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INVESTIGATION OF DRILLING PARAMETERS INDICATORS

by

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Dedicated to my parents and wife

for their support and understanding

ABSTRACT

Investigation of the Drilling Performance Indicators

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The factors which influence the performance characteristics of diamond impregnated core bits and roller cone bits are examined, and actual field drilling data are analysed to determine these factors.

Methods for selecting the appropriate bit type for optimised drilling are also highlighted.

The importance of core drilling to the exploration and exploitation of the earth's natural resources and to the integrity of engineering structures is highlighted.

An investigation of the slim hole continuous core drilling system and its application in the oil and gas exploration is analysed. The highly successful integration of oilfield, mining and geotechnical exploration technologies in a special investigation programme includes several elements which are important in the application of slim hole methods for oil and gas exploration are analysed. Many of the technical issues associated with a slim hole approach have been addressed in the development and application of the drilling, and coring equipment and systems.

The project has given an opportunity to evaluate the advantages and disadvantages, merits and limitations for applying different drilling and associated technologies for deep hole construction to safety.

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Chapter One

INTRODUCTION TO DRILLING

1.1 Aim of the Research

Drilling bits were predominantly investigated in the early stages of drilling research at the University of Nottingham. Initial research on drilling bits was carried out by Ambrose, 1987, who analysed the performance of impregnated core bits. In this research, a number of different rock samples were drilled with a variety of different bits. Amongst the laboratory test results produced were graphs of penetration rate against bit wear rate. Monitoring and logging of the drilling parameters was conducted during the drilling operations.

Initial laboratory tests on Syndrill non-core polycrystalline diamond compact (PDC) bits in coal measures rocks were conducted for rockbolt holes (Singh et al., 1989 and Al-Ameen et al., 1992). Substantial modifications in the laboratory drilling rig and electronic circuits were carried out by Waller, 1991. The automatic optimisation of drilling performance using a computerised method was undertaken by Rowsell, 1991, and the design and development of the drilling optimisation scheme were described. Syndite PDC non-core bits were tested in coal measures rocks by Shah, 1991. In this research, nearly all results were graphs of operating parameters against bit advance per revolution.

More study of new design of Syndax3 thermally stable polycrystalline diamond compact core bits, was conducted by Ersoy, 1995. His study included an analysis of the microscopic wear mechanisms, and the influence of rock parameters on the performance of PDC.

The purpose of the present study is to contribute to the understanding of drilling parameters and determine their affect on the performance of both tri-cone and impregnated core bits in field conditions. To highlight the importance and applications of core drilling. Also to investigate the options and challenges of applying the slim hole continuous core drilling system for oil and gas explorations.

1.2 Principles of Drilling

The wide variations in drilling conditions encountered under field conditions make it difficult to develop general rules of operation for maximum drilling efficiency. Field experience usually provides the basis for operations in a particular area, but testing often is too costly and experience too late. Consequently, a method for determining optimum drilling techniques and parameters for any particular drilling condition, with a minimum of engineering effort and drilling experience, is greatly needed.

The drilling parameters, or variables, associated with rotary drilling have been analysed and divided in two groups as independent and dependent parameters as shown in figure 1.1, (Barr and Brown, 1983, Ambrose, 1987, Shah, 1992). The independent variables are those which can be directly controlled by the drilling rig operator and dependent variables are those which represent the response of the drilling system to the drilling operation. There are, of course, many factors other than those discussed here that effect drilling efficiency and footage cost. These include such factors as formation hardness, abrasiveness of formation and well depth. As these items cannot be conveniently controlled, their influence on costs must simply be accepted.

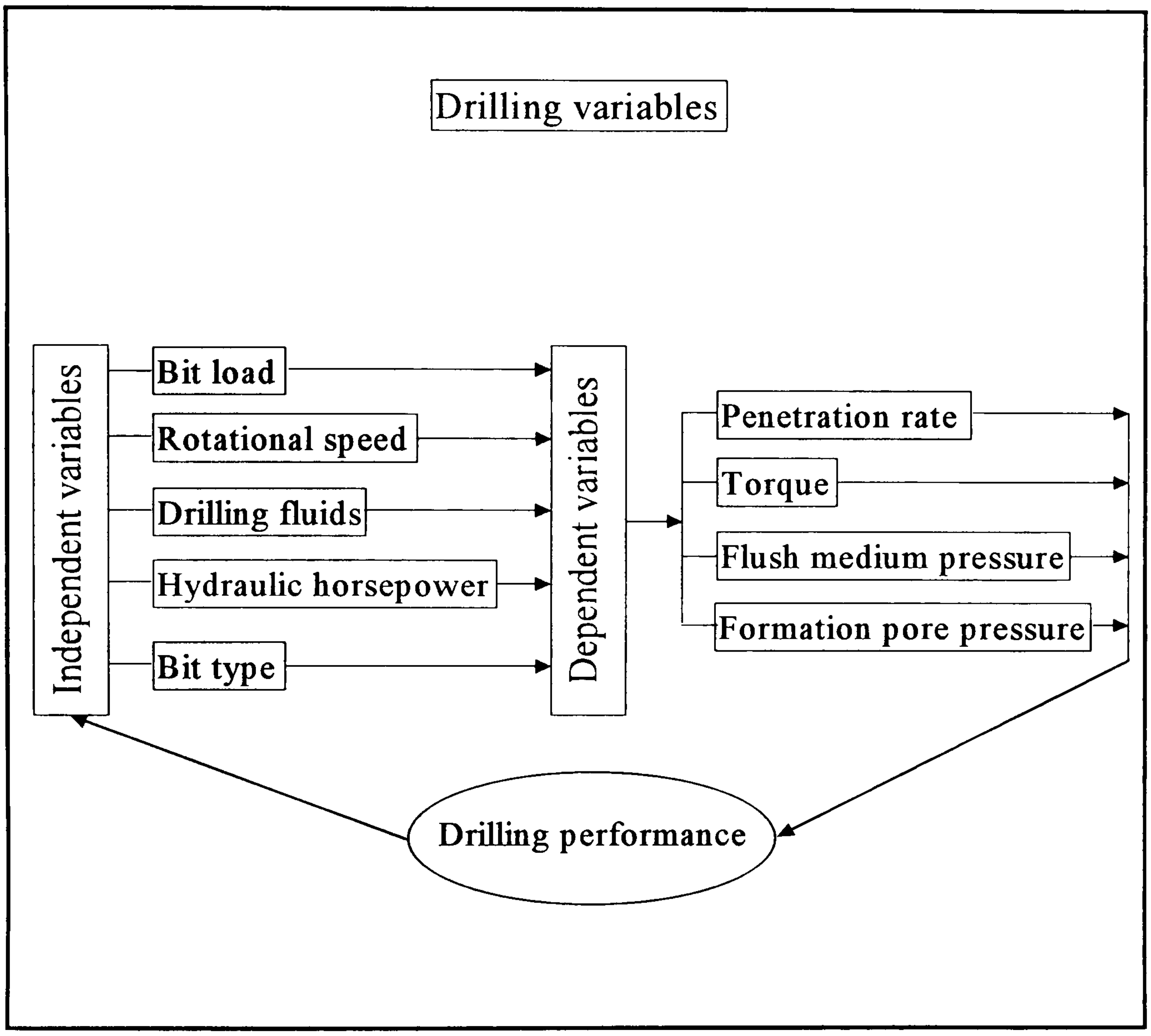


Figure 1.1 Drilling variables associated with rotary drilling.

1.3 Dependent Variables

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

1.3.1 Penetration Rate

The rate of penetration (ROP) of the rotary bit through rock, is expressed in units of distance per unit time. The rate of penetration is considered as one of the primary factors which affect drilling costs and hence it is given a prior consideration when planning for optimised drilling.

The subject of drilling rate has been extensively analysed from both the theoretical standpoint and the experimental standpoint with the objective of maximising drilling rate and improving operating efficiencies (Lummus, 1969, 1970, Eckel, 1967, Huff and Varnado, 1980, Kelsey, 1982, Holester and Kipp, 1984, Ambrose, 1987, Warren and Armagost, 1988, Waller, 1991, and Shah, 1992). Miniature drill bits have been widely used in the laboratory to study combinations of independent drilling variables, as well as to relate drilling rate to measurable rock properties. The determination of the rate of penetration is one of the most important objectives, and is therefore considered and presented in detail in this thesis. Collectively, contributions to the understanding of these factors on the penetration rate has been greatly exploited in an effort to drill faster and more economically.

1.3.2 Torque

Torque is defined as the force required to turn the drill rod, which leads to the bit rotating against the resistance to the cutting and friction forces.

In shallow boreholes, the torque is the result of the forces resisting the cutting and shearing action generated at the bit/rock contact by the rotation of the bit. In deep boreholes, additional torque is required to overcome additional forces between the drill rods and the flushing medium. Torque is usually measured in Nm or lb-ft.

The torque required to rotate a bit is of interest for several reasons. First, it may give information about the formation being drilled and/or the condition of the bit. Second, bit torque exerts a significant influence on the "bit walk" experienced in directional wells. Finally, a prediction of bit torque may be useful in matching a bit and mud motor for optimal performance.

Several authors, (Paone et al., 1969, Clark, 1979, 1982, Warren, 1983, Ambrose, 1987, Waller, 1991 and Shah, 1992) have presented theoretical bit torque relationships derived by testing many types of rocks with coring and non-coring bits, and found that the penetration rate increases with torque and a critical value of torque exists below which penetration does not occur. The torque relationship for a given bit is determined largely by the applied weight on bit and the depth of penetration of bit indenters.

1.3.3 Flush Medium Pressure

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

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

1) a processes that affects the unbroken rock, and
2) processes that act on the rock once it is broken into chips.

The chip removal process is probably more important in terms of total effect on ROP, but the strengthening of the unbroken rock is not negligible. Although several authors (Garnier, 1959, Feenstra, 1964 and Warren, 1984) have discussed in considerable detail the chip removal process.

This reduction of the ROP is often attributed to increasing "differential pressure", increasing hydrostatic head, increasing in-situ stresses, decreasing porosity with depth, and chip hold-down. For the flush medium to flow down the drillstring and up the annulus, a pressure difference must exist between the flush descending within the drill rods and that ascending in the annulus outside the drill rods. The pressure required to cause flow has to counteract the difference in the fluid densities, due to suspended rock particles and has to overcome the frictional resistance to flow. Increasing the ROP of the bit increases the weight of suspended rock particles and hence the differential fluid pressure. Pump pressure is used to overcome the frictional resistance and weight imbalance of suspended rock particles. Increasing the fluid flow rate also results in an increase in the differential pressure.

1.3.4 Formation Pore Pressure

The properties of the rock being drilled can, from the definition of drilling variables discussed in the introduction, be considered as an independent variable, the drilling rig operator has no control over it, as they help determine the response to the drilling operation rather than being a response in itself.

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

The formation pressure is related to pore spaces of the formations which contain fluids such as water, oil or gas. The overburden stress is created by the weight of the overlying rock matrix and the fluid-filled pores. The rock matrix stress is the overburden stress minus the formation pressure. Formation fluid or pore pressures are usually categorised as normal, subnormal and abnormal or over pressured. When formation pore pressure is approximately equal to hydrostatic pressure of drilling fluid for a given vertical depth, formation pressure is described to be normal. When the formation is opened to the atmosphere during drilling, a column of drilling fluid from the ground surface down to the formation depth (hydrostatic pressure) would balance the formation pressure. If the formation pressure is less than that of the hydrostatic pressure, then it is called subnormal formation pressure. Formations with pressure higher than hydrostatic are encountered at various depth in many areas. These formations are referred to as being abnormally pressured or over pressured. Generally, abnormal pore pressures are associated with fluids trapped within the pore spaces of rocks by low permeability barriers such as salt domes, folds or faults.

Numerous authors have demonstrated the severe reduction in ROP with different rotary bits as the borehole pressure increases. (Garnier and van Lingen, 1959, Cunningham and Eenink, 1959, Black, et al., 1977, Bourgoyne et al., 1986).

1.4 Independent Variables

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

1.4.1 Bit Load

A range of terms are used to describe this parameter such as thrust, bit load, bit pressure, axial load or axial pressure, and weight on bit (WOB). Weight on bit is a basic controllable drilling variable. A bit load needs to be applied for the bit to drill. The amount of bit load applied in practice depends on many factors, which include the type of bit, the bit diameter, the presence of discontinuities in the rock mass, the type of drilling rig and equipment etc., but it is primarily governed by the physical properties of the rock being drilled. This is because the bit penetrates the rock when the pressure exerted by the bit indenters exceeds the strength of the rock and feeds it forward. The weight on bit requirement depends on the size and geometry of the bit and the resistance (strength) of the rock. The rig must be capable of producing the required WOB with sufficient stability for drilling a given hole size with a selected bit size.

A number of authors have conducted tests to investigate the effect of WOB on drilling performance, (Paone et al., 1969, Schmidt, 1972, Clark, 1979, 1982, Osman and Mohammed, 1992, Speer, 1958). These investigations showed that low WOB results in free rotation of the bit, which produces low rate of penetration and poor chip formation, excessive bit wear because of the bit sliding over the surface of the rock. High WOB, above a critical value leads to the drill machine stalling. Maximum ROP is achieved when optimum value of WOB is reached, after which, an increase in WOB gives little increase in the penetration rate. The limiting value of WOB is determined by the torque capacity of the equipment. The above researchers have also concluded that the optimum WOB gives high penetration rate and low bit wear. Consequently, each drill has a characteristic optimum WOB for maximum penetration which corresponds to good indentation at the bit rock interface and to optimum indexing. The optimum WOB also depends on the other optimal drilling conditions.

1.4.2 Rotational Speed

The drilling process consists of a series of fracture generating events. The drilling rate for a constant depth of bit indenter, penetration will depend on the bit rotational speed. The relationship between rotational speed (RPM) and rate of penetration (ROP) has been investigated by the previously mentioned authors. It has been confirmed that generally there is a near linear relationship between the two parameters in soft rocks. Drilling rate is not proportional to rotary speed in medium and hard formations due to the requirement that some finite time is required for fracture development in hard rocks.

For a given penetration rate to be achieved, the bit weight and rotational speed should be continuously maintained, and adequate flush flow maintained to ensure rock cuttings removal from the hole. However, the increase in bit rotary speed result in greater wear on the bit and may also cause chatter, micro-chipping and cracking of cutting indenters or teeth of the bit. The rotational speed may also be restricted by the stability of the rig and the drill rods.

1.4.3 Drilling Fluid

The term "drilling fluid" includes all of the compositions used to remove cuttings from the borehole. An effective drilling process can only be continued, when the bottom of the hole is maintained clean. This is achieved by a sufficient flow flushing medium, which can be; air, water, oil, oil/water emulsion, mud or foam (Moore, 1958). Drilling rate is proved to be faster and bit life longer with air as compared to water or mud. Drilling was originally performed with air or water as a drilling medium used to cool the bit and flush away the drill cuttings. As these two media were usually, easily available, cheap and satisfactory for the shallow boreholes and hard formations being drilled at that time. Through the years many additional requirements have been placed on the drilling fluid. To satisfy these demands, as boreholes began to be drilled deeper, and especially with the rapid development of oil well drilling in soft and often caving sedimentary formation, the composition has been modified greatly from the air or water that was originally used.

To overcome problems such as borehole instability, a drilling fluid called mud was developed, consisting of water and bentonite clay. Mud has a number of properties such as its caking ability, its higher density, viscosity and its thixotropic properties, which make it particularly suitable for drilling deep and soft formations that would otherwise prove difficult to drill. However, water is still commonly used as a flushing medium and mud used only where necessary due to the drawback of the large quantities of bentonite needed to make the mud and the extra equipment, which result in extra costs (Gray and Young Jr, 1973).

Although at the present time numerous brand names of drilling fluids are commercially available for a range of purposes and conditions, the main function of all these fluids is the successful, speedy and satisfactory completion of the well. The selection of the type of drilling fluid is largely determined by the expected hole conditions. The adjustment of drilling fluid properties is intimately related to the well depth, casing programme and the drilling equipment.

1.4.4 Hydraulic Horsepower

Hydraulics has long been recognised as one of the most important considerations in the design of drilling programmes. Improved bottom hole cleaning afforded by jet rock bits and high levels of bit hydraulic horsepower permit the use of the most effective combination of weight and rotary speed and minimises the risk of bit fouling. These benefits became apparent during the early days of jet bit drilling as contractors began to search for ways to maximise the effectiveness of their hydraulic systems. The results are extended bit life and faster penetration rates.

An increasing number of commercial bits are becoming available with interchangeable nozzles, providing the flexibility of rig-site hydraulics optimisation. With these interchangeable nozzles, the hydraulic energy (or power) of the drilling fluid that is dissipated across the bit face can be adjusted to match that portion of the rig's hydraulic power that is available for the bit after other system losses have been considered. (Kendal and Goins, 1960; Randall, 1975, Tibbitts et al., 1979, Hollester and Kipp, 1984, Kelly and Pessier, 1984). The degree to which drilling rate was affected by bit hydraulic horsepower depends on the rock/drilling-fluid combination.

1.4.5 Bit Type

Achieving the highest rate of penetration with the least possible bit wear is the aim of every drilling engineer when selecting a drilling bit. Because formation properties and bit type are the largest factors that affect penetration rate, and obviously, formation properties cannot be changed before drilling and thus selection of the correct bit type is of major importance in achieving high rates of penetration.

The rapid evolution of the roller-cone bits and the perfection of techniques for manufacturing diamond-impregnated core bits, have profoundly influenced recent drilling practices. Bit footage and consequently, footage costs, have dramatically improved as a result of these developments. Advances in metallurgy and heat-treatment techniques and the development of lubricated sealed bearings have made possible the widespread introduction of journal bearings. The bearings have significantly prolonged bearing life. Milled-tooth cutting structures are being replaced by shaped inserts of carbide composition, reducing the tooth abrasion of these cutting elements. The longer inserts make high penetration rates possible well within the life of the bearings, allowing lower over-all drilling costs to offset the increase in bit expenses. Cone offset and other features of milled-tooth bits have been incorporated into the design of the carbide insert bit (Estes, 1971). The use of jets in the bit fluid bath has substantially improved hole cleaning and chip removal, and the use of jets in planned hydraulics programmes has become widespread (Eckel, 1967, Kendall, 1960 and Rabia, 1985). A variety of bit types and sizes are now available for rocks of varying abrasiveness, strength and drilling types.

Bit selection, like the selection of the correct WOB, RPM and hydraulics, is dependent upon a degree of trial and error. Unfortunately, there is no foolproof method of selecting the best available drilling bit for the formations to be drilled. The aim of any bit selection programme is to reduce the trial and error to a minimum. There are many proposed methods for bit selection and often more than one is used before reaching a decision. Bit selection methods include:

1) Cost analysis.
2) Dull bit evaluation.
3) Offset well bit record analysis.
4) Offset well log analysis.
5) IADC bit coding.
6) Manufacturers' product guides.
7) Geophysical data analysis.
8) General geological considerations.

However, these methods are discussed in detail in chapters 2.

Chapter Two

BIT SELECTION AND EVALUATION

2.1 Introduction

The process of drilling a hole in the ground requires the use of drilling bits. Indeed, the bit is the most basic tool used by the drilling engineer, and the selection of the best bit and bit operating conditions is one of the most important aspects of drilling engineering. Bit performance and life are critical factors in determining drilling cost and reliability.

The purpose of this chapter is an introduction to the selection and operation of drilling bits. Included in the chapter are discussions of various bit types available, the criteria for selecting the best bit for a given situation and standard methods for evaluating dull bits.

An extremely large variety of bits are manufactured for different situations encountered during rotary drilling operations. It is important for the drilling engineer to learn the fundamentals of bit design so as to fully understand the differences among the various bits available. Selecting the appropriate bit for a particular interval can improve the rate of penetration (ROP) and increase bit life, and likewise, an inappropriate bit may wear prematurely. A drilling engineer must make many critical decisions while working on a rig, but many times a lack of information may force settlement for less than the best option. Selecting a bit for drilling a particular formation is one such decision. A wrong bit selection, because of incomplete information or understanding, can increase drilling time and costs.

The selection of a suitable bit appears straightforward if one merely reads bit comparison tables, however, in the field, bit selection is considerably more difficult. Often the bit selection is more of an abstract and intutional decision based on experience rather than an analytical decision based on facts. Usually bits are selected on the basis of analysing offset bit records only. Such an analysis may not result in an optimum bit programme if the best bit had never been used in the offset well. The use of offset records alone will indicate the best bit from the list of used bits only. A full knowledge and understanding of bits design innovations, such achieving longer bearing life, will considerably improve the performance of the chosen bit. Also, in many field applications, the new generation tungsten carbide insert and rock bits have proven less expensive than polycrystalline diamond compact bits. Nonetheless, it has also been proven that the use of the appropriate bit regardless of type, for the interval being drilled plays a crucial role in achieving success.

2.2 Bit Types Available

Rotary drilling bits usually are classified according to their design as either drag bits or rolling cutter bits. All drag bits consist of fixed cutter blades that are integral with the body of the bit and rotate as a unit with the drillstring . The use of this type of bit dates back to the introduction of the rotary drilling process in the 19th century. Rolling cutter bits have two or more cones containing the cutting elements , which rotate about the axis of the cone as the bit is rotated in the bottom of the hole. A two-cone rolling cutter bit was introduced in 1909.

2.2.1 Drag Bits

The design features of the drag bit include the number and shape of the cutting blades or stones, the size and location of the water courses, and the metallurgy of the cutting elements. Drag bits drill by physically machining cuttings from the bottom of the borehole. This type of bit includes bits with steel cutters, diamond bits, and polycrystalline diamond (PDC) bits. An advantage of drag bits over rolling cutting bits is that they do not have any rolling parts, which require strong, clean bearing surfaces. This is especially important in the small hole sizes, where space is not available for designing strength into both the bit cutter elements and the bearings needed for a rolling cutter. Also, since drag bits can be made from one solid piece of steel, there is less chance of bit breakage, which will leave junk in the bottom of the hole. Removing junk from a previous bit can lead to additional trips to the bottom and thus loss of considerable rig time.

Drag bits with steel cutter elements perform best relative to other bit types in uniformly soft, unconsolidated formations As the formations become harder and more abrasive, the rate of bit wear increases rapidly and the drilling rate decreases rapidly. This problem can be reduced by changing the shape of the cutter element and reducing the angle at which it intersects the bottom of the hole. Also, in soft formations, the cuttings may stick to the blades of a drag bit and reducing their effectiveness. This problem can be reduced by placing a jet so that drilling fluid impinges on the upper surface of the blade. Because of the problem of rapid dulling in hard rocks and bit cleaning in sticky formations, drag bits with steel cutting elements largely have been displaced by other bit types in almost all areas.

2.2.2 Polycrystalline Diamond (PDC) Bits

Polycrystalline diamond bits are new generation of drag bits which have been made possible by the introduction of a sintered polycrystalline diamond drill blank as a bit cutter element. The drill blanks consist of a thin layer of synthetic diamond that is bonded to a cemented tungsten carbide substrate in a high-pressure/high-temperature process. They are considered a composite material exhibiting the characteristics of hardness, abrasion resistance, and high thermal conductivity of diamond with the toughness of tungsten carbide. As shown in Figure 2.1, the sintered polycrystalline diamond compact is bonded either to a tungsten carbide bit-body matrix or to a tungsten carbide stud that is mounted in a steel bit body. Presently, cutters are available in a variety of sizes and shapes, depending on the bit design and application.

The principal advantage of the matrix body bit construction is the ease with which complex shapes can be obtained. Tungsten carbide is very erosion and abrasion resistant, allowing the bit to have high fluid velocities across the face. In addition, this material is better able to contend with drilling fluids that contain high solids contents or hematite mud systems which are very abrasive. An economic disadvantage does exist with tungsten carbide bit bodies since the raw material is more expensive than the steel required for steel body bits.

Figure 2.1. Example of Polycrystalline Diamond Cutter Bit.

Steel body bits are manufactured from alloy steel that is heat treated to the proper hardness. The cutter attachment is achieved through an interference shrink fit process. A beneficial feature of these bits is the inherent strength of cutter retention through press fitting. This process allows the bit to be easily rebuilt since damaged cutters can be replaced. This has proven to be a distinct advantage to operators in low cost drilling environments. Field experience has shown that steel body bits are susceptible to erosion and abrasion. This generally occurs in conjunction with high bit pressure drops, extended bit runs, and/or high solids content drilling fluids. This becomes the limiting factor when studs cutters can not be replaced or the nozzle retention system is hampered, due to erosion or abrasion, thus losing the rebuilding advantage as discussed earlier.

Polycrystalline diamond bits are primarily designed to drill by shearing. A vertical penetration force is applied to the cutter due to the selected drill collar weight, and a horizontal force (torque) is applied from the rotation motor necessary to turn the bit. The rotation force may be provided from a top drive or a down hole motor. The PDC bits are still evolving rapidly. They perform best in soft, firm, and medium-hard, nonabrasive formations that are not "gummy". Successful use of these bits has been accomplished in sandstone, siltstone, and shale, although bit balling is a serious problem in very soft, gummy formations, and rapid cutter abrasion and breakage are serious problems in hard, abrasive formations.

Bit hydraulics can play an important role in reducing bit balling. The hydraulic cleaning action of PDC bits is usually achieved primarily by using jets for steel-body bits and by using water courses for matrix-body bits. Other important design features of a PDC bit include the size, shape, and number of cutters used and the angle of attack between the cutter and the surface of the exposed formation. A self sharpening feature is inherent to the diamond layer. As the diamond layer wears away new diamond is exposed. This is due to the relative difference in abrasion resistance between the diamond and the cobalt binder. The cobalt binder acts as solvent/catalyst which promotes the intergrowth of the diamond crystals. This feature is further enhanced by the lower abrasion resistance of tungsten carbide, thus maintaining a positive angle between the cutter wear flat and the formation. The cutter wear flat is defined as the flattened area of the cutter which is caused by wear.

2.2.3 Rolling Cutter Bits

The roller or tri-cone bit is by far the most common bit type currently used in rotary drilling operations. This bit type is available with a large variety of tooth design and bearing types and, thus, is suited for a wide variety of formation characteristics.

The drilling action of a rolling cutter bit depends to some extent on the offset of the cones. Offsetting causes the cone to stop rotating periodically as the bit is turned and the teeth scrape the hole bottom much like a drag bit. This action tends to increase drilling speed in most formation types. However, it also promotes faster tooth wear in abrasive formations. The offset of the bit is a measure of how much the cones are moved so that their axes do not intersect at a common point of the centreline of the hole. Cone offset is sometimes expressed as the angle the cone axis would have to be rotated to make it pass through the centreline of the hole. Cone offset angle varies from about 4^0 for bits used in soft formations to zero for bits used in extremely hard formations.

The shape of the bit teeth also has a large effect on the drilling action of a roller cutter bit. Long, widely spaced, steel teeth are used for drilling soft formations. The long teeth easily penetrate the soft rock, and the scraping/twisting action provided by alternate rotation and blowing action of the offset cone removes the material penetrated. The wide spacing of the teeth on the cone promotes bit cleaning. Teeth cleaning action is provided by the intermeshing of teeth on different cones and by fluid jets between each of the three cones. For harder rock types, the teeth length and cone offset must be reduced to prevent teeth breakage. The drilling action of a bit with zero cone offset is essentially a crushing action. The smaller teeth also allow more room for the construction of stronger bearings.

The metallurgical requirements of the bit teeth also depend on the formation characteristics. The two primary types used are:
1) Milled tooth cutters and
2) Tungsten carbide insert cutters.

The milled tooth bits designed for soft formations usually are faced with a wear-resistant material, such as tungsten carbide, on one side of the tooth. The application of hard facing on only one side of the tooth allows more rapid wear on one side of the tooth than the other, and the tooth stays relatively sharp. The milled tooth bits designed to drill hard formations are usually case hardened. As shown in Figure 2.2, this case-hardened steel should wear by chipping and tends to keep the bit sharp.

The tungsten carbide teeth designed for drilling soft formations are long and have a chisel-shaped end. The inserts used in bits for hard formations are short and have a hemispherical end. These bits are sometimes called button bits. Examples of various insert bit tooth designs are shown in Figure 2.3.

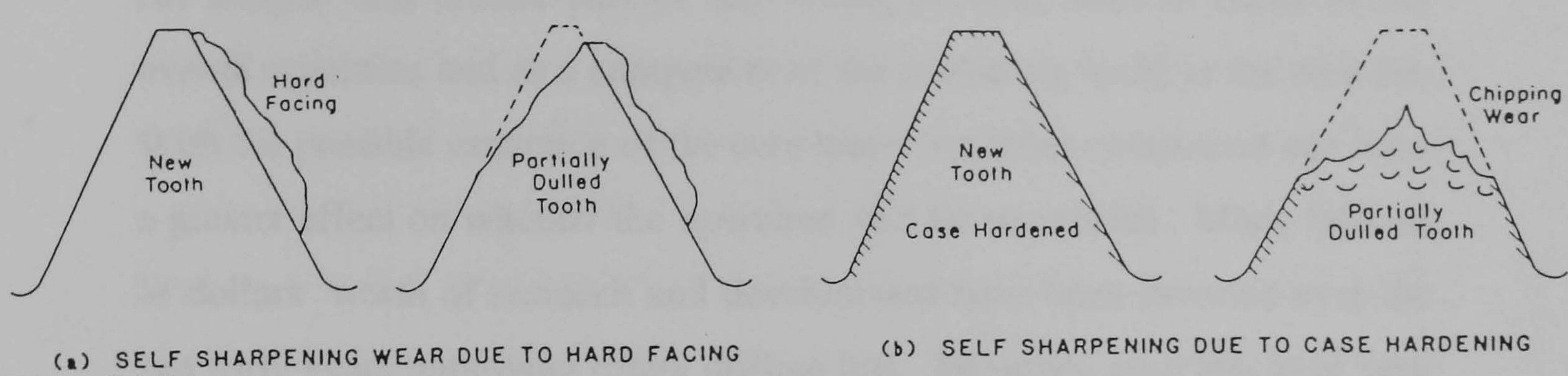


Figure 2.2. Wear Characteristics of milled-tooth Bits.

