University of Stavanger

**Faculty of Science and Technology**

# MASTER'S THESIS

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| Study program/ Specialization:<br>M.Sc, Petroleum Engineering/ Drilling | Spring semester, 2012<br>Open |
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| Titel of thesis:<br>Drill bit selection and optimization in exploration well 6507/6-4A in the Nordland Ridge Area. | |
| Credits (ECTS): 30 | |
| Key words:<br>Drill Bit Optimization<br>Drilling cost analysis | Pages: ………72………....<br>+ enclosure: …11……......<br>Stavanger, ………………..<br>Date/year |

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# List of symbols

D - Bit diameter, [inches]

T - Torque, [ft-lb]

MSE - Mechanical Specific Energy, [Kpsi]

Em - Mechanical Efficiency, [ ]

$C_f$ - the drilling cost, in [$/ft]

$C_b$ - the cost of bit, in [$]

$C_r$ - the rig cost, in [$/h]

$C_m$ – downohole motor cost [$/h]

$t_r$ – the drilling time, in [h]

$t_t$ - the trip time, in [h]

$t_c$ – the connection time, in [h]

# List of abbreviations

PDC - polycrystalline diamond compact bit

TCI - Tungsten Carbide Inserts bit

ROP – Rate of Penetration

IADC - International Association of Drilling Contractors

RPM – Revolutions per Minute

TSP - Thermally stable PDC

WOB – Weight on Bit

MSE - Mechanical Specific Energy

MW – Mud Weight

RKB – Rotary Kelly Bushing

MSL – Mean Sea Level

MD – Measured Depth

TD – True Vertical Depth

LWD – Logging While Drilling

MWD – Measurement While Drilling

DST – Drill Stem Test

NCS - Norwegian Continental Shelf

ARSL - Apparent Rock Strength Log

PV – Plastic Viscosity

USD – United Stated Dollar

# Abstract

The primary objective of this thesis is to analyze and optimize drilling bits which were used to drill of an exploration offshore well in Norwegian Continental Shelf (NCS). The first part ot the thesis work reviews the available drill bits and designs, including the one used in the project. I will also briefly present well 6507/6-4A and its objects in order to improve understanding the operational aspects of the project.

The second part deals with drill bit optimization simulation for the well 6507/6-4A in the Nordland Ridge Area. The simulation was built based on the geological and well construction, operational real data obtained from the well. In the well 6507/6-4A, two target section were simulated using DROPS Drilling Simulator, Sesam 12 ¼" and Sesam 8 ½". The simulation criteria was based on ROP, cost reduction and drilling time. The simulations result in increase in average ROP and decrease in both costs and duration time.

## Acknowledgment

First of all I would like to thank PGNiG Norway AS for giving me the opportunity to write the thesis. I would also like to thank my supervisors in PGNIG Norway AS, Józef Dzięgielowski, Steinar Bryne and Marek Hoffmann for their support as well as kindly providing me valuable data and information.

I would like to express my gratitude to Professor Bernt Sigve Aadnøy and Doctor Mesfin Belayneh at the University of Stavanger for continuous support and useful comments. Working with such experienced people is very encouraging and developing, especially to the young man at the start of the professional career.

I would also like to thank Bjørn Thore Leidland from ACL Group A/S for the opportunity to implement the practical part of the thesis to the simulator and for all the help throughout this project.

Stavanger, June 2012

Piotr Boryczko

# 1 Introduction

## 1.1 Background

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 increased 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 equipments.

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. Drilling bit is the main part of drill string which is placed at the bottom of it. Bits are used to crush or cut the rock formation.

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

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. Therefore, in this thesis, drill bit optimization simulation will be carried by DROPS Simulator. The simulation will analyze the combinations of bits and parameters in order to produce an optimized bits performance in terms of ROP, cost and time reduction.

## 1.2 Scope and Objective

The scope and objective of this thesis work comprises both literature studies and computer simulations. The activities are:

- Literature study on various bits and designs and bit selection criterions.
- Presentation of theoretical ROP models and drilling optimization methods.
- Review the geological and drilling features of the simulated well.
- Perform simulation study on the selected section Sesam 12 ¼" and Sesam 8 ½" of well 6507/6-4A to:
    - Selection of appropriate tools and parameters to reduce the cost and duration of drilling.
    - Observe the correlation between parameters and the progress of the drilling and tool wear
    - Comparison of the results obtained from simulation with those applied in practice. Discussion

## 1.3 Assumptions and limitations

In the well 6507/6-4A in section Sesam 12 ¼" three PDC and one Kymera hybrid bit were used, while in section Sesam 8 ½" three Kymera hybrid bits were used. However, DROPS simulator was designed for tricone and PDC types bits.

In this thesis work I assume, after consultation, that the performance of the Kymera bit is equivalent to tricone bit 537 IADC code. Therefore, the results and conclusions are limited by the assumption I made. If the DROPS simulator have been designed for Kymera, an improved results can be obtained.

# 2 Review of bits and designs

## 2.1 Roller cone 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-steel-grade alloy. Figure 2.1 shows a typical Milled tooth bit and Tungsten Carbide Insert bit.

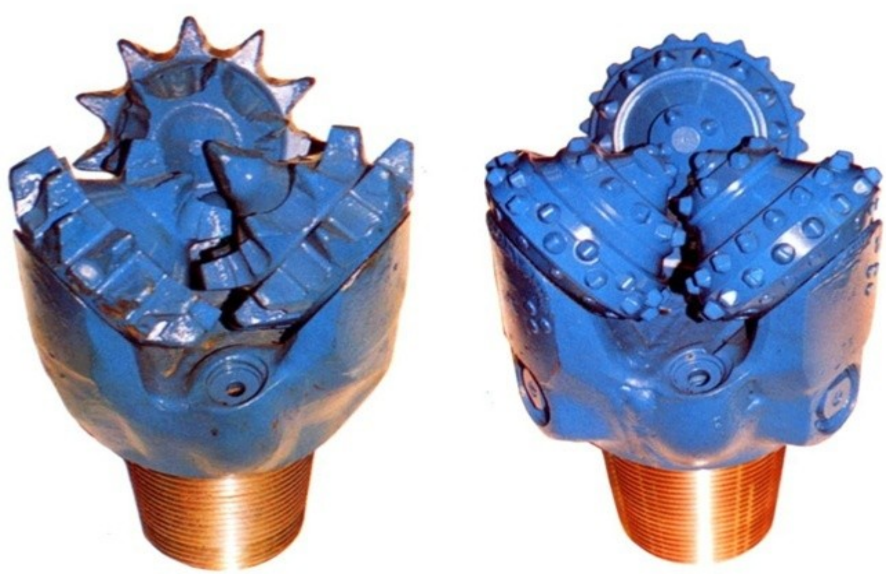


Figure 2.1 Milled tooth bit and Tungsten Carbide Inserts bit[1].

### 2.1.1 Bit design

Journal angle, cone profile

One of the main design features of roller cone bits is journal angle. The journal angle is the angle formed by an axis of the journal relative to a horizontal plane.

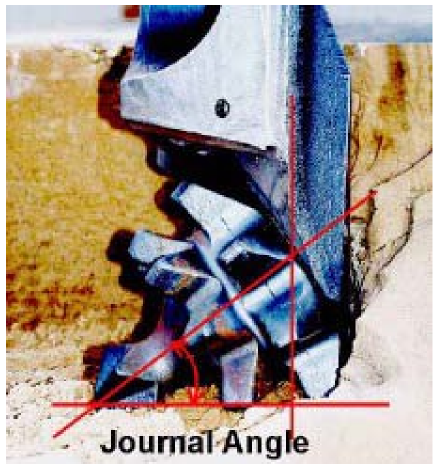



Figure 2.2 Journal angle[2].

There is a close relationship between cone profile and stability of the bit. Cones with rounded profile provide a faster ROP, but are more labile. While cones with more flat profile are more durable, yet deliver lower penetration. The journal angle has a direct influence on the size of the cone, with its growth the cone size declines.

The journal angle depends on the type of rock:

- soft formations – (journal angle $33^0$) – allows greater penetration of the formation
- medium formations – (journal angle $34^0$ – $36^0$) – decrease of cutter action
- hard formations – (journal angle $39^0$) – further decrease of cutter action

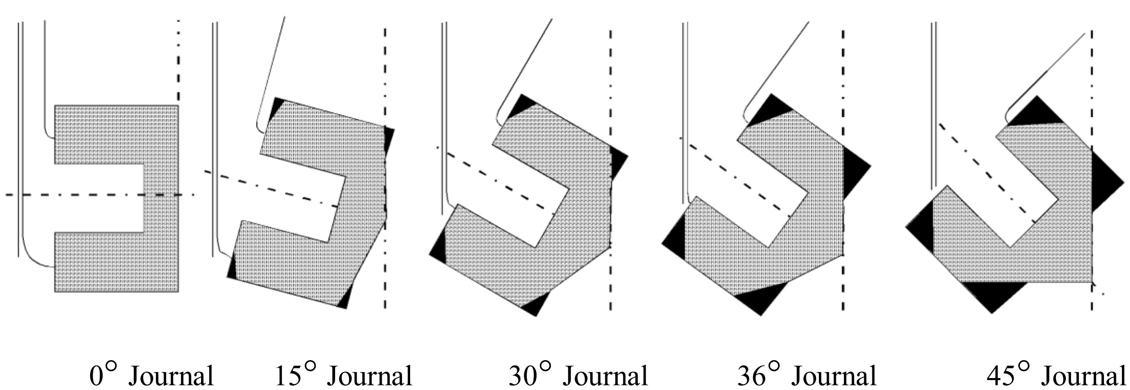



Figure 2.3 Journal angles in roller cone bits[3].

Cone offset

The “offset” specifies to a certain degree a drilling action of the roller cone bit. Figure 2.4 illustrates cone offset. Shift of the cone’s axis to the centerline of the bit is defined as “offset”. The roller cone bit with no offset has the intersection point of cones axis in the centre of the bit. The size of offset depends on the type of rock to be drilled. Its values range from $4^0$ for soft formations to $0^0$ for hard formations. Angular measure of the offset is called skew angle.

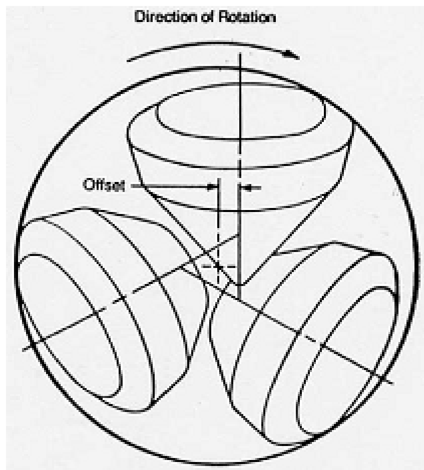



Figure 2.4 Cone offset[4].

The cone offset results in interim stops in rotation and brake the hole like a drag bit. With increasing the offset the bit wear increases proportionally.

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 2.5 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.

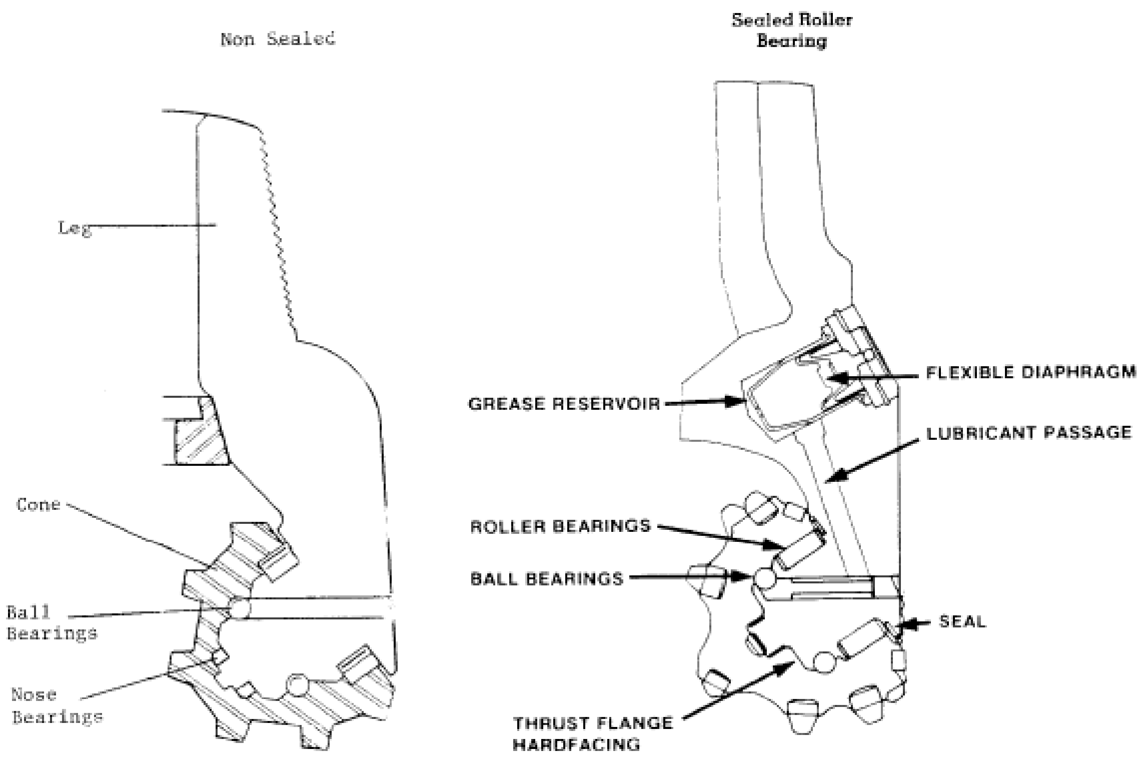



Figure 2.5 Non Sealed and Sealed Bearing[3].

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.

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.

Bit hydraulics

Regular circulation bits have a single drilling fluid channel down their axis (Fig. 2.6A). This solution is used in large – diameter wells. More developed tools like jet circulation bits have mud channels in the dome of the bit which direct drilling fluid into cones (Fig. 2.6B). These channels are terminated with interchangeable nozzles mounted with ring. The aim of the nozzles is increase mud velocity, which will provide good downhole cleaning from cuttings. Number of nozzles depends on the construction of the roller cone bit and can be 1, 3, 4. Nozzle diameter has an important role in bit hydraulics. Their proper selection provides an effective hole cleaning and cuttings removal, faster drill rates and decrease of drilling costs. Available elongated nozzles improve proper hole cleaning. However, they are more vulnerable to failure in harsh conditions.

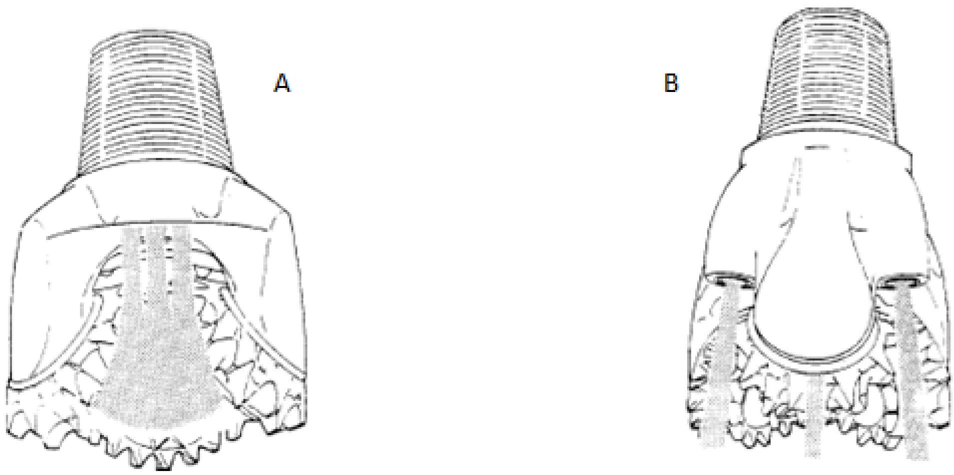



Figure 2.6 Regular Circulation (A) and Jet Nozzle Circulation (B)[3].

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.

The teeth are designed to crush or gouge of the formation as the bit rotates. Teeth are arranged on the circumference of cones by creating rows. Rows of one cone are among the rows of the second cone. This arrangement causes the self-cleaning of any excavated material, which could cause the bit balling and other obstacles in the drilling process.

Crowns of teeth that are farthest from the axis of the bit are called "calibration rows". Their task is to maintain the diameter of the hole. Therefore, the teeth of the crown must be particularly resistant to the abrasive action of rocks. Teeth are reinforced with an erosion resistant material to fulfill their job.

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°)

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 insert 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.

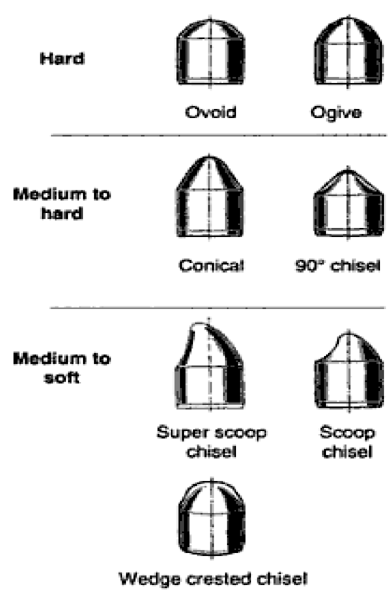



Figure 2.7 Teeth shapes[5].

### 2.1.2 IADC Tricone bit classification

Nowadays several major manufacturers are operating on the global market of drilling tools. Each of them used its own nomenclature and product names. This fact, the introduction of new products and increasing the number of possible configurations gave rise to the need for an effective way of comparing a drilling bits. The International Association of Drilling Contractors (IADC) noticed this problem, and in 1972, adopted systemic classification codes by means of three numbers and one letter[20].

The first digit describes the type and application of drill bit and can be 1 - 8. Numbers 1 to 3 are for steel tooth bits and correspond to growing compressive rock strength (soft, medium, hard). Numbers 4 to 8 are for TCI bits and number value also increases with rock strength growth.

The second code digit is a subdivision of hardness inside each of the classes defined by the first digit. The numbers 1 to 4 particularize the formation toughness.

The third digit relates to design features such as bearing system or gouge protection and can be 1 to 9:

1: standard roller bearing
2: roller bearing, air cooled
3: roller bearing, gage protected
4: sealed roller bearing
5: sealed roller bearing, gage protected
6: sealed friction bearing
7: sealed friction bearing, gage protected
8: directional
9: special application

The fourth character, the letter, to define additional construction features. For more complex tools more than one letter can be used. They are :

A: air application, journal bearing bits with air circulation nozzles
B: special bearing seal, application at high RPM
C: center jet
D: deviation control
E: extended jets
G: extra gauge/body protection
H: horizontal/steering application
J: jet deflection
L: lug pads, pads very close to gage diameter

M: motor application, special design for use on downhole motors
S: standard steel tooth model
T: two-cone bits, sometimes used for deviation control and penetration rate
W: enhanced cutting structure
X: chisel tooth insert
Y: conical tooth insert
Z: other insert shape

For example Baker Hughes MX – 55 has an IADC code 6 – 3 – 5 which means:

6 - TCI bit for medium formations
3 – medium to hard formation hardness
5- sealed roller bearing with insert gauge protection

### 2.1.3 Grading of dull Tricone drill bits

The grading and appropriate assessment of bit dullness are important factors in the effectiveness of the drilling. Too quick wear of the bits proves its wrong selection, results in increasing the duration and therefore the cost of the operation. Any abnormal wear is noted and appropriate measures are taken to avoid them in the future. The main goal is to improve the selection in the next drilled holes.

