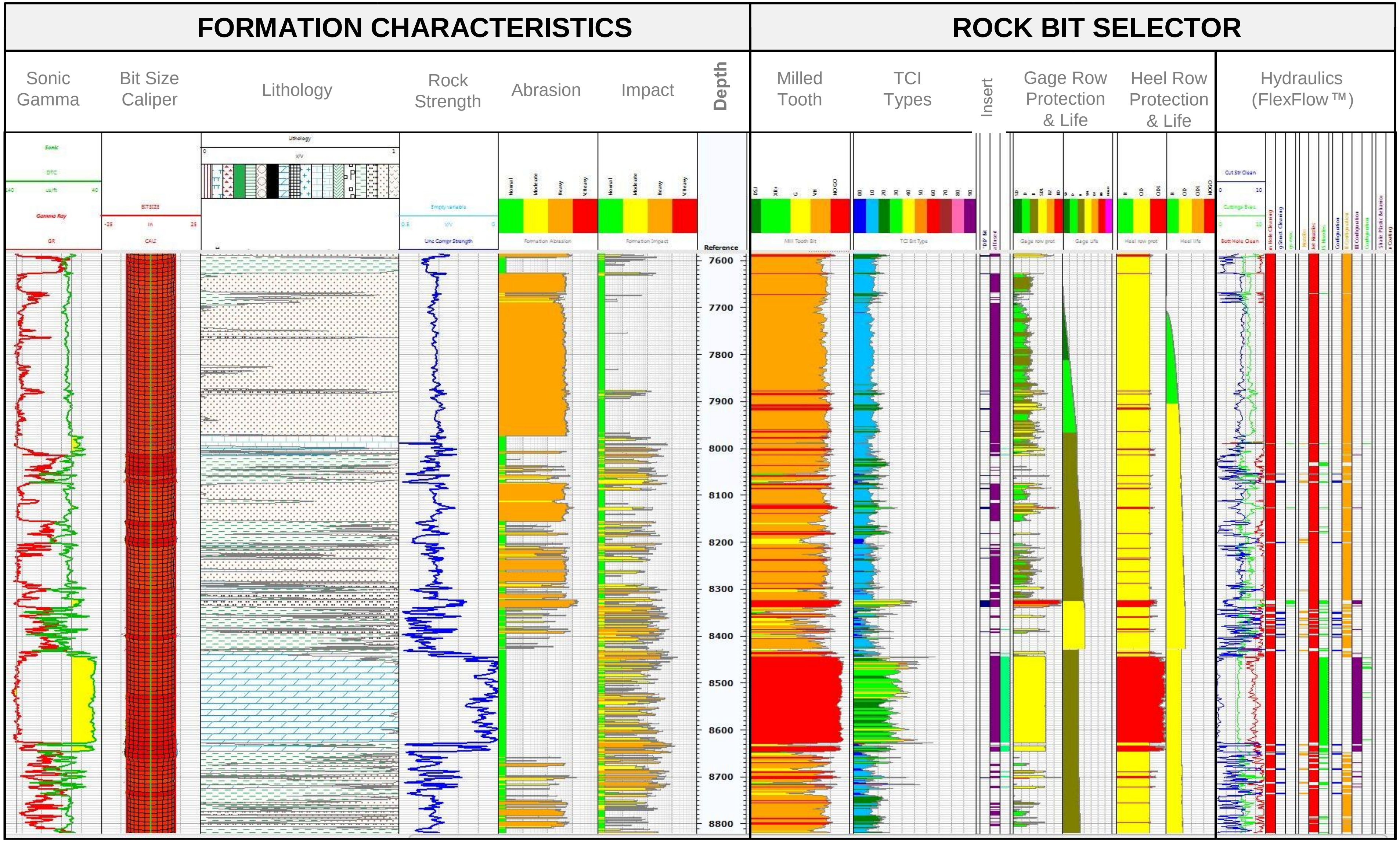
***FIG**: Example for drilling parameters graphs of well OMG503 in excel*



HOLE SIZE	PRIMARY	BACKUP
36" Hole section	**<u>TC RR :</u>** L3A	**<u>-</u>**
26" Hole Section	**<u>TCI-New:</u>** SB535C (Smith) X 01 **<u>MT-New:</u>** T11CPT (NOV) X01	**<u>TCI-RR:</u>** ER24JMRS (Varel) X 01
16'' Hole Section	**<u>PDC-New :</u>** TFF913S(NOV) X 01 **<u>MT-New:</u>** SB215C (smith) X01	**<u>PDC-RR :</u>** Q609F(BAKER)
12 1/4" Hole Section	**<u>PDC-New :</u>** SP619A (Aldim) X01 **<u>MT-New:</u>** DT4GMRS (VAREL) X01	**<u>PDC-RR:</u>** R616SP2DGHXU (Varel) X01
8 1/2" Hole Section	**<u>Hyb - New</u>:** SP813W (ALDIM) X01 **<u>MT-New:</u>** SB137 (SMITH) X 01	**<u>PDC– RR:</u>** DSF713 (NOV) x01
6" Hole Section	**<u>IMPREG bit- NEW</u> :** K505BCTPX (SMITH) X 01 **(box bit will be used with turbine)** **<u>MT-New:</u>** RT4G (NOV) X 01	**<u>PDC-RR :</u>** FX94 (DBS)

***FIG**: Bit program of well OMG501*

***FIG**: PDC Bit Selector DBOS "Formation, Blades, Cutters, Profile"*



Classification	***Rock strength***	***Lithology type***	***Bit selection***	***Classification***	***Rock strenght***	***Lithology type***	***Bit selection***
so weark rock strength	<4000	Anhydrite	PDC			Basalt	Nat.Dia./Impreg.Dia
		Chalk	PDC	high rock trength	32000-60000	Chert	TSP/Nat.Dia/Impre.Dia
		Salt	PDC			Dolomite	TSP/Nat.Dia/PDC
		Sandstone	PDC			Granite	TSP/Nat.Dia/Impre.Dia
		Schiste	PDC			Limestone	TSP/Nat.Dia/PDC
weak rock strength	4000-8000	Anhydrite	PDC			Quartzite	TSP/Nat.Dia/Impre.Dia
		Chalk	PDC	so hard rock strength	>60000	Sandstone	TSP/Nat.Dia/PDC
		Limestone	PDC			Schiste	TSP/Nat.Dia/PDC
		Sandstone	PDC			Volcanic tuff	Nat.Dia/impre.Dia
meduim rock strength	8000-16000	Schiste	PDC			Basalt	Nat.Dia/impre.Dia
		Anhydrite	PDC			Chert	Nat.Dia/impre.Dia
		Basalt	Nat.Dia.			Dolomite	Nat.Dia/impre.Dia
		Chalk	PDC			Granite	Nat.Dia/impre.Dia
		Dolomite	TSP/PDC			Limestone	Nat.Dia/impre.Dia/PDC
hard rock strength	16000-32000	Limestone	TSP/PDC			Quartzite	Nat.Dia/impre.Dia
		Sandstone	TSP/PDC			Sandstone	Nat.Dia/impre.Dia/PDC
		Schiste	TSP/PDC			Schiste	Nat.Dia/impre.Dia/PDC
		Volcanic tuff	Nat.Dia.			Volcanic tuff	Nat.Dia/impre.Dia

FIG*: PDC Bit classification according to rock strength*

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