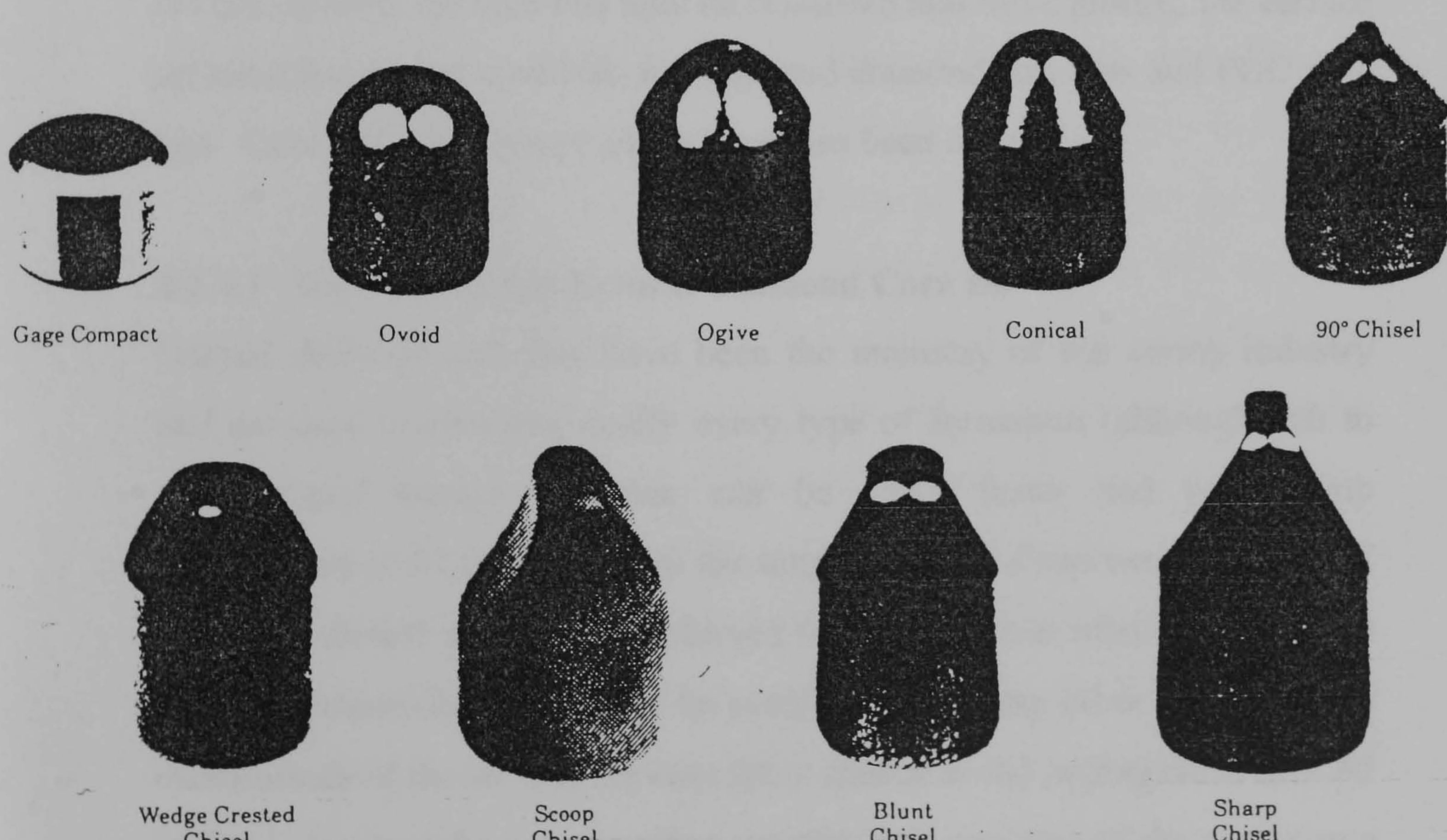


Figure 2.3. Various Tungsten Carbide Insert Cutters Used in Roller Cone Bits.

2.2.4 Core Bits

An integral and crucial part of any coring process, both in terms of the overall operation and as a component of the drillstring itself, is the core bit. With the possible exception of the core barrel, no other component can have a greater effect on whether the operation will be successful. Many billions of dollars worth of research and development have been invested over the last forty years improving rotary drilling bits. However, core bits have seen little change except for the addition of the Polycrystalline Diamond Compact (PDC) to existing product lines. In fact, it is estimated that only 5% of the world's wells are cored and therefore, the number of core bits compared to conventional bits, is small (Art Park, 1985).

In rock drilling, the core bits may be classified into three groups; the surface set natural diamond core bits, impregnated diamond core bits and PDC core bits. Core bits using rotary cones have also been developed.

2.2.4.1 The Surface Set Natural Diamond Core Bit

Natural diamond core bits have been the mainstay of the coring industry and are used to core practically every type of formation (although soft to medium-hard formations often can be cored faster and better with impregnated or PDC bits). With the introduction of these new bits, natural diamonds should probably be reserved for coring those relatively hard and abrasive formations that cannot be cored easily by any other method. The manufacture of the surface set core bit is similar to the impregnated core bit in that it involves the use of carbon moulds and sintering of the matrix in a muffle furnace. However, the surface set core bit differs from impregnated diamond bit by having the diamonds, which are much larger than used in impregnated core bit, set only on the surface of the crown. By varying the diamond type, size and quality, the matrix and the profile, this type of bits will drill and core satisfactorily in all solid and homogeneous formations and can be made to suit any core barrel. It does not perform well in broken or loose zones, if this problem is expected, then Carbonado diamonds are recommended. The selection of the correct size, grade, type of diamond is a major factor influencing the cost per foot/metre of diamond bits. The size, quality, quantity and exposure of the diamonds used in a surface set core bit are dependent on the rock type drilled. Soft formation core bit use larger diamonds in the size 12 to 20 stones per carat, which can be of a lower quality and fewer in quantity. However, hard formations core bits use smaller diamonds in the size range 50 to 90 stone per carat, which are of a higher quality and greater in quantity.

In this type of core bit, the diamonds are placed in the matrix at a depth which leaves about one eight to one third of them exposed. Smaller diamond exposure is used in hard fractured and abrasive formations, whereas greater diamond exposure is used in soft and medium rocks. The matrix of surface set core bit is highly resistant to wear and abrasion, whether from the bit rotating against the formation or from the high velocity mud flowing through the water courses moulded into it, whereas matrix wear is an important feature of the impregnated core bit. The matrix material is of paramount importance, since it holds the bit together as well as securing the diamonds in place while they drill. Standard matrix is used for low abrasive formations, and extra hard matrix is used for high abrasive rocks. The selection of matrix hardness is very important for the core recovery.

The semi round profile is the most commonly used crown shape for thin walled core bits. It requires a low bit load and a lower diamond content, because the profile has the smallest crown surface area. A stepped profile is used in manufacture of thick walled core bits. This profile gives good penetration and straight hole, especially in harder formations when using higher bit loads.

In order to distribute a flushing medium over the core bit face, it is essential requirement for a core bit to have flush channels. There are three types of channels in the surface set bits; the full face discharge, the internal, and the spiral type. The full face discharge type of flush channels comprises of a series of holes through the core bit front and the matrix which direct the flushing medium directly onto the cutting face. The flush channels can be oval, rectangular or round in shape and are designed to limit contact of the flushing medium with the core sample. This prevents erosion and washing away of the core, when soft formations are drilled. The number and size of face discharge flush channels are dependent on the core bit size and type of formations to be drilled. The face discharge flush channels are mainly used for thicker walled core bits.

The internal discharge type of the flush channels consists of a slot passing directly across the core bit front from the inner to outer wall of the crown. The number of flush channels increases when the core bit size increases, because the matrix segments are usually kept at a uniform length. When soft formation is drilled, a greater flush flow rate will be required.

The third type of the flush channels, known as the spiral type, consists of spirally radiating flush channels over the core bit face from the inner surface to outer surface of the core bit. This type of channel is especially suitable for core bits containing medium to large sized diamonds which produce large amounts of cuttings.

2.2.4.2 Impregnated Diamond Core Bits

The concept of impregnated core bits has been around for approximately five decades. The early impregnated core bits were only used on a limited scale and utilised predominantly crushed and lower grade natural diamonds. This restricted their application as the surface set core bits could be manufactured with superior performance characteristics. However, with the wider availability and increased quality of synthetic diamonds manufactured to various levels of impact resistance, core bit manufacturers were able to develop the impregnated core bit concept to maximise the benefits of synthetic diamonds. This led to impregnated core bits becoming fully accepted within the drilling industry. The major reasons for this acceptance are the recent developments which have resulted in many cases, having superior performance characteristics and lower costs than surface set core bits. This is particularly so in the sector of the market previously occupied by surface set core bits (Cumming, 1956).

The benefit of greater core bit life for impregnated core bit is particularly advantageous when wireline coring and coring at greater depth, as it greatly reduces the time wasted and the risk of a borehole caving when round tripping to replace worn out core bits. Although a new surface set core bit often have a greater penetration rate than a comparable impregnated core bit, a uniform penetration rate offers and allows for easier coring operations by an impregnated core bit. Other factors which have contributed to the recent wide use of impregnated core bit are their durability against rough handling and their suitability for coring in fractured formations. Also they are more suitable for use at high rotational speeds and lower bit loads, which allows lighter weight drilling rigs and equipment to be used, and reduces the tendency for borehole deviation.

Impregnated core bits are now the predominant type used by the core drilling industry and have been used in the field work presented in this thesis. Figure 2.4 shows a typical diamond impregnated core bit, and Figure 2.5 illustrates the essential components of which it is comprised.

The manufacture of a diamond impregnated core bit starts with the construction of the crown. The crown material is a powder mixture of cobalt, tungsten carbide, copper, nickel, aluminium, molybdenum and iron which can be tailored to control wear resistance of the matrix. If required, further matrix powder and diamond grain can be added and the process repeated to build up the desired crown thickness, or depth of impregnation. A backing powder, which contains no diamonds, is then placed on top of the compressed matrix powder and diamond grain, to provide a firm fix for the cutting crown to the core bit blank. The core bit blank is pressed into the mould and the whole assembly is placed in a controlled temperature and environment of muffle furnace, where sintering of the matrix takes place.

The diamonds used in an impregnated core bit are very much smaller than those used in a surface set core bit and are typically in the size range 80-1000 stone per carat. The concentration of the diamonds, i.e. actual size, quality and quantity, used in an impregnated core bit depends on the rock properties it is designed to drill and the drilling equipment limitations. However, the general rule for diamond selection is that the harder the rock, the finer sizes, lower quantity and higher quality diamonds are used. Nearly all diamonds used are synthetic in origin and therefore have good properties for drilling. A range of grades is available for different applications (Atkins, 1983).

Figure 2.4. An Illustration of a Typical Impregnated Diamond Core Bit.

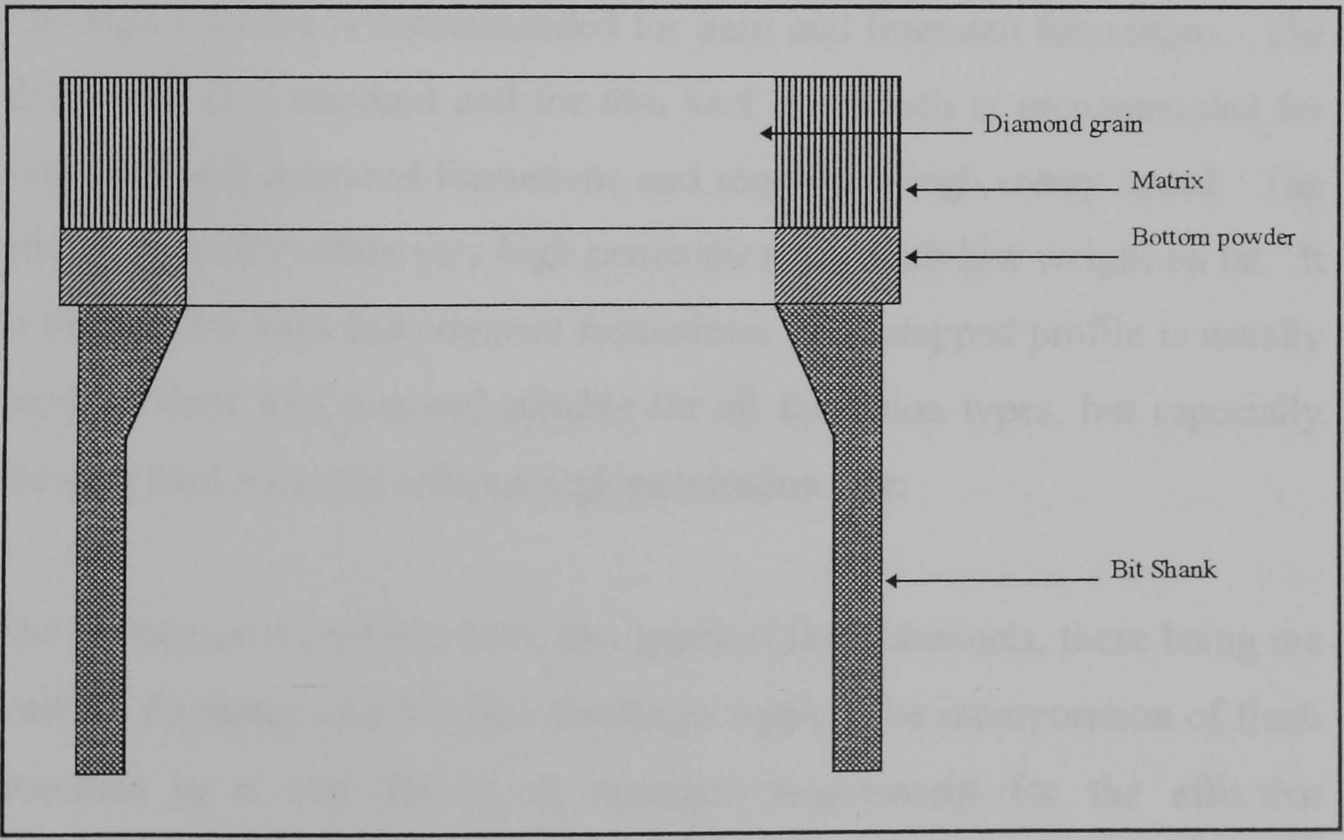


Figure 2.5. An Illustration of a the Essential Components of an Impregnated Diamond Core Bit.

The impregnated core bits have four initial crown profiles which are round, flat, circle set and stepped, and these are illustrated in Figure 2.6.

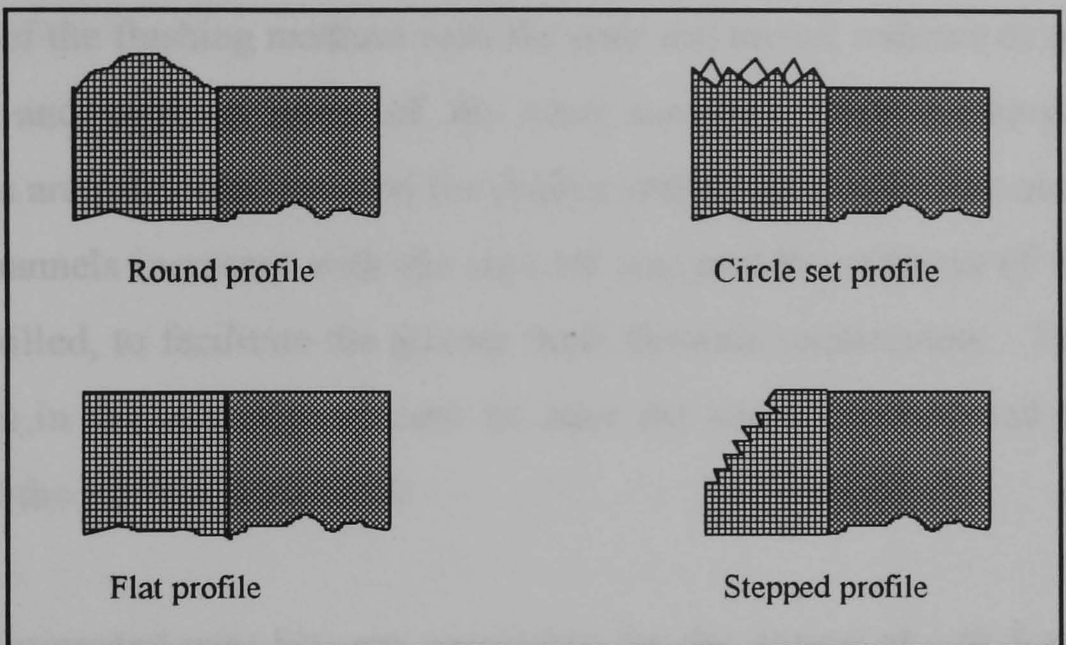


Figure 2.6. Initial Crown Profiles of Impregnated Diamond Core Bits.

The round profile is recommended for hard and fractured formations. The flat profile is a standard and for thin kerf bits which is recommended for very hard and fractured formations and requires a high rotary speed. The circle set profile offers very high penetration rate with low weight on bit. It is suitable for hard and compact formations. The stepped profile is usually used for thick kerf bits and suitable for all formation types, but especially for very hard rock and offers a high penetration rate.

The impregnated core bits have two types of flush channels, these being the internal discharge and the face discharge types. The incorporation of flush channels in a core bit is an essential requirement for the effective distribution of the flushing medium over the core bit face and borehole bottom. Most core bits are the internal discharge type in which the flush channels consist of slots across the core bit front from the inner to the outer wall of the core bit. Face discharge flush channels consist of a series of holes through the core bit front and matrix, which pass the flush medium directly onto the cutting face. These flush channels are designed to restrict contact of the flushing medium with the core and hence, reduces or prevents erosion and washing away of the core sample. Face discharge flush channels are primarily intended for thicker walled core bits. The number of flush channels increases with the core bit size and the softness of the rock being drilled, to facilitate the greater flush flowrate requirement. The flush channels in the impregnated core bit have the same function and form as those of the surface set core bit.

The impregnated core bits are unsuitable for the coring of soft formations due to the fact that the synthetic diamonds used have a relatively small upper size limit. The small sized diamonds restrict flush flow over the crown of the bit and are not able to break up large rock fragments which are usually produced when drilling soft formations. These large rock fragments tend to roll between the bottom of the core bit and the rock surface. These problems cause the core bit to become clogged and cease cutting and therefore make the bit unsuitable for coring in soft formations.

Due to the inevitable shocks and heating to which a diamond is subjected when drilling, its cutting edge will slowly wear away and it will eventually become blunt and cease cutting. This slow natural blunting action can be accelerated by improperly applied drilling parameters and poorly maintained equipment.

The crown of an impregnated core bit consists of a large number of small diamonds evenly distributed within a sintered matrix. As an impregnated core bit drills, the matrix is subjected to abrasion and slowly wears away.

The rate at which it wears is ideally the same as the rate at which the diamonds wear and therefore as the diamonds become blunted and cease to cut effectively, they are released from the matrix and new sharp diamonds are exposed to take over their cutting role. This action gives the impregnated core bit a self sharpening characteristic which allows the bit to be used until the whole of the crown is consumed. As impregnated core bits are manufactured in a whole range of matrix harnesses, the selection of the proper hardness is important to ensure the bit wears away at the correct rate and retains its cutting efficiency. However, the general guide lines for the selection of matrix hardness are; the harder the formation, the softer the matrix, and the more "troublesome" the conditions, i.e. powerful machine, vibration, abrasive or broken formations, the harder the matrix, (Atkins, 1983).

2.2.4.3 Polycrystalline Diamond Compact (PDC) Core Bits

Although PDC has existed for more than 40 years, real advances in drilling efficiency were achieved in the early 1980s. A growing understanding of PDC thermal wear rate response, rock cutting, mechanics, and design features that affect bit performance has contributed to the rapid evolution of PDC bits. The PDC bit is a new generation of the old drag or fishtail bit and does not have moving parts such as bearings PDC was originally developed for cutting tools in machining applications and is considered to provide high abrasion resistance essential to long life in a drag type bit (Madigan and Caldwell, 1981). New, more hydraulically and mechanically efficient bit designs and optimisation of operating parameters have increased the PDC application to include shallow and intermediate holes in mine extraction and mineral and oil explorations.

The introduction of PDC cutters for rock drilling available in large pieces (up to 50 mm in diameter) and therefore, rock cutting elements for a PDC bit can be cut from these large discs in shapes which have optimum geometry for use in core bits (Clark and Shafto, 1987). Coring bits with PDC cutters are designed to drill rock primarily by a shearing action which requires less energy than by crushing. This means that less bit load can be used for drilling which results in less wear and tear on the drilling rig and drill string.

The manufacture of polycrystalline diamond bits consists of three main components, and namely are man-made diamond crystals, tungsten carbide matrix and steel alloy. The use of these three materials is based on their characteristics such as machinability, strength, ductility, thermal conductivity, erosion/abrasion and thermal shock resistance. The man-made diamond crystals are bonded to a cemented tungsten carbide substrate or brazed onto a bit head in a high temperature and high pressure process depending on whether the bit is a matrix or a steel body respectively. The matrix body bits are manufactured utilising a tungsten carbide powder bonded together with a binder metal composed of a nickel-copper alloy. The matrix crown profile, steel bit blank and the shank are the main components in the manufacturing of the bit body.

2.3 Bit Selection and Evaluation

The drill bit's performance determines much of the drilling costs, and performance, in turn, depends on the bits selected and how they are run. Unfortunately, the selection of the best available bit for the job, like the selection of the best drilling fluid or casing cement composition, can be determined only by trial and error. The following methods can be used to select the most appropriate bit type for a particular formation:(a) well bit records and geological information; (b) specific energy; (c) bit dullness; and (d) the most valid criterion for comparing the performance of various bits is the cost per unit interval drilled. Since no amount of arithmetic allows us to drill the same section of the hole more than once, comparisons must be made between succeeding bits in a given well or between bits used to drill the same formations in different wells. The formations drilled with a given bit on a previous nearby well can be correlated to the well in progress using well logs and mud logging records.

The initial selection of bit type in a wildcat area can be made on the basis of what is known about the formation characteristics and drilling cost in an area. The terms usually used by drilling engineers to describe the formation characteristics are drillability and abrasiveness. The drillability of the formation is a measure of how easy the formation is to drill. It is inversely related to the compressive strength of the rock, although other factors are also important. Drillability generally tends to decrease with depth in a given area. The abrasiveness of the formation is a measure of how rapidly the teeth of a milled tooth bit will wear when drilling the formation. Although there are some exceptions, the abrasiveness tends to increase as the drillability decreases.

In the absence of prior bit records, general rules are often used for initial bit selection, but the drilling cost per foot must eventually be the final criterion applied. However, the rules indicate certain tendencies shown to be common on the basis of past experience. Some of these rules, used by many drilling engineers are as follows;

1) The International Association of Drilling Contractors (IADC) classification charts provide an approximate listing of the bit type applicable in a given formation hardness.
2) The initial bit and features selected should be governed by bit cost considerations. Premium rolling-cutter design features and high-cost diamond and PDC drag bits tend to be more applicable when the daily cost of the drilling operation is high. The cost of the bit probably should not exceed the rig cost per day.
3) Three-cone rolling-cutter bits are the most versatile bit type available and are a good initial choice for the shallow portion of the well.
4) Diamond drag bits perform best in nonbrittle formations having a plastic form of failure, especially in the bottom portion of a deep well, where the high cost of tripping operations favours a long bit life, and a small hole size favours the simplicity of a drag bit design.
5) PDC drag bits perform best in uniform sections of carbonates or evaporates that are not broken up with hard shale stringers or other brittle rock types.
6) PDC drag bits should not be used in formations, which have a strong tendency to stick to the bit cutters.
7) When using a rolling-cutter bit:
   a) The bit with the longest tooth size possible should be used.
   b) A small amount of tooth breakage should be tolerated rather than selecting a shorter tooth size.
   c) When enough weight cannot be applied economically to a milled tooth bit to cause self sharpening tooth wear, a longer tooth size should be used.
   d) When the rate of tooth wear is much less than the rate of bearing wear, a longer tooth size or a better bearing design should be selected, or more bit weight should be applied.

e) When the rate of bearing wear is much less than the rate of tooth wear, a shorter tooth size or more economical design should be selected or less bit weight should be applied.

2.3.1 Cost Per Interval Drilled

Often data are available for bit performances in offset wells in the same or in similar formations. Experienced rig personnel and bit suppliers can interpret the offset bit records, correcting for mud differences, depth changes and variations in bit hydraulics practices. Then the expected performance of the candidate bit selection could be reasonably forecasted. The expected performance and net cost of each candidate bit would then be used to calculate its expected average drilling cost per foot. The candidate drill bit with the lowest drilling cost per foot under normal circumstances is the bit selected to run. These comparisons of bit records and drilling cost calculations are carried out beforehand, so to ensure that the chosen drill bit is available at the rig site before the preceding bit is tripped out of the hole. Comparisons are normally made using the following standard drilling cost equation:

$$C = \frac{B + (T + t)R}{F} \tag{3.1}$$

where,

C = cost per foot ($/ft)

B = bit cost ($)

T = trip time (h)

t = rotating time (h)

R = rig cost per hour ($/h)

F = length of section drilled (ft)

The above equation shows that cost per interval drilled (foot) is controlled by five variables. For a given bit cost, B, and hole section, F, cost per foot will be highly sensitive to changes in rig cost per hour, R, trip time, T and rotating time, t. The trip time may not always be easy to determine unless a straight running in and pulling out of hole is made. If the bit is pulled out for some reason, say a wiper trip, then such duration if added, will influence the total trip time and, in turn, cost per foot. Bit performance, therefore, would be changed by arbitrary factor. Rotating time is straightforward and is directly proportional to cost per foot, assuming that other variables remain constant.

The cost per foot is greatly influenced by the cost of the rig. For a given hole section in a field that is drilled by different rigs, having different values of rig costs, the same bit will produce different values of cost per foot, assuming that the rotating time is the same. In this case, if the value of rig cost is taken as arbitrary, then the above equation would yield equivalent values of cost per foot, which is not a real value and does not relate to actual or planned expenditure.

In different parts of a given hole section, performance of a bit could be determined from the cumulative cost per foot (CCF). In this method, a cost per foot for short intervals is determined by the above equation and assuming a reasonable figure for round-trip time. When the CCF value starts increasing, (Moore, 1974) suggests that it is time to pull the bit out of the hole. In other words, the CCF would be used as a criterion for determining the depth at which the current bit becomes uneconomical. (Rabia, 1985), points out, that the drawbacks with the use of the CCF method are; (a) accurate measurement and prediction of footage, trip and rotating times are necessary; and (b) the CCF may suddenly increase as a result of drilling a hard streak of formation and may decrease once the bit passed this streak. These uncertainties on the evidence of one CCF value may result in pulling out of a bit prematurely. Therefore, a simpler and more practical method, is required, whereby the performance of a bit can be quantified in each formation type of the section it drills. This method is capable of being correlated with cost per foot to simplify the analysis of well cost and is known as the Specific Energy.

2.3.2 Drilling Specific Energy

The specific energy method provides a simple and practical method for the selection of drill bits. Specific energy, SE, may be defined as the energy required to remove a unit volume of rock and may have any set of consistent units. The drilling specific energy equation has been derived by considering the mechanical energy expanded at the bit. (Moore, 1974), has shown that the specific energy for rotary drilling may be calculated from the following equation:

$$SE = \frac{20WN}{DF}t \tag{3.2}$$

Where,

SE = Drilling specific energy (MJ/m^3)

W = Weight on bit (kg)

N = Rotating speed (rpm)

D = The hole diameter (mm)

F = Footage (ft)

t = Rotating time (min)

Several researchers (Teale, 1965, Paone et al., 1969, Schmidt, 1972, Mellor, 1972, Tandanand and Unger, 1975, Rabia, 1980, Barr and Brown, 1983, Miller and Ball, 1990, Rowsell and Waller, 1991) have shown that drilling specific energy is dependent on the design and geometry of the drill bit, drill type, methods of cuttings removal, depth of drill hole, weight on bit, rotational speed, rate of penetration and the rock strength. It was concluded by (Rabia, 1982) that the specific energy is not a fundamental intrinsic property of rock. This means that, for a formation of a given rock strength, a soft formation bit will produce an entirely different value of specific energy from that produced by a hard formation bit. This property of specific energy, therefore, affords accurate means for selection of appropriate bit type. The bit that gives the lowest value of specific energy in a given section is the most economical bit.

The above mentioned authors observations conclude that, because the specific energy is considered as the amount of energy required to penetrate rock, then it is a very significant measure of drilling efficiency and an indicator of bit condition. Also, it follows that specific energy is a direct measure of bit performance in a particular formation and provides an indication of the interaction between bit and rock. The fact that specific energy, when compared with the penetration rate, is less sensitive to changes in weight and rotary speed makes it a practical tool for bit selection.

2.3.3 Bit Dullness

The dull bit condition indicates the difficulty the tool faced on bottom. A critical evaluation of the pulled bit provides vital clues for selection of a bit for the next run. The degree of dullness can be used as a guide for selecting a particular bit. Bits that wear too quickly are obviously less efficient and have to be pulled out of the hole more frequently, which increase total drilling cost. Dull bit grading can also indicate the weak areas of the tool or even poor operating practices. Improving these weak links and analysing rock strength can aid in picking the best possible bit for the next run.

Dull bit grading is considered an art, and expertise is gained through experience. A good understanding of how to grade and analyse dull bits can lead to better bit selection and use, eventually cutting overall drilling costs. Many bit manufacturers and drilling companies have described new systems of reporting dull bit conditions, but most people working at the drill sites find it difficult to identify the exact pattern of bit wear. The most commonly used scheme for dull bit was developed by the IADC. This checklist also indicates the remedial measures to prevent recurring problems. Once a bit dulling characteristic has been identified, steps can be taken to incorporate the suggested improvements in bit selection and its operation.

2.3.3.1 Grading Tooth Wear

The tooth wear is graded in terms of the fractional tooth height that has been worn away and is given a code from T-1 to T-8. T-1 indicates that one eighth of the tooth height has gone; T4 indicates that half of the tooth has been worn away, i.e., the teeth are 4/8 worn. Unfortunately, some teeth of a bit may be worn more than others and some may be broken, which make it difficult to characterise the tooth wear of the entire bit with a single number. Generally, the broken teeth are indicated by recording "BT" in a "remarks" column and the average wear of the teeth with the most severe wear is reported. Taking measurement of tooth height before and after the bit run, is considered the best way of obtaining tooth wear. However, with experience, more rapid visual estimates of tooth condition can be made using a profile chart guide see Figure 2.7.