The 1987 IADC dull grading system divides wear into eight subgroups as showed on table below.

| Cutting Structure | | | | Bearings/Seals | Gauge | Other Dull Char | Reason Pulled |
|---|---|---|---|---|---|---|---|
| Inner | Outer | Dull Char. | Location | | | | |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |

Table 2.1 IADC dull bit grading system[2].

The first four columns describe the cutting structure. The first reports the quality of the inner 2/3 of the bit face, while the second column refers to outer 1/3 of the cutting structure. The wear is defined using a linear scale of 0-8, for example tooth worn in 50% (4/8) is reported as T-4. The third subgroup describes the major wear characteristic of the cutting structure using a two – letter code. The fourth column defines the location of wear on the bit-face.

Column 5 describes the condition of bearings. For non – sealed bearings the condition is determined using a linear scale similar to the tooth wear. B-8 indicates that the cones are stuck, whereas for new bearings B-0 designation is used. In the case of sealed bearings (roller or journal) bits a letter code is introduced to describe the quality of the seal. An efficient seal is denoted by the letter 'E' and a 'F' is used to report damaged seal. As the PDC does not use bearings, this column is crossed in this case.

The sixth column refers to the gauge measurement. The loss of diameter is denoted by the letter 'O' and presented as the nearest eighth. For example diameter reduction by 0.5 [in] is written as G-0-4 (4 thus that 4/8 [in]). The letter 'I' indicates that bit is in gauge.

The seventh column describes secondary wear characteristics of the bit using two letter codes from column 3. It is worth noting that this column is used to describe not only the cutting structure damage, but the whole bit body. The last, eight column provides information about the reason the bit was pulled.

## 2.2 Fixed cutter bits

### 2.2.1 Natural diamond bits

Diamonds are the hardest known minerals, the most durable in the Mohs scale. Those used for the production of this type of bit are naturally occurring, industrial - grade. They can withstand demanding drilling conditions, their compressive strength is extremely high. Diamonds are characterized by high fastness to abrasion. However, low tensile strength feature makes them vulnerable to shocks.

Natural diamonds are sensitive to the generated heat during drilling. At temperatures from 773 to 1073 K diamonds are oxidized, and at about 1723 K graphitization occurs. This feature requires the use of large amounts of mud to ensure proper cooling of diamonds and a very good cleaning of the bottom of the hole.

Borts type diamonds are from Africa. They have spherical shape and are the most popular due to its low price. They have replaced a Carbonado diamonds.

Carbonado diamonds are from Brazil. They are fine-grained, porous with brownish to black color.

These diamonds strengthen the most vulnerable to wear side surfaces of the drilling bits and coring bits.

To drill in medium hard rock, less expensive, Congo diamonds are also used.

Figure 3.1 Types of diamonds[1].

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.

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 is restricted.
- 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.

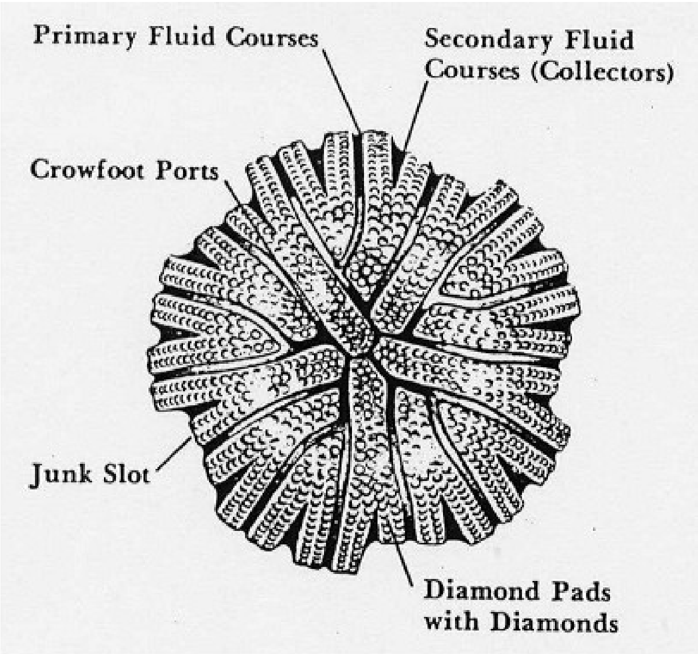



Figure 3.2 Typical natural diamond bit[4].

### 2.2.2 Diamond impregnated 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

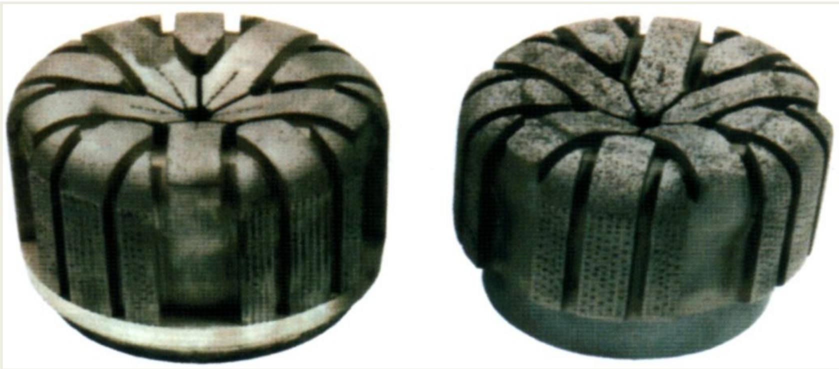


Figure 3.3 Diamond impregnated bits[1].

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.

### 2.2.3 TSP (Thermally stable PDC)

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.


Figure 3.4 TSP bit[1].

## 2.2.4 Polycrystalline diamond compact PDC bit

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.


Figure 3.5 PDC bit (A) and PDC cutters (B)[6].

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.

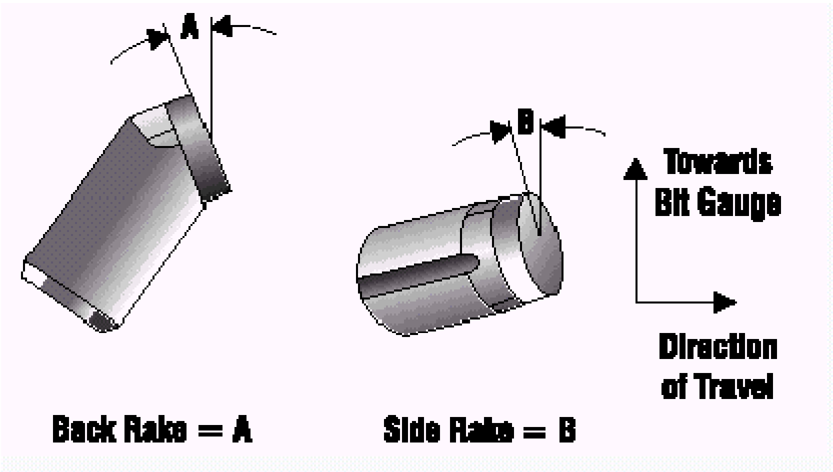



Figure 3.6 Back rake, Side rake angles[2].

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.

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).

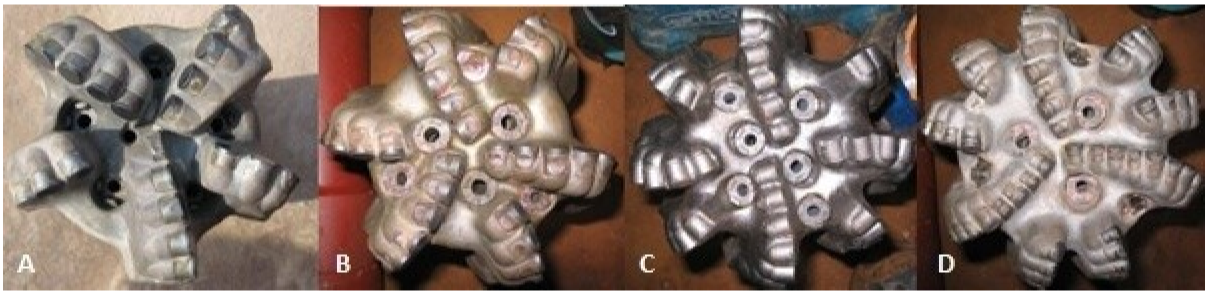



Figure 3.7 The design of PDC bits depending on the hardness of the rocks (from soft A to hard D)[7].

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[3]:

- 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.

## 2.3 Innovative solution –Kymera hybrid drill bit

Hughes Christensen Kymera hybrid bit merges positive aspects of existing solutions to increase efficiency in the most demanding applications[8,9]. Using high drilling performance of diamond PDC bit and stability of roller cones, Kymera is able to operate powerfully in highly interbedded formations with outstanding toolface control. During drilling geothermal wells in Iceland, it is shown that drills hard, basalt sections over two times faster than conventional roller-cone bits.

In comparison with existing roller cone bits, ROP has increased with a reduction in a value of WOB. Also the problem of bit bounce has been reduced. Compared with PDCs, there is considerably enhanced robustness in interbedded formations, reduced torque and improved directional control.

The Kymera hybrid bit is the right tool for application in directional drilling, both with motor and rotary, because of improved buildup rate ability and accurate steerability.

Figure 3.8 Kymera Hybrid Drill Bits[6].

The tool works well in offshore drilling in difficult geological conditions, with the time of the operation and directional control are key factors. The Kymera was first used on the Norwegian Continental Shelf during the exploration drilling, which is the subject of my thesis.

Advantages of the Kymera hybrid drill bit:

- Higher general ROP: maintains high value of ROP in soft formations specific to PDC bits and increases in ROP in harder rocks usually drilled by tricone bits.
- Reduced vibration: cope with the vibrations present during drilling existing tools
- Improved toolface control and stability.
- Better torque control.

## 2.4 IADC fixed cutter classification system

IADC[10] (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.

**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

**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

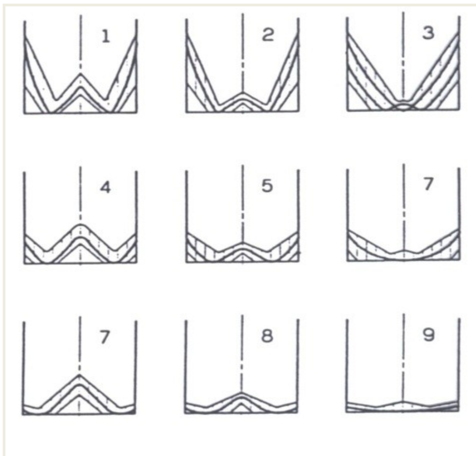


Figure 3.9 Fixed Cutter Bit profile[1].

**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

## 2.5 IADC fixed cutter dual grading system

Information provided by dull grading bits can be very useful. The fixed cutter dull grading system can be used for all non-roller cone bits, including natural diamond, polycrystalline diamond compacts (PDC), thermally stable polycrystalline (TSP) diamonds, impregnated bits and core bits. Eight features are included similar to the method used for the assessment of roller cone bits. The first four factors are used to estimate the size, type and location of wear. The fifth feature is used to describe the bearing wear, in the case of fixed cutter bits will not be judged because they do not occur in the construction of such tools. This place is always indicated by X in that case. The sixth column serves to assess reduction of diameter. The last two factors include additional data on the wear of the bit and the reason for pulling the bit out of the hole.

In order to evaluate the wear of the cutting structure a linear scale from 0 to 8 is applied.

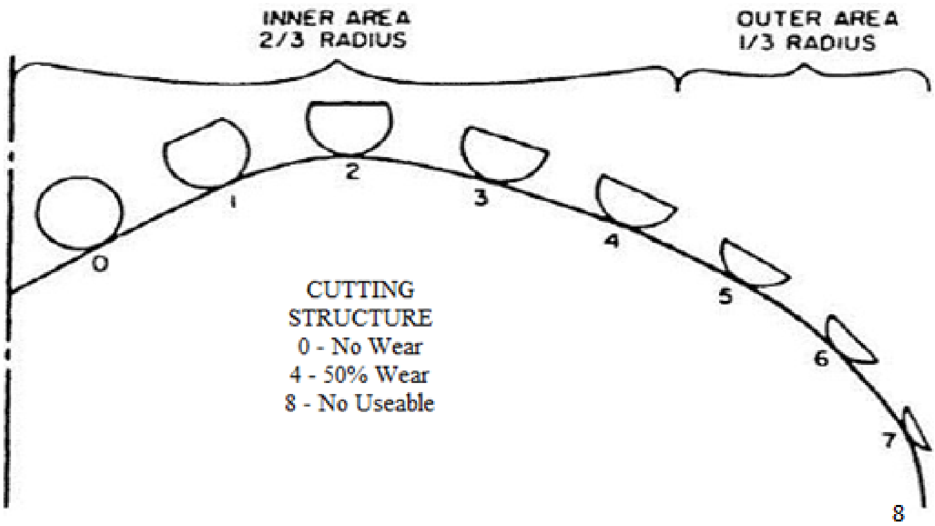



Figure 3.10 Cutting structure wear[10].

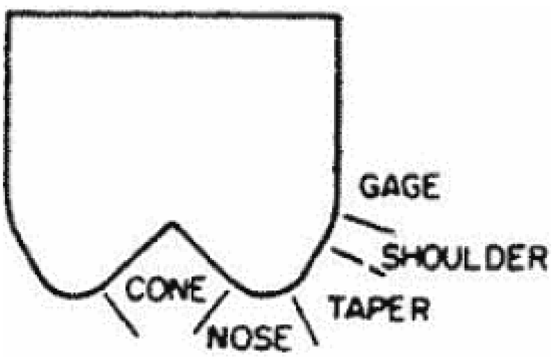
When grading first factor, inner rows, we have recorded an average wear for each area. The idea is the same in outer area calculations. For example:

$$\frac{0+1+2+3+4}{5}=2$$ - average wear for inner area.

In the case of the third and seventh columns use a list of possible failures. Overall, the six most common defects can be distinguished:

- No wear
- Worn cutter (WT)
- Broken cutter (BT)
- Lost cutter (LT)
- Bond failure (BF)
- Erosion (ER)

The fourth, location factor is used to specify the location of the major dull characteristics noted in the third space.




C – Cone
N – Nose
T – Taper
S – Shoulder
G - Gauge
A – All areas

Figure 3.11 Dull location[1].

The fifth place is always indicated by X in fixed cutter bits case.

The sixth, G column is used to record on the gauge of the bit. Letter I indicates that the bit is still in gauge. If not, the undergauge is notated to the nearest 1/16”.

Column number seven treats to additional factors causes the damage of the drill, regarding not only to the cutting structure. We use two letter codes from column three.

The last, eighth column is related to reasons for pulling bit out of the hole. A list of denotation is shown below[10]:

BHA- Change Bottomhole Assembly
DMF- Downhole Motor Failure
DSF - Drillstring Failure
DST – Drill Stem Test
DTF – Downhole tool
LOG - Run Logs
CM - Condition Mud
DP - Drill Plug
FM - Formation Change
HP - Hole Problems
HR – Hours
PP - Pump Pressure
RIG - Rig Repair
CP - Core Point
PR - Penetration Rate
TD - Total Depth/CSG Depth
TQ - Torque
TW - Twist Off
WC - Weather Conditions
WO - Washout Drillstring

# 3 Drill bit selection criterion

Even though our goal is to make the best preparation at the well planning stage, in industrial practice, the final bit selection is conducted in the field. The drilling engineer should be able to select properly, operate and evaluate the drill bit. It is not an easy task, considering diversification of drilled rocks and wide range of available tools.

There is no particular rule that ensure adequate bit choice. However, using several practical methods the right bit can be chosen with a fair degree of certainty. Ultimately, the personal experience is invaluable as well as an opportunity to compare the offset data in the area.

## 3.1 Through assessment and comparison of offset data

An exploratory drilling entails a number of constraints. Unknown geological structure makes difficult proper match between the rock and the bit. In this situation close collaboration between the geologist and drilling engineer is crucial. The bit supplier is expected to have an extra bits is case of unexpected difficulties and complications.

The circumstances are quite different in development drilling. Offset data from drilled wells and geology are helpful in drill bits selection. Sonic logs can be useful in rock strength estimation. Analysis of information obtained from reference wells allow to drill following wells faster, more efficiently and thus more economically. Summarizing, logging results, bit records and lithology should be taken into account in preparing a bit program.

## 3.2 Bit run cost equation

In order to allow comparison of bit run cost and thus selection of most cost effectively solution the following equation have been introduced. The calculation of cost per foot is conducted by the cost equation expressed as[11]:

$$C_f = \frac{(t_r + t_t + t_c)C_r + t_r C_m + C_b}{\Delta D}$$

where :
$C_f$ - the drilling cost, in [$/ft]
$C_b$ - the cost of bit, in [$]
$C_r$ - the rig cost, in [$/h]
$C_m$ – downhole motor cost, in [$/h]
$t_r$ – the drilling time, in [h]
$t_t$ - the trip time, in [h]
$t_c$ – the connection time, in [h]
$\Delta D$ – the formation interval drilled in [ft]

Values such as bit and rig costs are known. Since the well structure is determined, trip time can be estimated with considerable accuracy. In other words, in estimating cost for a specific selection and operation main unknown values are the penetration rate and bit life. What is it worth noting that driller has direct impact on them. However formation characteristics is uncertain factor. Finally bit selection is typically supported largely by offset data.

## 3.3 Specific energy equation

Teale defined the concept of Mechanical Specific Energy (MSE) as the energy required to remove 1cm$^3$ of rock. When a bit is operating at its peak efficiency, the ratio of energy to rock volume remains relatively constant. Teale derived the mechanical Specific energy equation to show the amount of work that a bit was performing per volume of rock drilled. He then conducted lab test that demonstrated the energy per volume of rock destroyed to be constant, regardless of changes in ROP, WOB or RPM. When a bit is operating at its peak efficiency, the ratio of energy to rock volume will remain relatively constant. This relationship is used operationally to adjust drilling parameters, such as WOB or RPM, to manage the drilling process. The instantaneous penetration rate depends upon rock strength, borehole pressure, and formation fluid pressures. Typically, increasing borehole pressure will reduce penetration rate in an impermeable rock while increasing the borehole and pore pressure differential will reduce penetration rate in a permeable rock. The MSE is approximately equal to the ratio of input energy to the output ROP. In this work, he came up with a relation as a function of drilling parameters as[12]:

$$MSE = E_m\left(\frac{4xWOB}{\pi xD^2x1000}+\frac{480xRPMxT}{D^2xROPx1000}\right)$$

D - Bit diameter, [inches]

T - Torque, [ft-lb]

MSE - Mechanical Specific Energy, [Kpsi]

Em - Mechanical Efficiency, [ ]

WOB - Weight on Bit, [lbs]

RPM - Rotational Speed, [rpm]

ROP - Rate of Penetration, [ft/hr]

## 3.4 ROP models

The object of drilling optimizations is to carry out efficient drilling operation. Nowadays there are two major advanced real-time analysis methods to improve the drilling process. These are mechanical specific energy (MSE) and inverted rate of penetration models.

As mentioned in the previous paragraph, MSE tool is an uncomplicated and practical criterion for selection of bits. The specific energy is defined as the amount of energy required in order to remove a unit volume of rock. However, this method does not take into account change in mud weight and bit wear.