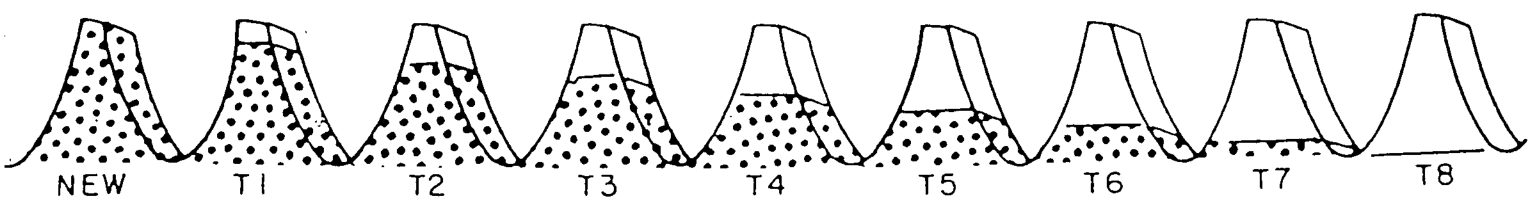


Figure 2.7. Tooth Wear Guide Chart for Milled-Tooth Bits.
(After Bourgryne *etal*, 1986)

The penetration rate of the bit just before pulling the bit should not influence the tooth wear evaluation. In some cases, unacceptably low penetration rates may occur before the tooth structure is completely worn. There are times when a half worn tooth bit will not drill, but this does not mean it should be reported as a T-8. Also, the cutting structures of insert bits generally are too hard to abrade as significantly as a milled steel tooth. The tooth inserts become broken or lost rather than worn. Thus, the tooth wear usually is reported as the fraction of the total number of inserts that have been broken or lost to the nearest eighth.

2.3.3.2 Grading Bearing Wear

Bearing failure usually results in (a) one or more locked cones so that they will no longer rotate or (b) one or more extremely loose cones so that the bearings have become exposed. The field evaluation of bearing wear is very difficult. The bit would have to be disassembled to examine the condition of the bearings and journals. An examination of the dull bit will reveal only whether the bearings have failed or are still intact.

Bearing life is described by eight codes, from B-1 to B-8. The number B-8 indicates that the bearing is wearing out or the bearing is locked. A slightly loose cone usually is reported as a B-7. When bearing wear cannot be detected, it usually is estimated based on the number of hours of bearing life that the drilling engineer thought the bearings would last. Linear bearing wear with time is assumed in this estimate of bearing life. The proper bearing wear code is frequently determined by using a bearing grading chart such as that shown in Figure 2.8.

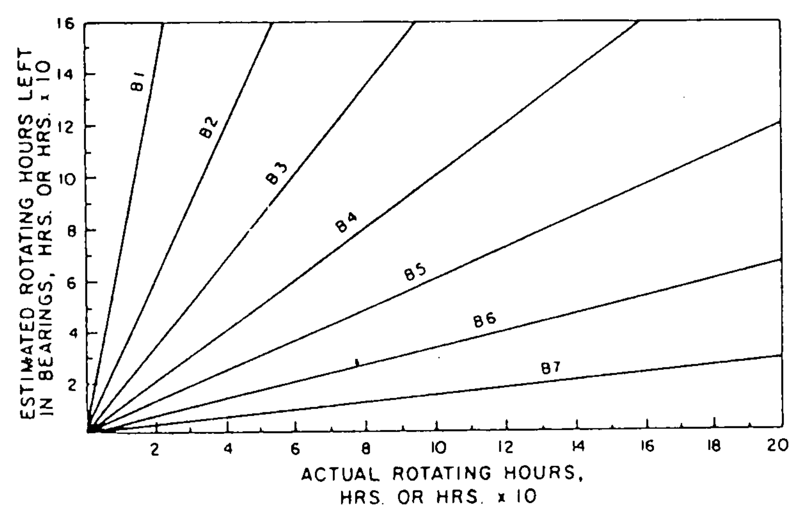


Figure 2.8. Bearing Grading Guide for Rolling Cutter Bits.
(After Bourgryne *etal*, 1986)

2.3.3.3 Grading Gauge Wear

When the bit wears excessively in the base area, the bit will drill an undersized hole. This can cause damage to the next bit run in the undersized hole. A ring gauge and a ruler should be used to measure the amount of gauge wear. The loss of diameter is reported to the nearest eighth. Thus, a bit that has lost 0.5 in. of diameter is graded a G-O-4. The "O" indicates the bit is "out of gauge" and the "4" indicates the diameter has worn 4/8 in. An "I" is used to indicate an "in-gauge" bit.

In addition to grading the bearings, teeth, and gauge wear of the bit, additional comments about the bit condition may be necessary. These remarks about the bit condition should enable those who subsequently will use the bit records to visualise readily the actual condition of the bit.

2.3.4 Variable Information Analysis

The bit selection is not an exact science, and the aim of any bit selection tool is to reduce the trial and error to the minimum amount. The analysis of variable information is considered only as a guide to force the thought process and offers a mental picture of the design requirements of the bit. The variable information sources includes:

- Offset well bit record analysis
- Offset well log analysis
- IADC bit coding
- Manufacturers' product guides
- Geophysical data analysis
- General geological considerations

Offset well logs and bit records are the most important source of information. Wireline well logs can provide a continuous recording of formation parameters versus depth which are very useful for correlation studies. Well to well correlations can give the following insight to the proposed well;

- The types of formations present.
- The elevation of formations in the well relative to others.
- Whether the well is within a given geological structure.
- Whether sufficient formation intervals exist to be economically drilled by a diamond bit.

- Approximate depths at which a bit may need to be pulled.
- The presence of faults.

Mud logs from offset wells can provide a wealth of information regarding the lithology of an upcoming well. Perhaps the greatest benefit is the geological analysis of cuttings to produce a geocolumn. This display serves as an excellent indicator of what will be drilled. In addition, the penetration rate log can be of use in determining the drillability of the proposed formation interval. Infereces to formation properties can be made, affecting the final bit selection and proposed operational parameters. With all this information correlated to depth, an assessment can be made of which formation intervals in the proposed well are diamond bit applicable.

If the previously mentioned data is unavailable, an offset bit record should be consulted. Otherwise, the risk of poor performance will be greatly increased. When selecting a bit, it naturally follows that an estimation of potential footage, penetration rate, and cost savings should be given. The following guidelines are recommended for selecting bit records;

1) The most recent bit record will normally be the best indicator of the type of performance to be expected in a proposed drilling interval.
2) Probability is highest when the drilling technology used is most similar to what will be available.
3) The nearest offset records increase the chance that the formations encountered in the proposed well will be the same and exhibit similar drillability. In faulted areas, an attempt should be made to verify that the offset data is on the same side of the fault as the proposed well. If not, a comparison of bit runs in the same formations is recommended, although they may be at different true vertical depths.

4) Bit sizes and casing programmes should be similar. Different bit sizes affects the ultimate penetration rate, even when all other variables are equal. Cost comparisons can also be affected.
5) Comprehensive dull grades should be available. They will provide a qualitative gauge of the formation abrasiveness. Furthermore, they can give insight to the required type and density of cutters needed to drill.
6) Similar mud type and mud weights are also important, in that different bits will perform differently depending on mud types and properties. An example of this is that PDC bits perform significantly better in oil based mud.
7) Finally, the total depth should be at least equal to or greater than the proposed well. If formation tops change radically, then a conformation should be made that the offset bits drilled the same formation to be drilled.

Methods have been proposed for selecting rock bits using offset well logs such as sonic and gamma-ray logs (Somerton and El-hadidi, 1970, Mason, 1984). These methods appear to work but involves substantial time in the analysis of the logs and in the interpretation of the results.

The international association of drilling contractors IADC bit code offers a method of bit selection based on bit type. If approximate formation properties are known, the table can be used to choose the appropriate bit type. Its drawback is that the geological description contained in the table, on which the bit type is selected, is rather limited. Even if this description was improved, the available geological knowledge from a prospective field would probably be inadequate for use with such a table to select bits.

The geophysical data analysis and the general geological considerations methods tend to be used in new fields where previous drilling is limited or non-existent. Seismic exploration data can be used to predict drillability and formation types. With a knowledge of the expected formation hardness and abrasivity the IADC coding or manufacturers' guides can be used to select bits. Figure 2.9 illustrates the methodology for bit selection.

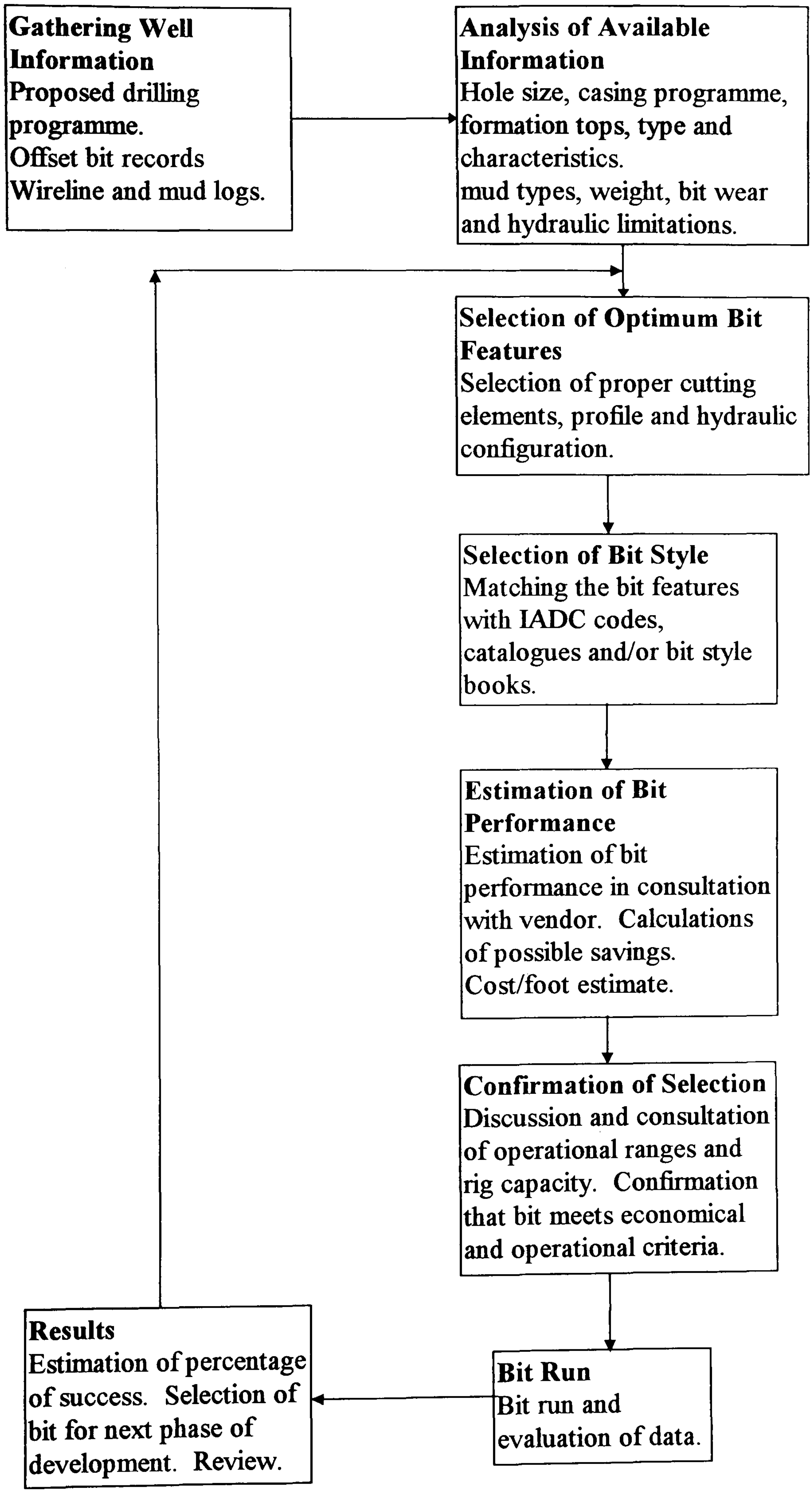


Figure 2.9 Methodology for bit selection.

Chapter Three

SLIM HOLE CONTINUOUS CORE DRILLING

3.1 Introduction

For many years, exploration world-wide has yielded disappointing results for the oil and gas industry as a whole. It has primarily evolved as a costly, time-consuming practice where each well is planned as a major discovery (Strong, 1989). Additionally, the information obtained during drilling is of minimal quality and detail to significantly impact the evaluation of the total exploration/exploitation play.

Recognising the need for a revolutionary change in exploration strategy, many companies decided to explore a new approach based on optimising initial seismic acquisition and using a high speed, automated, slim hole continuous core drilling system.

The high speed drilling system was a logical approach for many companies which hasresulted in several years of research effort. The adaptation to slim hole drilling posed several new technical changes, which are discussed herein.

3.2 The Evolution of Continuous Coring Slim Hole System

A slim hole well is defined in the drilling industry as a well where 90% or more of the length of the well is drilled with bits less than 7 in. (17.8 cm) in diameter, (Walker and Millheim, 1989). Slim hole drilling is not new, as both the explorationist and the exploitationist has recognised the possibility of using a small diameter wellbore to help reducing the overall drilling costs. In the fifties a major operator launched an initiative to drill slim hole exploitation wells in Arkansas and Oklahoma, and stated in the conclusions that slim hole wells could be cost effective, (Flatt, 1954). Slim hole drilling was developed in Sweden to explore and exploit the shallow reservoirs in the country, (Dah, 1982) again cited a 75% cost savings in this approach over conventional drilling practices. The success in Sweden encouraged explorationist and exploitationist to utilise more slim hole drilling in Europe, (Floyd, 1987), then in remote areas such as Indonesia, where the smallness of the overall drilling system and the reduction in wellbore size greatly impacted the logistical cost for drilling these wells, (Macfadyen and Boyington, 1986).

The greatest use of slim hole technology is for continuous coring by the mining industry. This technology has been considered as the only sure way to evaluate whether an ore body is large and has a sufficient mineral grade to justify the cost of sinking shafts or embarking on a costly open cut is to obtain data to delineate the ore body. With the apparent interest in slim hole and continuous core drilling over the last 40 years, both approaches has not gained acceptance by the oil and gas exploration and exploitation sectors. Due to this very pertinent concern, some key issues deserve to be exposed and briefly discussed. This chapter addresses these issues with the sole purpose of examining the possibilities of slim hole and continuous-core drilling in the oil and gas industry.

3.3 Reasons for Slim Hole Continuous Core Drilling

There are two basic reasons to consider drilling a slim hole. The first is very simple and basic; better economics. The second is related to the continuous core mining drilling industry. To achieve a high percentage core recovery and to be cost effective, it is preferable to drill a slim hole.

The argument against drilling a conventional slim hole well is production limitations imposed by the small diameter pipe and the difficulties in work over for such wells. The other often cited reasons, are the lack of good penetration rates using small diameter tri-cone bits, the deficiency of logging tools that would fit into the slim hole and difficulty to test, cementing the small hole and the inability to run multiple casing strings. Together with these complaints, an additional concern is the safety of drilling with a small annulus system when using continuous core drilling.

The current exploration paradigm of all companies exploring for oil and gas, is to spend a significant portion of an exploration budget on costly seismic programmes. (Ashton, 1984) presents the current exploration practised by most oil and gas exploration companies, and also cites a new paradigm that utilises the concept of continuous coring.

Rather than spending a significant amount of the exploration budget on costly seismic programmes The key information could be obtained by exploring the area as quickly and economically as possible. Information such as whether there are source rocks, seals to trap the hydrocarbons, potential reservoirs and hydrocarbons present. These main issues related to the area of interest give an indication of low or high probability of hydrocarbon accumulations.

Continuous coring leaves little to the imagination. With nearly 100% of the rock to evaluate, the entire geology unfolds. The core also provides the necessary rock data to improve the quality of the seismic interpretation that is essential for the more subtle trap determination. Therefore, the reduction of overall exploration costs is possible with an early continuously cored well.

It should be noted that slim hole costs include the drilling of continuous core over 90% of the entire depth of the well, as compared to no core in the conventional well. Walker and Millheim, 1989, claim that the use of conventional drilling system to continuously core would cost three to four times as much as slim hole continuous coring.

The advantage of having full sections of core is in its infancy of understanding. Core drilling provides the geologists, geophysicists, and engineers with the capabilities to evaluate the core at the well site and with data which was almost impossible to acquire previously. In the author's opinion, the barrier to the use of slim hole and continuous core drilling is, it is new and different which causes change. Otherwise, if the technical complaints about slim hole and continuous coring are satisfied and the coring paradigm provides better and more cost effective way to explore, then prior consideration should be given to the slim hole systems as an alternative to previous drilling practices.

3.4 Evolution of Continuous Coring Slim Hole System for Oil and Gas Exploration and Exploitation Drilling

The slim hole system has three basic variations; slim hole wells with little or no coring, slim hole wells where 90% or more is continuously cored, and slim holes that are a combination of coring and full-bored drilling. This section concentrates on the slim hole continuous coring system. When slim hole continuous coring is considered, then the obvious approach is the use of a mining drilling contractors which clearly demonstrate the distinctions between the conventional drilling systems and the mining drilling systems as practiced today.

The mining drilling machine is usually small and lightweight compared with the oilfield drilling rig that has similar depth capacity. A typical mining core drilling system is illustrated in Figure 3.1. Core hole drilling differs significantly from conventional oil field drilling.

Some of the most important characteristics of a typical operations are as follows; Mud circulation rates are low and range from 5 to 70 gpm ($3.1\text{x}10^{-4}$ to $4.4\text{x}10^{-3}$ m^3/s). Normally near 50 gpm in a 5.5 in hole and 12.5 gpm in a 3 in hole. Low rates are necessary due to high friction losses in the small annuli. Hole cleaning is not a problem because relatively few, and only very fine, cuttings are generated. Even though low pump rates generally keep the mud in laminar flow in the annulus, equivalent circulating density (ECD) increases 1-3 ppg as a result of friction. Further increase of up to 2 ppg may result from the high speed rotation (Bode, 1989). Very few drilled or added solids can be tolerated in the mud. The high speed rotation of the drill rod creates a centrifuge effect, forming mud rings on the inside of the drillstring.

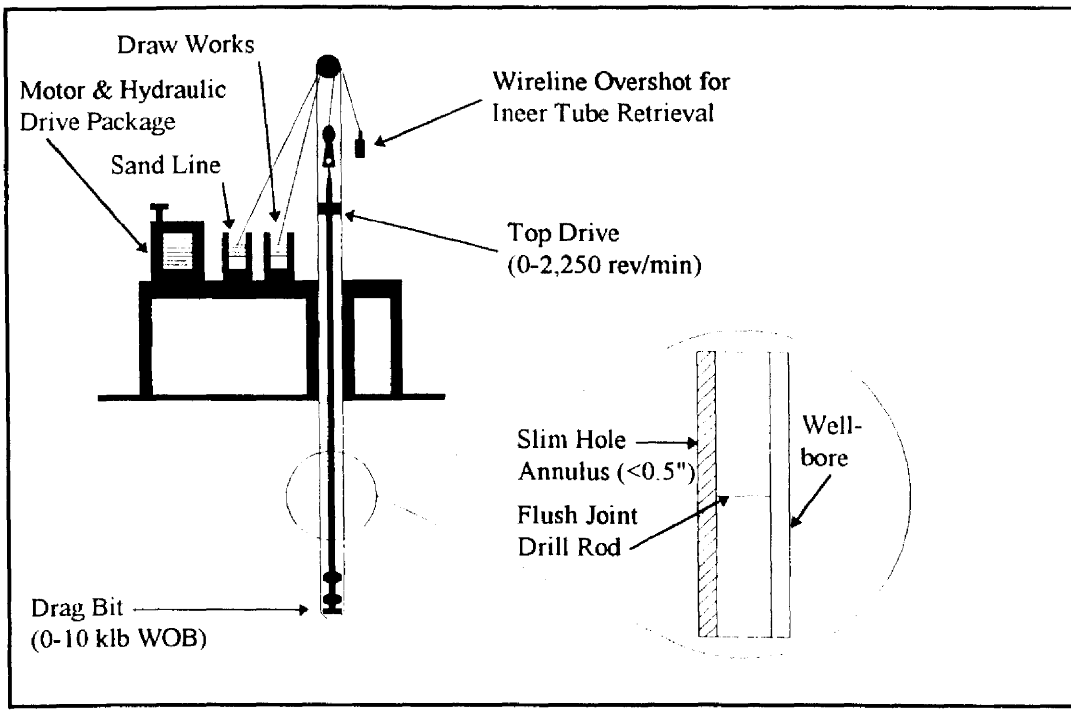


Figure 3.1. A typical mining core drilling system.

Rotation of the drill rod is by a top drive or a chucking device on the side, capable of speeds above 2,000 rpm. The drill rod is externally flush and may be internally upset at the connection, which is a modified buttress-thread type. The drill rod is rotated in a hole with commonly less than 1/2 in. (1.27 cm) of annular clearance. Because there is no room for buckling, the drill rods can have thinner walls than oil field drill pipe. The internal upset retains joint strength while the pipe body allows considerable fluid bypass around the core barrel during tripping. Small diameter, drag type core bits are used. Drilling rods are normally rotated at 300 - 600 rpm, yet some rigs are capable of rotating rods at speeds up to 2,000 rpm. Weight on bit is obtained by drilling with the bottom portion of the drillstring in compression, thereby eliminating the need for drill collars. Buckling and joint failure associated with drill pipe compression are not problems because of the support gained from the borehole wall.

Most mining bits are diamond impregnated cast bits, used for hard formations; however, surface set diamond core bits similar to oil field core heads are also used. The drill bit kerf is very narrow, commonly 0.5 - 1 in. This makes cutting more efficiently because less formation is actually drilled up, and speed variation between the inside and outside of the cutting face is reduced.

Well control equipment, if used at all, usually consists of a ram or bag type blowout preventer (BOP), an accumulator, and controls. Understanding of well control practices and of how actually to handle a kick is questionable and poorly documented within the mining industry. Because the mining industry is interested in finding mineral deposits, continuous coring is often practiced. The best way to core continuously is with a wireline retrievable system. Cores are retrieved by pulling the inner core barrel through the drillstring by wire line, necessitating doubledrum drilling units. Core barrels have lock dogs and fishing necks similar to oil field wire line tools. While a core is pulled, the danger of swabbing a well is reduced by pumping down the drillstring, against and around the core barrel.

3.5 Continuous Coring Rigs

The main available rigs can be classified in three groups;

1) Slim hole destructive drilling rigs. Many of the small oil drilling rigs or workover rigs can drill slim holes, but these rigs are not necessarily designed for continuous coring. One must note the original approach of the microdrill rig which was conceived merely as an oil rig with reduced dimensions. This category excludes small mining rigs that are limited in depth.

2) Continuous cable coring mining rigs. These rigs, for the most part, have no rotary table and are designed for coring most of the well length. Several companies supply rigs able to reach depths of 2,000-6,000 m (6,096-19,685 ft).
3) Mixed oil drilling rigs. During the last few years, several attempts have been made to transform oil rigs into coring rigs by fitting them with mining rods, wireline core barrels, and chuck clamping systems.

3.5.1 Rig Designs

Conventional oil industry drilling rigs are quite effective in destructive drilling, even in slim holes. However, these rigs can only core limited lengths with limited efficiency because it is typically necessary to make a round trip to recover each core barrel.

Conversely, mining drilling rigs drill destructively only in the surface formations, always drill slim hole diameter, and core continuously for most of the well. Mining rigs and their equipment are quite effective for these operations because of the following;

- The smaller size reduces location area (about 9,000 sq. ft with mud pits) and makes them much lighter than oil rigs.
- The reduction in bulk allows helicopter transport or trailer mounting.
- The power required is low, typically 300-400 hp.
- The drillstring handling system uses a chuck clamping head to provide rotation and bit weight.
- The all-hydraulic design allows flexible control of weight on bit, drill rates and rotary speeds. The automated hydraulic controls are necessary to ensure protection of the fast-rotating drill string, especially in case of a sudden variation of torque.

- The continuous coring system allows recovery of the inner tube of the core barrel by using a wireline and without tripping the drillstring. For instance, at 2,000 m (6,561 ft), drilling is only interrupted 15-20 min for every 18-ft core recovered.

3.5.2 Mining Drilling Equipment

Mining rigs range in size from simple, one-man-operated drilling machines weighing only several thousand pounds up to three-man drilling machines weighing close to 100,000 lbm (45 Mg). Most mining rigs are capable of drilling only 6,000 ft (1829 m) or less, although a few can continuously core to 14,000 ft (4267 m). Because most mining rigs are hydraulic, the chuck or top drive systems can rotate the drill rods at variable speeds up to 2,000 rpm, depending on available torque. These systems are also used to raise and lower the rod hydraulically. The chuck has a stroke ranging from 2 to 11 ft (0.6 to 3.4 m), at which time it must be hydraulically raised to regrab (chuck) the rod. Drilling rod sizes range from 1.75 to 5 in. (4.4 to 12.7 cm) OD. The externally flush rod provides a smooth surface that acts as a bearing shaft inside the small annular clearance wellbore. Drill rod lengths vary from 3.28 to 19.69 ft (1 to 6 m). A benefit of the mining system is that each size rod can be used as casing, with the next smaller size of drill rod able to rotate inside the other pipe.

3.6 Drilling Operations

The technological approach of the mining industry for drilling and coring slim holes is considerably different from the typical oil industry approach. Because of the differences in equipment and its applications, an operator using mining equipment (rigs or rods) will have to adapt its techniques in relation to its knowledge of the technology and to the specifications required for safety, especially in the area of kick detection and control.

The reduced drill rod/wellbore annular clearance and the fast rotation of the drillstring require modification of the usual concepts regarding kicks. Because the annulus containing such a small fluid volume, a kick poses a serious threat of emptying the well. Thus, kicks must be detected early, after only a small influx of fluid. The standard procedures for controlling a kick by circulating the influx after checking surface pressures do not apply easily. The pressure drop distribution is inverted in comparison to that found in conventional oil wells. Indeed, as a result of the small annular clearance, most of the pressure drop occurs in the annulus section. In contrast, the pressure drop occurs inside the pipe in those wells drilled with conventional drilling rigs.

3.6.1 Drilling Fluids Hydraulics

Reduced annular clearance and fast pipe rotation contribute to turbulent flow over most of the well. Thus, many classical well hydraulic models become inadequate. The solids content in the mud must be kept as low as possible to avoid forming sludge inside the rods. Sludge built up on the rod inner wall makes core barrel recovery difficult and sometimes impossible. Therefore, solids control equipment, such as centrifuges, should be systematically implemented.

The mining industry has realised the need for a "no-solids" circulating fluid since the inception of the wireline retrieval core system. As the drill rod is rotated at high speeds, it acts as centrifuge that can cause solids platting on the ID. This would not only eventually restrict flow down the rod, but also, and more importantly, prevent wireline retrieval of the core, which could cause a rod trip. When possible, the mining industry uses water to core. If viscosity is required (e.g., to overcome rod vibration), a polymer is used. Large amount of sedimentary formation with reactive clays are rarely drilled by the mining industry. Therefore, the industry has little expertise in designing oilfield mud systems to inhibit the various formations with reactive clays.

Circulation rates required for the slim hole system vary significantly from those of conventional oilfield practices, primarily because of the high annular velocities in the small annular space and the lifting of finer cuttings. Common flow rates when an HQ rod is used range from 20 to 40 gpm (1.3×10^{-3} to 2.5×10^{-3} m^3/s), whereas those when the BQ rod is used vary from 8 to 15 gpm (5.1×10^{-4} to 9.5×10^{-4} m^3/s). Specific mining terminology is defined in Table 3.1.

						Rod diameters			
	Hole size		Bit OD	Core OD		Outer		Inner	
Standard	mm	in.	mm	mm	in.	mm	in.	mm	in.
AQ	48	1.890	47.6	27.0	1.063	44.5	1.752	34.9	1.374
BQ	60	2.362	59.6	36.4	1.433	55.6	2.189	45.9	1.807
NQ	75.7	2.980	75.3	47.6	1.874	70.0	2.756	60.3	2.374
HQ	96.1	3.783	95.6	63.5	2.500	88.9	3.500	77.8	3.063
PQ	122.7	4.831	122.2	85.0	3.396	114.9	4.524	102.8	4.047
SQ	146.1	5.752	145.3	108.2	4.260	138.1	5.437	126.0	4.961

- Chuck = a mechanical device that grips the drillrod and is contained within the drive head, which imparts rotation.
- Drillrod = an externally flush drillpipe with an internal upset at the connection.
- Mud ring = solids build-up on the ID of the drill rod caused by centrifuging associated with high speed rotation.
- Sand line = wireline used in the retrieval of the inner core barrel.

Table 3.1. Standard Mining Rod Sizes and Specific Mining Terminology.

3.6.2 Drill Rods

The thin wall coring rods have square-cut threads and flush joints with annular clearances less than 1 cm (0.4 in.). The smaller diameters make it possible to use the rods as retrievable intermediate casing in the open hole. Figure 3.2 shows a schematic of a typical slim hole with rod strings run as casing.

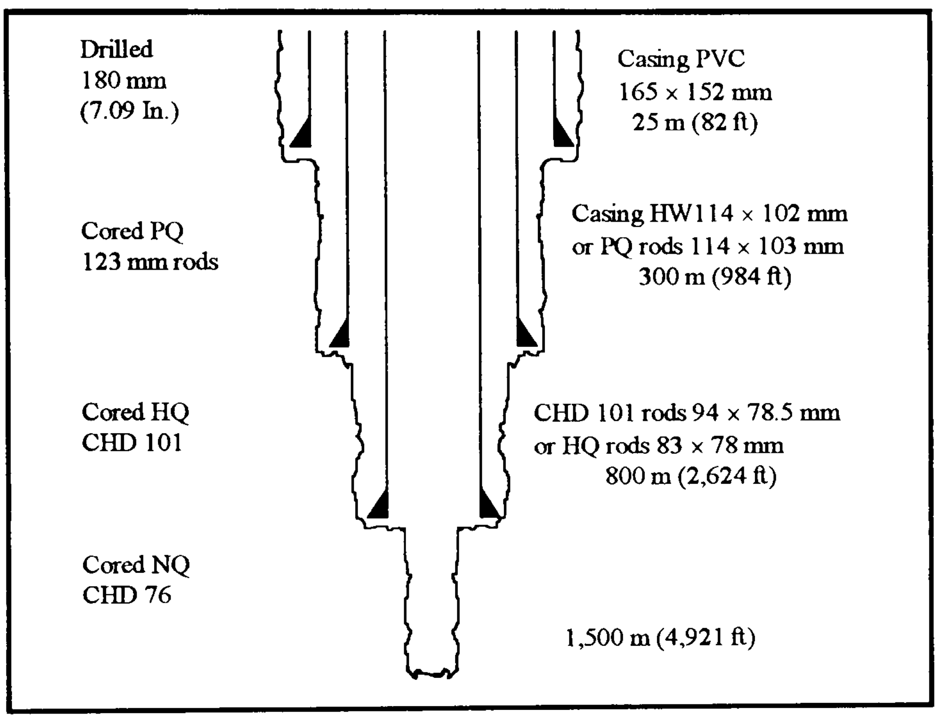


Figure 3.2. A Schematic Diagram of a Typical Slim Hole Drilling and Casing Programme.

The mining industry uses a flushed rods system that does not comply with oil industry specifications. Standard mining rod sizes (AQ, BQ, NQ, HQ, PQ, and SQ) are listed in Table 3.1. Mining standards are substantially lower than American Petroleum Institute (API) standards, particularly in terms of makeup torque and mechanical strength of rods and couplings. In some circumstances, the limits of mechanical strength may force the oil operator to stop operations early.

3.6.3 Cementing

Cementing volumes can be reduced using drill rods as a retrievable casing string. Because of the high pump pressures required to overcome the increased friction in the small annulus, cementing operations might become difficult with respect to channelling behind pipe and fracturing of weak formations. Reaming the well before running casing may offer one solution to this problem. The small volumes of cement required make it possible to search for more adaptable substitutes for working in those small diameters.

3.6.4 Bits

Drag type core bits are used almost exclusively by mining drilling companies. These bits, if properly designed, are ideal for drilling mineral type formations. Typical formations penetrated in minerals exploration are much harder, more competent, and more uniform than those drilled by the oil industry. Therefore, direct application of mining bit practices to sedimentary formations will not necessarily yield economic results. The impregnated diamond bit is used most often in mining coring. This bit has very small diamonds (310 to 525 diamond particles per carat) continuously embedded within a tungsten carbide matrix that wears as formation is drilled, exposing new cutting surfaces. Surface set diamond core bits are also used, but to a lesser extent, on softer formations. Polycrystalline diamond compact (PDC) bit technology is virtually unused in the mining industry.

Drag bits rotated at high speeds can penetrate the rock efficiently with a low weight on bit (WOB). A typical WOB range is from 2,000 to 10,000 lb (8896 to 44482 N). Drag bits are susceptible to catastrophic failure if the formation changes abruptly and the bit becomes "buried" and fluid starved. Therefore, a precise bit advance system is desired; however, this system does not exist on most mining rigs, although the design of one is very adaptable to a drilling machine with hydraulic controls.

3.6.5 Well Control

Well control practices generally are not a concern to the mining industry due to the fact that most formations penetrated in mining do not contain hydrocarbons. Use of this system for hydrocarbon exploration requires a thorough understanding of the physics associated with well control in the slim hole. Investigation of the system's physics reveal that slim hole well control is very possible. (Bode et al., 1989) give a detailed discussion of slim hole well control physics and practices.

3.6.6 Core Retrieval and Processing

One of the main intentions of continuous coring operations is the gathering of as much information as possible. Thus, immediate core processing and analysis must be particularly well organised. With a proper core lab set-up, a complete set of data could be measured on site, including such parameters as: porosity, permeability, saturation, geochemistry, gamma ray, magnetic susceptibility, fluorescence, and hydrocarbon analysis. Unfortunately, a suitable well site service for core processing does not seem to be available yet.

Moreover, mud logging operations are more productive because cores are analysed instead of cuttings, which are virtually non-existent when coring. Core samples are large and less contaminated by mud with a precise depth of origin known. On site core processing should make it possible to reduce to a minimum the amount of logs required. Most of the standard electric line logs are available for diameters down to 2 7/8 in., and production testing equipment is available down to 3 in. However, the compatibility should be checked with the processing methods used.

Core is retrieved by a wireline. Figure 3.3 illustrates the components of the system. Most mining operations cut cores of 5, 10, or 20 ft (1.5, 3, or 6 m). When coring is completed, a wireline overshot is lowered through the drill rods until it engages a spear point attached to the inner barrel containing the core. Upon reaching the surface, the inner barrel is laid down, another inner barrel is picked up and dropped or lowered to bottom, and the core is pumped out with a hydraulic pump. Various core barrel systems are available that consistently allow for 98 to 100% core recovery in all types of formations.

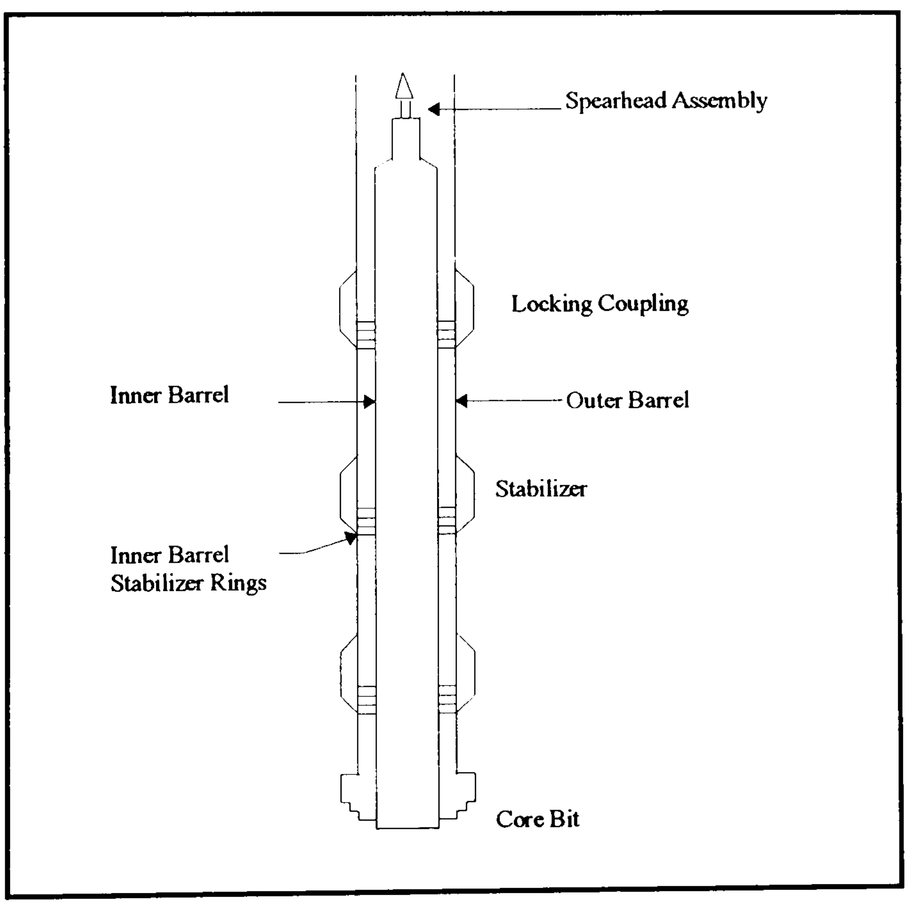


Figure 3.3. Wireline coring assembly.

Core analysis is typically performed by a mining engineer or core analysis service company. The responsibility of the mining drilling contractor normally ends with the boxing of the core at the site. Analysis of the core is similar to that in the oil and gas industry, with the primary objectives being to determine the reservoir (mineral) properties; little consideration is given to true geological and geophysical evaluation, although the recent mining literature reflects more of an interest in evaluating the complete core.

3.7 Challenges to Oilfield Drilling

The adaptation of slim exploration wells to the oil and gas industry brings new challenges to the oil field;

- Technology must improve some of the problems and limitations of slim hole drilling and improve the real-time analysis of cores and logs.
- Furthermore, formation testing in small diameter wells needs to be considered and studied.
- Safety of the rig and rig crew presents additional problems in areas including kick control, early gas detection, and implementation of explosion-proof standards for mining rigs.
- With the development of core hole drilling as a tool for the explorationist and reservoir engineer, exploration strategies may change as a result of the large amount of raw information immediately available at reduced costs. This approach may result in a redistribution of the respective input from and expenses to the geophysical and drilling departments.

3.8 Considerations for Oilfield Drilling

Slim hole exploration wells should be analysed as an option for an exploration project in the following circumstances:

- If a significant part of the drilling budget is for logistics.
- If difficulties are expected as a result of climate, environment, or site access.
- If seismic operations become complicated, costly, or difficult to interpret.
- If a well is re-entered for deepening.
- If there is a need particular or precise information supplied by continuous cores, including: stratigraphy, sonic velocities, formation age and maturation, source rock and cap rock nature, reservoirs, and formation fluids.
- If a field is evaluated for extension (for example, before expiration of permits). Because of the present limitations of slim hole exploration, especially concerning safety, kick detection, and well control, it appears that slim hole explorations are appraisal purposes than for wildcat exploration.
- Disposal of drill cuttings; lower volume for slim hole.

Chapter Four

CORE DRILLING

4.1 Introduction

The process of coring and core analysis has advanced considerably in recent years, especially in light of sophisticated and highly technical forms of investigation such as scanning electron microscopy, x-ray diffraction and thin section analysis.

Cores are the only way to supply intact specimens of the formation anatomy. Direct measurements on core samples furnish data not available from any other source, and cores afford the only opportunity for visual examination of the rock aside from cuttings analysis. Thus cores when viewed with an intelligent eye, yield geologic and engineering information that will increase understanding of the presence, quantity and distribution of formation hydrocarbons, and ultimately will aid in selection of processes to maximise their profitable recovery.

Of all commonly available coring methods, the conventional core analysis, is the most important source of information in that it furnishes measured values of basic rock properties. Porosity, permeability, residual fluids, lithology and texture are some of the parameters that characterise a core vertically, and representative samples are commonly taken every foot (and more frequently when core examination indicates the need). A quick look at these cores and their tabulated and plotted data identifies zones of greatest storage capacity (porosity), greatest flow potential (permeability) and the presence and magnitude of residual oil. Relative changes in these properties with depth are easily observed, and average properties of selected zones can be compared for relative quality. Grain size, an indication of sorting, colour of the rock, presence of laminations and other important structures are described. Fractures, intensity and distribution of oil fluorescence are also reported. Data such as grain size distribution, grain density and acid solubility typically are furnished as supplementary data on request.

A drilling programme of boreholes to depths up to 2000 m for the investigation of possible sites for the repository for the disposal of radio active waste included the requirement for high quality continuous core drilling. These special requirements prompted the adoption of a blend of oilfield, mining and geotechnical exploration equipment and procedures to achieve the various objectives within the quality standards.

This chapter summarises the main elements of the equipment, systems and procedures adopted and presents some data on performance comparisons between a mining rig approach and that using a modified conventional oilfield rig. Comments on the application of this experience to slim hole continuous core drilling for oil and gas exploration and exploitation, are made in chapter six.

4.2 Field Programme

In order to investigate the performance of various types of impregnated core bit and drilling operations, this study focuses on data obtained from an investigative drilling programme. In this special investigation programme, the integration of oilfield, mining and geotechnical exploration technologies including several elements which are important in the application of slim hole methods for oil and gas exploration is analysed. Many of the technical issues associated with a slim hole approach is addressed in the development and application of the drilling, coring equipment and systems.

4.2.1 Geotechnical Investigation Drilling Programme

A programme of boreholes to depths up to 2000 m for the investigation of potential sites for the UK national repository for the disposal of low and intermediate level radio active waste included the requirement for high quality continuous coring through a range of geologies, a 159 mm (6-1/4 in) minimum diameter hole for a comprehensive wireline logging programme and a suite of testing both during drilling and at the end of each borehole interval. The requirement for a deep high quality geotechnical investigation programme provided a rare opportunity to integrate technologies from various drilling applications to develop a routine exploration method for this type of special geoscientific investigation and to help evaluate the suitability of slim hole methods for exploration and exploitation drilling in the oil and gas industry.

The investigation is part of a geological and hydrogeological study for potential sites for a deep, low and intermediate level radio active waste repository which will eventually be mined at a depth of 500-1000 m below the surface. Two sites were being considered at the start of the investigation at Sellafield, Cumbria, England and at Dounreay, Caithness, Scotland. The preferred site at which the current work is being concentrated is at Sellafield.

The two sites presented an opportunity to gain experience with a standardised system in different conditions from site size to geology and support logistics considerations. The unusual specification for continuously cored holes using a wireline system and enlargement to allow the installation of standard oilfield casing in standard hole sizes required some innovation. Where possible available equipment was utilised on cost grounds and in view of the limited lead time available for mobilisation. The package adopted was essentially contractor designed to meet an end product specification.

The geologies of the two sites are both variant of the crystalline basement under sedimentary cover repository scenario. At Sellafield, the generalised succession is principally a Permo-Triassic sequence comprising abrasive fine to medium grained sandstone, shale and poorly sorted breccias overlying Carboniferous Limestone and a basement of lower Palaeozoic age, the Borrowdale Volcanic Group. The Permo-Triassic includes the St Bees Sandstone, a formation noted for its abrasivity. Bit records from wells in the formation in the adjoining Irish Sea Basin show abnormal gauge wear. The Borrowdale Volcanic Group comprises welded tuffs, with interbeds of volcanic breccia and some intrusive andesite sills.

At Dounreay, a Devonian sequence of interbedded siltstones and sandstones some 400-500 m thick overlies a basement complex of metamorphic rocks of the Precambrian Moinian series. The Moinian rocks are very strong and abrasive with many quartz rich feldspar veins.

4.2.1.1 Borehole Design

The borehole design was dictated by the desire to provide isolation of certain formations for well control as well as for hydrogeological and geochemistry evaluation together with the requirement for a 159 mm (6-1/4 in) TD diameter and the need to accommodate multiple string completions and downhole pumps for long term testing. In the initial holes, coring was carried out from near surface to final depth. The procedure was to core and carry out associated testing during drilling in the 159 mm (6-1/4 in) diameter cored hole as far as the next casing point. Sector logging and testing was carried out in the 159 mm (6-1/4 in) diameter hole after which the hole was opened to the appropriate diameter and standard oilfield casing or liners in sizes from 508 mm (20 in) to 178 mm (7 in) installed and cemented. A typical design scheme for a worst casing scenario is shown on Figure 4.1. Actual borehole configurations are summarised on Figure 4.2.

In some boreholes, coring was commenced deeper. The initial drilling was carried out using conventional destructive drilling methods typically in 216 mm (8-1/2 in) to allow testing during drilling and high resolution logging to be carried out. Holes were opened as for the coring sections prior to casing.

The drilling programme was developed between the client's specialist and the contractor as there were certain provisions required by the contractor and there was a general desire to optimise rig time. One requirement was the need to install a technical casing in hole sizes greater than 159 mm (6-1/4 in) for continuous coring. This was necessary because wireline coring tool joints are relatively weak and successful mechanical performance of a wireline system depends on the support from the hole or from a matching casing or tubing

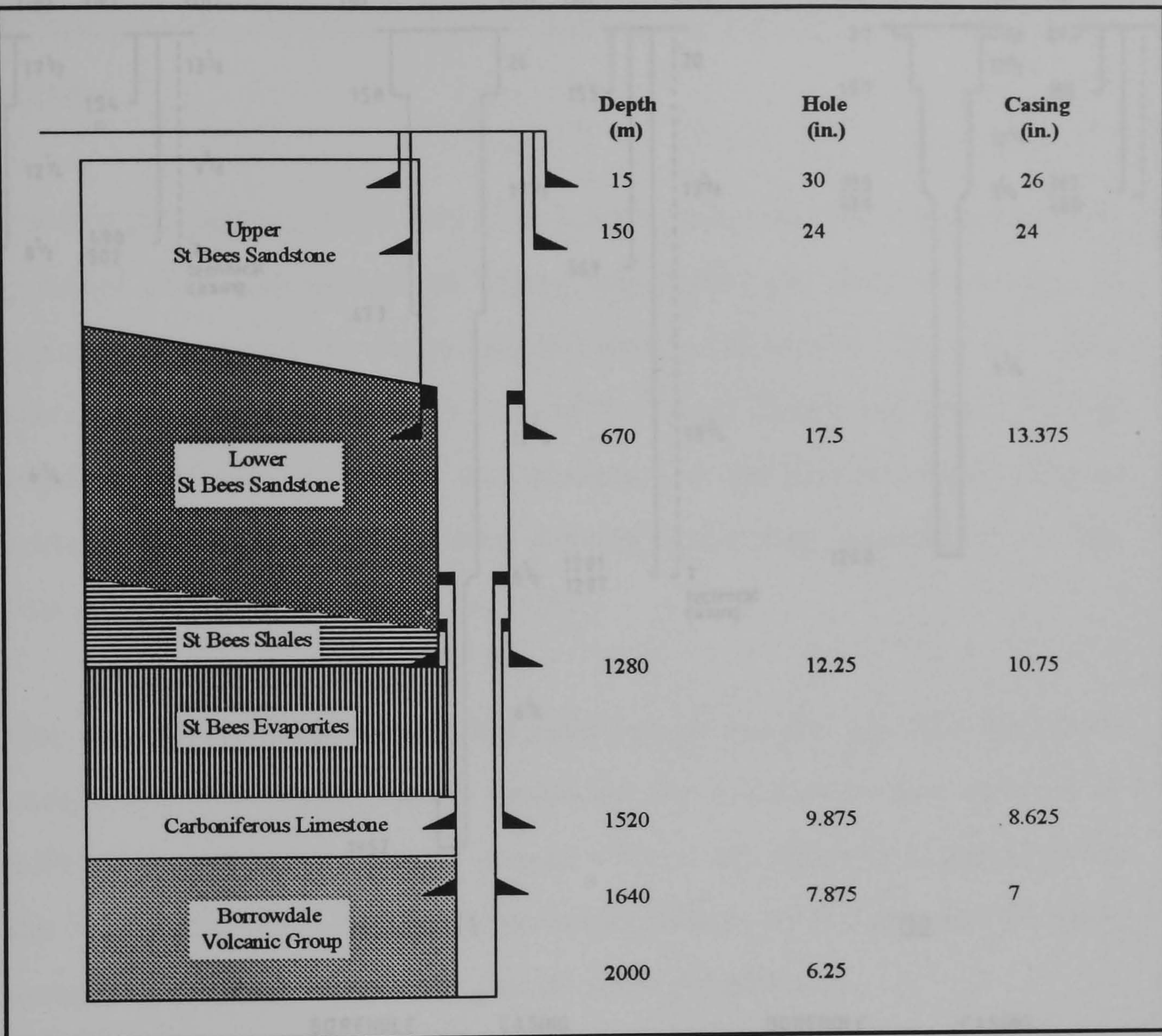


Figure 4.1. Typical Borehole Design Scheme for Worst Case Scenario.

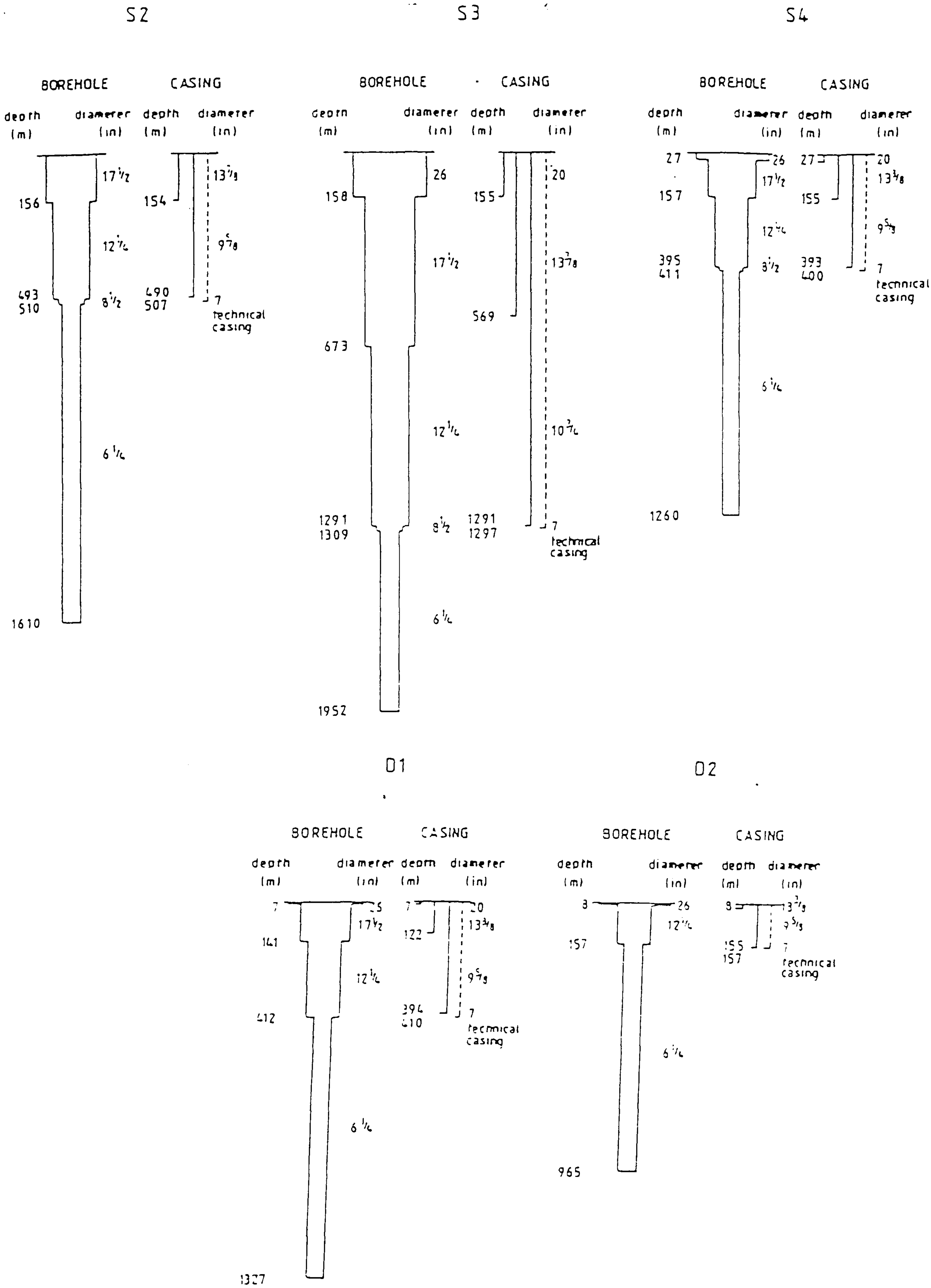


Figure 4.2. Actual Borehole Configurations.

string. In effect, the small mud filled annulus between the pipe and casing or hole provides continuous support and reduces flexing and vibration in the string.

For this programme, a 178 mm (7 in.) casing was used for this purpose and installed after each permanent casing was drilled out after cementing. A typical arrangement for the technical casing is shown in Figure 4.3. The casing was hung free at the bottom in the larger casing and centralised as required. A bell entry guide was machined in the lowest casing collar to ensure free passage of the coring, logging and testing assemblies. A seal was provided in the wellhead assembly.

One noteworthy feature of the borehole design was the use of a sub sea or compact type wellhead which facilitated the installation and removal of both permanent and temporary casings without the necessity to nipple down the BOP stack. This was a convenient expedient particularly for the more complex casing schemes and it proved very cost effective.

4.2.1.2 Drilling Rigs and Equipments

Three rigs have been used to date on the project. Two are 3000 m capacity diesel electric land rigs modified with electric driven 800 hp (540 kW) hydraulic power packs, hydraulic top drive units and specialist heavy duty wireline coring facilities. The third is a heavy duty mining drilling rig which included specific features for deep coring.

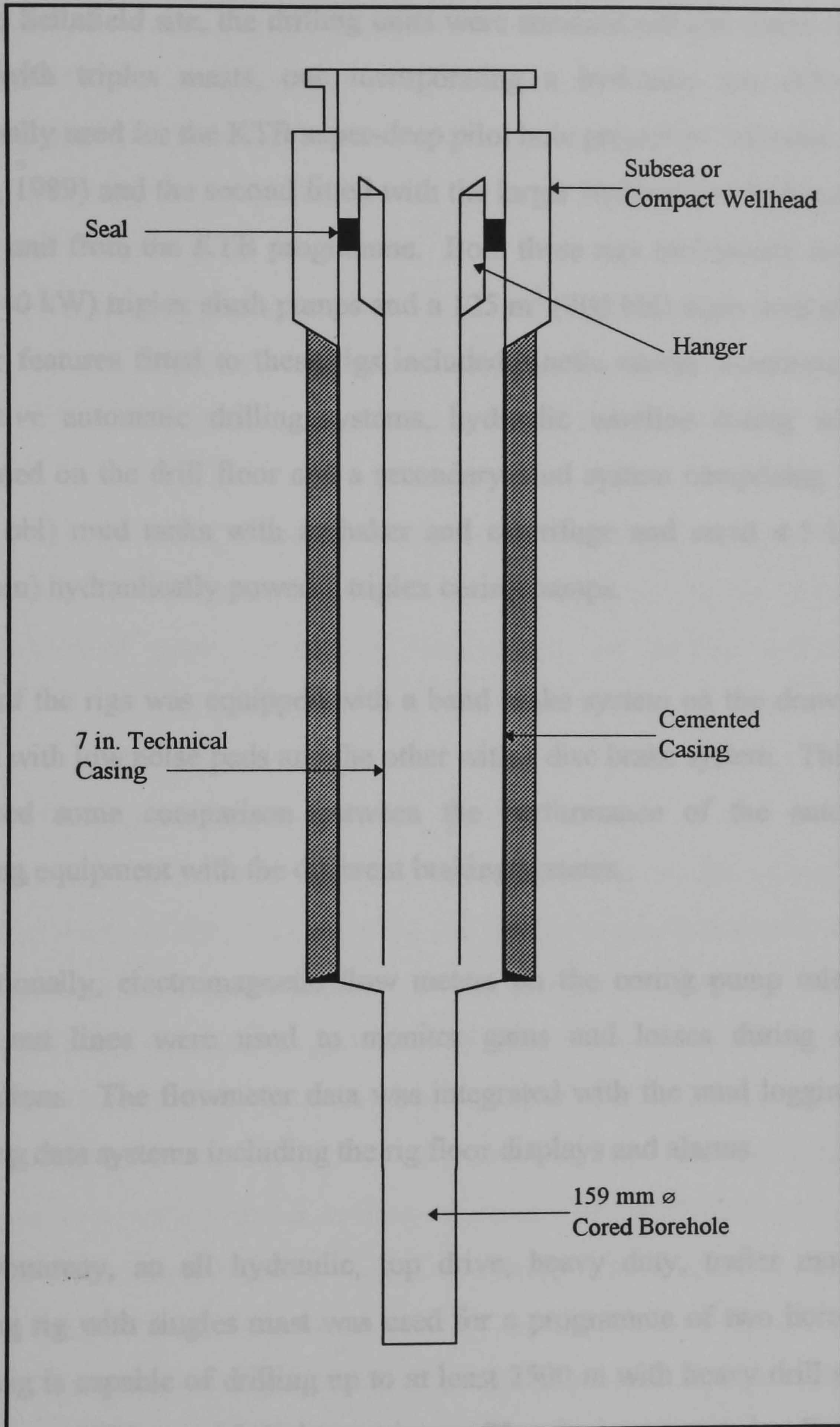


Figure 4.3. A Typical Arrangement For Technical Casing.

At the Sellafield site, the drilling units were standard oilfield diesel electric rigs with triples masts, one incorporating a hydraulic top drive unit originally used for the KTB super-deep pilot hole project in Germany (Chur et al., 1989) and the second fitted with the larger replacement hydraulic top drive unit from the KTB programme. Both these rigs incorporate two 800 hp (540 kW) triplex slush pumps and a 125 m^3 (800 bbl) main mud system. Other features fitted to these rigs included kinetic energy monitoring and sensitive automatic drilling systems, hydraulic wireline coring winches mounted on the drill floor and a secondary mud system comprising 30 m^3 (200 bbl) mud tanks with a shaker and centrifuge and small 4.5 l/s (70 gal/min) hydraulically powered triplex coring pumps.

One of the rigs was equipped with a band brake system on the drawworks fitted with low noise pads and the other with a disc brake system. This also allowed some comparison between the performance of the automatic drilling equipment with the different braking systems.

Additionally, electromagnetic flow meters on the coring pump inlet and flow out lines were used to monitor gains and losses during coring operations. The flowmeter data was integrated with the mud logging and drilling data systems including the rig floor displays and alarms.

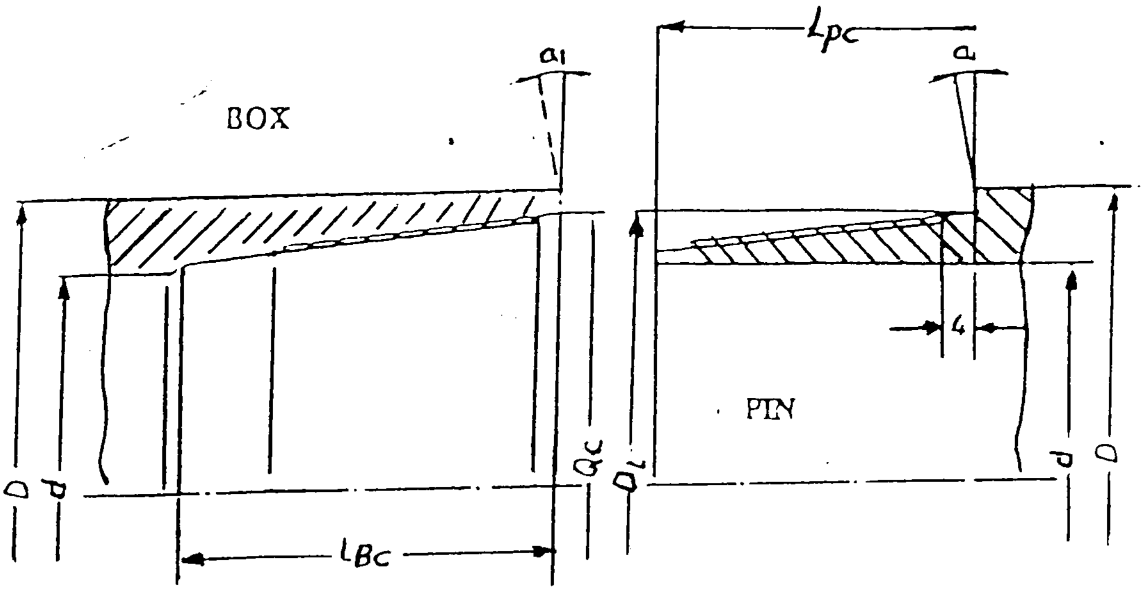
At Dounreay, an all hydraulic, top drive, heavy duty, trailer mounted, mining rig with singles mast was used for a programme of two boreholes. This rig is capable of drilling up to at least 2500 m with heavy drill strings and up to 3000 m with lighter strings. The rig incorporated a fine feed system for coring, a pipe handling robotic arm to handle single lengths of drill pipe from pipe racks to the centre line of the hole, a 60 m^3 (400 bbl) mud system with shaker and centrifuge and electromagnetic flowmeters for monitoring flow in and flow out as part of the mud logging and drilling data facility. A 300 hp duplex (200 kW) mud pump and an identical triplex coring pump to those units provide for coring at Sellafield were included in the rig inventory.