ROP models taking into account factors such as drilling parameters, bit design and bit wear, are able to compute formation drillability. In practice, by changing the drilling parameters or bit type that are components of theoretical models, the optimization is achieved, and thus effective bit run takes place. Rate of penetration models, unlike the MSE method, include bit wear and the effect of changing mud weight.

Combination of improved MSE method (drilling effects included) with ROP models gives useful tool to constant evaluation a bit wear and drilling variables during operation, resulting in an enhanced drilling performance.

In industrial practice allow the selection of optimized conditions to obtain the minimum cost per foot. Through their use, considerable decrease in costs and also increase in rate of penetration are obtained[13].

**Borgouyne & Young ROP Model**

In this model, Rate of penetration value depends on several factors such as bit weight, rotary speed, impact force, bit hydraulics, cutter wear, pore pressure and compaction (Borgouyne and Young 1974). Its mathematical formula is as follows[13]:

$$ROP = f_1 \, x \, f_2 \, x \, f_3 \, x \, f_4 \, x \, f_5 \, x \, f_6 \, x \, f_7 \, x \, f_8$$

Variables $f_1$ to $f_8$ in the equation include the impact of the factors listed below:

- $f_1$ - rock drillability which is relative with formation rock strength $f_1 = e^{2.303\, a_1}$
- $f_2$ – the effect of depth $f_2 = e^{2.303\, a_2 (10000 - D)}$, $D$ in [ft]
- $f_3$ – pore pressure effect, ROP increases with overpressure $f_3 = e^{2.303\, a_3 D^{0.69} (g_p - 9)}$, $g_p$ – pore pressure in pound per gallon equivalent

- $f_4$ – the effect of overbalance on ROP induced by increase in mudweight $f_4 = e^{2.303 a_4 D(g_p - P_c)}$, $P_c$ – mud weight in pound per gallon
- $f_5$ – the effect of change in WOB on ROP $f_5 = \left[\frac{\left(\frac{w}{d_B}\right) - \left(\frac{w}{d_B}\right)t}{4 - \left(\frac{w}{d}\right)t}\right] a_5$, $w$-WOB, $d_B$ – bit diameter
- $f_6$ – the effect of rotary speed on ROP $f_6 = \left(\frac{N}{60}\right)^{a_6}$, $N$ - revolutions per minute
- $f_7$ – the effect of bit wear on ROP, $f_7 = e^{-a_7 x h}$ , $h$ – the amount of bit wear
- $f_8$ – the effect of bit hydraulics influence on ROP, $f_8 = \left(\frac{F_j}{1000}\right)^{a_8}$, $F_j$ – described in Borgouyne and Young

**Real-Time Bit Wear Model Development**

This model is closely related to Borgouyne & Young ROP Model. Drilling data like ROP, WOB, RPM, flow rate, MW and pore pressure are known from offset wells. By inverting the equation from Borgouyne & Young ROP Model, we get the value of $f_1$ – formation drill ability (ft/hr).

$$f_1 = \frac{ROP}{f_2 \ x \ f_3 \ x \ f_4 \ x \ f_5 \ x \ f_6 \ x \ f_7 \ x \ f_8}$$

Fractional bit wear, denoted by h, is simplified and assumed as linear decreasing trend vs. depth mathematically expressed as:

$$h = \frac{(Depth_{Current} - Depth_{in})}{(Depth_{Out} - Depth_{in})} x \frac{DG}{8}$$

DG - IADC dull grade bit wear state which is reported when the bit is pulled and has a value from 0 and 8.

Mechanical specific energy uses the ROP value straight in its formula. To find a correlation between MSE value and rock drill ability a new model is suggested. The new model can be expressed as:

$$MSE = K_1 x \left(\frac{1}{f_1}\right)^{K_2}$$

where $K_1$ and $K_2$ are constants obtained from offset wells data. Their values are site-specific, directly related to the particular field conditions.

**Perfect – Cleaning Model**

Warren developed a rate of penetration model for soft formation roller cone bits, which implies that the cuttings treatment does not affect the obtained ROP. Hence, its practical application in order to predict ROP is severely constrained. However, Perfect Cleaning model is important because it is the starting point for obtaining the Imperfect – Cleaning model discussed further. This model correlated ROP to weight on bit (WOB), rotary speed (RPM), rock strength and bit diameter. Its mathematical formula is as follows[22]:

$$R = \left( \frac{aS^2 d_b^3}{N^b W^2} + \frac{c}{N d_b} \right)^{-1}$$

Where the first term, $\frac{aS^2 d_b^3}{N^b W^2}$, defines the maximum rate at which the bit breaks the rock into cuttings. The second term takes into account the distribution of the applied WOB to more teeth, as with the increase in WOB the teeth penetrate deeper into the rock.

**Imperfect – Cleaning Model**

This model build on the previous one, also consisting of the modified impact force and the mud properties, in order to take into consideration the cuttings removal[22].

$$R = \left( \frac{aS^2 d_b^3}{N W^2} + \frac{b}{N d_b} + \frac{c d_b \gamma_f \mu}{F_{jm}} \right)^{-1}$$

This equation shows the constant transition from cuttings generation to cuttings removal as the controlling factor on ROP. The bit size in the third term reveals the effect of the change in nozzle standoff distance as the diameter changes.

## 3.5 Drill-off test

It is a common applied procedure in industrial practice to optimize drilling parameters such as WOB and RPM for a particular drill bit. Drill off test is carried out every time a new bit is running in a hole, new rock formation is faced or ROP decline is noticed. This method has to be conducted within a homogenous formation assuming that the drill string is a linearly elastic rod which length is changed depending on the quantity of employed tension[2].

# 4 Drill bit optimization simulation

## 4.1 Well location map

PL 350 is a part of block 6507/6 (264 $km^2$) and is situated on the Sør High of the Nordland Ridge in the Norwegian Sea. The Skarv Field is 10 km away to the west and the Heidrun Field is about 25 km in the SSW. There are two targets Sindbad and Sesam that are situated in the central-western part of the block[15].

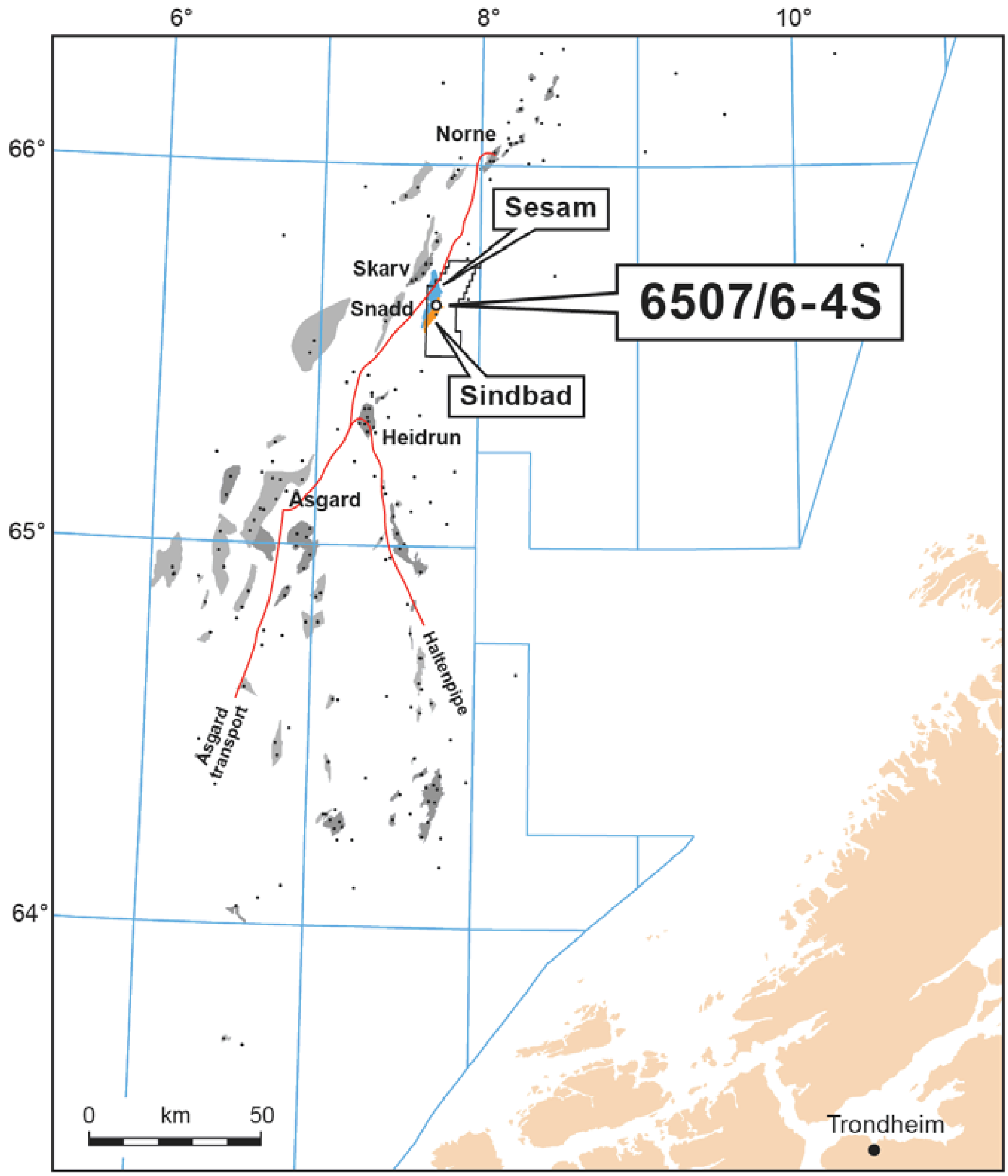



Figure 4.1 Well location[14].

## 4.2 Geological structure

The prospects are located within the Nordland Ridge which is bounded directly to the west by the fault and to the east by the basin. The Sindbad structure is a tilted fault block striking north-east to south-west and dipping to the south-east. The Sesam formation is also a tilted fault block striking and dipping in the same directions as Sindbad structure.

## 4.3 Well design and objects

The water depth at the planned spud location is 333 meters. The well was drilled by Borgland Dolphin, a semi submersible drilling rig. The distance from RKB to MSL (air gap) is 31 m. The two prospects have been achieved by drilling the wells 6507/6-4 S (Sindbad) and the 6507/6-4 A (Sesam) from a shared well-head[15].

The well 6507/6-4S has been drilled vertically from seabed to 950m MD RKB where a small angle will be build up to avoid a minor fault at the Sindbad target level before reaching a final Total Depth (TD), at 1339 m MD RKB/ 1328m TVD SS. The well was logged while drilling to provide realtime directional, pressure while drilling and LWD data.

The well 6507/6-4A has been drilled deviated, from a kick-off point at 950 m MD RKB reaching a maximum inclination of $39{,}6^0$. The well dropped to vertical again by 4205 m MD RKB and drilled vertically through the Sesam reservoir and to a TD at 4957 m MD RKB/ 4391 m TVD SS. The well was logged while drilling to provide realtime directional, pressure while drilling and LWD data.

The well is generally classified as a regular exploration well with normal pressure and temperature. The shallow target - Sindbad, is regarded as regular. The deeper target - Sesam, is considered to be a wildcat prospect. Despite the fact that the area is habitation to cold water corals is regarded not environmentally sensitive.

A number of objectives were related to the complex operation of drilling of an exploration offshore well in Norwegian Continental Shelf (NCS). Therefore, formation evaluation data by MWD/LWD logging, coring, wireline logging, pressure testing, fluid sampling and mini-DST were achieved in order to establish:

- Hydrocarbon presence and properties
- Reservoir properties – thickness and quality
- Identify hydrocarbon contacts / hydrocarbon down to levels

The well has not been kept for future testing or planned for later use. The well was plugged and abandoned in full compliance with Norsok standards.

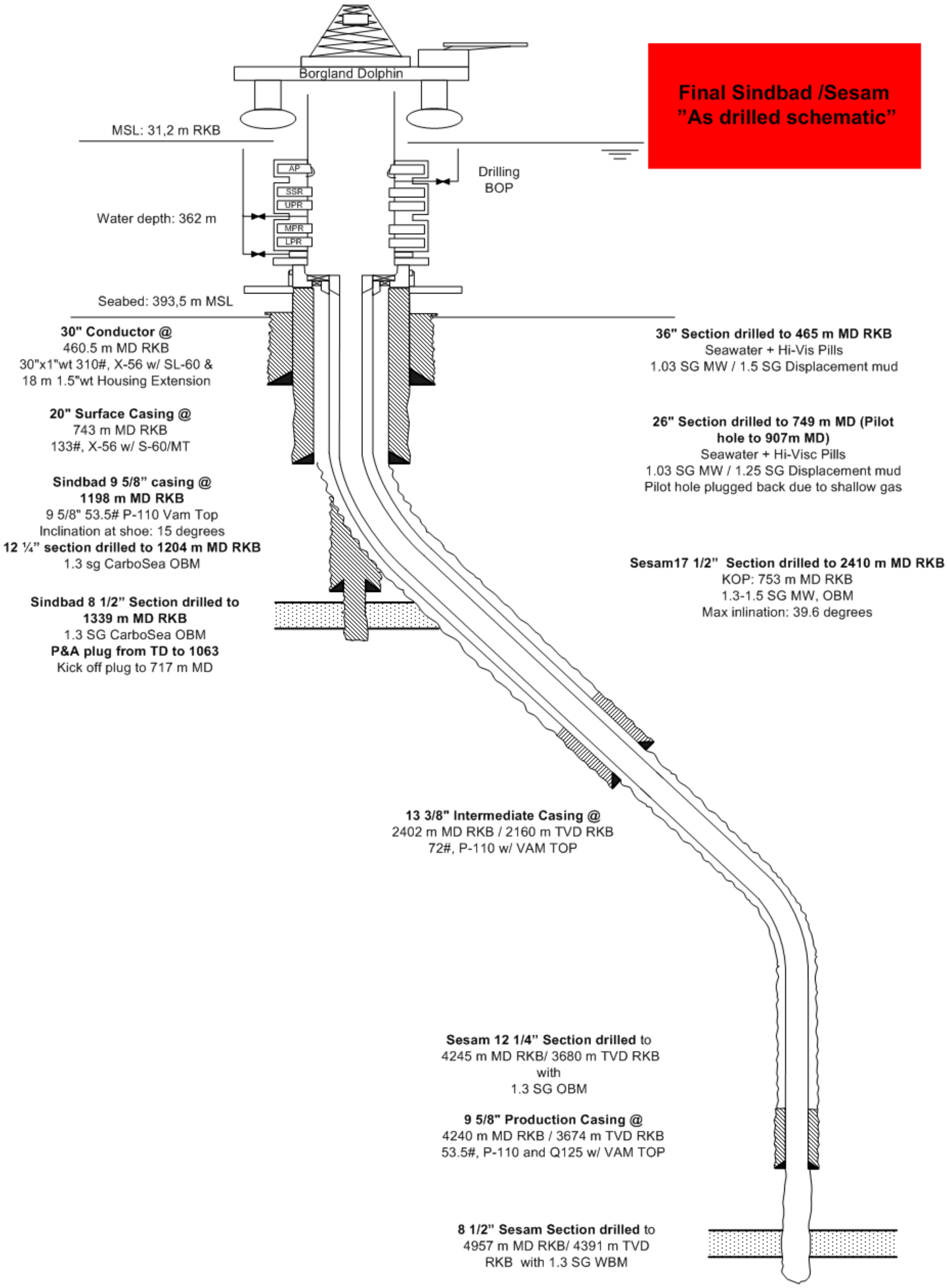



Figure 4.2 Well Sketch[16].

## 4.4 Well results

Shallower target - Sindbad was classified as a dry hole. No coring, wireline logging or mini-DST was performed. TD of Sindbad was set at 1339 m MD RKB.

Sesam – Permian carbonates - was classified as a dry hole, very tight reservoir formation. Coring and two wireline logging runs were performed. No mini-DST was performed. TD of Sesam was set at 4957 m MD RKB. Well define structure mapped on hard event. The well extended for data acquisition purposes (4629 – 4957 m MD).

At this point of the thesis, presenting the results of drilling exploration well, I would like to show the information concerning the two deepest sections 12 ¼” and 8 ½”. These will form the subject of the practical part of my thesis and further considerations. Drilling crew has encountered many obstacles during drilling these two sections.

Sesam 12 ¼” hole.
This section has proved very difficult and demanding. This was due to many factors, including very hard Triassic formations on Haltenbaken and length of the section – 1843m. As a result instead of the planned use of one bit, four bits were used, which resulted in three unplanned bit trips (4 bits used in total: 3 PDC and 1 Kymera).

Sesam 8 ½” hole
Anticipated H2S was not observed. This section was also very hard and problematic. One unplanned bit trip - three bit runs instead of two planned (new bit after core point). Low ROP value and relatively rapid wear of drill bits.

Figure 4.3 Worn out bit from section 8 ½” [17].

## 4.5 Descriptions of geology and formation pressures

Figure 4.4 shows the pore and fracture pressure profiles[14].

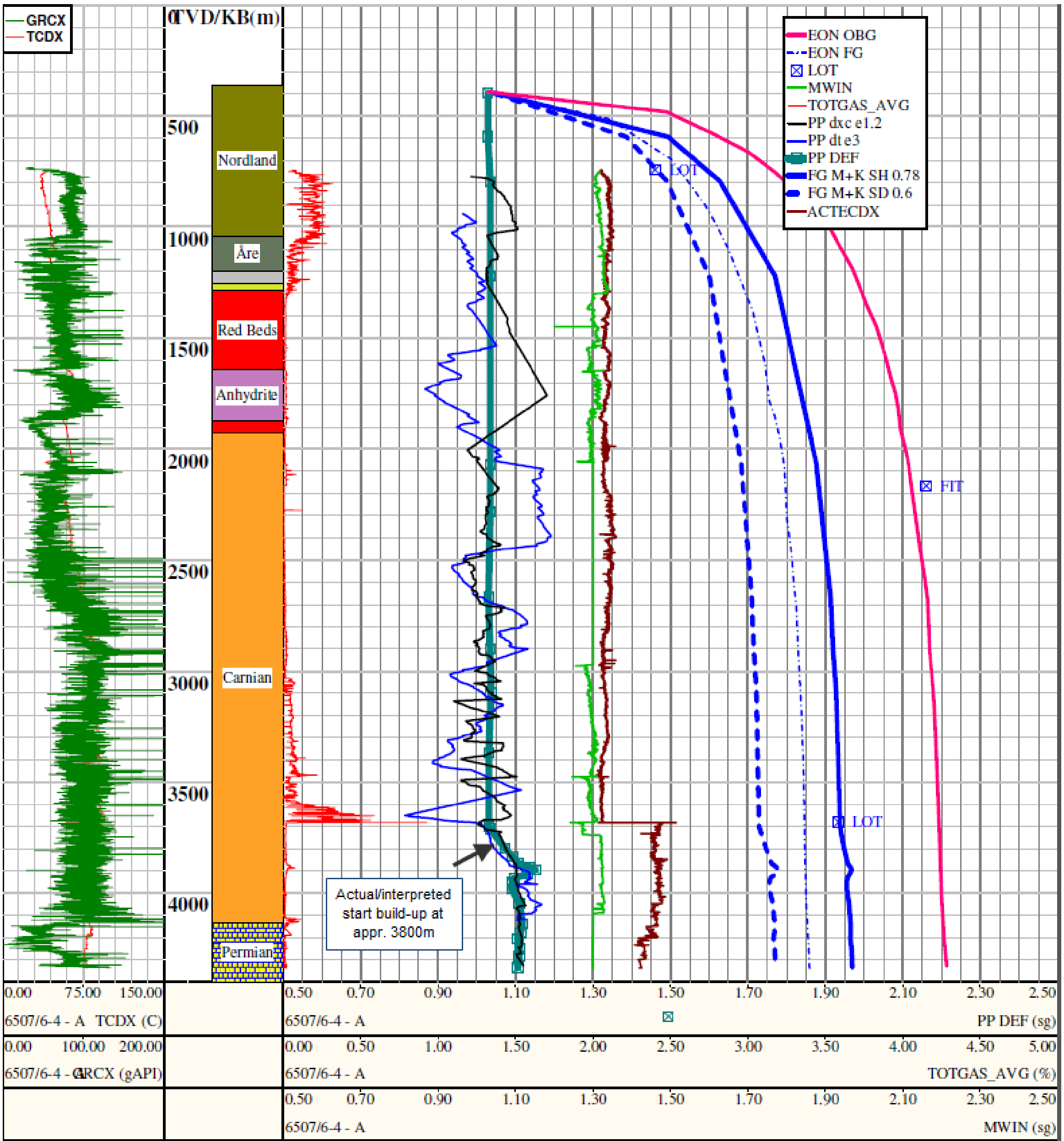


Figure 4.4 Operational window. Pore pressure and fracture gradient summary[14].