Each rig was equipped with 4-1/2 in or 4 in API drill pipe strings and associated drill collars for conventional drilling and hole opening together with 3-1/2 in API drill strings and 2-7/8 in tubing for testing.

Site layouts for the rigs and associated equipment were accommodated in about 4250 m^2 for the large oilfield units and 1800 m^2 for the mining rig plus additional space for offices, laboratories, car parking and tubular stores.

4.2.1.3 Wireline Coring System

The borehole specification required hole diameters in the continuously cored intervals of 159 mm (6-1/4 in) principally to accommodate borehole imaging tools for fracture mapping. This diameter requirement could be accommodated with the largest size of heavy duty wireline equipment available. The string selected is one of a suite of wireline strings which has been widely used over the last 10-15 years in Europe These strings were designed as a nesting set for drilling conditions where difficult and varied geology necessitates a system where the string can be used as casing if drilling can not be continue without casing due to hole conditions (Petersen, 1987). The principal data on this suite of strings are given in Table 4.1. These strings are rated on strength criteria for use up to 4000 m. Noteworthy is that the drilling sizes allow the use of standard oilfield casing and tubing sizes which are noted in the table.



	5-1/2 SK 101	4-1/2 SK 79	3-1/2 SK 57
D (mm)	152.4	118.0	90.5
d (mm)	123.5	95.0	70.0
a (°)	15	10.0	10.0
Q_c (mm)	142.0	109.0	83.2
L_{BC} (mm)	97.0	70.0	60.0
D_L (mm)	141.8	108.8	83.0
L_{PC} (mm)	96.0	60.0	50.0
Taper	1:12	1:10	1:10
TPI	4	4	4
Thread height (mm)	2.1 + 0.1	2.1 + 0.1	2.1 + 0.1
Pipe D	139.7	114.3	88.9
Pipe thickness (mm)	8.0	8.0	6.45
Grade	P105	N80	N80
Weight (kg/m)	28.5	21.3	13.4
Weight (lb/ft)	19.1	14.3	9.0
Pipe length (m)	9.0	9.0	9.0
Hole Size (mm)	159.0	124.0	94.0
Hole Size (in.)	6.25	4.88	3.70
Core Size (mm)	101.0	78.6	57.0
Core Size (in.)	4.0	3.1	2.25
Max depth (km)	4.0	4.0	4.0
Matching Casing (in.)	7.0	5.5	4.5

Table 4.1. Summary Details of Heavy Duty Wireline Coring Strings.

For this coring programme, the largest size string of the suite was used which gave the desired 159 mm hole diameter and nominal 100 mm (4 in) core.

With the objective of optimising core quality and surface handling, a UPVC corebarrel liner was utilised in the inner tube of the corebarrel reducing the core size to 95 mm. The use of a liner results in an increased bit kerf thickness and a less advantageous area ratio which generally decreases coring performance especially in strong, abrasive rocks, however, this was accepted as core quality was the foremost objective of the coring system. This type of liner is widely used in quality geotechnical and mining investigations to some 200 m depth where high quality cores are essential for engineering purposes. This particular material had not been used previously for holes deeper than 400 m. The liners were 2.65 mm thick and manufactured to fine tolerances and cut to a precise length so that insertion on site was simple. The manufacturing specification was as follows:

Length	6265.00 mm + / 2.0 mm
Outside diameter	102.75 mm + / 0.10 mm
Inside diameter	96.75 mm + / 0.15 mm
Inner barrel ID	104.00 mm nominal
	103.50 mm minimum
Liner clearance	0.325 mm minimum
Core diameter	95.00 mm nominal
Core clearance	0.8 mm nominal minimum

The liner material comprises Wellvic V8 167, a UPVC especially manufactured for stability on extrusion and known to be temperature stable up to 60° C. No liner distortion was noted with bottom hole temperatures approaching 60° C and circulating temperatures up to 40° C.

Even though each liner was subjected to a quality inspection at the point of manufacture, every length of core barrel liner was again checked on site for visual defects and internal and external diameters.

On recovery of the inner barrel, liners were extruded horizontally from the corebarrel inner tubes with water pressure acting against a sealed plug machined to fit the top of the liner and which allowed the extrusion force to be carried by the liner wall with no compression of the core. The core quality achieved with this system has been excellent. A corebarrel length of 6 m was selected on the grounds that this was probably equivalent to the projected average run length and it facilitated surface handling without introducing especially heavy handling equipment and the risk of damage during handling. This was a decision which has proven to be appropriate in this case, but for other applications, a longer corebarrel could be used. The outer barrel of the coring system is identical to the coring drill string.

Identical in hole wireline coring equipment was used on all rigs including corebarrels, corebarrel stabilisers, core catcher assemblies inner barrels, liners and wireline retrieval equipment. Pipe handling on the conventional rig was achieved using conventional slip type elevators as the tool joint upset gives sufficient assurance that the elevators will grip. It is more usual with wireline strings to use lift subs and associated elevators which increases the tripping time due the need to install and remove the lift plugs. On the mining rig, the power swivel incorporates a power slip system and elevators are not required.

The wireline coring system allows the sample barrel containing the core in the liner to be recovered from the borehole using an overshot and wireline so significantly reducing the round trip time to recover core. A second inner tube is returned to the corebarrel at the bottom of the string by free fall with the restriction afforded by the small annular clearance providing the necessary braking effect to limit the landing impact on the landing ring. Tripping of the drill string was only required where a bit change was necessary or to facilitate testing and/or logging.

The design and construction of wireline drilling strings requires careful analysis. The principal difference to a normal API drill string is that the tool joint is relatively weak to allow the passage of the corebarrel inner tube through the connection. The design of the tool joint controls the strength and hence depth rating of the string.

During the planning stage of the KTB super-deep pilot hole in Germany, various wireline coring strings were reviewed for their suitability for drilling the 4000 m deep initial scientific borehole. The heavy duty strings subsequently used for the Sellafield and Dounreay investigations were included in that study which included finite element analysis of the tool joints. The study concluded that these strings were capable of drilling to 4000 m depth on strength grounds. The actual string eventually used in the KTB programme was of similar design, but with a 152 mm (6 in) hole size and non upset pipe necessitating the use of lift subs.

The manufacturing process of the tube for wireline coring strings must also be considered carefully. With tool joint strength so critical and the thickness of metal limited, good quality, uniform wall thickness pipe is essential. Both seamless and welded tube has been used successfully in the manufacture of this suite of wireline coring pipe. For dimensional accuracy, the welded pipe is preferred particularly for the smaller sizes. Suitable tube used for this wireline coring system is manufactured routinely in all sizes by the computer aided high frequency inductive welding process. Current welding technology, advanced processes and quality control during manufacture provides a high quality tubing for pipe applications.

In the case of the tube used for this investigation programme, lead time on welded pipe was such that a seamless alternative had to be adopted, but the grade is P-105 as against the N-80 grade normally used when welded tube is used. Tool joints are friction welded to the pipe. Tool joints on this heavy coring pipe are such that a thin hard band strip can be included to increase abrasion resistance and hard banding was included on all pin ends of the pipe used for this investigation.

Pipe failure with heavy duty strings are very rare and no in hole failure has been experienced to date with the 5-1/2 in string in use at Sellafield and Dounreay. However, a strict preventative inspection programme is in operation and all pipe run in the compression zone is inspected every 100 rotating hours and the pipe cycled in the string. The pipe is checked against a wear criteria similar to the API classification. The criteria used is presented in Table 4.2. As a guide, wireline pipe life is typically one tenth that of an equivalent API drill string and hence pipe costs are relatively high.

Class	Tool Joint OD (mm)	Pipe Body OD (%)
New	152.4	100
Premium	150.4	80
Class 2	149.0	65
Class 3	147.6	45

Table 4.2. Wear Classification Criteria for 5-1/2 SK 101 Pipe.

4.2.1.4 Drilling Fluids

The drilling fluid specification was for a lightweight, non-particulate polymer with a tracer to asses the degree of invasion and contamination of the drilling fluid in the formation by analysis of the fluid produced during the various testing programmes. A bentonite gel mud system was used for some of the hole opening intervals.

The coring fluid used at Sellafield was a water based XCD (dispersible xanthin viscosifing biopolymer) mud containing 1000 ppm lithium ion (as lithium chloride) as the tracer. Initially a preservative treated starch was added for filter loss below 10 cc. However, it was found that by keeping the 6 rpm Fann value at about 10, the flow behaviour of the XCD, together with the drilled fines in the mud, resulted in a satisfactory fluid loss range of 10-15 cc without starch. This reduced the complications in the mud chemistry for geochemistry laboratory studies.

The target Fann rheometer reading corresponded in this fluid to a Marsh funnel viscosity of between 38 and 50 s/qt which became established as a satisfactory range. The plastic viscosity remained below 8 cp reflecting the low solids content which ranged between a trace and 2%, the yield point ranged between 15 and 25 lb/ft^2 depending on the polymer concentration and gel strengths ranged from 5/8 to 10/15 lb/ft^2. The formations were such that visual oilfield variables and problems associated with maintaining an inhibitive water based fluid while drilling in sedimentary lithology did not occur.

The lithium ion concentration was required to be maintained within 2% of 1000 ppm, i.e. between 980 and 1020 ppm. This level was necessary to elevate the concentration above the background level. Five or six flow line samples were taken each day and the concentration checked.

Fluid densities were generally very low in the range 1.0 and 1.04 SG (8.33 to 8.65 ppg). Torque became a problem in the long open sections in some holes and after some experimentation, copolymer beads were added to increase the lubricity. This expedient was chosen as the beads were relatively inert and the least likely additive to cause any concern to the geochemistry analysis. A concentration of 1% by volume reduced torque by 40%.

Solid control equipment used on all rigs during coring comprised a shale shaker and 50 gpm (3 l/s) centrifuge. During hole opening and open hole drilling with mud, shakers and mud cleaners were used.

4.3 Hole Opening and Continuous Coring

Open hole drilling was carried out conventionally. Hole opening at Sellafield was achieved with normal hole openers in appropriate assemblies with rock bits being adapted as an expedient in some of the stronger rocks to reduce the risk of tool failure and increase the speed. Hole opening was carried out in stages from 159 mm (6-1/4 in) to 216 mm (8-1/2 in) then to 311 mm (12-1/4 in) and finally where necessary to 445 mm (17-1/2 in).

In the initial borehole at Dounreay, hole opening was carried out using down-the-hole hammers and insert hole opener bits with air and foam flush in a single pass from the 159 mm (6-1/4 in.) cored hole diameter to the final size. This method was selected due to the strong nature of the rocks and, despite significant water flow in some intervals, these operations were very successful. In the 159 mm to 311 mm (12-1/4 in.) interval, some 400 m long, the hole opening was achieved in 64 hr with one hammer hole opener bit. Air usage was a maximum of 2300 ft^3/m with a 2500 kg weight-on-bit.

Continuous coring using the 139.7 mm (5-1/2 in) heavy duty wireline coring system was carried out in all holes over part or all of the hole depth. The coring was carried out using a conventional wireline coring procedure used widely in the geotechnical investigation, mineral and coal exploration industries. Rotation was provided by hydraulic top drive units at rotational speeds generally in the range of 150-220 RPM with corresponding weights on core bits of 1500-2500 kg. Core recovery and quality were the main objectives.

A routine was developed to optimise rig time using additional inner tubes, all of which were interchangeable within the system, to reduce non drilling time and all components of the coring system were carefully checked as part of the quality system adopted for the project.

Coring was interrupted each 50 m to allow testing to be carried out to determine the environmental pressure in the 50 m interval. This necessitated tripping the coring string and running a testing assembly on a testing string. At Sellafield, all pipe was racked in the rig mast, but at Dounreay, all pipe had to be laid down each trip with the singles rig, although this procedure was assisted by the use of the pipe handling device which was added later to the rig to improve tripping speeds.

All boreholes were drilled within the specified verticality tolerance of 10°. Controlled drilling with the wireline coring system resulted in actual inclinations at total depth ranging from 0.9° to 6.4°.

The coring was extremely	S2	S3	S4	D1	D2
Hole Depth (m)	1610	1952	1260	1327	965
Core Length (m)	1577	1259	849	1319	956
No of Coring Runs	331	246	162	285	204
Average Run Lengths (m)	4.76	5.11	5.24	4.62	4.69
Maximum Core Run (m)	6.12	6.36	6.50	6.43	6.45
Minimum Core Run (m)	0.10	0.00	0.00	0.10	0.10
Apparent Core Recovery (%)	100.39	100.14	100.44	99.03	99.34
Actual Core Recovery (%)	99.72	99.83	100.09	99.05	* 98.42
Modified Core recovery (%)	99.90	100.00	10.14	99.20	* 98.60

Table 4.3. Coring and Core Recovery Summary.

* Virtually all losses occurred in one a fault zone 20-30 in length at some 560 m depth.

Apparent Core Recovery	The summation of lengths of individual core contained in the corebarrel liner measured after extrusion on the catwalk to the nearest 10 mm and expressed as a percentage of total length cored.
Actual Core Recovery	The summation of the lengths of individual pieces of reconstructed boxed core measured to the nearest 5 mm and expressed as a percentage of total length cored.
Assessed core recovery	The actual core recovery adjusted for the apparent loss equating to the number of saw cuts multiplied by the original blade thickness.

4.4 Well Control

Perhaps the most important aspect in the application of wireline coring systems to deep drilling in potential hydrocarbon bearing formations is the question of well control. This has been addressed by others developing the use of slim hole methods for oil and gas exploration and exploitation, particularly that published in relation to the SHADS project (Walker, and Millheim, 1989. and Bode, et al., 1989). The small annulus inherent with the wireline system necessitates attention to procedures for the identification of influxes and losses, tripping strings and corebarrel inner tubes and for the kill procedure itself in the event of a kick.

In view of the relatively small annular volume compared with traditional pipe-hole systems, any gas influx will result in a gas column over an extended length of borehole. Annular friction at different pump rates and different mud properties is also very sensitive and care must be taken not to over pressurise formations with high equivalent circulatory densities (ECD). The measured ECD's during this programme were as high as 1.35 SG (11.2 lb/gal) with a mud density of 1.02 SG (8.5 lb/gal). This raises the issue of well control during drilling because the high ECD may mask a kick until circulation is stopped for a connection or any other reason. Initial detection must be fast and appropriate action taken to confirm that an influx has occurred quickly then proceed to kill the kick as soon as possible.

The relatively large wireline coring system used for this programme contrasts with the slim and ultra slim hole systems being used or considered in some sectors of the industry for exploration. On the SHADS project, typical hole diameters were 111 mm (4-3/8 in) as against the 159 mm used in this case. However, the whole question of well control was of concern.

For the coring operations, the secondary mud system incorporated electromagnetic flowmeters to ensure early detection of small influxes and losses. Low pressure flowmeters were installed on the inlet side of the small triplex coring pump and on a secondary flow line returning from the well. The suction line was pre-charged to allow the use of identical 80 mm flowmeters in both lines rather than using a larger size on the pump suction or a high pressure on the pump delivery. The geometry of the flow line ensured that the flow meters and pipework either side were always full. The flowmeter data acquisition was incorporated in the mud logging unit and displayed as flow in, flow out and flow difference both on the analogue chart recorders and on the VDU screen in the unit and on the drill floor. Alarms could be set as required on the flow data. Checks for consistency in readings could easily be carried out by flowing across the top of a closed BOP.

The accuracy and resolution of these devices is very high compared with conventional pit gains and loss measurements. In this case, the flow meters were calibrated for flows from zero to 6.3 l/s (100 gal/min) and flow differences to 0.6 ml/s (0.01 gal/min) were displayed with alarms set for flow differences of 6 ml/s (0.1 gal/min). Normal pit level monitors were also included in the system.

Tripping and flow check procedures were modified when using the wireline coring string. Pipe annular volumes are reversed with this system compared with conventional drill pipe. With the corebarrel inner tube removed, tripping pipe is relatively straightforward providing precautions are taken to ensure effective hole fill and displaced mud is controlled. Trip logs are completed prior to tripping and trip tank volumes are especially carefully monitored. Kick drills are held more regularly than normal to ensure that

all crew members are familiar and reminded of the procedures. The role of each person in the crew is rehearsed as reaction time is much shorter than with normal drilling systems.
With the small annulus, the drill pipe is filled from the surface with a hose when tripping out rather than the normal method of filling the annulus.

Tripping the inner barrel during core retrieval is another potentially dangerous condition. Prior to retrieving the inner barrel, a flow check is carried out and the flow difference checked from the VDU monitor. As the formations being drilled are considered to be low risk with respect to high pressure influxes and only very low volume, low pressure gas has been encountered, a wireline lubricator or stuffing box was not used. However, a pair of wireline cutters were maintained at a designated location on the rig floor to chop the wireline in an emergency. Flow returns during the initial delatching and acceleration of the inner barrel are monitored carefully.

Circulating rates are measured each shift both at different pump rates and different rotary speeds as pressure loss in the small annulus is sensitive to changes in rotary speed.

Swab and surge potential is greatly increased with small annulus systems which also necessitates careful attention to tripping speeds. Swabbing increasing the potential for influxes or breakout in highly stressed wells and surge pressures causing fracturing of wells are important considerations. The effects of swabbing may have resulted in unexpected breakouts in some boreholes which would be unexpected from the stress field data and surge pressures may have contributed to fracturing of a short interval of another borehole. Simulator models suggest that surge pressures can increase from 6 Mpa (850 lb/in^2) to 25 Mpa (3575 lb/in^2) from 500 m to 2000 m depth which are very significant. These superimposed rock stress conditions are particularly important in strong rocks which can sustain high stress differences. Similar experiences have been encountered in other crystalline drilling in smaller sizes which can only be attributed to surge pressures during tripping. Further work is needed to fully understand these effects.

4.5 Core Handling

The quality management system in operation includes procedures designed to ensure that all core is handled in a controlled manner and eliminate orientation errors and minimise the possibility of induced fractures occurring post coring. The cores are handled several times in the site core facility and later at outside laboratories and stores. Controlled processing of core handling is a feature of the system. Accidental damage has been eliminated by designing the core handling facilities such that lifting of unboxed core is unnecessary.

When the inner tube of the corebarrel is removed from the coring drill string, it is placed in a rigid 'scabbard' to protect it from bending and dynamic effects as it is lowered to the catwalk. The retrieval latching assembly, corebarrel head and core catcher and bit assembly are removed when the corebarrel is in the horizontal position on the catwalk and the core within the liner extruded on to a purpose designed cutting bench. To prevent orientation errors, the liners are marked throughout with a directional arrow in the manufacturing process. On removal from the inner barrel, the liner is cleaned and indelibly marked with reference letters across each cut position and the run number and additional orientation arrows added. All marking is checked and the apparent recovery of the core in the liners measured and recorded for hole depth and recovery reconciliation before the core is cut into 1.5 m lengths for boxing. As each length is cut, tight fitting elastic end caps are fitted and the cut lengths slid onto a multi-channel receiving trolley for transportation to the core storage and handling facility.

At the core store, the liner is cut longitudinally within a jig and all identification marks repeated on the lower part of the liner. The lengths are slid into boxes which accommodate two 1.5 m lengths and then photographed after labelling. The core is later logged, described and specimens selected for engineering evaluation. The purpose of the core in this circumstances is different from the general use in the oilfield and the handling and sealing requirements are therefore not necessary appropriate to oilfield exploration, but the procedures could be adapted to suit all end uses.

4.6 Logging and Testing Programme

During the coring programme, environmental pressure measurements are made at nominal 50 m intervals. These tests were designed to measure the environmental head and hydraulic conductivity of discreet sections of the borehole as drilling progressed to allow a piezometric pressure profile to be established and an indication of formation permeability to be made.

The procedure included the deployment of a single packer with test assembly at the top of the section. A typical test comprised a short shut in period, lowering of the borehole fluid column by about 50 m and then allowing the response section to flow for about one hour followed by the main shut in period which lasted from eight to twenty hours. These low pressure tests required special procedures and equipment modifications to eliminate spurious pressure responses during packer inflation and tool operation. In some tests, swabbing was adopted to induce flow.

These tests have proved to a very effective method of establishing the formation pressure profile and indicative assessed permeability of the formations.

At the end of each section of boreholes construction, a comprehensive wireline logging programme including borehole imaging and VSP surveys was carried out prior to a further programme of hydrogeological testing comprising:

- Full sector testing over the entire open hole section with artificial lift usually by gas lift with production logging.
- Discrete extractive testing from isolated zones using straddle packers.
- Hydrofracture stress measurements.

This testing is directed towards a detailed understanding of the permeability and formation pressures as well as to obtain a range of samples for geochemical analysis.

Chapter Five

ANALYSIS OF THE DRILLING RESULTS

5.1 Introduction

As drilling costs increase world-wide, significant cost leverage can be obtained by even incrementally reducing drilling times. One area of potential savings in drilling cost is to improve the efficiency of the drilling process, or specifically, increasing the rate of penetration (ROP) of the drilling bits. Two major drilling projects were considered in this investigative study to analyse their drilling performance. One is mainly a core drilling geotechnical site investigation, located at Sellafield, England, which is explained in detail in chapter 4. The second is an oil field development drilling project, located 400 km to the south east of Tripoli, Libya, at which roller cone bits were the predominant bits used. Two fully instrumented field drilling rigs which are used to obtain data from in this research are summarised in this chapter. The operational performance of the rigs and instrumentation systems are demonstrated. The data obtained in these drilling fields are carefully selected and presented which include roller cone bits and impregnated core bits in a various types of rocks. The performance characteristics of these bits are significantly affected by a group of factors which include drilling variables, bit features, rock properties and bit wear. This chapter examines the effect of some operational parameters such as the rotation speed, weight on bit and bit hydraulics on the performance of bits. These parameters are recorded on the daily report sheets and then carefully selected for analysis.

The main objectives in the examinations of the drilling variables are to determine the effects of the drilling variables on the performance of these bits and to find out the optimum or the best drilling parameters for these bits in given conditions. The second objective is to analyse the performance of the wireline coring system of slim hole drilling and its application to the oil exploration as a method of reducing costs. Any slight improvement in the drilling efficiency of the bits' drilling process represents a considerable savings of the overall costs.

5.2 Methodology

Selecting wells for which drilling data remained constant was important if the effects of the drilling parameters on drilling efficiency was to be determined. As is usually the case with drilling variables evaluations, it is difficult to maintain exact duplication of the drilling variables and be assured of identical formation properties to maintain quality comparisons with offset wells. It is understandably much simpler to maintain more direct control of the drilling variables on wells located locally. Two such drilling projects were being drilled and were therefore, selected for this investigation. The first is being drilled and located at Sellafield, England, and described in detail in chapter 4. The second is an oilfield development drilling project, located 400 km to the south west of Tripoli, Libya, North Africa.

In the Sellafield investigative drilling project, most of the sections could not be used in the study due to large variations in drilling parameters such as weight on bit (WOB), revolutions per minute (RPM), and hydraulic horsepower at the bit. This left only the 6.25 in. and the 8.5 in. hole sections (core drilled) to be analysed. From the oilfield development drilling and for the same reasons, only the 17.5 in. and the 8.5 in. hole section has been considered.

5.3 Description of Rig and Wireline Coring System

KDSL rig 36 is a Superior 700 diesel electric rig with a triples mast. The rig capacity of over 3000 m was more than adequate for the conventional drilling, core drilling and testing required within the programme.

Rig 36 was modified by the addition of a Saltgitter RB 130 hydraulic top drive unit. Other features fitted to the rig included a cathead kinetic energy monitoring system, automatic drilling systems, hydraulic wireline coring winch and a supplementary coring mud system with a 70 imperial gal/min hydraulically powered triplex coring pump. Additionally, electromagnetic flow meters on the coring pump inlet and outlet lines were used to monitor gains and losses during core drilling operations. These are particularly relevant with the small annular clearances inherent with slim hole wireline coring systems. The flowmeter data was integrated with the mud logging systems, rig floor displays and alarms as described in the next section.

The rig was equipped with 4.5 in. American Petroleum Institute (API) drill pipe string and associated drill collars for conventional drilling and hole opening together with 3.5 in. API drill strings for testing.

To ensure the highest quality and quantity of core recovered, the downhole equipment selected for the continuous core drilling comprised a BRR 139.70 mm (5.5 in.) heavy duty wireline coring string with associated core barrels, core barrel stabilisers, core catcher assemblies, inner barrel, and wireline inner barrel retrieval equipment. The coring equipment cut a 159 mm (6.25 in.) hole and nominally a 100 mm (4 in.) diameter core. The nominal 6.00 m length core barrel incorporated a 3.00 mm thick UPVC inner barrel liner to assist in core preservation.

5.3.1 Sensors

The sensors forming the mud logging system were positioned about the rig as shown on Figure 5.1. The data collected by the unit were recorded and presented on:

i. Chart Traces.
ii. On the drilling printouts, with file recording for each metre drilled and every 500 pump strokes.
iii. On line tripping printouts recording every single or stand tripped.
iv. Off line drilling printouts for each metre drilled.
v. Disc records of drill and tripping data.
vi. Formation Evaluation Log (FEL) on a 1:500 scale.

The FEL graphically summarised the data produced including rotation, weight on bit, and interpreted lithology. The lithological and stratigraphic information presented on this log is based on the microscopic examination of mud samples, and is used only for comparative information.

Electromagnetic flowmeters were installed on the secondary mud system for coring operations, as mentioned in the previous section. The flowmeter data was incorporated into the mud logging unit and displayed as flow in, flow out and flow difference both on the analogue chart recorders and on the monitors in the unit and the drill floor.

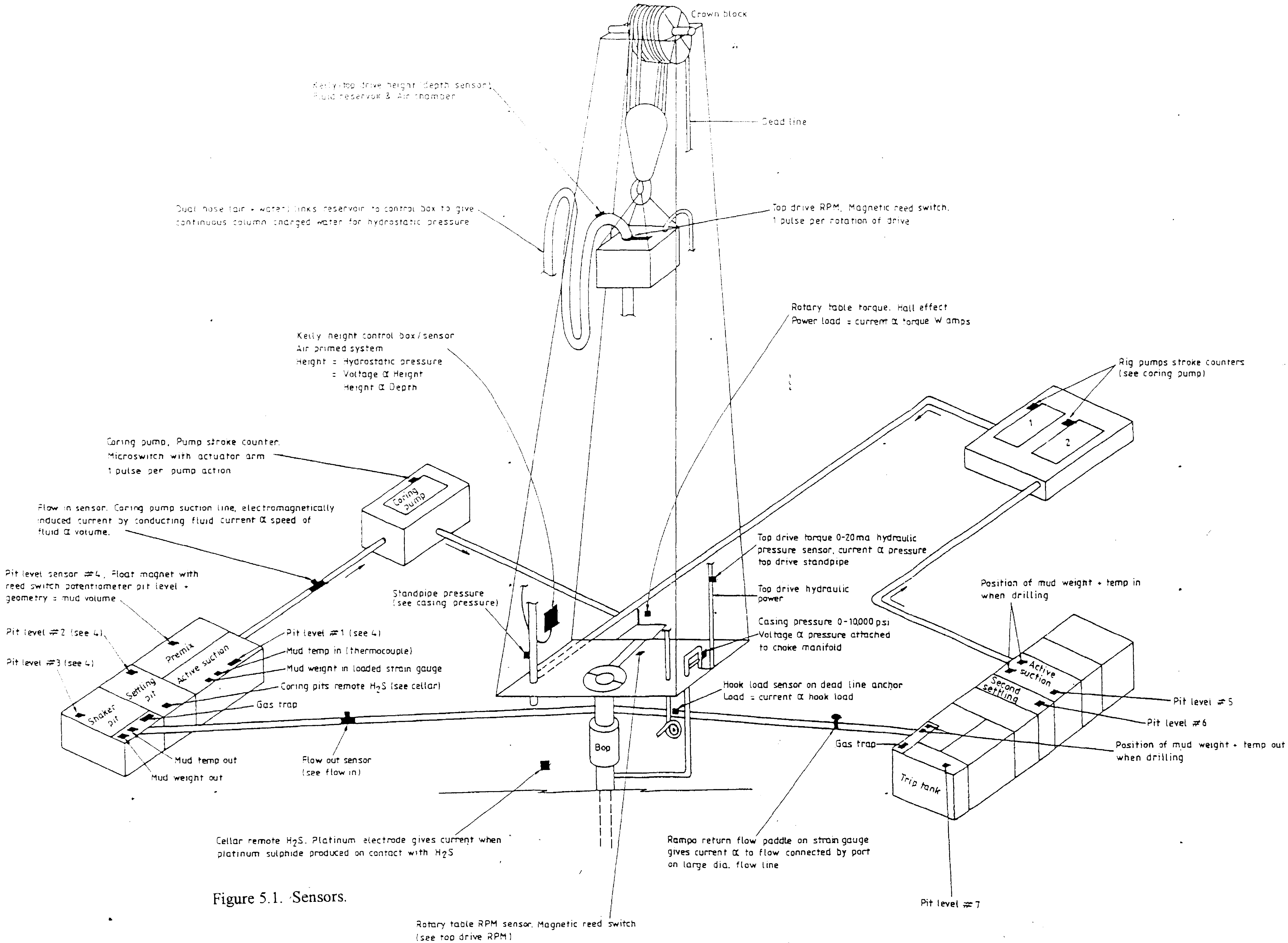


Figure 5.1. Sensors.

5.3.2 Hole Opening

Open hole drilling was carried out with tri-cone rock bits in appropriate assemblies. Hole opening was carried out in stages from 159 mm (6.25 in.) to 216 mm (8.5 in.) then to 311 mm (12.25 in.) and finally to 445 mm (17.5 in.) as appropriate.

5.3.3 Coring

Continuous core drilling was carried out using the 139.7 mm (5.5 in.) heavy duty wireline coring system. The procedure for core drilling was that conventionally used in geotechnical investigation, mineral and coal exploration industries. Rotation was provided by a hydraulic top drive unit at rotational speeds up to 220 RPM with corresponding weights on the core bit of 4000 to 10000 lbs. Core recovery and quality were the main objectives.

A routine was developed to optimise rig time using additional inner barrels, all of which were interchangeable within the system, to reduce the non-drilling time and all components of the coring system were carefully checked as part of the quality system adopted for the project.

Core drilling was interrupted approximately every 50 m to allow testing to be carried out to determine the environmental pressure measurements (EPM) in the 50 m interval. This necessitated tripping the coring string and running a testing assembly on a testing string. Both coring and testing strings were racked in the rig mast when not in use.

5.5 Oilfield Drilling Operation

An oil exploration company for the onshore operations of the National Petroleum Institute provided drilling data from 10 wells drilled in a field. The Ghani field is located 400 miles to the south east of Tripoli, Libya. The drilling data were correlated to the depth drilled and classified according to lithology, mechanical data, and drilling fluid properties. The records indicated that most of these wells penetrated limestone, shale, anhydrite, dolmite, and dense limestone. The most common formation penetrated by these wells are shale and limestone.