The description of the geological formations is obtained from reference (18).

### 4.5.1 Sesam 12 ¼" section (2411m – 4245m MD)

Middle Triassic Red Beds, 2410m – 3100m MD

This is a relative sandy unit consisting of primarily interbedded sandstone and siltstone with some interbedded claystone and traces of limestone/dolomite. The typical characteristic feature of the Triassic is the rapid variation in the lithology and erratic log pattern. The sandstone is clear-light grey, friable-loose, occasionally orange-light brown. The siltstone is variegated grey-red brown, very calcareous and dolomitic. Claystone is variegated brown-dusky red, occasionally green grey, firm, very calcareous and dolomitc.

Early-Middle Triassic Red Beds, 3100m – 3275m MD
This unit is more claystone rich than the section above – especially this is the case towards the base of the section. The section consists of claystone with minor siltstone and sandstone and traces of dolomite/limestone. The claystone is moderate brown-dark red brown, firm-hard, micaceous, calcareous and dolomitic. The siltstone is grey-red, firm-hard and dolomitic. The limestone/dolomite is white-orange brown, occasionally clear and hard.

Lower Triassic Red Beds, 3400m – 4680m MD
This is a sandier unit, but the high resistivity indicates a relative tight formation. Most of the sediments, including the sandstones and siltstones, are calcareous which most likely will act as pore fillings and make the rock very tight. The considerable depth of these sediments will also result in a very tight formation. Sandstone: brown grey-grey red, quartz grains are clear-light grey, firm-hard, predominantly very fine-medium. Claystone/Shale: light-medium grey-medium, firm-hard. Siltstone light-medium grey. Limestone: light grey, firm-hard, argillaceous-very argillaceous, occasionally grading Marl.

### 4.5.2 Sesam 8 ½ section (4246m – 4957m MD)

Permian, 4680m – 4957m MD
This unit contains mainly marl, claystone and limestone. In lower part conglomerate has been encountered. Marl: light greenish grey, soft to firm, occasionally moderate hard, in part grading to Claystone. Locally sandy in upper part, occasional loose Quartz grains. No visual porosity. Sandstone: medium dark grey, medium grey to light grey, predominantly very fine, occasional black carbonaceous speckles, rare loose Quartz grains. Limestone: white to light grey, soft to hard, blocky to subblocky. Claystone: medium grey to dark grey, occasionally light to medium grey, soft to firm, locally moderate hard. Conglomerate: loose quartz grains, fine to very coarse grained, poorly sorted. Quartzite conglomerate: aggregates: dark reddish brown-light brown, moderately orange pink, clear, very fine grained-very coarse. Siltstone: medium dark grey, firm to moderately hard.

## 4.6 The simulation process, input parameters

The DROPS™ Drilling Simulator is a program designed to optimize the drilling process, and thus cost reduction. For this purpose, offset data are used and Apparent Rock Strength Log (ARSL) is created for a particular field. ARSL log is the basis for further work on the simulator, therefore its correctness is highly important.
It is crucial to gain a variable value of rock strength along the entire well. Drilling parameters are a source of data to calculate rock strength. Their advantage is availability along the whole wellbore. Rock strength directly relates to the ROP predictions.

Simulator requires three main types of files to generate ARSL log. These files are :

- **<BITFILE>.bit** contains detailed data about the design features and performance of drill bit
- **<DRILLFILE>.drill** provides specific data about operating parameters
- **<LITHOLOGY>.lith** contains detailed data on the drilled geological formation with their percentage of occurrence
- **<SURVEYFILE>.path** contains the profile coordinates of the well

After generating the ARSL, the program evaluates log accuracy with theoretical models implemented into simulator, by carrying out the operation named Drillbehind. The DrillBehind performs an inverse ARSL calculations, in order to calculate the theoretical values of ROP. Afterwards, previously calculated ROP is compared to the field reported ROP. The DROPS simulator carries out these operations automatically.

The sample fragments of input files for the two selected sections Sesam 12 ¼" and Sesam 8 ½" are placed in the APPENDIX part of thesis.

### 4.6.1 Lithology file of the formations

The lithology file describes the relative content of each type of lithology for every meter of the section.[19]

Due to the fact that the simulator does not take account of certain geological formations, which have been drilled in this well, it was necessary to make certain assumptions. After discussion with the academic supervisor, Mr Skinnarland from Impetro and the PGNiG Norway company employees, aimed at finding the nearest possible equivalent rocks, the following assumptions were made:

- Claystone is replaced by Shale
- Marl is replaced by Lime
- Anhydrite/Gypsum are replaced by Dolomite

The file is created on the basis of analysis of geological profiles from Composite log. The simulator operates on following parameters and types of rock:

MD - Measured Depth (m)
TD – True Vertical Depth (m)
SAND – Percent Sand (%)
SHAL – Percent Shale (%)
LIME – Percent Limestone (%)
DOLO – Percent Dolomite (%)
SILI – Percent Siltstone (%)
CONG – Percent Conglomerate (%)
COAL – Percent Coal (%)
Formation top Identifier
NULL – Parameter Not Used
NULL – Parameter Not Used
P.P. - Pore Pressure Gradient
PERM – Permability (1=Perm,0=Not Perm)

### 4.6.2 Drilling operational parameters

The operation data file describes the required operating parameters for every meter in the relevant section drilled. I created the input files for the two selected sections Sesam 12 ¼" and Sesam 8 ½". The simulator takes into account the following drilling parameters:

MD – Measured Depth(m)
TD – True Vertical Depth(m)
ROP – Rate Of Penetration(m/h)
WOB – Weight On Bit(ton)
RPM – Revolutions Per Minute
GPM – Flowrate (l/min)
PV – Plastic Viscosity(cp)
MW – Mud Weight(kg/l)
MUDTYPE – Mud type(1=oil,0=water)
DMODE – Drill Mode(R=Rotary,S=Rotary,A=AutoBHA)

### 4.6.3 Drill bit parameters

The bit file describes the type of bit and its parameters. Similar to the previous types, also this file has been created for sections Sesam 12 ¼” and Sesam 8 ½”. As in the lithology file, it has been necessary to make an assumptions. Since the Hughes Christensen Kymera hybrid bit is a new solution, it has not been implemented in DROPS software. As a result of consultation, the most accurate approximation is the choice of Tricone bit with IADC code 537. The simulator includes the following bit features:

Bit Type – (N/A)
IADC Code – (N/A)
Bit Diameter – (Inch)
TVD In – (Meter)
TVD Out – (Meter)
MD In – (Meter)
MD Out – (Meter)
Wear In - (N/A)
Wear Out - (N/A)
Cost – (US Dollars)
Cost DHM – (US Dollars/ Day)
Manufacturer - (N/A)
Bit Description - (N/A)
Nozzle1..Nozzle8 – (1/32 Inch)

Primary Number of Cutters - (N/A)
Backup Number of Cutters - (N/A)
Primary Cutter Size - (Inch)
Backup Cutter Size - (Inch)
Primary Backrake – (Degree)
Backup Backrake - (Degree)
Primary Siderake - (Degree)
Backup Siderake - (Degree)
Number of Blades - (N/A)
Junk Slot Area – ($Inch^2$)
Thickness – (1/64 Inch)
Exposure - (Inch)
Distance - (Inch)

I have made also following assumptions:

- Rig cost – 185 000 $/day
- Connection time – 10min/90ft
- Trip time – 1 hour/1000ft R.T.
- Kymera bit /Tricone bit cost – 60 000$
- PDC bit cost – 50 000$
- Coring at the depth of 4726m – 4753m MD, Sesam 8 ½” section is ommited.

Outcomes of my work are significant not only for the PGNiG Norway company I cooperate with, but also for the authors of the DROPS simulator.

### 4.6.4 Survey parameters

The survey file contains the profile coordinates of the well to be optimized using DROPS simulator. The simulator includes the following well path features:

MD – Measured Depth (m)
TD – True Vertical Depth (m)
INCLIN – Inclination angle (Degrees)
AZIMUTH – Azimuth angle (Degrees)

An example of the Survey file *<SURVEYFILE>.path :*

| MD | INCLIN | AZIMUTH | TD |
|---|---|---|---|
| 2411 | 39.52 | 330.08 | 2164.76 |
| 2412 | 39.52 | 330.08 | 2165.53 |
| 2413 | 39.52 | 330.08 | 2166.3 |
| 2414 | 39.52 | 330.08 | 2167.07 |
| 2415 | 39.52 | 330.08 | 2167.84 |
| 2416 | 39.52 | 330.08 | 2168.61 |
| 2417 | 39.52 | 330.08 | 2169.38 |
| 2418 | 39.52 | 330.08 | 2170.15 |
| 2419 | 39.52 | 330.08 | 2170.92 |

# 5 Simulations results and discussion

This chapter presents the results of simulation in two stages. The first stage will present simulations of the carried out drilling. I will discuss the influence of drilling parameters and other variables on the rate of penetration. Parameters used in the simulations are consistent with safety requirements, technical capabilities of equipment and formations conditions (Operational window Fig. 4.4). The second part presents drilling cost optimization analysis. Improved selection of tools and obtained more favorable average rate of penetration, has enabled a significant reduction in drilling costs and the duration of the operation.

## 5.1 Simulation result in 12 ¼" section

### 5.1.1 Drilling parameters review

**Simulation number 0** (reference well), was based on the input data (input files) that were obtained during the 6507/6-4A drilling. Four bits were used in drilling section 12¼", three PDC and one Kymera hybrid bit. According to the IADC dull grading system, the reason the PDC bits were pulled out was unsatisfactory penetration rate. Kymera bit was pulled out because of bearing damage, total loss of outer tooth height, diameter reduction ¼ " out of gauge, which consequently led to insufficient drilling progress. Simulation number 0 will provide a reference point for subsequent simulations, aimed at obtaining more efficient drilling parameters and the average ROP than actually obtained.

| 6507/6-4A Sesam – 12 ¼" Section Bit Review | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Run | Type | Jets | Depth In (m) | Depth Out (m) | Dist. (m) | Hrs bit | IADC Grading | | | | | | | |
| | | | | | | | I | O | D | L | B | G | O | R |
| 1 | PDC | 7x13 | 2411 | 3457 | 1046 | 78 | 1 | 2 | CT | G | X | 1 | NO | PR |
| 2 | PDC | 7x13 | 3457 | 3967 | 510 | 33.9 | 1 | 2 | CT | G | X | 2 | NO | PR |
| 3 | PDC | 6x14, 1x15 | 3967 | 4039 | 72 | 3.3 | 0 | 2 | WT | S | X | 1 | CT | PR |
| 4 | Kymera | 3x14, 3x16 | 4039 | 4245 | 206 | 7.4 | 1 | 8 | RO | S | 8 | 4 | SD | PR |

Table 5.1 IADC dull bit grading for 12 ¼" bits[21].

**In simulation number three** I decided to remove third bit (003-pdc), because of insufficient ROP. I merged section drilled by third PDC bit with previous, second PDC (002-pdc) bit section. However, compared with the real well (simulation 0), a significant decrease in average ROP and increase in second PDC bit wear occurred. Drilling parameters used in simulation three are inadequate.

**In simulation number five**, I changed the drill bit selection and the length of the sections drilled by them. I used one PDC bit (001 – pdc, run 1) with extended than in previous simulations drilling section. Then, two Kymera bits (004-tri, run 2 and 004-tri, run3) with shorter operating times, in order to reduce tool wear at the bottom of the section were used. As a result of adjusting drilling parameters, increase in average ROP with a decrease in tool wear were obtained. The concept of selection of tools considered appropriate, however, parameters require further optimization.

**In simulation number six**, I made changes in working parameters of two Kymera bit (run2, run3), which approximation in DROPS simulator is Tricone bit IADC 537. Increased flowrate has improved bottom hole cleaning. As a consequence, an increase in the efficiency of the second bit (run2, ROP from 10.14 [m/h] to 10.51 [m/h]), with a slight decline in its wear. Increased in WOB (from 12 [t] to 17.7[t]) with declined in rotation speed caused, both ROP and bit wear growth. In consequence, average ROP increased from 10.80 [m/h] in simulation number five to 11.67 [m/h] in sixth simulation.

**In simulation number nine**, by increasing with flow rate and with other parameters unchanged, an increase in average ROP occurred. It confirms the significant impact of cutting removal on drilling progress.

**In simulation number ten**, mud weight increased from 1.30 s.g. to 1.35 s.g. In the case of the first and the second tool, results in a slight increase in rate of penetration. A decreased in WOB for third bit results in decrease in its ROP (7.60 m/h to 6.68 m/h), improved bit wear (from 7.5 to 6.6). Overall, average ROP in this simulation, unsatisfactory. A decisive relationship between WOB and ROP, also subsequently with bit wear.

**For the simulations number eleven and twelve**, minor changes in WOB for the third bit (run 3, 004-tri) and an increase in flow rate in simulation twelve. A slight reduction in tool wear, lack of satisfactory improvement in rate of penetration.

**In the thirteenth simulation**, because of satisfactory results of drilling PDC bit (run1, 001-pdc), I decided to extend its drilling section of 25 m, from 1439m to 1464m. The length of the second bit (run2, 004-tri) section has shortened. The mud density was reduced from 1.35 s.g. to 1.32 s.g. Increased WOB and RPM parameters for the third bit results in a substantial increase in the ROP and wear. As a result, a slight increase in overall average ROP .

**$14^{th}$ simulation**. The increase in mud flow has a positive impact on the drilling progress of first and second tool (run1 and run2). Growth in plastic viscosity (PV from 21 to 23 cP) for PDC bit. A further problem with the third bit wear, reducing the WOB did not produce the desired results. Finally, drop in an average rate of penetration from 11.82 m/h to 11.80 m/h.

**In simulation number fifteen**, searching for the optimum parameters for the bit run 3. The increase in WOB gives rise ROP, a further problem with the wear of the bit.

Further increase in flow rate in the **simulation number sixteen** has the beneficial effects on the growth of average rate of penetration. Other parameters remain unchanged. For the first time, an average ROP is larger than the one obtained in real conditions, well 6507/6-4A (simulation number 0).

Increase in WOB second bit (run2) from 17.5 [t] to 18.5[t], RPM for PDC bit (run1) and a further gradual increase in flow rate result in increased averaged ROP for **simulations 18 to 22** (ROP from 12.02 to 12.40). A noticeable decrease in second and third bits wear (run2 and run3). Establishment of stable, optimal drilling parameters for first (run1, 001-pdc) and second (run2, 004-tri) bits.

**Simulations number 23 – 28** are designed to find optimal parameters for the third bit (run3, 004-tri) representing a compromise between the expected, as far as possible ROP and tool wear. Finally, I recognize the **best simulation of number 28**. The obtained average rate of penetration is indeed smaller than that in simulation 27, but taking into account the bit wear I consider this difference to be negligible.

The carried out simulations described above, are shown in numerical and graphical form in the following tables and graphs.

| Simulation | Run | BitID | From | To | Diff | WOB | RPM | FLOW | PV | MW | Bit Wear | ROP | Avg ROP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 Reference | 1 | 001 – pdc | 2411 | 3457 | 1046.0 | 15.2 | 142.4 | 4256.9 | 21 | 1.30 | 3.0 | 14.19 | 11.90 |
| | 2 | 002 – pdc | 3457 | 3967 | 510.0 | 16.4 | 145.9 | 3898.2 | 20 | 1.29 | 4.0 | 15.36 | |
| | 3 | 003 – pdc | 3967 | 4039 | 72.0 | 15.7 | 152.5 | 4086.5 | 20 | 1.29 | 2.0 | 3.87 | |
| | 4 | 004 – tri | 4039 | 4245 | 206.0 | 15.8 | 125.2 | 3800.0 | 20 | 1.29 | 7.0 | 7.20 | |
| 3 | 1 | 001 – pdc | 2411 | 3457 | 1046.0 | 20.0 | 140.0 | 3000.0 | 21 | 1.30 | 3.8 | 16.22 | 8.04 |
| | 2 | 002 – pdc | 3457 | 4039 | 582.0 | 14.0 | 160.0 | 3000.0 | 21 | 1.30 | 7.2 | 4.38 | |
| | 3 | 003 – tri | 4039 | 4245 | 206.0 | 13.7 | 160.0 | 3000.0 | 21 | 1.30 | 7.5 | 6.70 | |
| 5 | 1 | 001 – pdc | 2411 | 3850 | 1439.0 | 20.0 | 140.0 | 3000.0 | 21 | 1.30 | 4.4 | 12.90 | 10.80 |
| | 2 | 004 – tri | 3850 | 4039 | 189.0 | 17.5 | 130.0 | 3000.0 | 21 | 1.30 | 5.8 | 10.14 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 12.0 | 130.0 | 3000.0 | 21 | 1.30 | 5.8 | 5.19 | |
| 6 | 1 | 001 – pdc | 2411 | 3850 | 1439.0 | 20.0 | 140.0 | 3000.0 | 21 | 1.30 | 4.4 | 12.90 | 11.67 |
| | 2 | 004 – tri | 3850 | 4039 | 189.0 | 17.5 | 130.0 | 3150.0 | 21 | 1.30 | 5.7 | 10.51 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.5 | 110.0 | 3300.0 | 21 | 1.30 | 7.3 | 7.43 | |
| 9 | 1 | 001 – pdc | 2411 | 3850 | 1439.0 | 20.0 | 140.0 | 3050.0 | 21 | 1.30 | 4.3 | 12.96 | 11.75 |
| | 2 | 004 – tri | 3850 | 4039 | 189.0 | 17.5 | 130.0 | 3150.0 | 21 | 1.30 | 5.7 | 10.51 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.5 | 115.0 | 3300.0 | 21 | 1.30 | 7.5 | 7.60 | |
| 10 | 1 | 001 – pdc | 2411 | 3850 | 1439.0 | 20.0 | 140.0 | 3050.0 | 21 | 1.35 | 4.3 | 13.01 | 11.52 |
| | 2 | 004 – tri | 3850 | 4039 | 189.0 | 17.5 | 130.0 | 3150.0 | 21 | 1.35 | 5.7 | 10.61 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 15.5 | 115.0 | 3300.0 | 21 | 1.35 | 6.6 | 6.68 | |
| 11 | 1 | 001 – pdc | 2411 | 3850 | 1439.0 | 20.0 | 140.0 | 3050.0 | 21 | 1.35 | 4.3 | 13.01 | 11.68 |
| | 2 | 004 – tri | 3850 | 4039 | 189.0 | 17.5 | 130.0 | 3150.0 | 21 | 1.35 | 5.7 | 10.61 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3300.0 | 21 | 1.35 | 7.1 | 7.22 | |
| 12 | 1 | 001 – pdc | 2411 | 3850 | 1439.0 | 20.0 | 140.0 | 3200.0 | 21 | 1.35 | 4.3 | 13.17 | 11.70 |
| | 2 | 004 – tri | 3850 | 4039 | 189.0 | 17.5 | 130.0 | 3300.0 | 21 | 1.35 | 5.6 | 10.70 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 16.0 | 110.0 | 3300.0 | 21 | 1.35 | 6.7 | 6.76 | |