The bit mechanical data included size, type, running time, depth in, depth out, dullness, and nozzle size. Roller cone soft and medium formation bits were the most common types used for drilling both shales and limestones. The bit sizes ranged from 8.5 to 26 in., and the maximum depth drilled in these wells was 10,247 ft.

The bits were graded on a conventional sliding scale from zero (sharp, new) to eight (completely dull). Each increment indicates one eighth fractional wear of the teeth.

The mechanical data also included weight on bit and rotary speed. The weight on bit ranged from 10 to 45 lb for drilling limestone and from 10 to 35 lb for drilling shale. The rotary speed ranged from 30 to 120 RPM for drilling limestone and from 30 to 80 for drilling shale.

The oil exploration company also provided information on circulation pressures and rates as well as mud pump dimensions. Rates of penetration were calculated from bit running time, depth in, and depth out. The important properties of drilling fluids, such as mud weight, plastic viscosity, solid contents, and water loss, were included in the drilling data. The mud weight ranged from 8.6 to 10.2 lb/gal, and the plastic viscosity ranged from 8 to 15 cp.

Some experimental data was provided by the company for shear strength at atmospheric pressure (p_o) for both limestone and shale. The company provided and tested five cylindrical core plugs (two from shale zones and three from limestone zones) for source material for the compressive strength tests. Table (5.1) below shows the results of the failure load on each of the core plugs. The average shear strength were determined from the last column in the table: 4.8×10^5 psf for the limestone formations and 2.9×10^5 psf for shale formations.

Formation	Sample	Diameter in.	Failure Load lb	Shear strength lb/sq ft
Limestone	1	1.5	10,753.6	438,141
	2	1.5	7,038.7	286,782
	3	1.5	17,670.8	719,973
Shale	4	1.5	8,984.5	366,061
	5	1.5	5,475.6	223,096

Table 5.1 Shear strength calculated from load tests.

5.6 Rotation Speed (RPM)

The influence of bit rotational speed (RPM) on the performance characteristics of various rock bits types and sizes, was examined in different formations by analysing the drilling runs whilst flush flowrate and weight on bit maintained constant.

It should be noted that the author had no influence on the drilling process by pre-setting the drilling parameters. The drilling data presented are from actual drilling operations which were being done for the purpose of field developments and not for the purpose of this investigation.

Normally, by setting the circulation rate, data were then carefully selected from drilling runs in which all drilling parameters other than rotational speed were maintained constant. The data points were selected at each level of rotational speeds during bit runs, the resulting points are presented in graphical form in Figures 5.2-5.8.

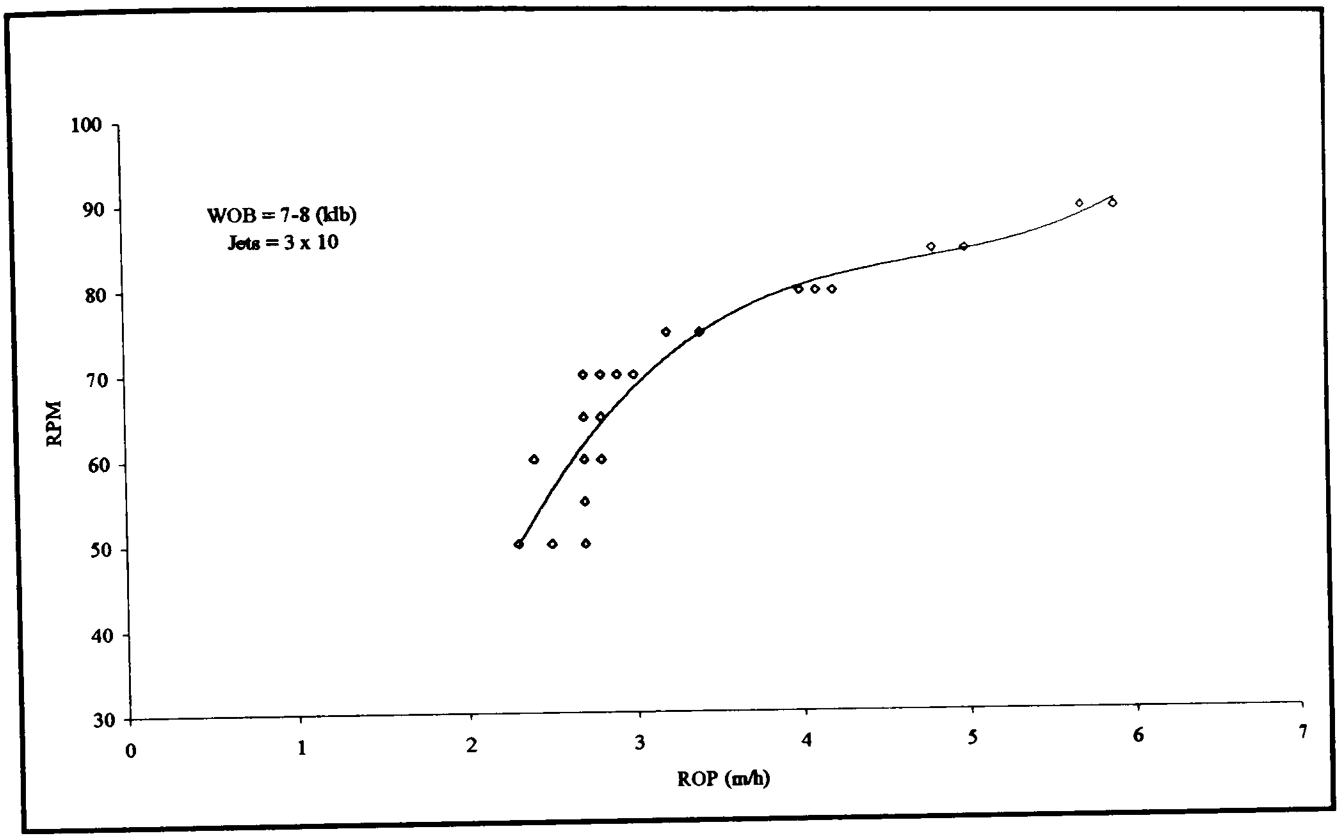


Figure 5.2. Rotational speed (RPM) Vs Rate of penetration for Security, S86F tri-cone (8.5") bit type while drilling St Bees sandstone, England.

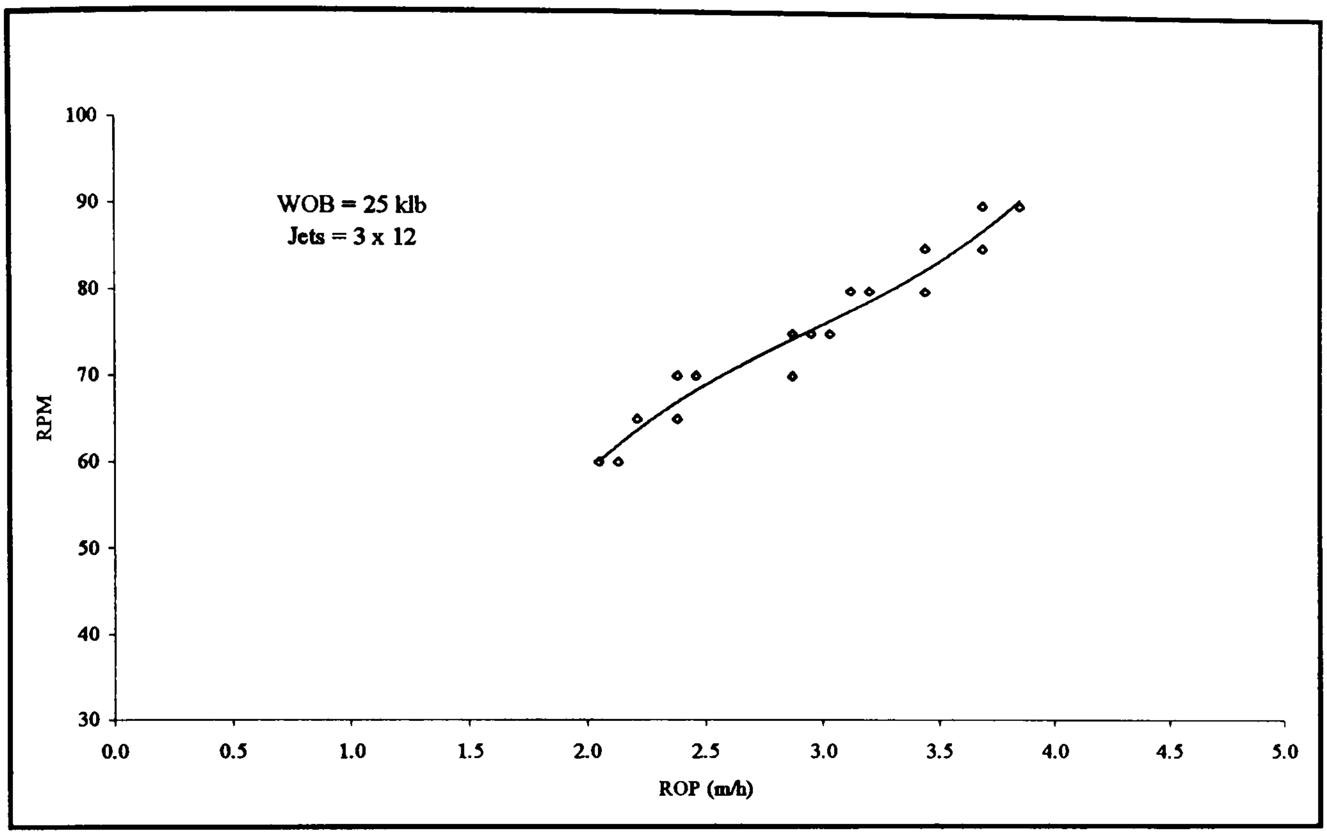


Figure 5.3. Rotational speed Vs Rate of penetration, for Security -S86F- (8.5") tri-core bit type, while drilling Beda limestone, Libya.

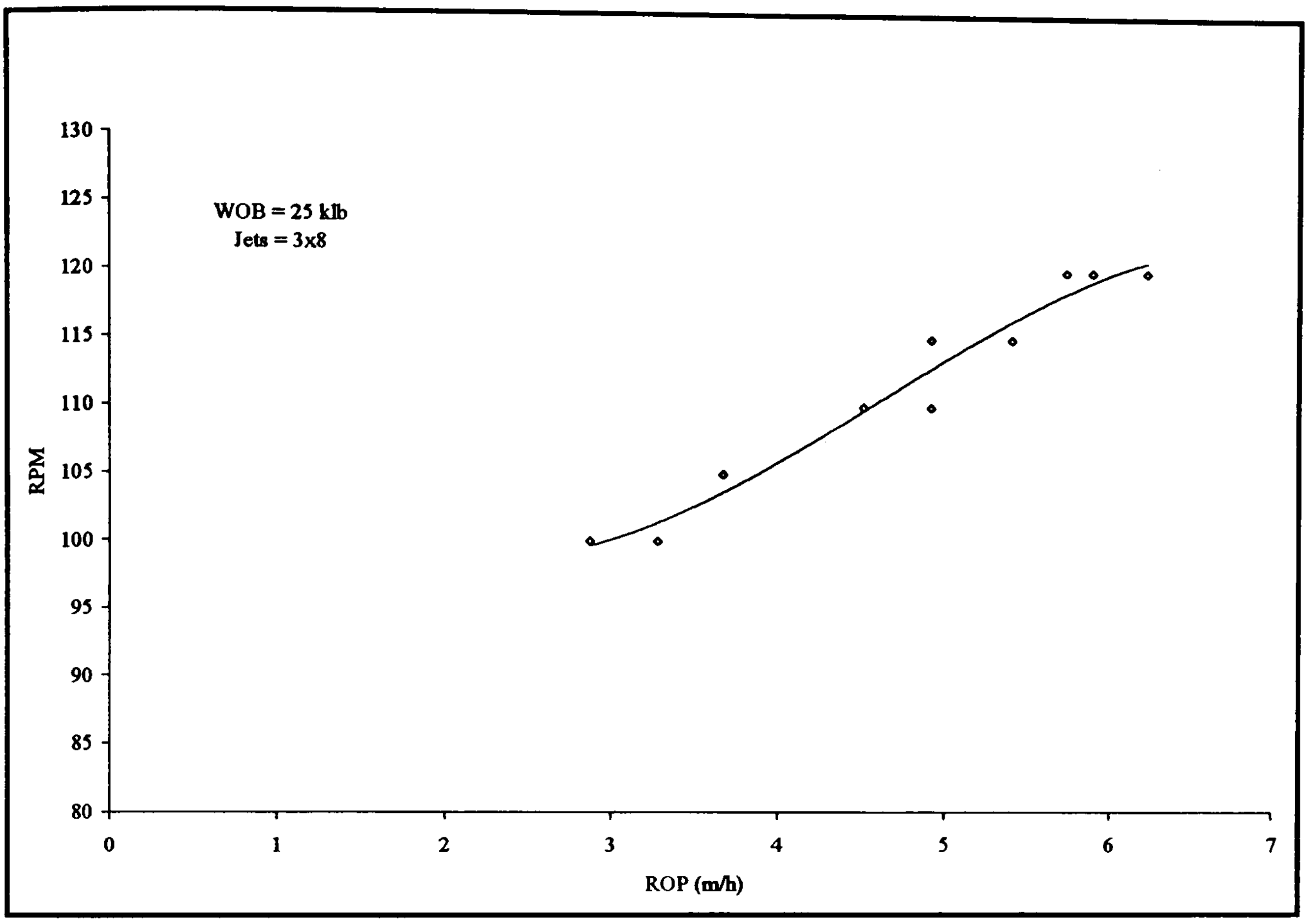


Figure 5.4. Rotational speed Vs Rate of penetration for Security. M44NG (17.5") tri-cone bit type while drilling Gialo East Shale, Libya.

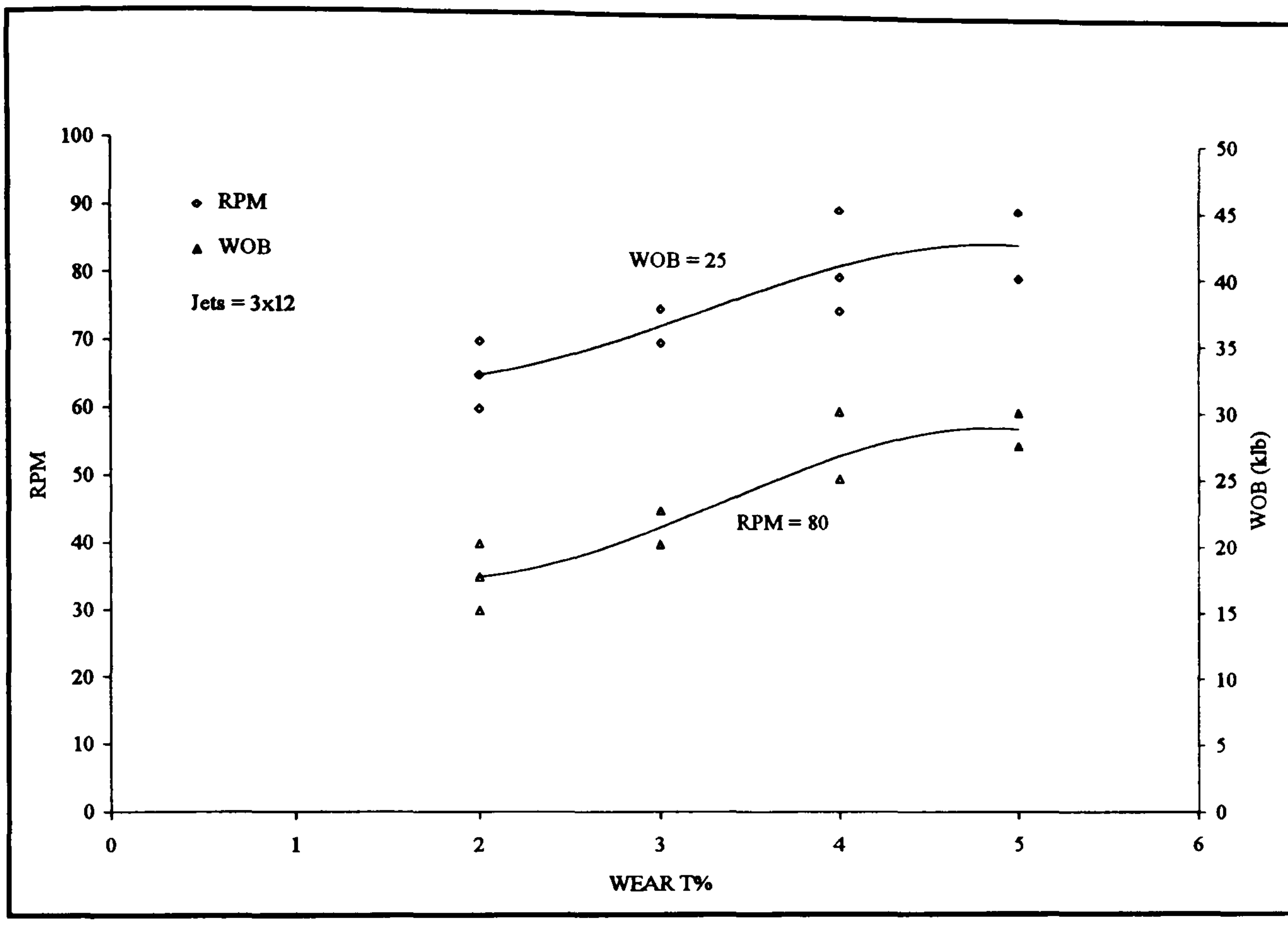


Figure 5.5. Rotational speed and weight on bit Vs Wear, for Security - S86F- (8.5"). tri-cone bit type, while drilling Dahra shales, Libya.

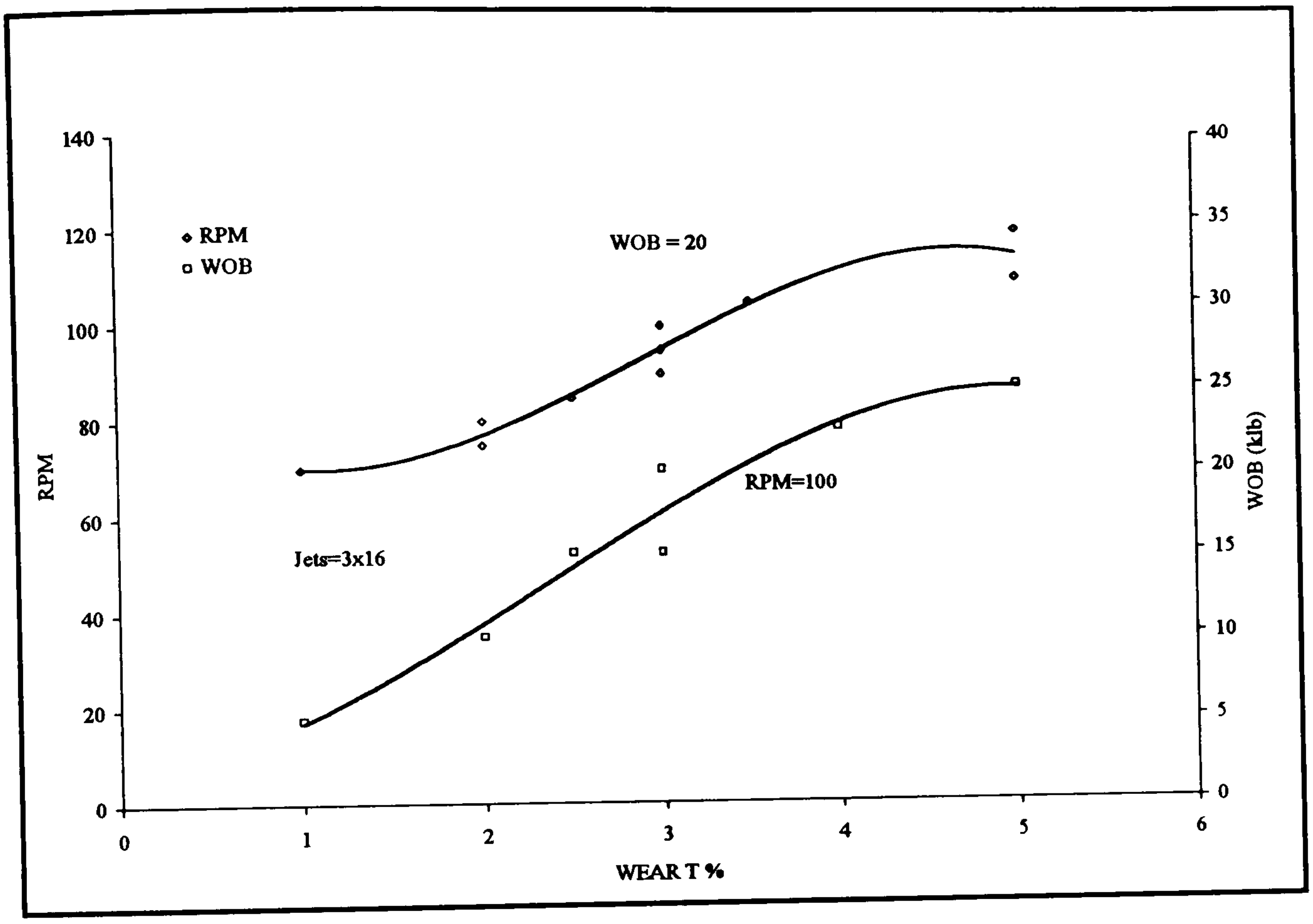


Figure 5.6. Rotational speed and Weight on bit Vs Tooth wear, for (17.5") HTC -R- tri-cone bit type, while drilling Beda limestone, Libya.

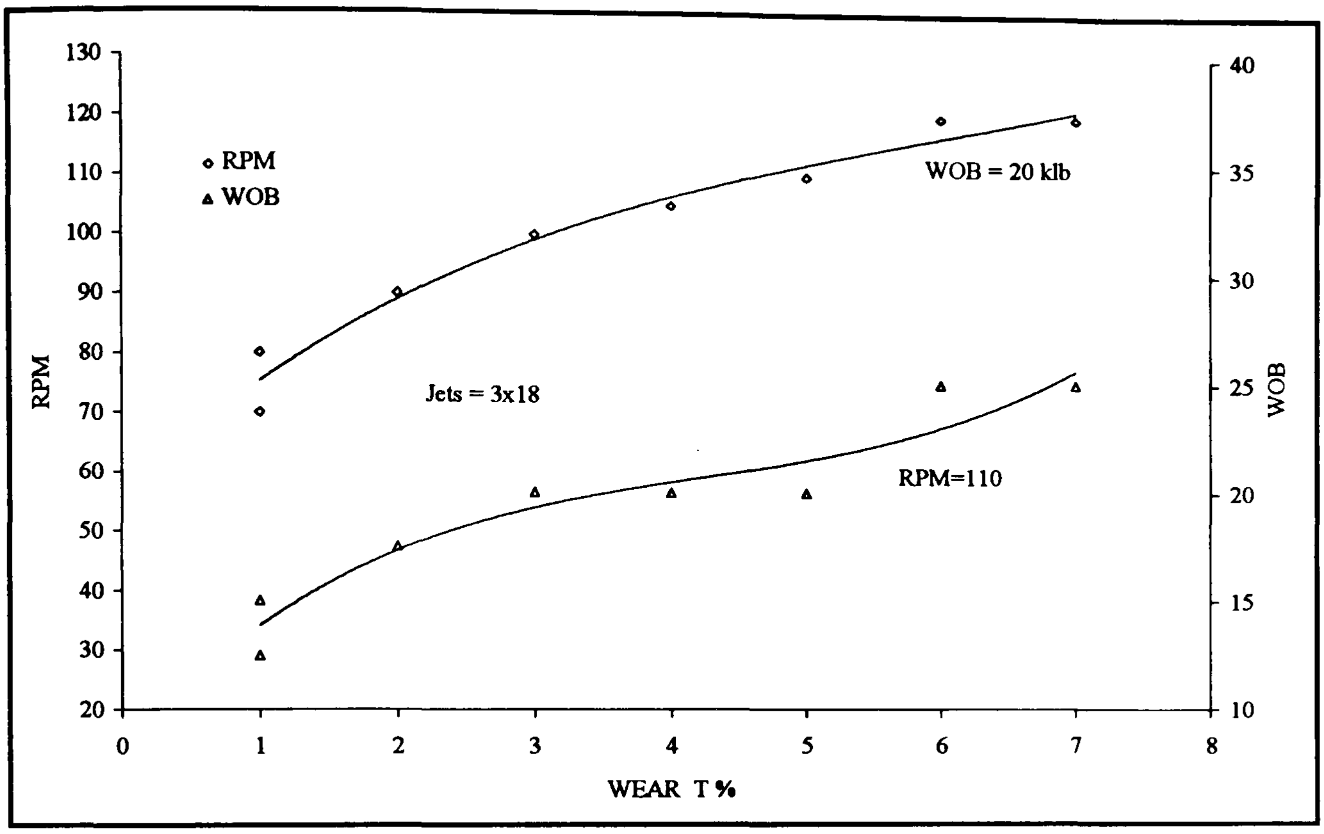


Figure 5.7. Rotational speed and Weight on bit Vs Tooth wear, for Security M44NG- (17.5") tri-cone bit type while drilling Gialo East Shales, Libya.

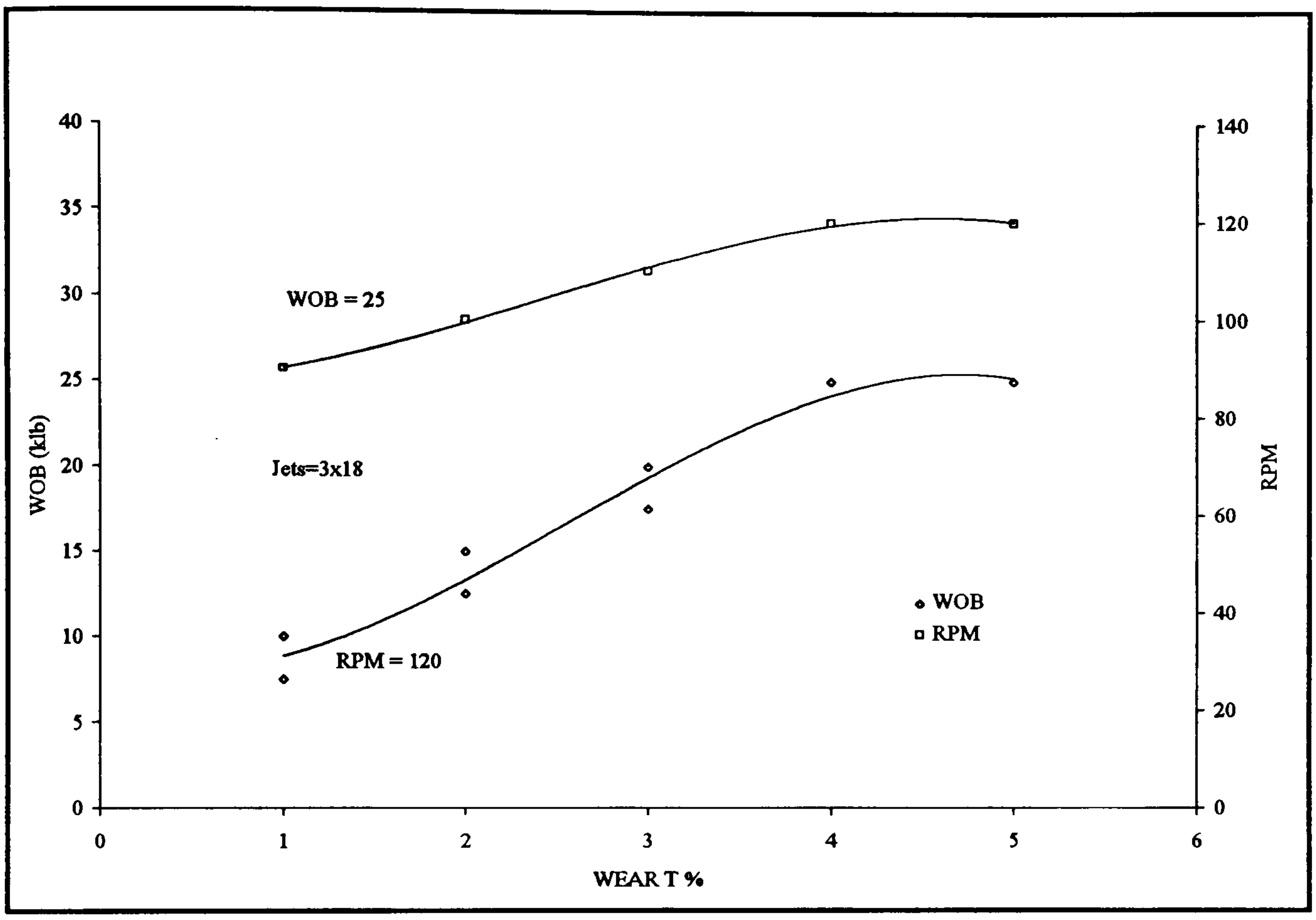


Figure 5.8. Weight on bit and Rotational speed Vs Tooth wear, for Security-S33S- (17.5") tri-cone bit type, while drilling Gir Dolanny Shales, Libya.

5.7 Weight On Bit (WOB)

The effect of WOB on the performance characteristics of drilling bits was examined by analysing the bit runs during which other variables such as bit types and sizes, formation type, rotational speeds and flushing flowrates were maintained constant. The graphs of WOB versus ROP from the drilling runs are shown in Figures 5.9 to 5.20 for six bits which include two of the same size but different types of core bits and three different sizes and types of roller cone bits.

Usually, after setting the circulation rate and environmental parameters, data then were then collected from drilling runs in which rotary speed (rev/min) was maintained constant and WOB was varied. The data points were collected at each of these WOB levels, then the resulting scatter in the data was presented in these figures by the least square fit which yielded a better fit than the linear fit model. Each figure indicates the bit manufacturer, size, type, rotation speed, formation and the jet size if applicable.