Table 5.2 Simulation 12 ¼ ” results.

| Simulation | Run | BitID | From | To | Diff | WOB | RPM | FLOW | PV | MW | Bit Wear | ROP | Avg ROP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 140.0 | 3200.0 | 21 | 1.32 | 4.3 | 13.24 | 11.82 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 17.5 | 130.0 | 3250.0 | 21 | 1.32 | 5.4 | 9.81 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 115.0 | 3300.0 | 21 | 1.32 | 7.3 | 7.38 | |
| 14 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 140.0 | 3400.0 | 23 | 1.30 | 4.3 | 13.31 | 11.80 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 17.5 | 130.0 | 3350.0 | 21 | 1.32 | 5.3 | 9.85 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 16.5 | 115.0 | 3300.0 | 21 | 1.32 | 7.1 | 7.15 | |
| 15 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 140.0 | 3400.0 | 23 | 1.30 | 4.3 | 13.31 | 11.87 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 17.5 | 130.0 | 3350.0 | 21 | 1.32 | 5.3 | 9.85 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 115.0 | 3300.0 | 21 | 1.32 | 7.3 | 7.38 | |
| 16 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 140.0 | 3500.0 | 23 | 1.30 | 4.3 | 13.40 | 11.93 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 17.5 | 130.0 | 3400.0 | 21 | 1.32 | 5.2 | 9.87 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 115.0 | 3350.0 | 21 | 1.32 | 7.3 | 7.39 | |
| 18 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 140.0 | 3600.0 | 23 | 1.30 | 4.2 | 13.49 | 12.02 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3500.0 | 21 | 1.32 | 5.5 | 10.52 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3400.0 | 21 | 1.32 | 7 | 7.23 | |
| 19 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 3600.0 | 23 | 1.30 | 4.3 | 13.71 | 12.16 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3500.0 | 21 | 1.32 | 5.5 | 10.52 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3400.0 | 21 | 1.32 | 7 | 7.23 | |
| 20 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 3800.0 | 23 | 1.30 | 4.3 | 13.88 | 12.29 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3700.0 | 21 | 1.32 | 5.3 | 10.61 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3600.0 | 21 | 1.32 | 6.8 | 7.26 | |
| 21 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 3900.0 | 23 | 1.30 | 4.2 | 13.96 | 12.35 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3800.0 | 21 | 1.32 | 5.3 | 10.65 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3700.0 | 21 | 1.32 | 6.8 | 7.28 | |
| 22 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 4000.0 | 23 | 1.30 | 4.2 | 14.04 | 12.40 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3800.0 | 21 | 1.32 | 5.3 | 10.65 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3800.0 | 21 | 1.32 | 6.7 | 7.30 | |

Table 5.3 Simulation 12 ¼ ” results.

| Simulation | Run | BitID | From | To | Diff | WOB | RPM | FLOW | PV | MW | Bit Wear | ROP | Avg ROP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 4000.0 | 23 | 1.30 | 4.2 | 14.04 | 12.33 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3850.0 | 21 | 1.32 | 5.2 | 10.68 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 16.5 | 110.0 | 3800.0 | 21 | 1.32 | 6.5 | 7.06 | |
| 24 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 4000.0 | 23 | 1.30 | 4.2 | 14.04 | 12.33 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3850.0 | 21 | 1.32 | 5.2 | 10.68 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 16.5 | 110.0 | 3850.0 | 21 | 1.32 | 6.4 | 7.07 | |
| 25 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 4000.0 | 23 | 1.30 | 4.2 | 14.04 | 12.41 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3850.0 | 21 | 1.30 | 5.3 | 10.67 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3850.0 | 21 | 1.30 | 6.7 | 7.31 | |
| 26 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 4000.0 | 23 | 1.30 | 4.2 | 14.04 | 12.39 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3850.0 | 21 | 1.30 | 5.3 | 10.67 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 16.5 | 115.0 | 3850.0 | 21 | 1.30 | 6.6 | 7.24 | |
| 27 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 4000.0 | 23 | 1.30 | 4.2 | 14.04 | 12.44 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3850.0 | 21 | 1.30 | 5.3 | 10.67 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 16.5 | 120.0 | 3850.0 | 21 | 1.30 | 6.8 | 7.40 | |
| 28 | 1 | 001 – pdc | 2411 | 3875 | 1464.0 | 20.0 | 145.0 | 4000.0 | 23 | 1.30 | 4.2 | 14.04 | 12.41 |
| | 2 | 004 – tri | 3875 | 4039 | 164.0 | 18.5 | 130.0 | 3850.0 | 21 | 1.32 | 5.2 | 10.68 | |
| | 3 | 004 – tri | 4039 | 4245 | 206.0 | 17.0 | 110.0 | 3850.0 | 21 | 1.32 | 6.6 | 7.31 | |

Table 5.4 Simulation 12 ¼ ” results.

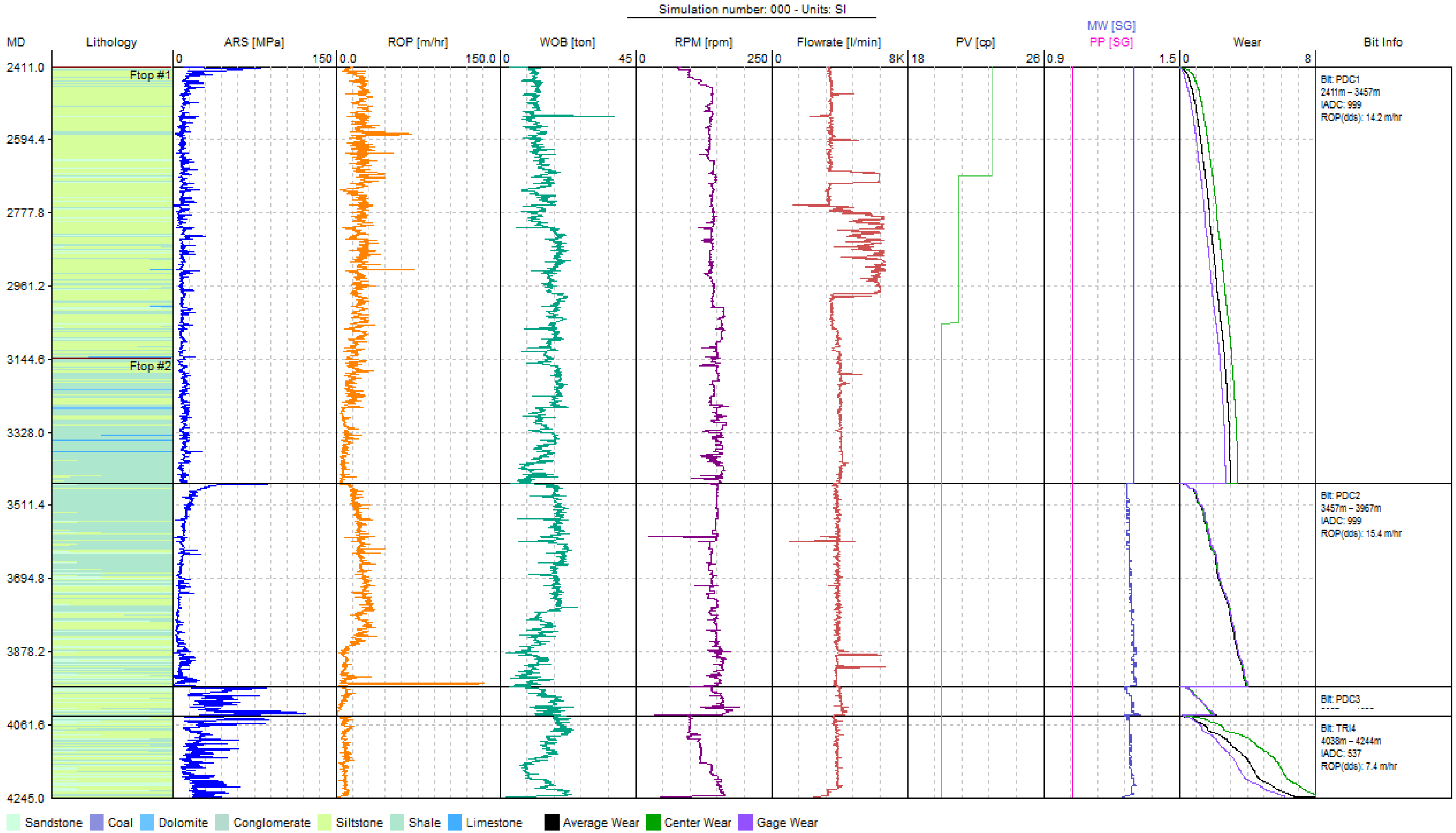



Figure 5.1 Simulation results, input files.

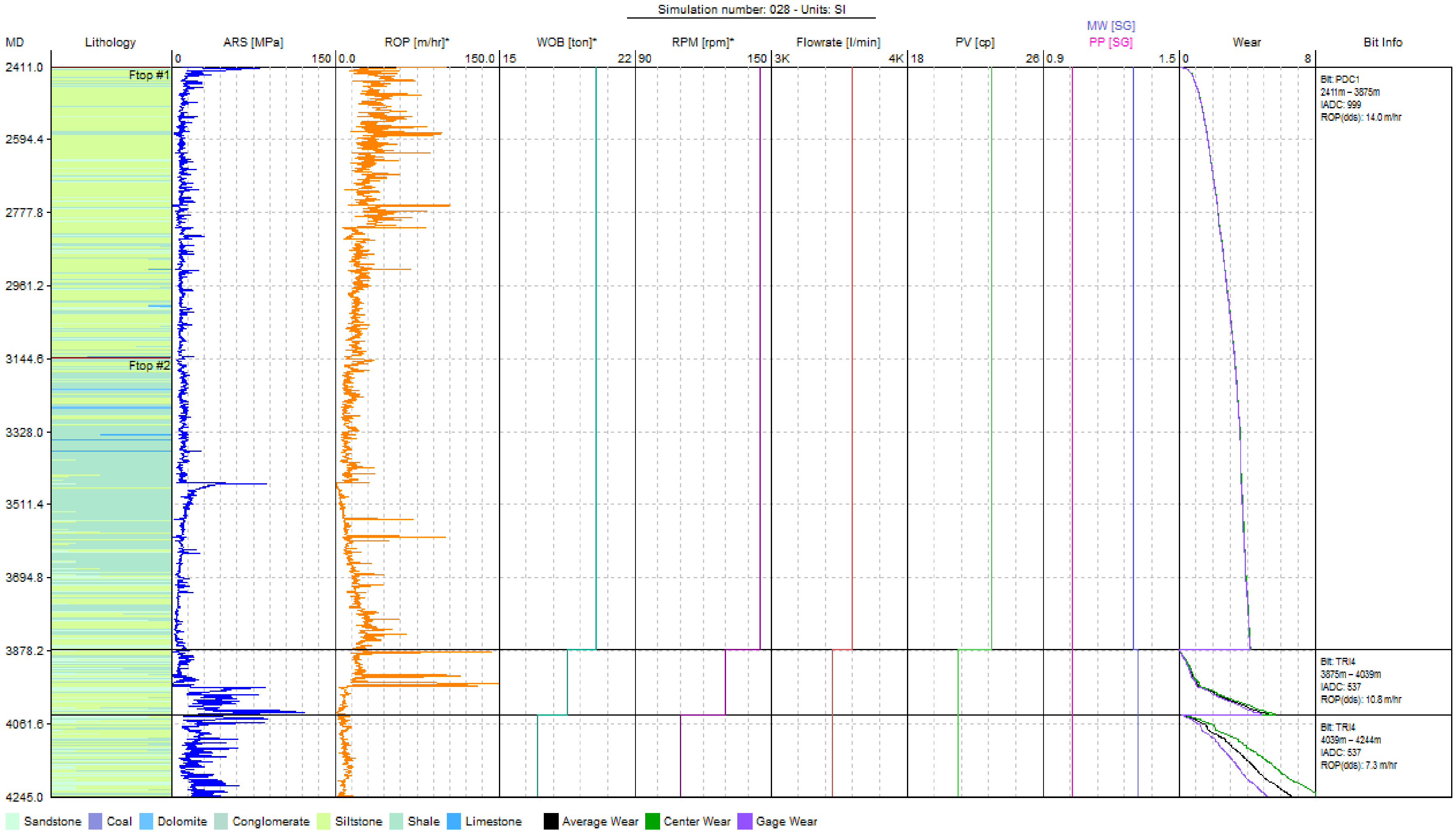



Figure 5.2 Simulation number 28 results.

### 5.1.2 Reduction of drilling costs review

Drilling parameters directly affect the resulting ROP. Also the cost and duration of the operation itself is dependent on many factors. One of them is obtained ROP. Can therefore be said that the drilling parameters have no direct impact on the overall cost of the entire drilling process. In this section, we discuss evolution of drilling costs, depending on the results of the simulation. The reference point will be the actual costs of drilling of exploratory well 6507/6-4A. The simulation results are presented in table form.

DROPS$^{TM}$ Drilling Simulator includes the following categories of costs:

- Bit cost [Thousand USD]
- Tripping cost [Thousand USD]
- Connection time cost [Thousand USD]
- Rotating cost – the cost of drilling excluding bit, trip and connection cost [Thousand USD]

As I mentioned in the introduction I have made also a following assumptions:

- Rig cost – 185 000 $/day
- Connection time – 10min/90ft
- Trip time – 1 hour/1000ft R.T.
- Kymera bit /Tricone bit cost – 60 000$ = 60 Thousand USD
- PDC bit cost – 50 000$ = 50 Thousand USD

<u>Bit costs</u>.

Simulation number 0 was based on the input data from the 6507/6-4A drilling. In a real well four drilling bits were used, three times PDC bit and once Kymera Hybrid bit. After adding, the following value is obtained:

$$3 \times 50 + 1 \times 60 = 210 \text{ Thousand USD}$$

In simulation number three I decided to use two PDC bit and one Kymera Hybrid bit, which gives:

$$2 \times 50 + 1 \times 60 = 160 \text{ Thousand USD}$$

In fifth simulation, I changed the drill bit selection and I used one PDC bit (001 – pdc, run 1) and two Kymera bits. As a result, the obtained value is:

$$1 \times 50 + 2 \times 60 = 170 \text{ Thousand USD}$$

I recognized it as the right choice and in the subsequent simulations, drill bit selection remains unchanged.

Tripping cost.

Tripping cost is the resultant of number of used drill bits and the length of each section drilled by them.

In simulation number zero, four bits were used which gives a cost of 374 Thousand USD.

In a subsequent, third simulation is a noticeable decrease in the tripping cost, from 374 Thousand USD to 273.3 Thousand USD, which is associated with a reduction in the number of tools used and the length of each tool section.

In simulations five to twelve, there was a slight increase in tripping cost (from 273.3 to 283.7 Thousand USD) as a result of change in sections length. In the first, PDC section (run1) was elongated from 1046 m to 1439m, whilst second, Kymera bit section (run2, 004-tri) decreased by the same length (from 582m to 189m). The length of third, Kymera bit section (run3, 004-tri) remained the same (206m).

From simulation thirteenth to the last, which is twenty eighth simulation, I decided to elongate further PDC section (run1, 001-pdc) and thus I shorten second section (run2, 004-tri). Tripping cost increased from 283.7 Thousand USD to 284.3 Thousand USD.

There is a noticeable correlation between the increase in the length of the longest section and the increased cost.

Connection cost. As the length of the section 12¼" is 1834 m for all simulations, the connection time cost is constant and is 128.9 Thousand USD.

Rotating cost. Its value is closely related with average, obtained rate of penetration. With an increase in ROP, drilling cost decreases. This relationship is shown in graph.

Taking into consideration all costs we get the Total cost in Thousand USD.

$$Total\ cost = Bit\ cost + Tripping\ cost + Connection\ time\ cost + Rotating\ cost$$

$$Cost\frac{\$}{m} = \frac{Total\ cost}{Section\ length}$$

I recognize the **best simulation of number 28**, because of compromise between the ROP, tool wear and costs.

| Simulation | Bit | Trip | Connect | Rotating | Total | Cost $/m | Time [h] | Avg ROP | Wear |
|---|---|---|---|---|---|---|---|---|---|
| 0 Reference | 210 | 374 | 128.9 | 1189.2 | 1902.225 | 1036.6 | 154.1 | 11.9 | 3, 4, 2, 7 |
| 3 | 160 | 273.7 | 128.9 | 1759.3 | 2321.889 | 1265.3 | 228.1 | 8.04 | 3.8, 7.2, 7.5 |
| 5 | 170 | 283.7 | 128.9 | 1309.7 | 1892.247 | 1031.2 | 169.8 | 10.8 | 4.4, 5.8, 5.8 |
| 6 | 170 | 283.7 | 128.9 | 1212.4 | 1794.985 | 978.2 | 157.2 | 11.67 | 4.4, 5.7, 7.3 |
| 9 | 170 | 283.7 | 128.9 | 1203.7 | 1786.260 | 973.4 | 156.1 | 11.75 | 4.3, 5.7, 7.5 |
| 10 | 170 | 283.7 | 128.9 | 1228.3 | 1810.849 | 986.8 | 159.2 | 11.52 | 4.3, 5.7, 6.6 |
| 11 | 170 | 283.7 | 128.9 | 1210.6 | 1793.168 | 977.2 | 157.0 | 11.68 | 4.3, 5.7, 7.1 |
| 12 | 170 | 283.7 | 128.9 | 1214.0 | 1796.532 | 979.0 | 157.4 | 11.7 | 4.3, 5.6, 6.7 |
| 13 | 170 | 284.3 | 128.9 | 1197.0 | 1780.214 | 970.1 | 155.2 | 11.82 | 4.3, 5.4, 7.3 |
| 14 | 170 | 284.3 | 128.9 | 1198.7 | 1781.941 | 971.1 | 155.4 | 11.8 | 4.3, 5.3, 7.1 |
| 15 | 170 | 284.3 | 128.9 | 1191.9 | 1775.053 | 967.3 | 154.5 | 11.87 | 4.3, 5.3, 7.3 |
| 16 | 170 | 284.3 | 128.9 | 1185.6 | 1768.813 | 963.9 | 153.7 | 11.93 | 4.3, 5.2, 7.3 |
| 18 | 170 | 284.3 | 128.9 | 1176.9 | 1760.141 | 959.2 | 152.6 | 12.02 | 4.2, 5.5, 7.0 |
| 19 | 170 | 284.3 | 128.9 | 1163.5 | 1746.728 | 951.9 | 150.8 | 12.16 | 4.3, 5.5, 7.0 |
| 20 | 170 | 284.3 | 128.9 | 1151.3 | 1734.504 | 945.2 | 149.2 | 12.29 | 4.3, 5.3, 6.8 |
| 21 | 170 | 284.3 | 128.9 | 1145.5 | 1728.683 | 942.1 | 148.5 | 12.35 | 4.2, 5.3, 6.8 |
| 22 | 170 | 284.3 | 128.9 | 1140.3 | 1723.548 | 939.3 | 147.9 | 12.4 | 4.2, 5.3, 6.7 |
| 23 | 170 | 284.3 | 128.9 | 1147.4 | 1730.559 | 943.1 | 148.7 | 12.33 | 4.2, 5.2, 6.5 |
| 24 | 170 | 284.3 | 128.9 | 1147.1 | 1730.286 | 942.9 | 148.7 | 12.33 | 4.2, 5.2, 6.4 |
| 25 | 170 | 284.3 | 128.9 | 1140.0 | 1723.215 | 939.1 | 147.8 | 12.41 | 4.2, 5.3, 6.7 |
| 26 | 170 | 284.3 | 128.9 | 1142.0 | 1725.179 | 940.2 | 148.0 | 12.39 | 4.2, 5.3, 6.6 |
| 27 | 170 | 284.3 | 128.9 | 1137.1 | 1720.342 | 937.5 | 147.4 | 12.44 | 4.2, 5.3, 6.8 |
| 28 | 170 | 284.3 | 128.9 | 1139.8 | 1723.000 | 939.0 | 147.8 | 12.41 | 4.2, 5.2, 6.6 |
| Cost reduction (Best simulation 28 – Reference simulation 0) | 40 | 89.7 | 0 | 49.4 | 179.225 | 97.6 | 6.3 | | |

Table 5.5 Costs analysis, 12 ¼” section.