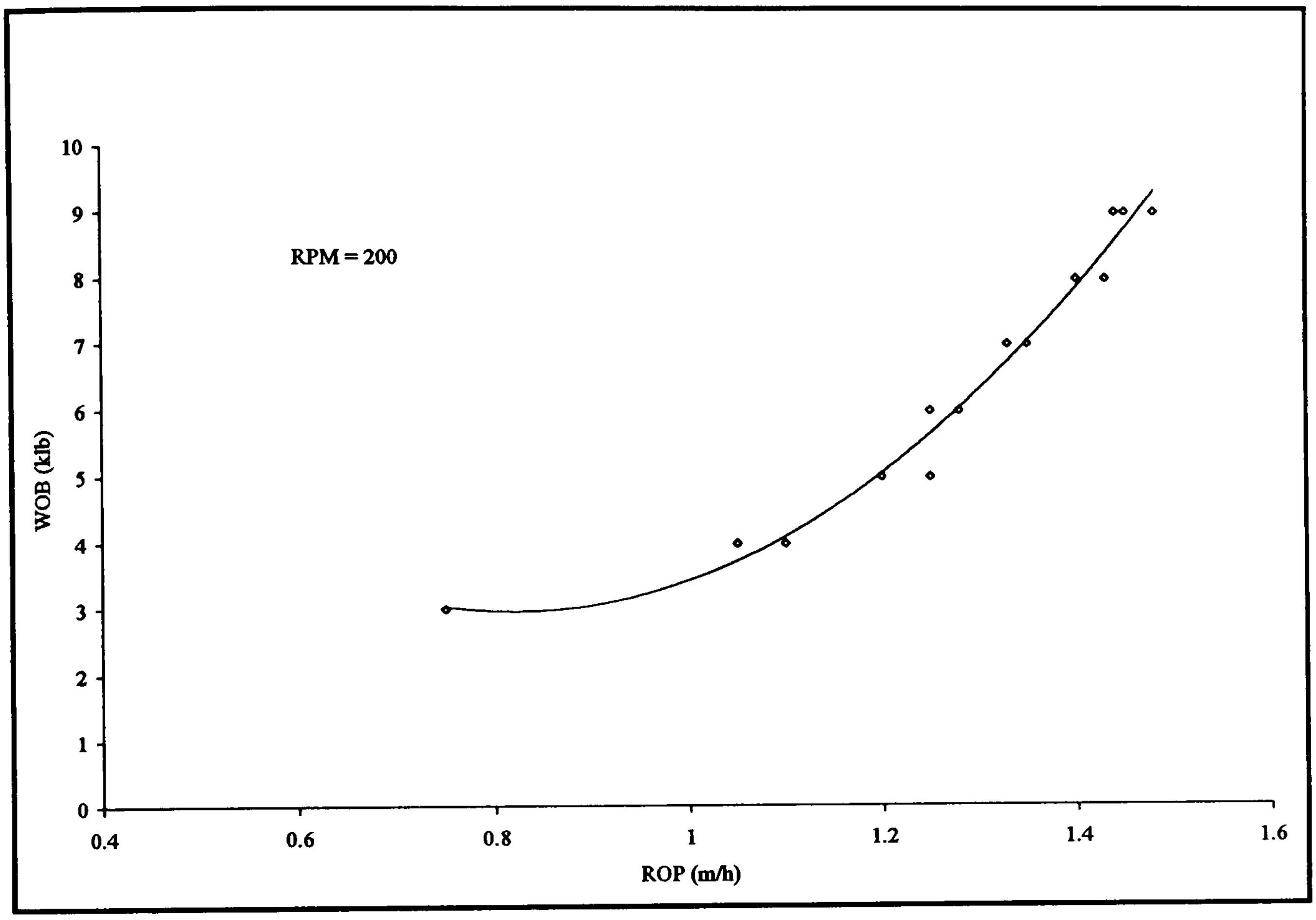


Figure 5.9. Weight on bit Vs Rate of penetration, for Eastman, B-9 (6.25"), IMP Diamond core bit type while drilling St Bees Sandstone, England.

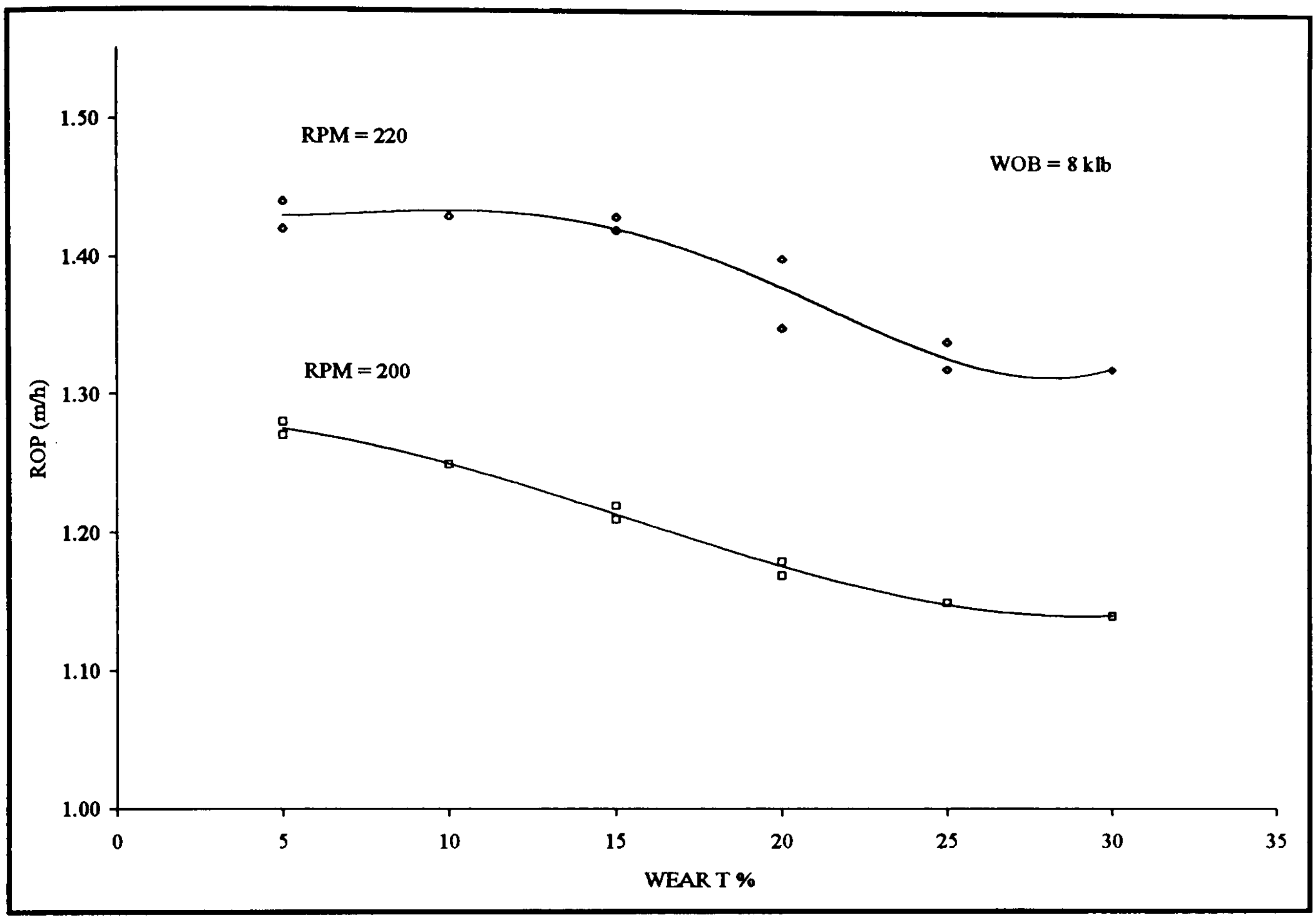


Figure 5.10. Rate of penetration Vs Tooth wear, for Eastman B-9 (6.25") IMP Diamond core bit type while drilling St Bees sandstone, England.

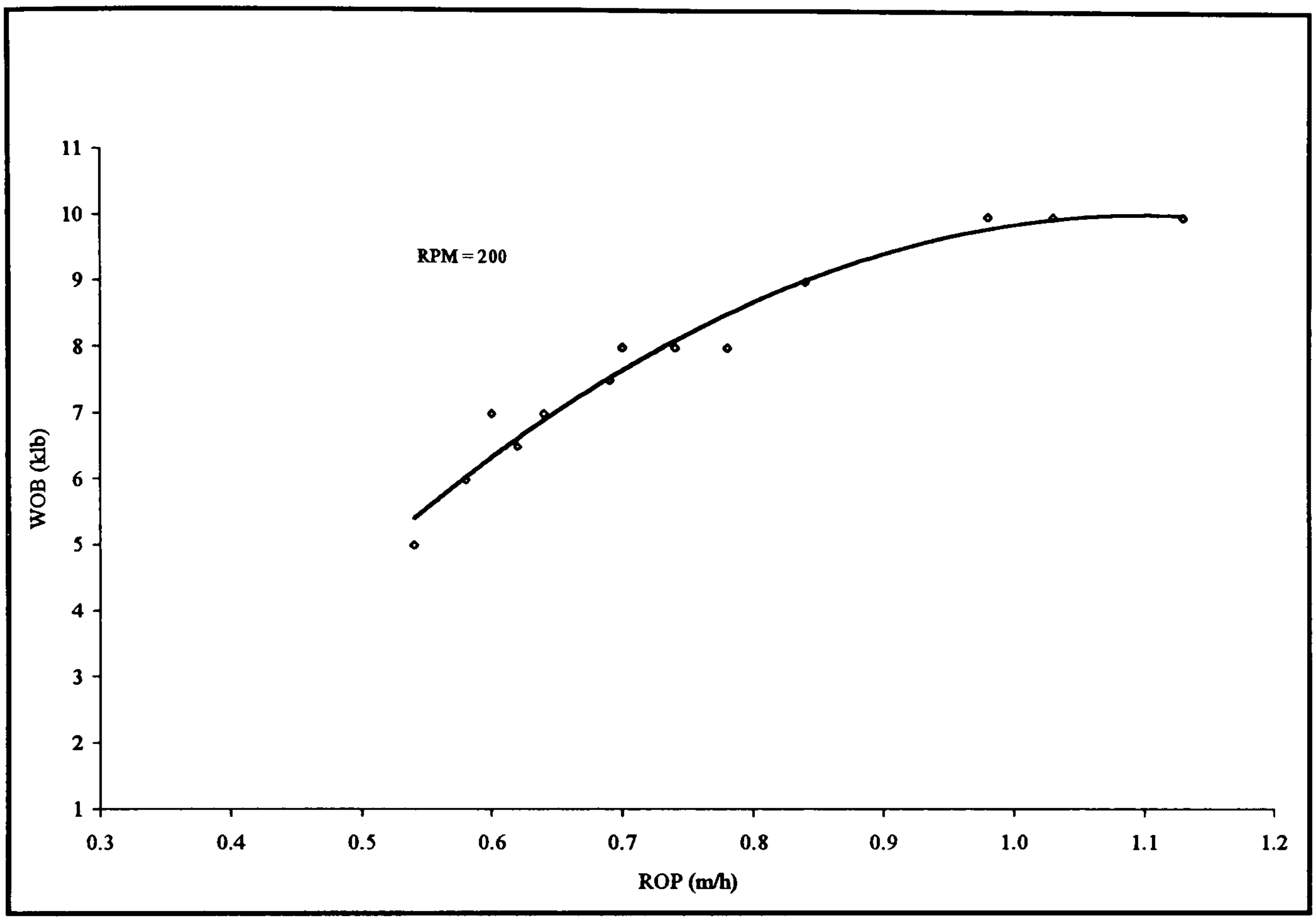


Figure 5.11. Weight on bit Vs Rate of penetration of a Dimatic M7S-1 (6.25"). IMP Diamond core bit type while drilling Borrowdale Volcanics, England.

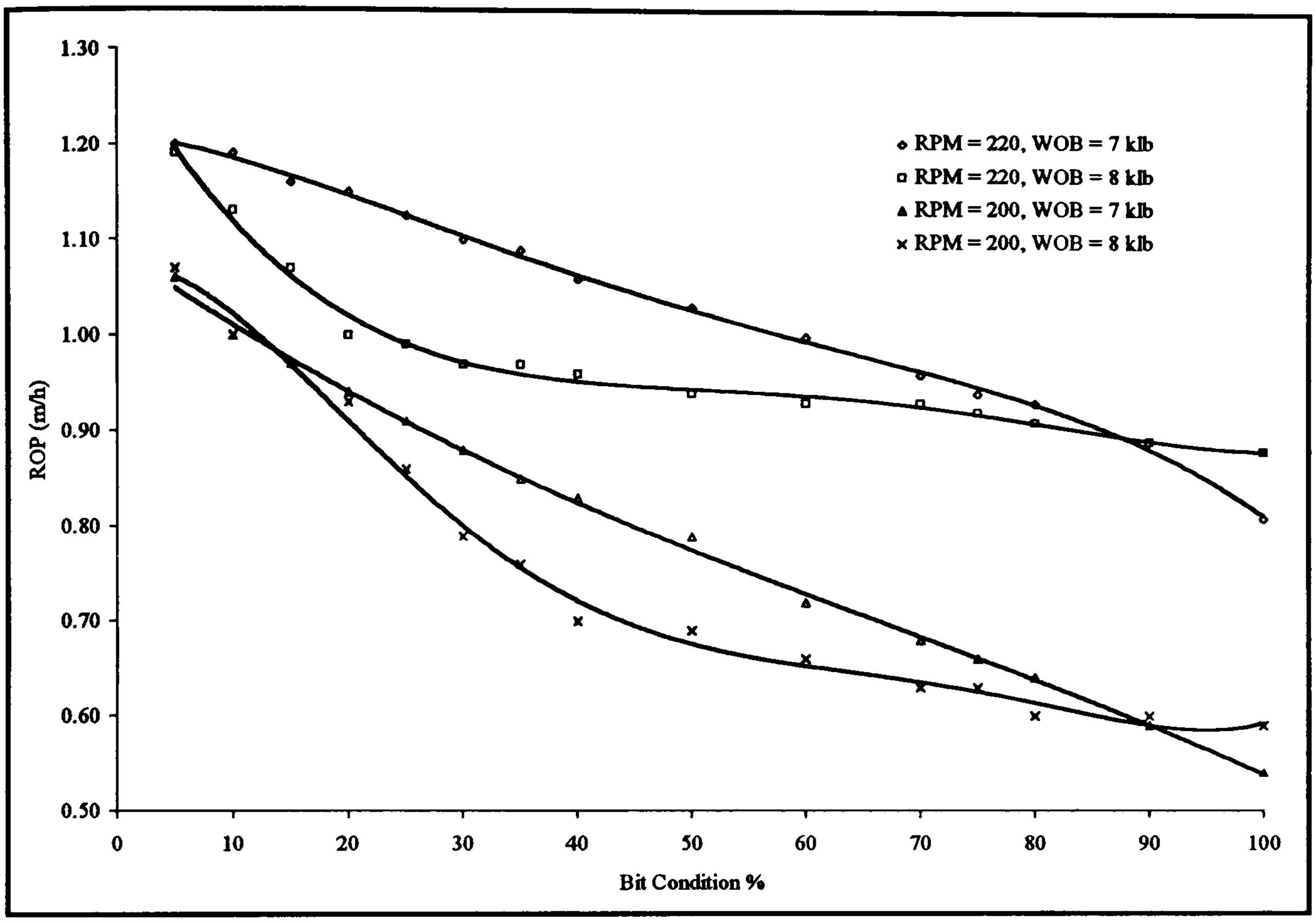


Figure 5.12. Rate of penetration Vs Bit condition for Dimatic (6.25") IMP Diamond (M7S-1) core bit while drilling Borrowdale Volcanic rocks, England.

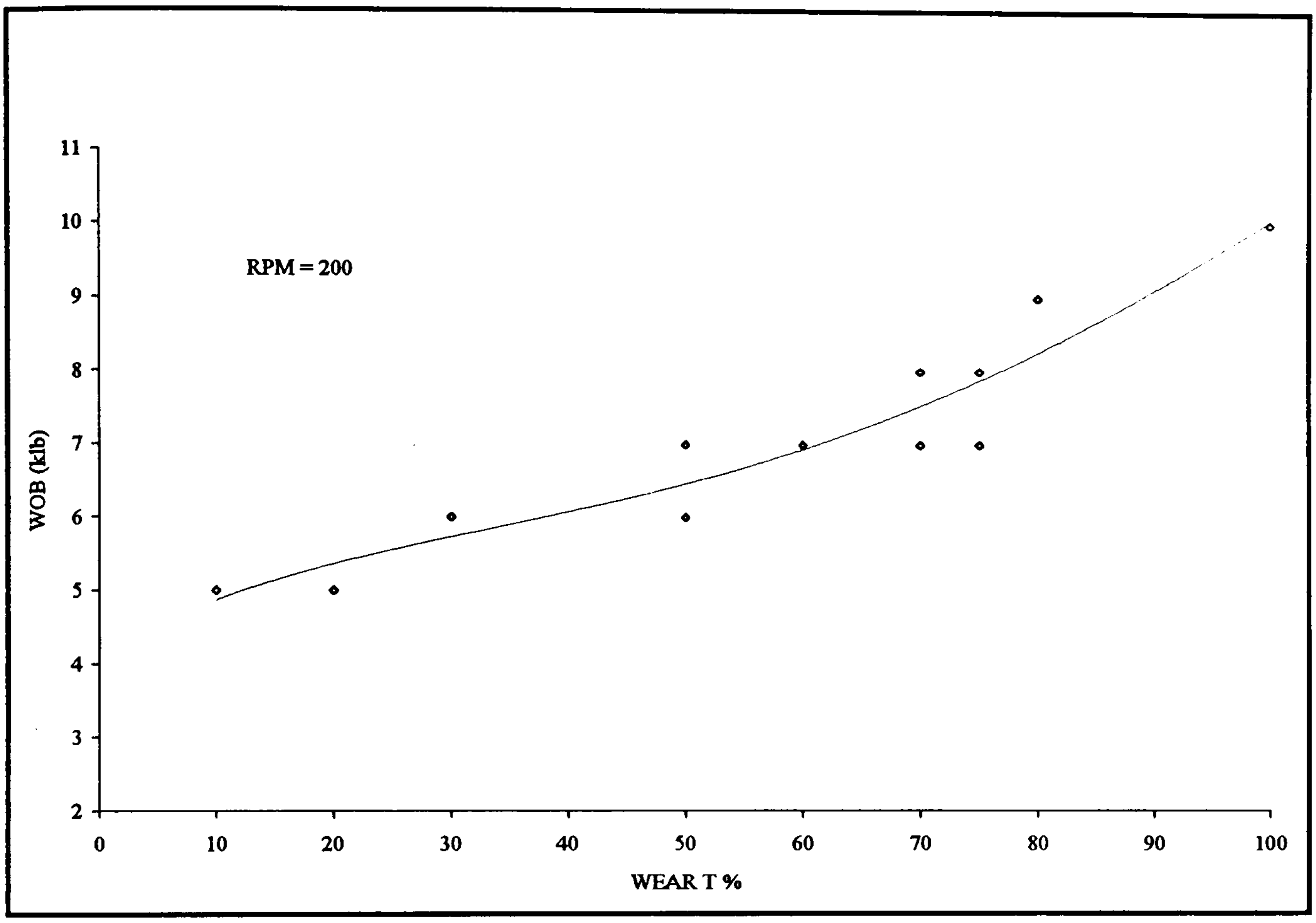


Figure 5.13. Weight on bit Vs Teeth Wear for a Dimatic M7S-1 (6.25"). IMP Diamond core bit type while drilling Borrowdale Volcanics, England.

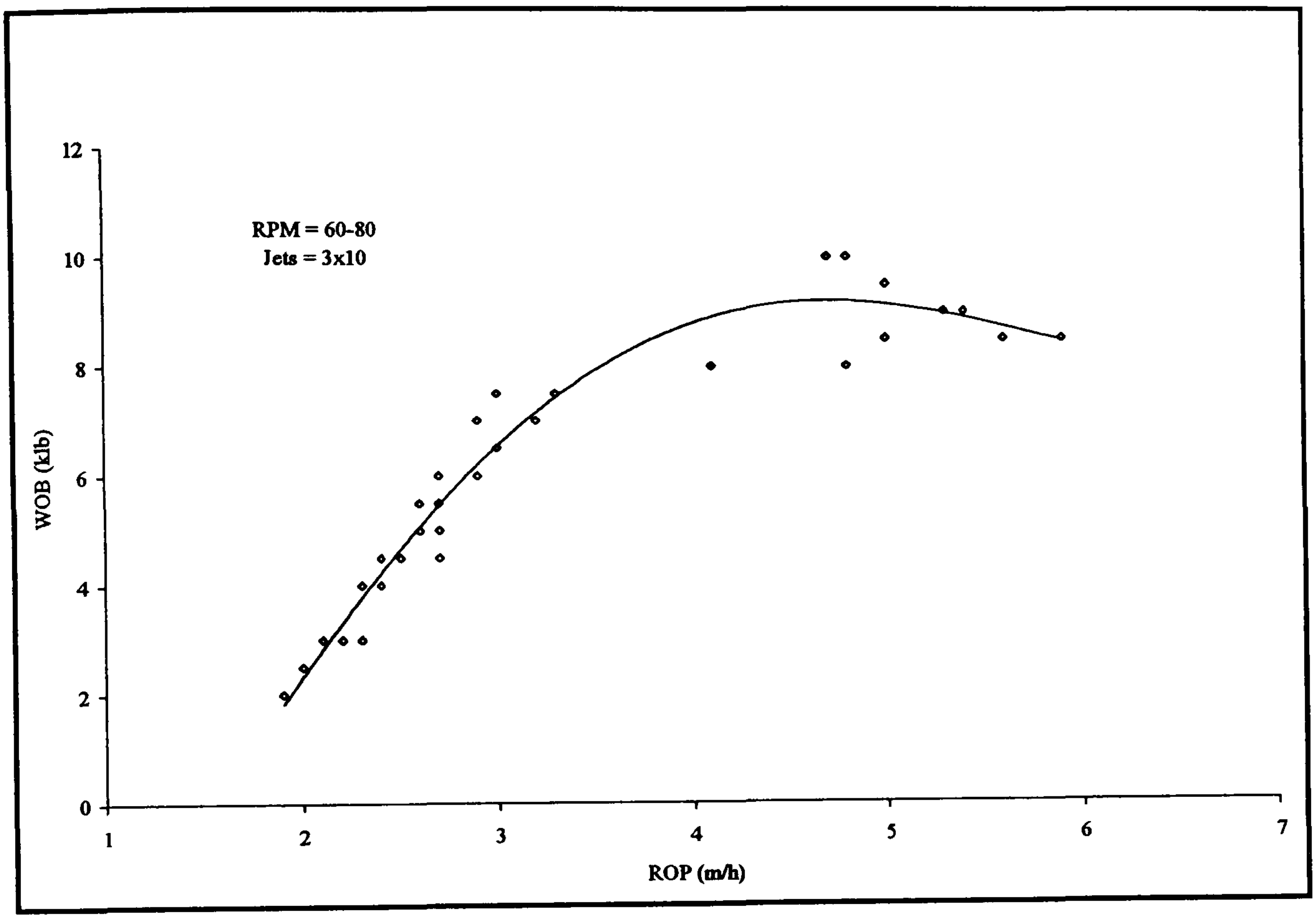


Figure 5.14. Weight on bit Vs Rate of penetration, for Security, S86F tri-cone (8.5") bit type while drilling St Bees sandstone, England.

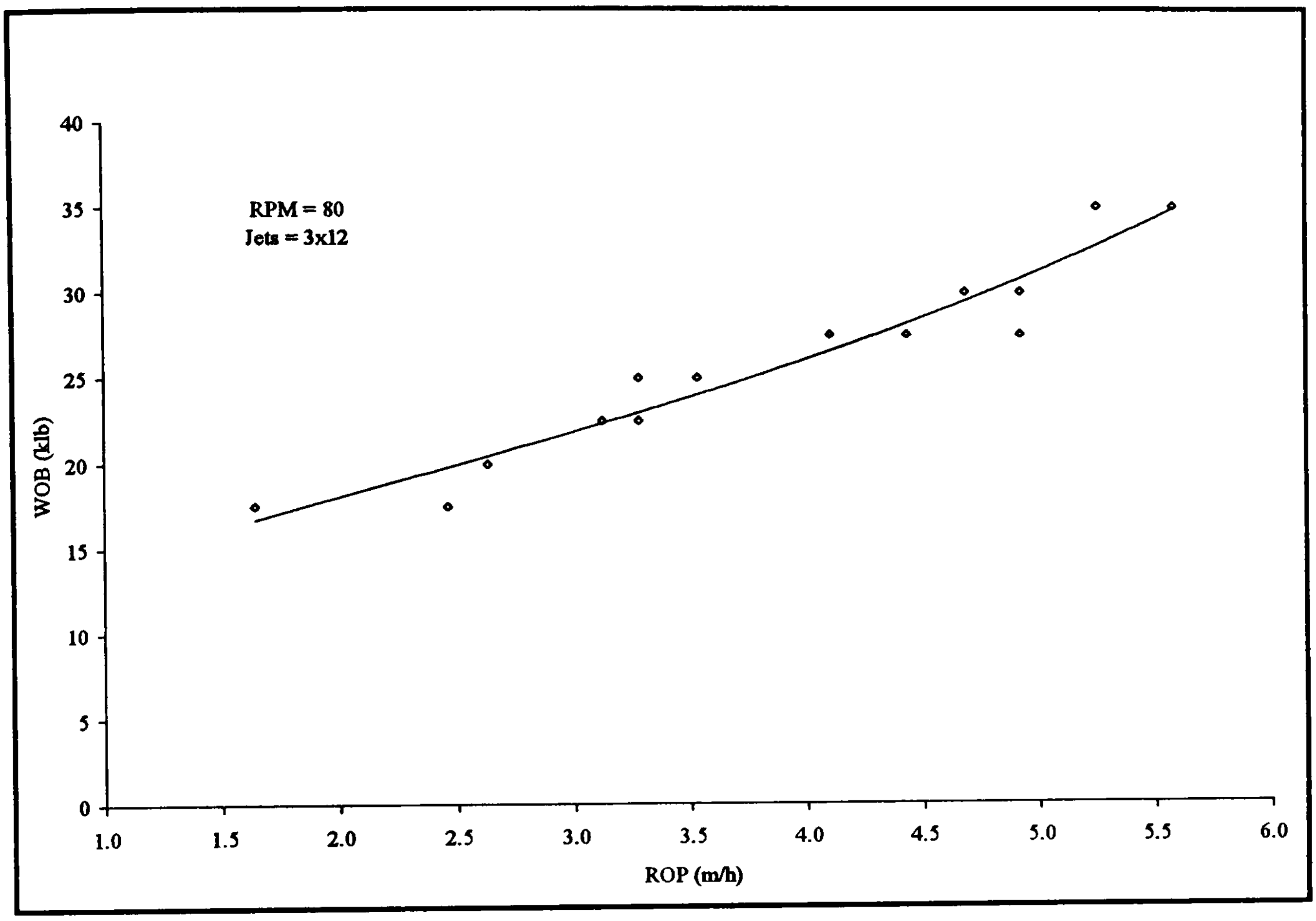


Figure 5.15. Weight on bit Vs Rate of penetration, for Security -S86F-(8.5") tri-cone bit type, while drilling Dahra shales, Libya.

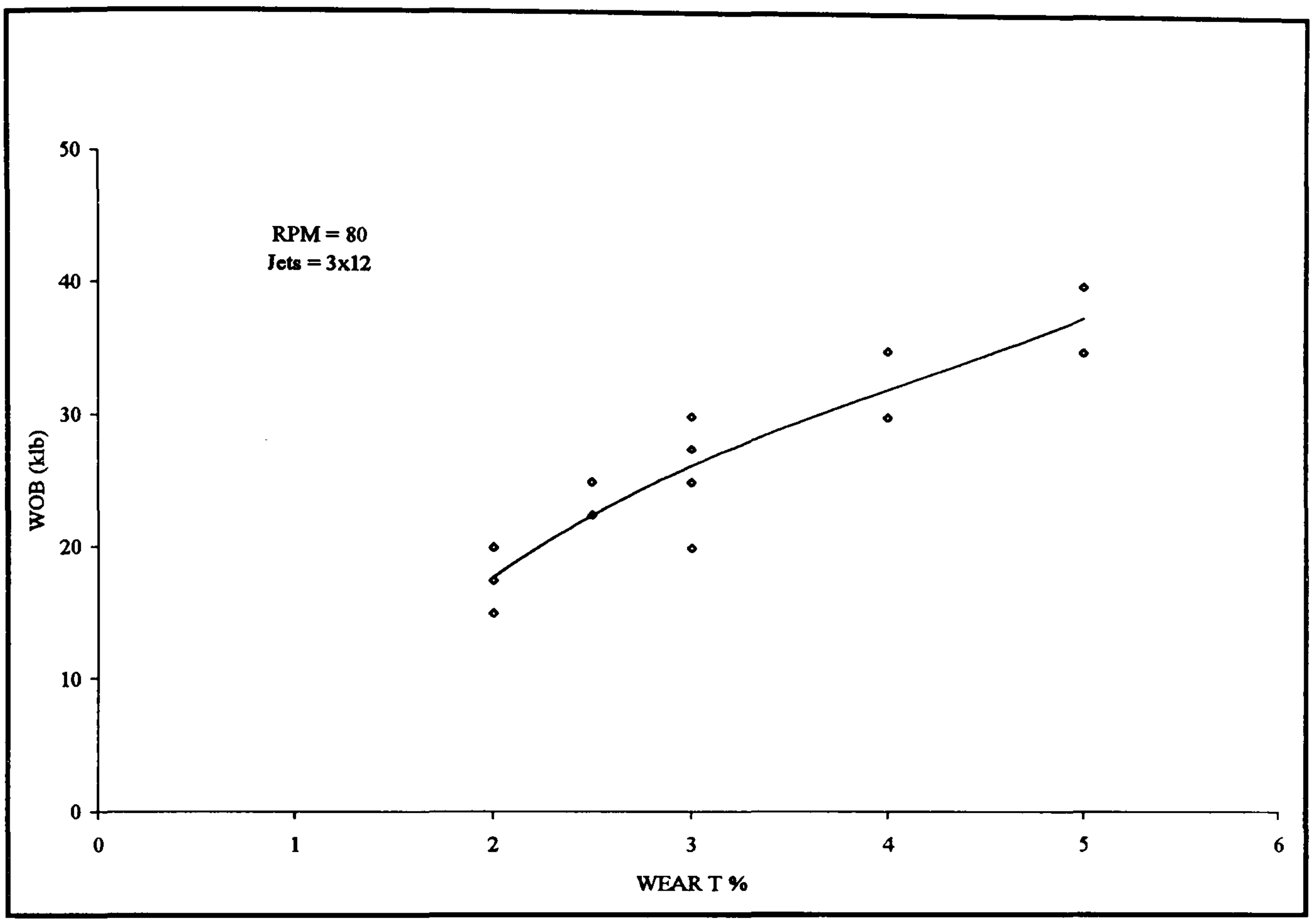


Figure 5.16. Weight on bit Vs Wear, for Security -S86F- (8.5") tri-cone bit type, while drilling Dahra shales, Libya.