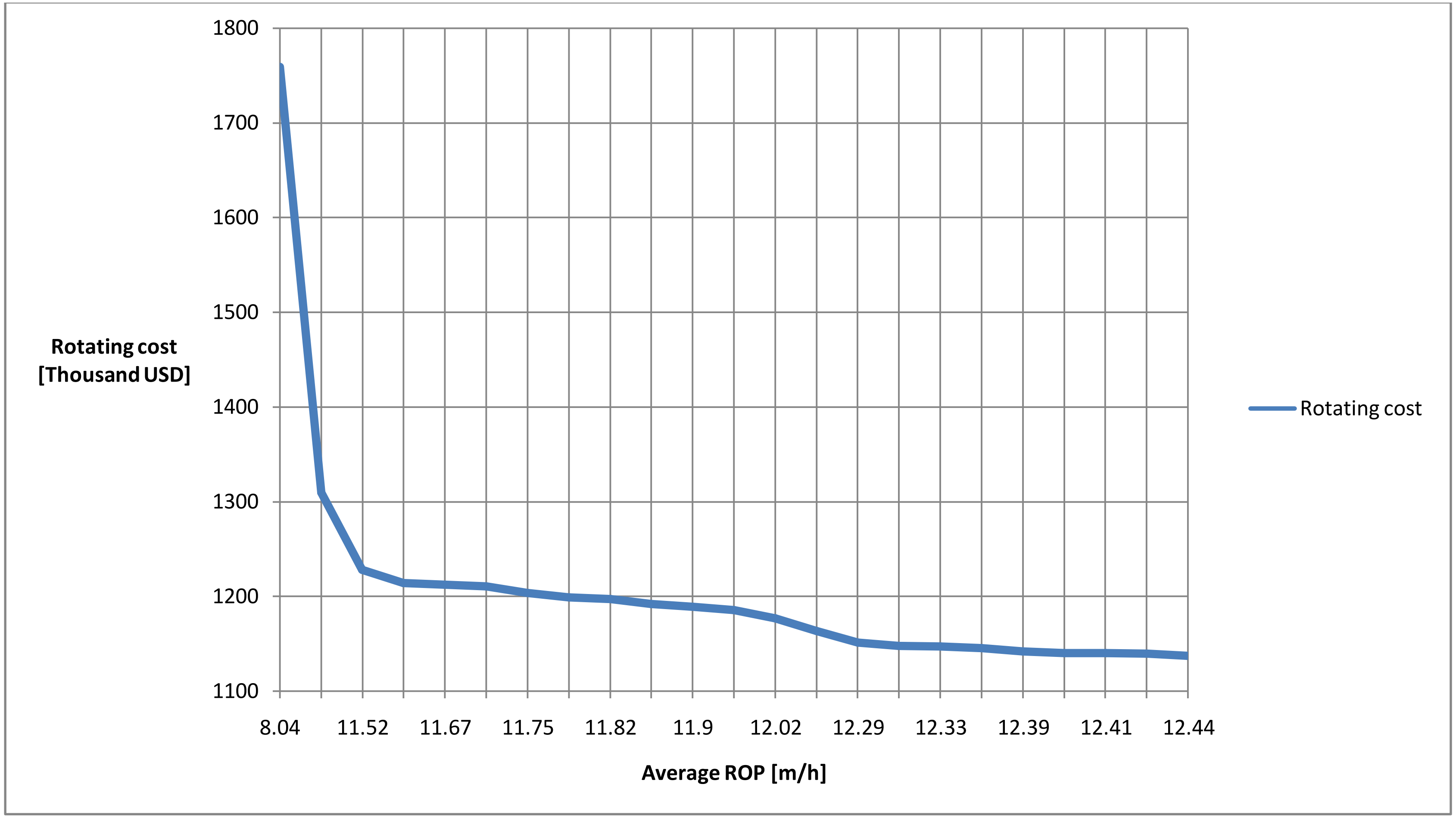



Figure 5.3 The relation between Rotating cost and Average ROP, 12 ¼" section.

## 5.2 Simulation result in 8 ½” section

### 5.2.1 Drilling parameters review

Analysis of this section shall be conducted in a manner similar to that of previous section 12 ¼”. Simulation number 0 was based on the input data (input files) from drilling a well 6507/6-4A. Three Kymera Hybrid bits were used in drilling section 8 ½”. According to the IADC dull grading system, the reasons the first Kymera bit was pulled out were achievement of the assumed working time, hours of bit, and slight damage. Second Kymera bit was pulled out because of run log. Third drilling tool was pulled out because of lost cone, bearing damage, significant loss of both inner and outer tooth height, severe diameter reduction, which consequently led to unsatisfactory drilling progress and destruction of bit. As mentioned earlier, I have omitted coring at the depth of 4726m – 4753m MD, and I merged this section with the second Kymera Hybrid bit.

**Simulation number 0** (reference well) will provide a reference point for subsequent simulations, aimed at obtaining more efficient drilling parameters and the average ROP than actually obtained.

| 6507/6-4A Sesam – 8 ½” Section Bit Review | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Run | Type | Jets | Depth In (m) | Depth Out (m) | Dist. (m) | Hrs bit | IADC Grading | | | | | | | |
| | | | | | | | I | O | D | L | B | G | O | R |
| 1 | Kymera | 2x14, 2x16 | 4246 | 4612 | 366 | 60.1 | 1 | 5 | WT | G | E | I | NO | HR |
| 2 | Kymera | 1x20, 1x22 | 4612 | 4753 | 141 | 20.9 | 1 | 3 | CT | G | E | I | CD | LOG |
| 3 | Kymera | 2x14, 2x16 | 4753 | 4957 | 204 | 39.5 | 6 | 7 | BT LC | A 1 | F | 10 | CT CR | PR |

Table 5.6 IADC dull bit grading for 8 ½” bits[21].

**In simulation number two**, minimal changes in operating parameters were made. Hence, the minor improvements in results.

**In the third simulation**, I increased WOB and RPM of second bit (run2, 002-tri) in order to improve its performance. Also flow rate for all three bits was raised. As a result, an increase in average ROP and reduction in tools wear were achieved.

**In fourth simulation**, I changed lengths of the first and second sections. To compensate the difference in the length of each tool operation, I shortened the length of the first bit’s section (from 366m to 204m) and elongated the section of the second bit (from 141m to 303m). In the case of the second tool, it led to a significant decrease in performance (WOB from 7.68 to

0.76) and an excessive wear. I increased drilling parameters such as WOB and RPM for the first bit, which produced good results in its performance. Finally, the overall result of the simulation was disappointing, but operating parameters for first bit I found worth consideration.

**In fifth simulation**, I introduced a correction in the length of each section. Also drilling parameters were balanced which consequently led to an increase of an average ROP and the bits wear reduction.

Determined length of the work of particular bits I consider as reasonable. In **simulations sixth to ninth** by a slight modifications of the drilling mud features such as increase in flow rate and mud density and with other parameters unchanged, I achieved gradual increase in average ROP (6.46 – 6.56 – 6.57 – 6.63 [m/h]). I notice the important influence of cutting removal on drilling progress.

**In 10$^{th}$ simulation**, in order to decrease the wear of the second bit, I reduced WOB from 14.5 to 14.0 [t] and RPM from 110 to 105 rotation per minute. However, I haven not managed to decrease wear. Negative result is the reduction of an average ROP.

For the **simulations eleven and twelve**, changes in WOB and RPM for the first and second bit. In simulation twelfth, obtained relevant parameters and the best performance for the third drilling tool. A slight improvement in average rate of penetration resulted.

In **thirteenth simulation**, stabilization of mud properties. Unsatisfactory results of drilling second Kymera bit (run2, 002-tri), incorrect drilling parameters, insufficient WOB. As a result, a slight decrease in overall average ROP.

Simulations **number fourteen and fifteen** were conducted to achieve optimal parameters for the first and second bits. By increasing in rotation for bit run1 and WOB for bit run2, I have achieved their best performance so far. Finally, I recognize the best simulation number fifteen, which compromises between bits wear and obtained average ROP.

| Simulation | Run | BitID | From | To | Diff | WOB | RPM | FLOW | PV | MW | Bit Wear | ROP | Avg. ROP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 Reference | 1 | 001 - tri | 4246 | 4612 | 366 | 14.1 | 101.4 | 2447.2 | 16.9 | 1.31 | 5.0 | 6.14 | 6.06 |
| | 2 | 002 - tri | 4612 | 4753 | 141 | 12.5 | 99.4 | 2133.4 | 15.9 | 1.31 | 4.0 | 6.86 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.4 | 120.7 | 1829.3 | 15.0 | 1.30 | 7.0 | 5.51 | |
| 2 | 1 | 001 - tri | 4246 | 4612 | 366 | 14.1 | 101.0 | 2450.0 | 17.0 | 1.31 | 5.0 | 6.25 | 6.11 |
| | 2 | 002 - tri | 4612 | 4753 | 141 | 12.5 | 100.0 | 2410.0 | 16.0 | 1.31 | 3.5 | 6.53 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.3 | 120.0 | 1830.0 | 15.0 | 1.30 | 6.7 | 5.64 | |
| 3 | 1 | 001 - tri | 4246 | 4612 | 366 | 14.0 | 101.0 | 2600.0 | 17.0 | 1.31 | 4.7 | 6.26 | 6.32 |
| | 2 | 002 - tri | 4612 | 4753 | 141 | 14.0 | 110.0 | 2500.0 | 16.0 | 1.31 | 4.1 | 7.68 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.0 | 120.0 | 2200.0 | 15.0 | 1.30 | 5.7 | 5.72 | |
| 4 | 1 | 001 - tri | 4246 | 4450 | 204 | 15.0 | 110.0 | 2600.0 | 17.0 | 1.31 | 3.3 | 7.04 | 1.52 |
| | 2 | 002 - tri | 4450 | 4753 | 303 | 14.0 | 110.0 | 2600.0 | 16.0 | 1.31 | 9.1 | 0.76 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 17.0 | 120.0 | 2400.0 | 15.0 | 1.30 | 5.1 | 5.44 | |
| 5 | 1 | 001 - tri | 4246 | 4550 | 304 | 14.0 | 110.0 | 2600.0 | 17.0 | 1.31 | 4.4 | 6.53 | 6.46 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 14.0 | 110.0 | 2500.0 | 16.0 | 1.31 | 5.6 | 7.25 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.0 | 120.0 | 2300.0 | 15.0 | 1.30 | 5.5 | 5.74 | |
| 6 | 1 | 001 - tri | 4246 | 4550 | 304 | 14.5 | 110.0 | 2600.0 | 17.0 | 1.31 | 4.6 | 6.76 | 6.56 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 14.0 | 110.0 | 2500.0 | 16.0 | 1.31 | 5.6 | 7.25 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.0 | 120.0 | 2400.0 | 15.0 | 1.30 | 5.4 | 5.77 | |
| 8 | 1 | 001 - tri | 4246 | 4550 | 304 | 14.5 | 110.0 | 2600.0 | 17.0 | 1.32 | 4.6 | 6.76 | 6.57 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 14.0 | 110.0 | 2500.0 | 16.0 | 1.32 | 5.6 | 7.25 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.0 | 120.0 | 2400.0 | 15.0 | 1.31 | 5.3 | 5.79 | |
| 9 | 1 | 001 - tri | 4246 | 4550 | 304 | 14.5 | 110.0 | 2600.0 | 17.0 | 1.32 | 4.6 | 6.76 | 6.63 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 14.5 | 110.0 | 2550.0 | 16.0 | 1.32 | 5.7 | 7.52 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.0 | 120.0 | 2450.0 | 15.0 | 1.31 | 5.3 | 5.79 | |

Table 5.7 Simulation 8 ½” results.

| Simulation | Run | BitID | From | To | Diff | WOB | RPM | FLOW | PV | MW | Bit Wear | ROP | Avg. ROP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | 1 | 001 - tri | 4246 | 4550 | 304 | 14.5 | 110.0 | 2600.0 | 17.0 | 1.32 | 4.6 | 6.76 | 6.61 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 14.0 | 105.0 | 2550.0 | 16.0 | 1.32 | 5.7 | 7.43 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.0 | 120.0 | 2450.0 | 15.0 | 1.31 | 5.3 | 5.79 | |
| 11 | 1 | 001 - tri | 4246 | 4550 | 304 | 15.0 | 105.0 | 2600.0 | 17.0 | 1.32 | 4.6 | 6.83 | 6.68 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 15.0 | 105.0 | 2550.0 | 16.0 | 1.32 | 5.8 | 7.59 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 18.0 | 120.0 | 2450.0 | 15.0 | 1.31 | 5.3 | 5.79 | |
| 12 | 1 | 001 - tri | 4246 | 4550 | 304 | 15.0 | 105.0 | 2600.0 | 17.0 | 1.32 | 4.6 | 6.83 | 6.71 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 15.0 | 105.0 | 2600.0 | 16.0 | 1.32 | 5.7 | 7.62 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 19.0 | 110.0 | 2500.0 | 15.0 | 1.31 | 5.2 | 5.87 | |
| 13 | 1 | 001 - tri | 4246 | 4550 | 304 | 15.0 | 105.0 | 2600.0 | 17.0 | 1.32 | 4.6 | 6.83 | 6.67 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 15.0 | 100.0 | 2600.0 | 17.0 | 1.32 | 5.5 | 7.44 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 19.0 | 110.0 | 2500.0 | 15.0 | 1.31 | 5.2 | 5.87 | |
| 14 | 1 | 001 - tri | 4246 | 4550 | 304 | 15.0 | 105.0 | 2600.0 | 17.0 | 1.32 | 4.6 | 6.83 | 6.77 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 16.0 | 100.0 | 2600.0 | 17.0 | 1.32 | 5.9 | 7.89 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 19.0 | 110.0 | 2500.0 | 15.0 | 1.31 | 5.2 | 5.87 | |
| 15 | 1 | 001 - tri | 4246 | 4550 | 304 | 15.0 | 110.0 | 2600.0 | 17.0 | 1.31 | 4.7 | 6.97 | 6.83 |
| | 2 | 002 - tri | 4550 | 4753 | 203 | 16.0 | 100.0 | 2600.0 | 17.0 | 1.32 | 5.9 | 7.89 | |
| | 3 | 003 - tri | 4753 | 4957 | 204 | 19.0 | 110.0 | 2500.0 | 15.0 | 1.31 | 5.2 | 5.87 | |

Table 5.8 Simulation 8 ½” results.

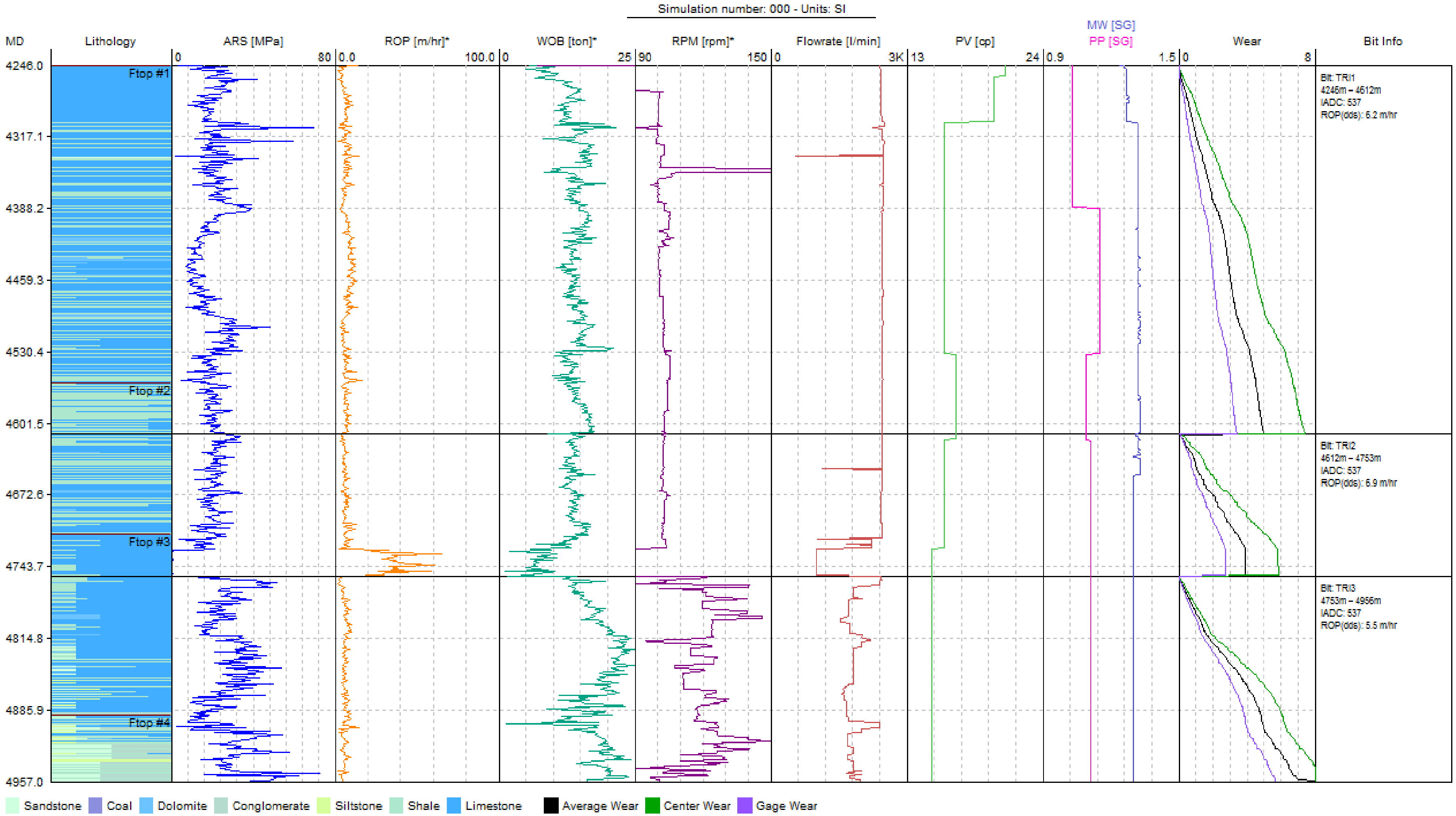



Figure 5.4 Simulation results, input files, 8 ½”.

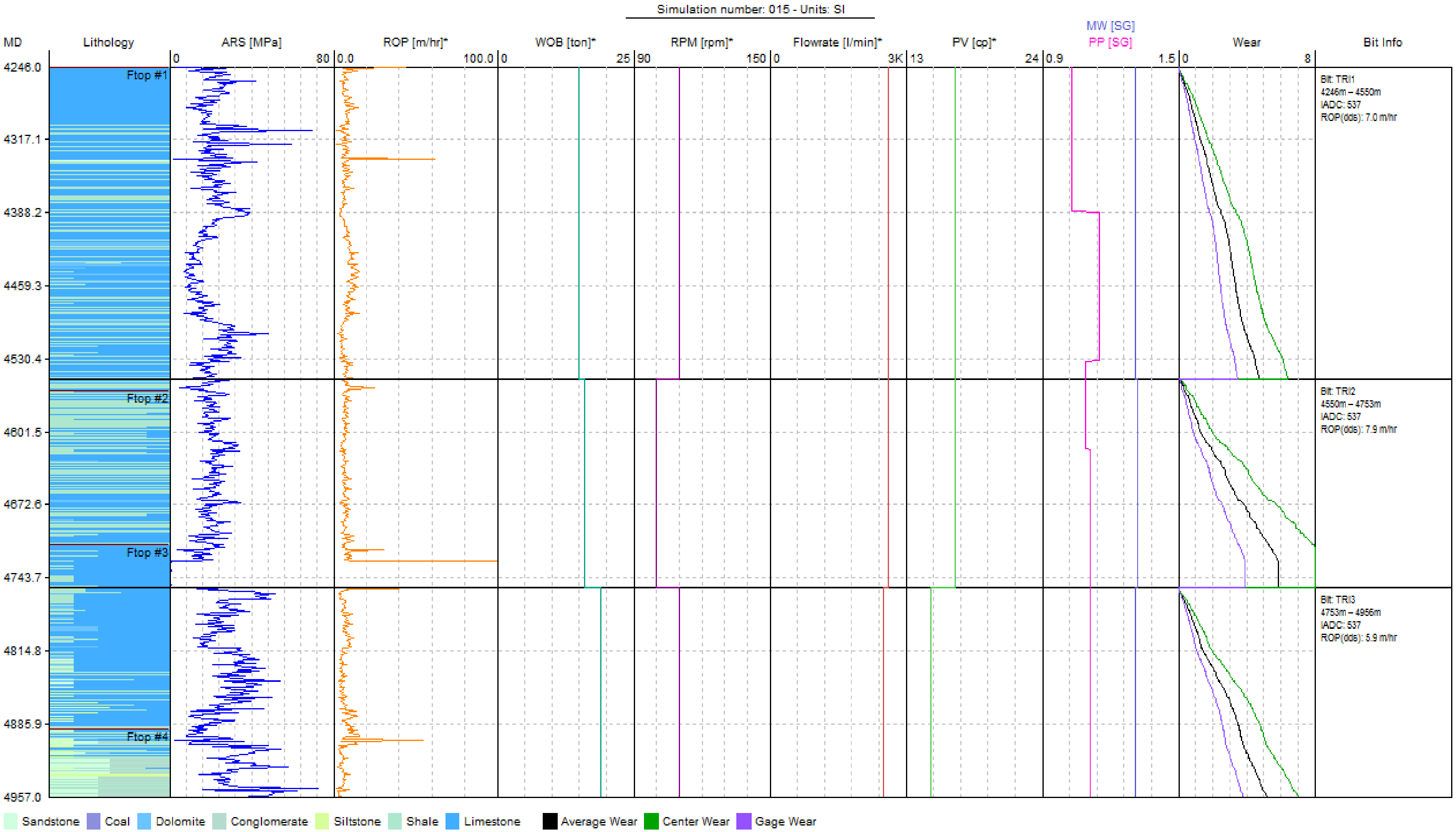



Figure 5.5 Simulation number 15 results, 8 ½”.

### 5.2.2 Reduction of drilling costs review

The way of reasoning and discussing the costs will be similar to that used in the previous section. The actual cost of drilling 6507/6-4 A exploratory well will be the reference point.. The simulation results are presented in table form. Assumptions are similar to those from the previous section.

DROPS Drilling Simulator includes the following categories of costs:

- Bit cost [Thousand USD]
- Tripping cost [Thousand USD]
- Connection time cost [Thousand USD]
- Rotating cost – the cost of drilling excluding bit, trip and connection cost [Thousand USD]

<u>Bit costs</u>.

In all carried out simulations, the same, three Kymera Hybrid bits have been used. Summing up the results, the following value is obtained:

$$3 \times 60 = 180 \text{ Thousand USD}$$

<u>Tripping cost</u>.

Tripping cost is the resultant of number of used drill bits and the length of each section drilled by them.

In simulations number zero, two and three, three bits were used with the same drilling distances, which gives a cost of 353.2 Thousand USD.

In simulation four, there was a slight decrease in tripping cost (from 353.2 to 349.1 Thousand USD) as a result of change in sections length. In the first, Kymera section (run1, 001-tri) was shortened from 366 m to 204m, whilst second, Kymera section (run2, 002-tri) increased by the same length (from 141m to 303m). The length of third, Kymera section (run3, 003-tri) remained the same (204m).

In simulations fifth to the last, the fifteenth simulation, I decided to balance first two sections because significant drop in ROP in second run. Hence, I shortened second section (run2, 002-tri). Tripping cost increased from 283.7 Thousand USD to 284.3 Thousand USD.

<u>Connection cost</u>. As the length of the section 8 ½” is 711 m for all simulations, the connection time cost is constant and is 50 Thousand USD.

Rotating cost. Its value is closely related with average, obtained rate of penetration. With an increase in ROP, drilling cost decreases. This relationship is shown in graph.

Taking into consideration all costs we get the Total cost in Thousand USD.

$$Total\ cost = Bit\ cost + Tripping\ cost + Connection\ time\ cost + Rotating\ cost$$

$$Cost\,\frac{\$}{m} = \frac{Total\ cost}{Section\ length}$$

I recognize the **best simulation of number 15**, due to obtained satisfactory ROP, tool wear and costs.

| Simulation | Bit | Trip | Connect | Rotating cost | Total | Cost $/m | Time [h] | Avg. ROP [m/h] | Wear |
|---|---|---|---|---|---|---|---|---|---|
| 0 Reference | 180 | 353.2 | 50 | 905.2 | 1488.464 | 2090.5 | 117.3 | 6.06 | 5.0, 4.0, 7.0 |
| 2 | 180 | 353.2 | 50 | 898.3 | 1481.558 | 2080.8 | 116.4 | 6.11 | 5.0, 3.5, 6.7 |
| 3 | 180 | 353.2 | 50 | 868.6 | 1451.802 | 2039 | 112.5 | 6.32 | 4.7, 4.1, 5.7 |
| 4 | 180 | 349.1 | 50 | 3599.6 | 4178.727 | 5869.0 | 467.8 | 1.5 | 3.3, 9.1, 5.1 |
| 5 | 180 | 351.6 | 50 | 849.3 | 1430.926 | 2009.7 | 110.1 | 6.46 | 4.4, 5.6, 5.5 |
| 6 | 180 | 351.6 | 50 | 836.2 | 1417.86 | 1991.4 | 108.4 | 6.56 | 4.6, 5.6, 5.4 |
| 8 | 180 | 351.6 | 50 | 835.9 | 1417.545 | 1990.9 | 108.2 | 6.57 | 4.6, 5.6, 5.3 |
| 9 | 180 | 351.6 | 50 | 827.7 | 1409.327 | 1979.4 | 107.2 | 6.63 | 4.6, 5.7, 5.3 |
| 10 | 180 | 351.6 | 50 | 830.3 | 1411.938 | 1983.1 | 107.6 | 6.61 | 4.6, 5.7, 5.3 |
| 11 | 180 | 351.6 | 50 | 822 | 1403.651 | 1971.4 | 106.4 | 6.68 | 4.6, 5.8, 5.3 |
| 12 | 180 | 351.6 | 50 | 817.4 | 1399.052 | 1965 | 106 | 6.71 | 4.6, 5.7, 5.2 |
| 13 | 180 | 351.6 | 50 | 822.5 | 1404.138 | 1972.1 | 106.6 | 6.67 | 4.6, 5.5, 5.2 |
| 14 | 180 | 351.6 | 50 | 810.4 | 1392.015 | 1955.1 | 105 | 6.77 | 4.6, 5.9, 5.2 |
| 15 | 180 | 351.6 | 50 | 803.9 | 1385.563 | 1946 | 104.1 | 6.83 | 4.7, 5.9, 5.2 |
| Cost reduction (Best simulation 15 – Reference simulation 0) | 0 | 1.6 | 0 | 101.3 | 102.901 | 144.5 | 13.2 | | |

Table 5.9 Costs analysis, 8 ½” section.

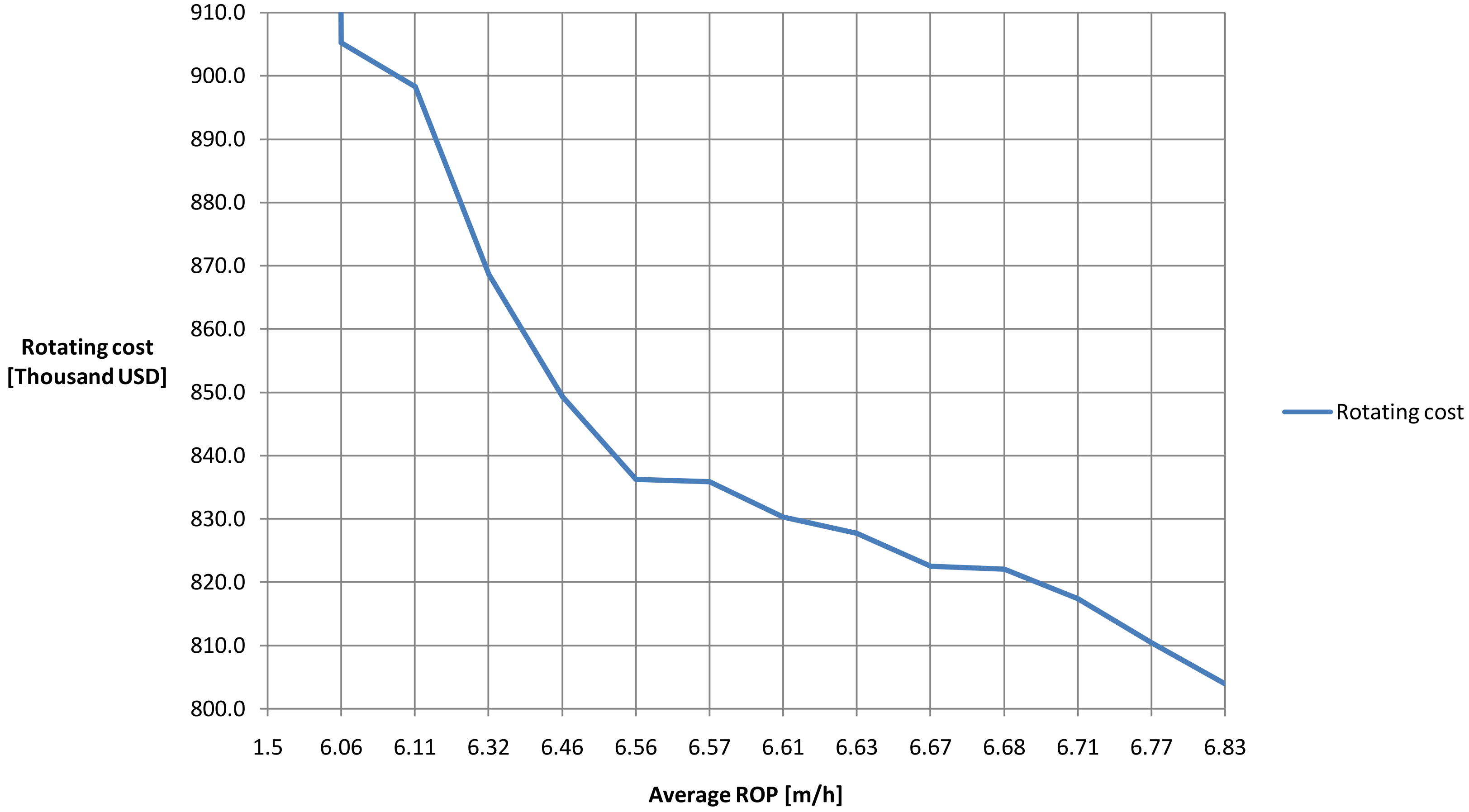



Figure 5.6 The relation between Rotating cost and Average ROP, 8 ½” section.

# 6 Summary and conclusion

Table 6.1 shows the summary of the simulations presented in chapter 5.

| | Section 12 ¼” | | | | Section 8 ½” | | | |
|---|---|---|---|---|---|---|---|---|
| Parameter | Average ROP | Total Cost | Cost $/m | Time | Average ROP | Total Cost | Cost $/m | Time |
| Unit | [m/h] | Thousand USD | USD | [h] | [m/h] | Thousand USD | USD | [h] |
| Reference 0 Input files | 11.90 | 1902.225 | 1036.6 | 154.1 | 6.06 | 1488.464 | 2090.5 | 117.3 |
| Best simulation result | 12.41 | 1723.000 | 939.0 | 147.8 | 6.83 | 1385.563 | 1946 | 104.1 |
| Difference obtained | 0.51 | 179.225 | 97.6 | 6.3 | 0.77 | 102.901 | 144.5 | 13.2 |
| Improvement % | 4.3 | 9.42 | 9.42 | 4.09 | 12.71 | 6.91 | 6.91 | 11.25 |

Table 6.1 Both sections results comparison and summary.

**Summary**

The table shows, that in case of 12 ¼”section, obtained average ROP seems slight and is only 4.3 %, but only its growth resulted in savings of 49.4 Thousand USD. What is more, further savings achieved due to reduction in number of used drill bits, resulted in savings of 40 Thousand USD, as well as noteworthy reduction in the tripping cost of 89.7 Thousand USD. One drill bit less entailed one trip less and shorter duration time, which is an meaningful saving. Overall, a significant reduction of 9.42% in Total cost was achieved, which sums up to 179.225 Thousand USD.

For section 8 ½ " the percentage increase in average ROP is almost three times higher (12.71% than 4.3%), but the total cost of reduction is not as significant as in previous one. The fact that the outcome is lower is not surprising, because the Section 8 ½ "is much shorter (711m compared with 1834m) and the geological conditions encountered are much more demanding. Smaller cost reduction is also apparent from the fact, that in contrast to the previous section, cost reduction was mostly only for the Rotating cost (101.3 Thousand USD saved) by increasing the ROP and a slightly (1.6 Thousand USD saved) in the tripping cost by changing the length of drilled sections. The cost of used bits remained constant, with the number and type unchanged throughout the simulation.

## Conclusions

Both the appropriate drilling parameters and the correct selection of the type and quantity of drilling bits, have a significant impact on the costs and drilling duration. That is why I have conducted numerous complex simulations.

The results obtained could have been more accurate and correspond more to real conditions, if used DROPS simulator would have taken into account Kymera Hybrid bit and some geological formations (claystone, marl, anhydrite). For this reasons, it was important to take an appropriate assumptions in order to conduct more precise simulations. However, obtaining accurate results was not the main object, but to observe the correlation between the types of geological formations, types of drilling tools, operating parameters and the results obtained, such as ROP, duration and costs. I found this software very useful and approachable tool even for less experienced user. This work can certainly be a supporting material to improve the DROPS drilling simulator.

Nowadays, the oil and gas industry places a strong emphasis on cost reduction and economizing. One solution is surely to simulate phenomena and operations in virtual conditions, at relatively low cost. In order to make the best possible selection of drilling tools and operating parameters. Especially in offshore drilling, errors and difficulties encountered are particularly dangerous and costly. Therefore, the tool used and the methods of reasoning in this thesis can be useful and applied by PGNiG Norway AS in terms of the company concessions and future activities on the Norwegian Continental Shelf.

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# Appendix

### Bit file. 12 ¼" Sesam

[Info]
Version = 1.1
Well = 6507/6-4A
Prepared By = Piotr Boryczko
Comment = Tool number 4 is different type, pdc with tricone bit combined. Kymera Hybrid Technology

[PDC1]
Bit Type = pdc
IADC Code = 999
Bit Diameter = 12.25
TVD In = 2164.76
TVD Out = 2970.86
MD In = 2411.00
MD Out = 3457.00
Wear In = 0.0
Wear Out = 3
Cost = 50000
DHM Cost = 0
Manufacturer = Baker Hughes
Bit Description = QD507X
Nozzle1 = 13
Nozzle2 = 13
Nozzle3 = 13
Nozzle4 = 13
Nozzle5 = 13
Nozzle6 = 13
Nozzle7 = 13
Nozzle8 = 0
Primary Number of Cutters = 50
Backup Number of Cutters = 21
Primary Cutter Size = 0.625
Backup Cutter Size = 0.529
Primary Backrake = 15
Backup Backrake = 20
Primary Siderake = 23
Backup Siderake = 30
Number of Blades = 7
Junk Slot Area = 27.5
Thickness = 0.5
Exposure = 0
Distance = 0

[PDC2]
Bit Type = pdc
IADC Code = 999

Bit Diameter = 12.25
TVD In = 2970.86
TVD Out = 3404.56
MD In = 3457.00
MD Out = 3967.00
Wear In = 0.0
Wear Out = 4
Cost = 50000
DHM Cost = 0
Manufacturer = Baker Hughes
Bit Description = QD507X
Nozzle1 = 13
Nozzle2 = 13
Nozzle3 = 13
Nozzle4 = 13
Nozzle5 = 13
Nozzle6 = 13
Nozzle7 = 13
Nozzle8 = 0
Primary Number of Cutters = 50
Backup Number of Cutters = 21
Primary Cutter Size = 0.625
Backup Cutter Size = 0.529
Primary Backrake = 15
Backup Backrake = 20
Primary Siderake = 23
Backup Siderake = 30
Number of Blades = 7
Junk Slot Area = 27.5
Thickness = 0.5
Exposure = 0
Distance = 0

[PDC3]
Bit Type = pdc
IADC Code = 999
Bit Diameter = 12.25
TVD In = 3404.56
TVD Out = 3474.52
MD In = 3967.00
MD Out = 4039.00
Wear In = 0.0
Wear Out = 2
Cost = 50000
DHM Cost = 0
Manufacturer = Baker Hughes
Bit Description = QD507X
Nozzle1 = 14
Nozzle2 = 14
Nozzle3 = 14

Nozzle4 = 14
Nozzle5 = 14
Nozzle6 = 14
Nozzle7 = 15
Nozzle8 = 0
Primary Number of Cutters = 52
Backup Number of Cutters = 21
Primary Cutter Size = 0.625
Backup Cutter Size = 0.529
Primary Backrake = 10
Backup Backrake = 15
Primary Siderake = 22
Backup Siderake = 30
Number of Blades = 7
Junk Slot Area = 27.5
Thickness = 0.5
Exposure = 0
Distance = 0

[TRI4]
Bit Type = tri
IADC Code = 537
Bit Diameter = 12.25
TVD In = 3474.52
TVD Out = 3679.59
MD In = 4039.00
MD Out = 4245.00
Wear In = 0.0
Wear Out = 7
Cost = 60000
DHM Cost = 0
Manufacturer = Baker Hughes
Bit Description = KG533FX
Nozzle1 = 14
Nozzle2 = 14
Nozzle3 = 14
Nozzle4 = 16
Nozzle5 = 16
Nozzle6 = 16
Nozzle7 = 0
Nozzle8 = 0

## Drill file. Sesam 12 ¼"

DrillingParameterDataFile
Well: 6507/6-4A
Section: 12.25
Date: Date
SectionStart: 2411
SectionEnd: 4245
PreparedBy: Piotr Boryczko

9
MD_MeasuredDepth(m)
TD_TrueVerticalDepth(m)
ROP_RateOfPenetration(m/h)
WOB_WeightOnBit(ton)
RPM_RevolutionsPerMinute
GPM_Flowrate(l/min)
PV_PlasticViscosity(cp)
MW_MudWeight(kg/l)
MUDTYPE_Mudtype(1=oil,0=water)
DMODE_DrillMode(R=Rotary,S=Rotary,A=AutoBHA)

| MD | TD | ROP | WOB | RPM | GPM | PV | MW | MUDTYPE | DMODE |
|---|---|---|---|---|---|---|---|---|---|
| 2411 | 2164.76 | 12.87 | 5.21 | 83.47 | 3400.10 | 23 | 1.3 | 1 | Rotary |
| 2412 | 2165.53 | 14.56 | 6.89 | 83.03 | 3352.51 | 23 | 1.3 | 1 | R |
| 2413 | 2166.3 | 13.76 | 3.32 | 79.46 | 3360.13 | 23 | 1.3 | 1 | R |
| 2414 | 2167.07 | 15.39 | 5.05 | 80.32 | 3314.59 | 23 | 1.3 | 1 | R |
| 2415 | 2167.84 | 13.14 | 13.69 | 78.98 | 3374.00 | 23 | 1.3 | 1 | R |
| 2416 | 2168.61 | 8.88 | 9.87 | 79.1 | 3388.20 | 23 | 1.3 | 1 | R |
| 2417 | 2169.38 | 11.3 | 9.54 | 78.06 | 3458.67 | 23 | 1.3 | 1 | R |
| 2418 | 2170.15 | 8.36 | 9.85 | 78.93 | 3436.42 | 23 | 1.3 | 1 | R |
| 2419 | 2170.92 | 9.33 | 10.37 | 99.94 | 3385.45 | 23 | 1.3 | 1 | R |
| 2420 | 2171.69 | 10.73 | 11.46 | 101.16 | 3409.31 | 23 | 1.3 | 1 | R |
| 2421 | 2172.46 | 7.41 | 12.13 | 100.68 | 3508.10 | 23 | 1.3 | 1 | R |
| 2422 | 2173.23 | 5.88 | 10.81 | 100.58 | 3312.96 | 23 | 1.3 | 1 | R |
| 2423 | 2174 | 26.5 | 10.79 | 98.9 | 3443.68 | 23 | 1.3 | 1 | R |
| 2424 | 2174.77 | 11.42 | 10.61 | 98.03 | 3476.53 | 23 | 1.3 | 1 | R |
| 2425 | 2175.54 | 11.34 | 12.7 | 96.96 | 3443.21 | 23 | 1.3 | 1 | R |
| 2426 | 2176.32 | 16.78 | 11.21 | 97.65 | 3451.63 | 23 | 1.3 | 1 | R |
| 2427 | 2177.09 | 9.83 | 12.76 | 97.92 | 3381.00 | 23 | 1.3 | 1 | R |
| 2428 | 2177.86 | 17.14 | 9.93 | 98.18 | 3485.74 | 23 | 1.3 | 1 | R |
| 2429 | 2178.63 | 25.91 | 11.1 | 97.8 | 3304.14 | 23 | 1.3 | 1 | R |
| 2430 | 2179.4 | 16.58 | 11.32 | 97.87 | 3448.95 | 23 | 1.3 | 1 | R |
| 2431 | 2180.17 | 17.78 | 11.51 | 97.74 | 3464.21 | 23 | 1.3 | 1 | R |
| 2432 | 2180.94 | 18.87 | 11.61 | 97.38 | 3468.96 | 23 | 1.3 | 1 | R |
| 2433 | 2181.71 | 16.81 | 12.39 | 97.31 | 3432.76 | 23 | 1.3 | 1 | R |
| 2434 | 2182.48 | 20.03 | 11.79 | 97.93 | 3437.75 | 23 | 1.3 | 1 | R |

## Lithology file. 12 ¼" Sesam

LithologyDataFile
Well: 6507/6-4A
Section: 12.25
Date: Date
Section Start: 2411
Section End: 4245
Preared by: Piotr Boryczko

14
MD_Measured Depth(m)
TD_TrueVerticalDepth(m)
SAND_PercentSand(%)
SHAL_PercentShale(%)
LIME_PercentLimestone(%)
DOLO_PercentDolomite (%)
SILI_PercentSiltstone(%)
CONG_PercentConglomerate(%)
COAL_PercentCoal(%)
FormationtopIdentifier
NULL_ParameterNotUsed
NULL_ParameterNotUsed
P.P._Pore Pressure Gradient(kg/l)
PERM_Permability(1=Perm,0=NotPerm)

Formation_ID_begin
1: Ftop #1
2: Ftop #2
3: Ftop #3
Formation_ID_end

| MD | TD | SAND | SHAL | LIME | DOLO | SILT | CONG | COAL | FTID | NULL | NULL | P.P. | PERM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2411 | 2164.76 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 2412 | 2165.53 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 2413 | 2166.3 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 2414 | 2167.07 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 2415 | 2167.84 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 2416 | 2168.61 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 1 |
| 2417 | 2169.38 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 1 |
| 2418 | 2170.15 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 1 |
| 2419 | 2170.92 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 1 |
| 2420 | 2171.69 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 1 |

**Survey file. 12 ¼" Sesam**

| MD | INCLIN | AZIMUTH | TD |
|---|---|---|---|
| 2411 | 39.52 | 330.08 | 2164.76 |
| 2412 | 39.52 | 330.08 | 2165.53 |
| 2413 | 39.52 | 330.08 | 2166.3 |
| 2414 | 39.52 | 330.08 | 2167.07 |
| 2415 | 39.52 | 330.08 | 2167.84 |
| 2416 | 39.52 | 330.08 | 2168.61 |
| 2417 | 39.52 | 330.08 | 2169.38 |
| 2418 | 39.52 | 330.08 | 2170.15 |
| 2419 | 39.52 | 330.08 | 2170.92 |
| 2420 | 39.52 | 330.08 | 2171.69 |
| 2421 | 39.52 | 330.08 | 2172.46 |
| 2422 | 39.52 | 330.08 | 2173.23 |
| 2423 | 39.52 | 330.08 | 2174 |
| 2424 | 39.52 | 330.08 | 2174.77 |
| 2425 | 39.52 | 330.08 | 2175.54 |
| 2426 | 39.52 | 330.08 | 2176.32 |
| 2427 | 39.52 | 330.08 | 2177.09 |
| 2428 | 39.52 | 330.08 | 2177.86 |
| 2429 | 39.52 | 330.08 | 2178.63 |
| 2430 | 39.52 | 330.08 | 2179.4 |
| 2431 | 39.52 | 330.08 | 2180.17 |
| 2432 | 39.52 | 330.08 | 2180.94 |
| 2433 | 39.52 | 330.08 | 2181.71 |
| 2434 | 39.52 | 330.08 | 2182.48 |
| 2435 | 39.52 | 330.08 | 2183.25 |
| 2436 | 39.52 | 330.08 | 2184.03 |
| 2437 | 39.52 | 330.08 | 2184.8 |
| 2438 | 39.52 | 330.08 | 2185.57 |
| 2439 | 39.52 | 330.08 | 2186.34 |
| 2440 | 39.52 | 330.08 | 2187.11 |
| 2441 | 39.52 | 330.08 | 2187.88 |
| 2442 | 39.52 | 330.08 | 2188.65 |
| 2443 | 39.52 | 330.08 | 2189.43 |
| 2444 | 39.52 | 330.08 | 2190.2 |
| 2445 | 39.52 | 330.08 | 2190.97 |
| 2446 | 39.52 | 330.08 | 2191.74 |
| 2447 | 39.52 | 330.08 | 2192.51 |
| 2448 | 39.52 | 330.08 | 2193.28 |
| 2449 | 39.52 | 330.08 | 2194.05 |
| 2450 | 39.52 | 330.08 | 2194.83 |
| 2451 | 39.52 | 330.08 | 2195.6 |
| 2452 | 39.52 | 330.08 | 2196.37 |
| 2453 | 39.52 | 330.08 | 2197.14 |
| 2454 | 39.52 | 330.08 | 2197.91 |
| 2455 | 39.52 | 330.08 | 2198.68 |
| 2456 | 39.52 | 330.08 | 2199.46 |
| 2457 | 39.52 | 330.08 | 2200.23 |
| 2458 | 39.52 | 330.08 | 2201 |
| 2459 | 39.52 | 330.08 | 2201.77 |
| 2460 | 39.52 | 330.08 | 2202.54 |
| 2461 | 39.52 | 330.08 | 2203.31 |
| 2462 | 39.52 | 330.08 | 2204.08 |

## Bit file. 8 ½” Sesam

[Info]
Version = 1.1
Well = 6507/6-4A
Prepared By = Piotr Boryczko
Comment = No

[TRI1]
Bit Type = tri
IADC Code = 537
Bit Diameter = 8.5
TVD In = 3680.59
TVD Out = 4046.33
MD In = 4246.00
MD Out = 4612.00
Wear In = 0.0
Wear Out = 5
Cost = 60000
DHM Cost = 0
Manufacturer = Baker Hughes
Bit Description = HP522X
Nozzle1 = 14
Nozzle2 = 14
Nozzle3 = 16
Nozzle4 = 16
Nozzle5 = 0
Nozzle6 = 0
Nozzle7 = 0
Nozzle8 = 0

[TRI2]
Bit Type = tri
IADC Code = 537
Bit Diameter = 8.5
TVD In = 4046.33
TVD Out = 4187.18
MD In = 4612.00
MD Out = 4753.00
Wear In = 0.0
Wear Out = 4
Cost = 60000
DHM Cost = 0
Manufacturer = Baker Hughes
Bit Description = HP522X
Nozzle1 = 20
Nozzle2 = 22
Nozzle3 = 0
Nozzle4 = 0

Nozzle5 = 0
Nozzle6 = 0
Nozzle7 = 0
Nozzle8 = 0

[TRI3]
Bit Type = tri
IADC Code = 537
Bit Diameter = 8.5
TVD In = 4187.18
TVD Out = 4390.88
MD In = 4753.00
MD Out = 4957.00
Wear In = 0.0
Wear Out = 7
Cost = 60000
DHM Cost = 0
Manufacturer = Baker Hughes
Bit Description = HP522X
Nozzle1 = 14
Nozzle2 = 14
Nozzle3 = 16
Nozzle4 = 16
Nozzle5 = 0
Nozzle6 = 0
Nozzle7 = 0
Nozzle8 = 0

## Drill file. 8 ½" Sesam

DrillingParameterDataFile
Well: 6507/6-4A
Section: 8.5
Date: Date
SectionStart: 4246
SectionEnd: 4957
PreparedBy: Piotr Boryczko

9
MD_MeasuredDepth(m)
TD_TrueVerticalDepth(m)
ROP_RateOfPenetration(m/h)
WOB_WeightOnBit(ton)
RPM_RevolutionsPerMinute
GPM_Flowrate(l/min)
PV_PlasticViscosity(cp)
MW_MudWeight(kg/l)
MUDTYPE_Mudtype(1=oil,0=water)
DMODE_DrillMode(R=Rotary,S=Rotary,A=AutoBHA)

| MD | TD | ROP | WOB | RPM | GPM | PV | MW | MUDTYPE | DMODE |
|---|---|---|---|---|---|---|---|---|---|
| 4246 | 3680.59 | 13.77 | 9.25 | 46.33 | 2410.82 | 21 | 1.24 | 0 | Rotary |
| 4247 | 3681.59 | 11.67 | 5.7 | 51.35 | 2410.82 | 21 | 1.25 | 0 | R |
| 4248 | 3682.59 | 2.41 | 10.25 | 55.02 | 2410.82 | 21 | 1.26 | 0 | R |
| 4249 | 3683.59 | 4.32 | 8.61 | 64.59 | 2410.82 | 21 | 1.26 | 0 | R |
| 4250 | 3684.59 | 4.98 | 5.02 | 80.03 | 2427.06 | 21 | 1.27 | 0 | R |
| 4251 | 3685.59 | 3.15 | 8.57 | 60.58 | 2427 | 21 | 1.27 | 0 | R |
| 4252 | 3686.59 | 1.8 | 7.89 | 64.83 | 2427.03 | 21 | 1.27 | 0 | R |
| 4253 | 3687.59 | 2.52 | 7.99 | 64.74 | 2427 | 21 | 1.27 | 0 | R |
| 4254 | 3688.59 | 3.23 | 10.81 | 90.13 | 2427 | 21 | 1.27 | 0 | R |
| 4255 | 3689.59 | 4.43 | 10.62 | 89.93 | 2427 | 21 | 1.27 | 0 | R |
| 4256 | 3690.59 | 4.22 | 10.12 | 89.8 | 2427 | 21 | 1.27 | 0 | R |
| 4257 | 3691.59 | 4.24 | 9.19 | 89.68 | 2427 | 21 | 1.27 | 0 | R |
| 4258 | 3692.59 | 3.73 | 7.75 | 89.66 | 2427 | 20 | 1.27 | 0 | R |
| 4259 | 3693.59 | 3.69 | 6.77 | 89.71 | 2427 | 20 | 1.27 | 0 | R |
| 4260 | 3694.59 | 1.83 | 10.29 | 89.65 | 2427 | 20 | 1.27 | 0 | R |
| 4261 | 3695.59 | 4.18 | 10.52 | 89.73 | 2427 | 20 | 1.27 | 0 | R |
| 4262 | 3696.59 | 4.07 | 13.52 | 89.81 | 2427 | 20 | 1.27 | 0 | R |
| 4263 | 3697.59 | 4.64 | 12.22 | 89.47 | 2427 | 20 | 1.27 | 0 | R |
| 4264 | 3698.59 | 4.22 | 12.52 | 89.58 | 2427 | 20 | 1.27 | 0 | R |
| 4265 | 3699.59 | 4.04 | 11.82 | 89.66 | 2427 | 20 | 1.27 | 0 | R |
| 4266 | 3700.59 | 4.33 | 12.29 | 89.6 | 2427 | 20 | 1.27 | 0 | R |
| 4267 | 3701.59 | 5.55 | 13.47 | 89.72 | 2427 | 20 | 1.27 | 0 | R |
| 4268 | 3702.59 | 4.33 | 12.66 | 80.02 | 2427 | 20 | 1.27 | 0 | R |
| 4269 | 3703.59 | 6.96 | 13.43 | 81.17 | 2427 | 20 | 1.27 | 0 | R |

## Lithology file. 8 ½" Sesam

LithologyDataFile
Well: 6507/6-4A
Section: 8.5
Date: Date
Section Start: 4246
Section End: 4957
Preared by: Piotr Boryczko

14
MD_Measured Depth(m)
TD_TrueVerticalDepth(m)
SAND_PercentSand(%)
SHAL_PercentShale(%)
LIME_PercentLimestone(%)
DOLO_PercentDolomite (%)
SILI_PercentSiltstone(%)
CONG_PercentConglomerate(%)
COAL_PercentCoal(%)
FormationtopIdentifier
NULL_ParameterNotUsed
NULL_ParameterNotUsed
P.P._Pore Pressure Gradient(kg/l)
PERM_Permability(1=Perm,0=NotPerm)

Formation_ID_begin
1: Ftop #1
2: Ftop #2
3: Ftop #3
4: Ftop #4
Formation_ID_end

| MD | TD | SAND | SHAL | LIME | DOLO | SILT | CONG | COAL | FTID | NULL | NULL | P.P. | PERM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4246 | 3680.59 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 4247 | 3681.59 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 4248 | 3682.59 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 4249 | 3683.59 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 4250 | 3684.59 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |
| 4251 | 3685.59 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1.03 | 0 |

## Survey file. 8 ½” Sesam

| MD | INCLIN | AZIMUTH | TD |
|---|---|---|---|
| 4246 | 0.15 | 36.13 | 3680.59 |
| 4247 | 0.15 | 36.13 | 3681.59 |
| 4248 | 0.15 | 36.13 | 3682.59 |
| 4249 | 0.15 | 36.13 | 3683.59 |
| 4250 | 0.15 | 36.13 | 3684.59 |
| 4251 | 0.15 | 36.13 | 3685.59 |
| 4252 | 0.15 | 36.13 | 3686.59 |
| 4253 | 0.15 | 36.13 | 3687.59 |
| 4254 | 0.15 | 36.13 | 3688.59 |
| 4255 | 0.15 | 36.13 | 3689.59 |
| 4256 | 0.15 | 36.13 | 3690.59 |
| 4257 | 0.15 | 36.13 | 3691.59 |
| 4258 | 0.15 | 36.13 | 3692.59 |
| 4259 | 0.15 | 36.13 | 3693.59 |
| 4260 | 0.15 | 36.13 | 3694.59 |
| 4261 | 0.15 | 36.13 | 3695.59 |
| 4262 | 0.15 | 36.13 | 3696.59 |
| 4263 | 0.15 | 36.13 | 3697.59 |
| 4264 | 0.15 | 36.13 | 3698.59 |
| 4265 | 0.15 | 36.13 | 3699.59 |
| 4266 | 0.15 | 36.13 | 3700.59 |
| 4267 | 0.15 | 36.13 | 3701.59 |
| 4268 | 0.15 | 36.13 | 3702.59 |
| 4269 | 0.15 | 36.13 | 3703.59 |
| 4270 | 0.15 | 36.13 | 3704.59 |
| 4271 | 0.15 | 36.13 | 3705.59 |
| 4272 | 0.15 | 36.13 | 3706.59 |
| 4273 | 0.15 | 36.13 | 3707.59 |
| 4274 | 0.48 | 33.99 | 3708.59 |
| 4275 | 0.48 | 33.99 | 3709.59 |
| 4276 | 0.48 | 33.99 | 3710.59 |
| 4277 | 0.48 | 33.99 | 3711.59 |
| 4278 | 0.48 | 33.99 | 3712.59 |
| 4279 | 0.48 | 33.99 | 3713.59 |
| 4280 | 0.48 | 33.99 | 3714.59 |
| 4281 | 0.48 | 33.99 | 3715.59 |
| 4282 | 0.48 | 33.99 | 3716.59 |
| 4283 | 0.48 | 33.99 | 3717.59 |
| 4284 | 0.48 | 33.99 | 3718.59 |
| 4285 | 0.48 | 33.99 | 3719.59 |
| 4286 | 0.48 | 33.99 | 3720.59 |
| 4287 | 0.48 | 33.99 | 3721.59 |
| 4288 | 0.48 | 33.99 | 3722.59 |
| 4289 | 0.48 | 33.99 | 3723.59 |
| 4290 | 0.48 | 33.99 | 3724.59 |