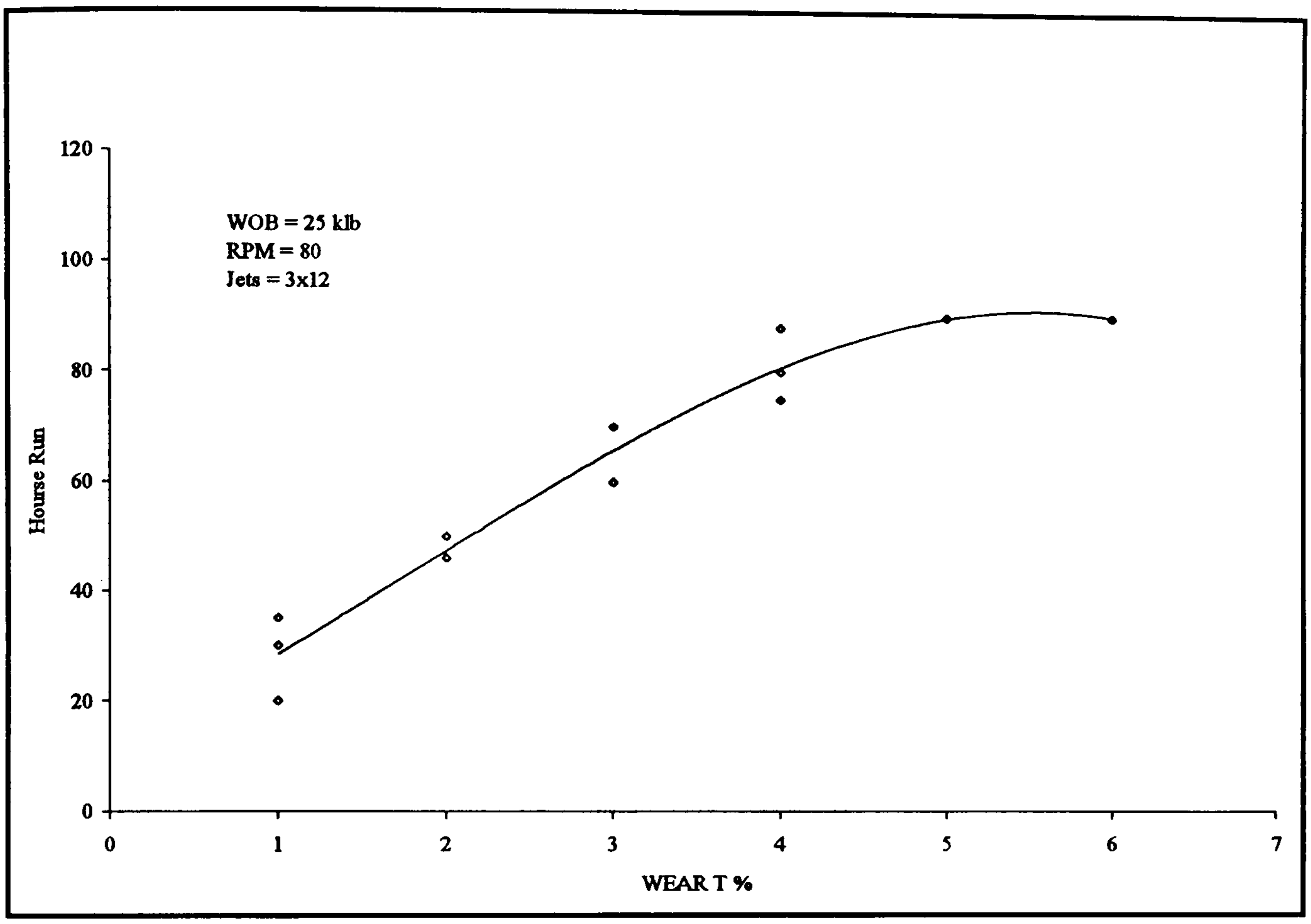


Figure 5.17. Rotation time Vs Wear, for Security -S86F- (8.5") tri-cone bit type, while drilling Dahra shales, Libya.

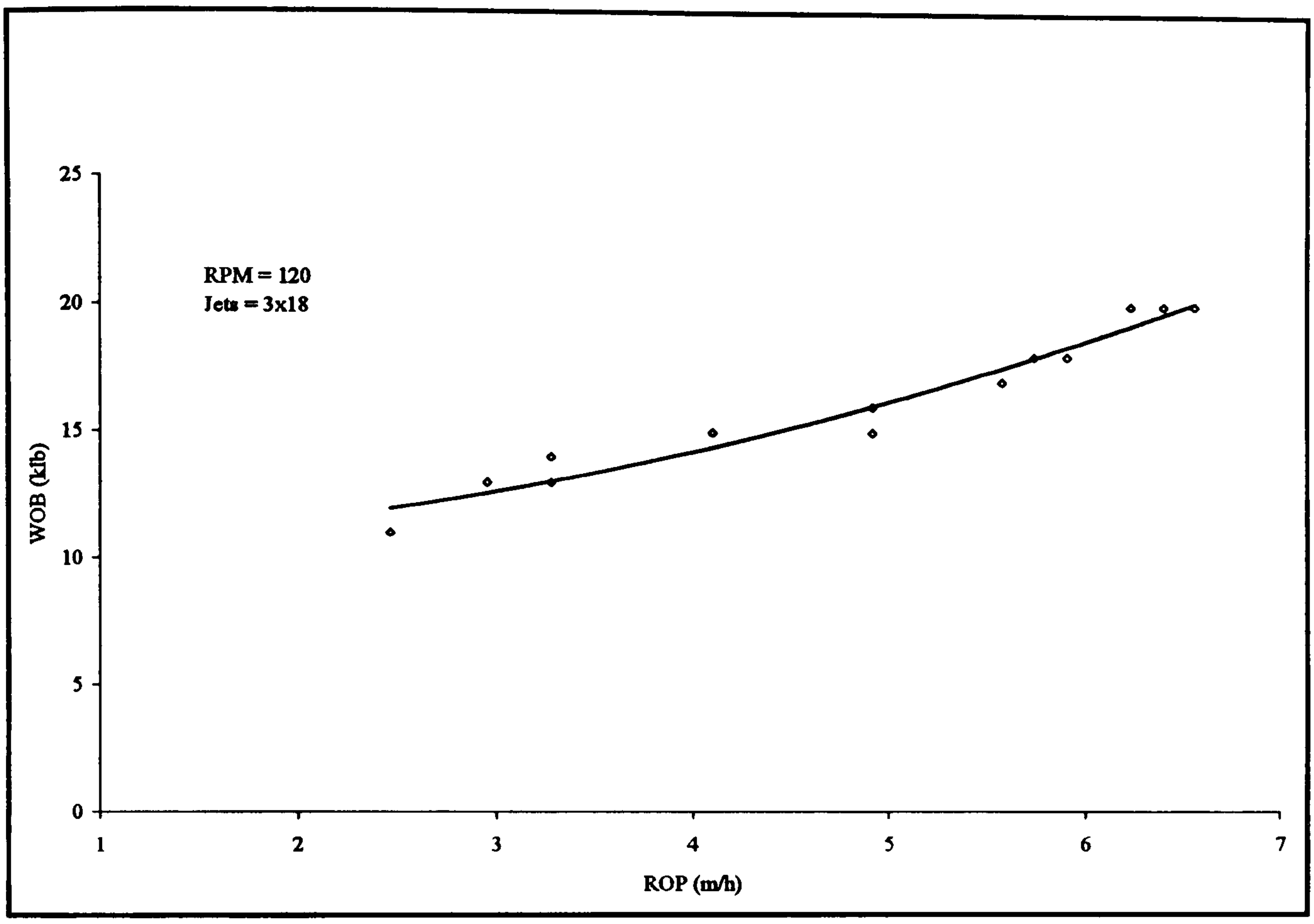


Figure 5.18. Weight on bit Vs Rate of penetration, for Security M44NG (17.5") tri-cone bit type while drilling Gialo East Shale, Libya.

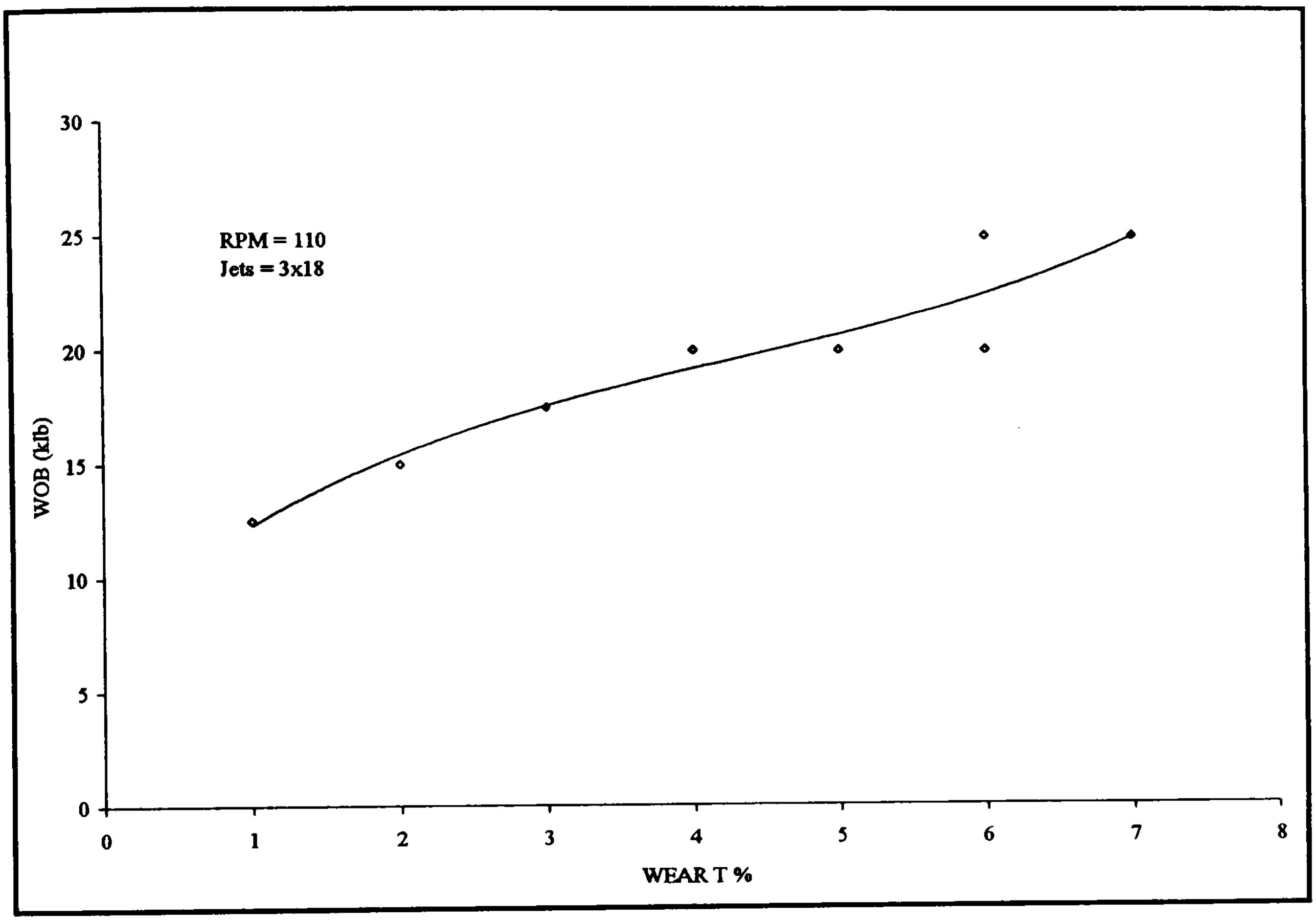


Figure 5.19. Weight on bit Vs Tooth wear, for Security -M44NG (17.5") tri-cone bit type while drilling Gialo East Shales, Libya.

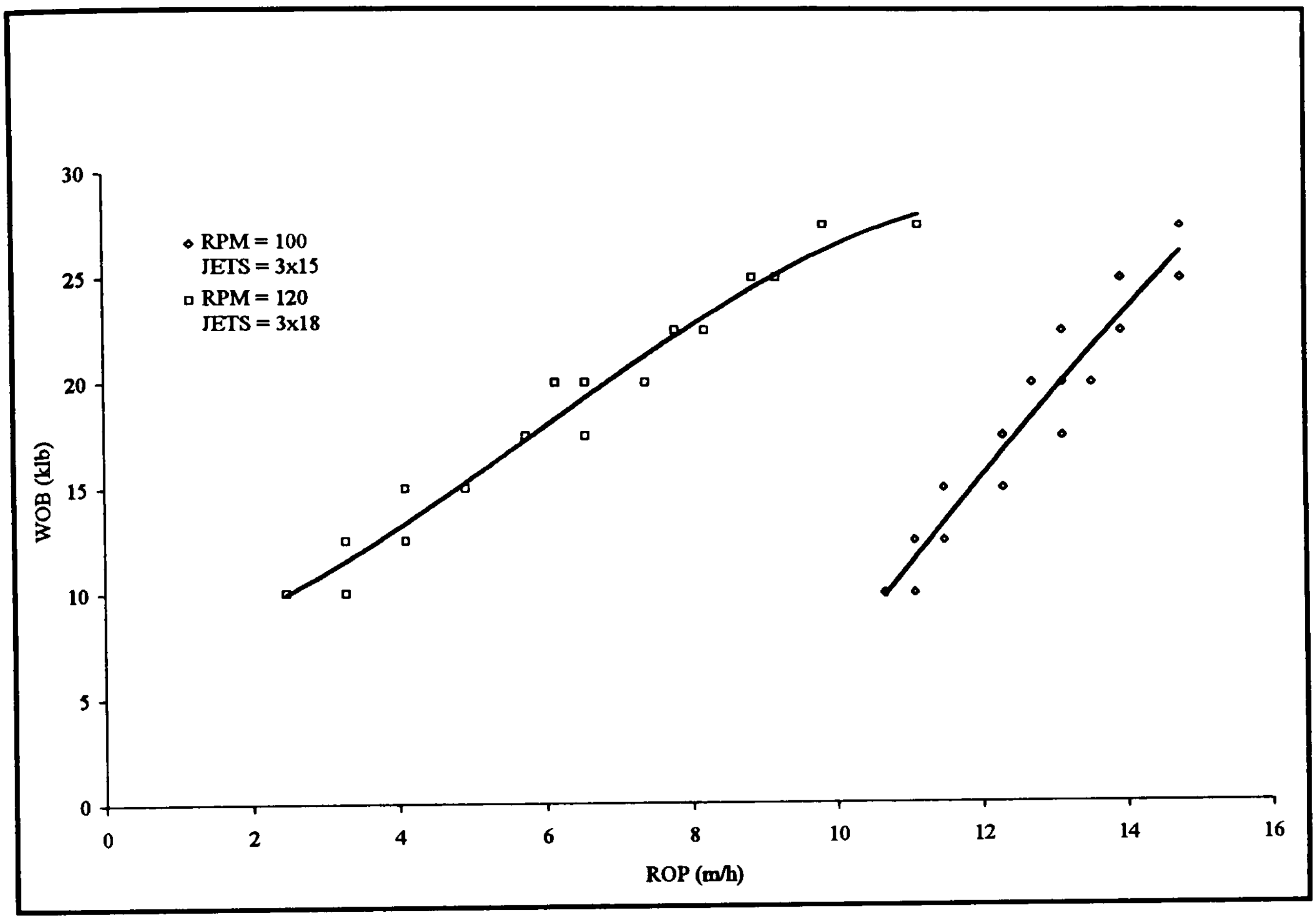


Figure 5.20. Weight on bit Vs Rate of penetration, for Security -S86F-(17.5") tri-cone bit type, while drilling Gir Dolanny Shales, Libya.

5.8 Bit Hydraulics

During the drilling of the shale intervals with the same Security-S86F- 8.5 in bit and with 3×12/32 in-diameter nozzles and while rotary speed was maintained at 80 RPM throughout, data points were collected. In the given shale interval to ensure comparable rock stress, and by keeping the mud properties constant and varying hydraulics, through a range of weights on the bit, data points were taken to examine the effect of hydraulics on the penetration rate. In the drilling bit industry, hydraulic horsepower hhp often is expressed in terms of hydraulic horsepower per square inch (hsi) of projected bit area. Both hhp and hsi are used in this study. Figure 5.21 shows the results of three 12/32 in-diameter nozzles for a range of 5.4 to 6.7 hsi. Also, to investigate the interactive effects of jet horsepower and crossflow; i.e., flow of fluid across the bit, average rate of penetration was calculated in different rock types in order to examine their effect. The findings are illustrated in Figure 5.22 which shows the effect of fluid flowrate on the penetration rate in various rock types.

A polymer low solid mud was used with properties as follows;

mud type	polymer oil-based
weight	8.9 lb/gal
marsh viscosity	45-50 sec/qt
plastic viscosity	10 cp
yield point	10-12 lb/100 ft^2
API filtration	15-10 cc
pH	9.5

In the drilling bit industry, hydraulic horsepower hhp often is expressed in terms of hydraulic horsepower per square inch (hsi) of projected bit area. Both hhp and hsi are used in this study.

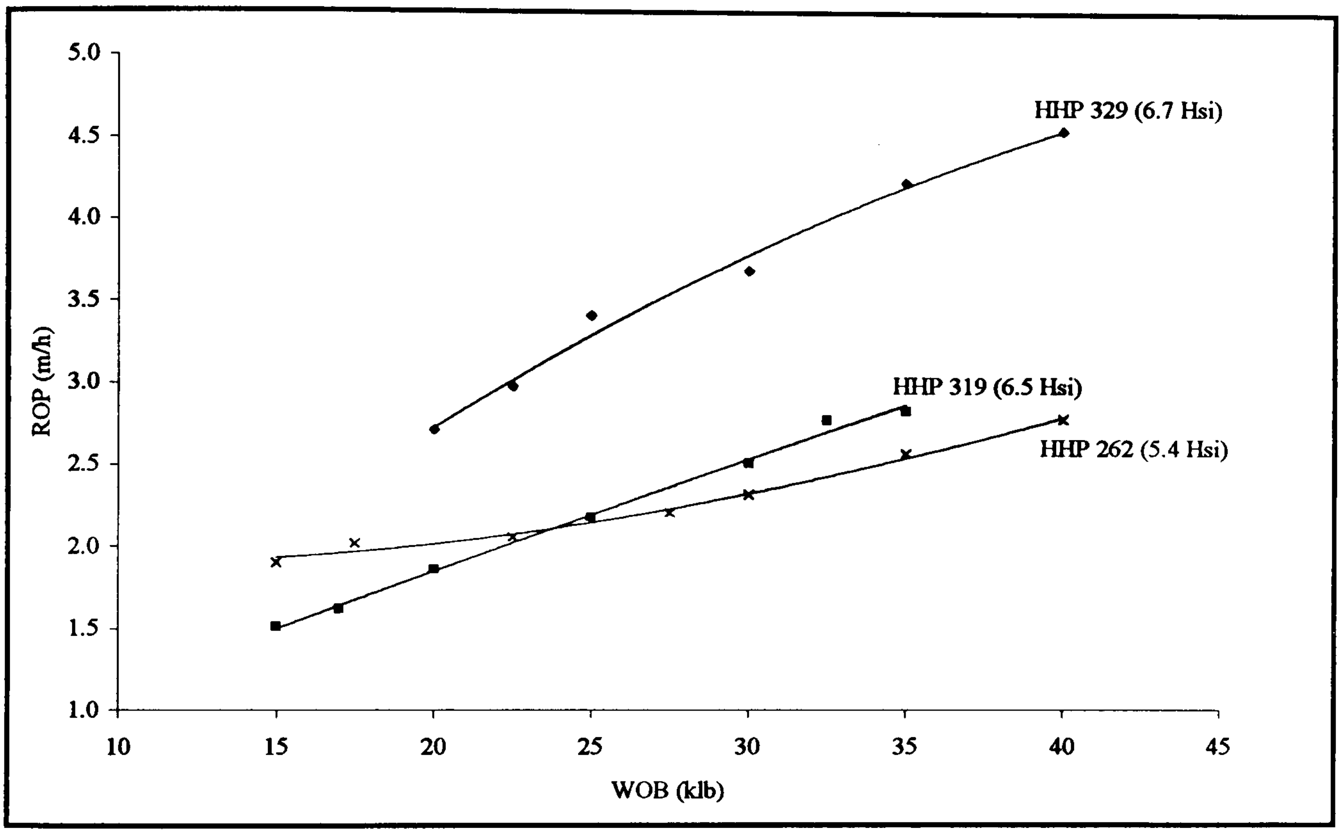


Figure 5.21. The effect of weight on bit Vs the rate of penetration for a range of different hydraulic horse power values.

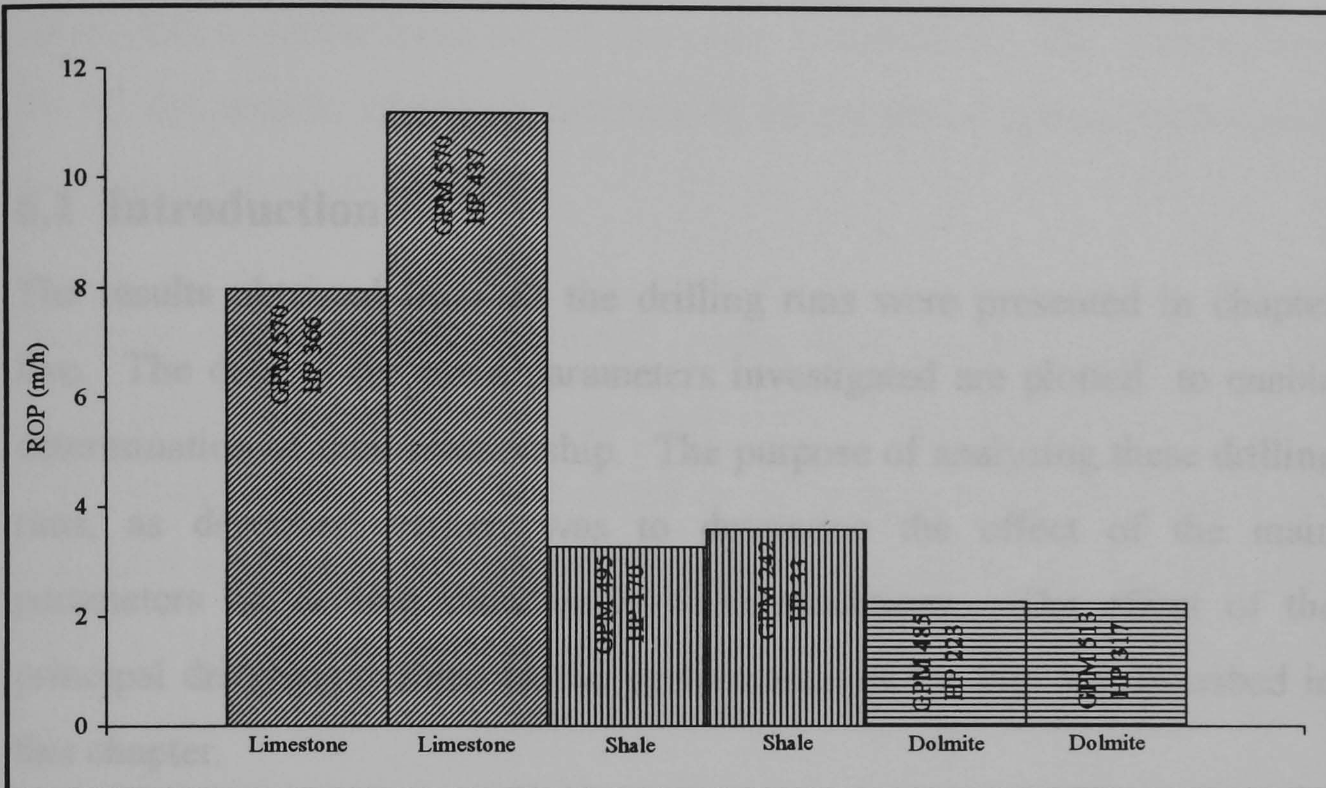


Figure 5.22. The inter active effects of jet horsepower and crossflow rate on the penetration rate in various rock types.

Chapter Six

DISCUSSION OF RESULTS AND CONCLUSIONS

6.1 Introduction

The results obtained from all the drilling runs were presented in chapter five. The data of the main parameters investigated are plotted to enable determination of their relationship. The purpose of analysing these drilling runs, as described earlier, was to determine the effect of the main parameters on drilling rates under field conditions. The effect of the principal drilling variables on the performance of the bits are described in this chapter.

An analysis to the highly successful geotechnical investigation drilling programme, mentioned in chapter four, is included. The integration of oilfield, mining and geotechnical exploration technologies for this special investigation programme includes several elements which are important in the application of slim hole methods for oil and gas exploration are analysed. Many of the technical issues associated with a slim hole approach is addressed in the development and application of the drilling, coring equipment and systems. In this chapter, comments are made on the application of this experience to slim hole drilling for oil and gas exploration and exploitation.

6.2 Rotational Speed

The effect of rotational speed on the drilling performance of drilling bits was analysed by examining the drilling run results presented in section 5.6

and illustrated in Figures 5.2-5.8. It is apparent that the influence, on the performance characteristics of drilling bits, of perturbing the bit rotational speed, has a similar form for all the cases investigated. The general trend for all the results, is that an increase in bit rotational speed, produces an increase in penetration rate.

However, at very high bit rotational speeds, there is often a slight reduction in the rate of increase of penetration rate with increased bit rotational speed. The reduction in the rate of increase in penetration rate with increased bit rotational speed, at high bit rotational speeds, is probably due to there being such a rapid production of rock fragments that the flush flowrate is insufficient to effectively remove them from under the bit and hence the bit is regrinding them.

Considering Figures 5.3 and 5.4, soft formations are generally drilled most effectively by a combination of deep tooth penetration and a gouging-scrapping action. This action is produced by the equipping of soft formation bits with relatively long, sharp, widely-spaced cutters affixed to highly-profiled, offset cones. The appropriate energy levels are obtained through combinations of relatively lower weights on bit and higher rotary speeds. These combinations of operating parameters were within the recommended ranges of WOB and RPM set-up by the International Association of Drilling Contractors (IADC). These recommendations set the upper and lower limits which were observed. The trade-off between WOB and RPM were kept in mind when using these recommendations. This good drilling practice entailed the selection of the appropriate WOB and RPM, which resulted the most economical combination of penetration rate and acceptable bit life as illustrated in Figures 5.5 to 5.8. The bit life is presented in wear % form of bit life remaining. The bits were graded on a conventional sliding scale from zero (sharp, new) to eight (completely dull). Drilling at very low WOB and low RPM levels was avoided to prevent the sliding action which produces unnecessarily low penetration rates. Also, operating at high WOB and high RPM was avoided which produces unnecessarily accelerated wear. Both combinations are uneconomical.

This field investigation of drilling rotary speeds confirms the comprehensive laboratory study by Ambrose, 1987, Ersoy, 1995, Shah, 1992, Rowsell, 1991 and Waller, 1992, which indicated to the effect of bit rotational speed on the rate of penetration.

6.3 Weight On Bit

The effect of WOB on the performance characteristics of drill bits was examined by analysing the bit runs through which the rotational speed and flushing flowrate were maintained constant. The graphs of WOB versus ROP from the drilling runs are shown in Figures 5.9 to 5.20 for six bits which include two of the same size but different core bits and three different sizes and types of roller cone bits.

The general trend of all the results, is that initially increasing values WOB produces a rapid increase in penetration rate. Then a linear curve is observed in the majority of the result graphs at moderate bit weights. Initially, when low bit weight is used, drilling rate and footage per bit will be very low. The reason is that drilling or making hole will be achieved only by a scraping action of the bit teeth or indenters. In this type of action, the teeth are worn off rapidly, and very little progress is made. This type of result often occur where operators are forced to reduce bit weight in hard formations because of crooked-hole problems and/or as a method of alleviating the problem of drill-pipe fatigue resulting from drill-string oscillation and vibration related to both high bit weights and rotational speed. Another reason where drilling rate is not directly proportional to bit weight is the lack of efficient cleaning below the bit and formation chips are being reground. However, increasing the WOB further tends to decrease the rate of increase in ROP in some drilling runs, noted in Figures 5.11 and 5.14. This type of behaviour often is called bit "floundering". The poor response of penetration rate at high values of bit weight is usually attributed to less efficient bottom hole cleaning at higher rates of cuttings generation or to a complete penetration of the cutting element into the hole bottom.

The nature and form of the penetration rate and wear characteristic of the impregnated core bits in the medium hard St Bees sandstone and the abrasive volcanic formations Figures 5.9-5.13 can be explained by considering their drilling process.

At low bit loads, the diamond indenters in the core bit do not penetrate the rock and when the core bit is rotated, they simply "skid" across the rock surface which produces a small amount of rock fragments, which results in a low penetration rate.

With an increase in the weight on bit, the point is reached when the diamond indenters in the core bit begin to penetrate the rock and when the core bit is rotated, rock fragments are produced. As the WOB is increased from this point, the depth of diamond indenter penetration is also increased and therefore there is an increase in penetration rate. During this phase of the drilling process, the diamond indenters are still subjected to wear when the core bit is rotated. The amount of wear occurring, per unit linear distance traversed by the diamond indenters, will now be slightly greater than at lower WOB, due to there being more rock fragments but, because of the increase in penetration rate, there is a net reduction in wear per meter drilled as the diamond indenters traverse a shorter linear distance for a given distance drilled.

When the WOB is further increased, the point is reached where the full diamond indenter protrusion is embedded in the rock and no greater amount of rock fragmentation can occur. Hence the maximum penetration rate is achieved. Any further increase in WOB above that required to produce this maximum penetration rate, can cause no greater amount of rock fragmentation and indeed may cause a reduction in the rate of increase of penetration rate, as is seen in Figure 5.11.

The increase in wear rate from its minimum level, even though the penetration rate is still increasing, is caused by the increased matrix abrasion and increased diamond wear and degradation. Increased matrix abrasion at higher WOB, could be due to the liberated rock fragments being more numerous and more restricted in their passage over the core bit face, or from the intact rock itself when at full diamond indenter penetration. Support of this hypotheses can be drawn from the minimum wear rate occurring at a slightly lower WOB than the maximum penetration rate in the drilling runs performed.

The increased bit wear rate at higher WOB is possibly caused by the greater force being applied to each individual diamond indenter. This increases its wear rate and also makes it more prone to breaking up and being lost. The difference in the magnitudes of penetration rates and wear rates and the WOBs at which these effects occur is due to variation in bit design and type and the physical properties of the rocks being drilled.

6.4 Bit Hydraulics

It is apparent from observations and by analysing Figure 5.20 that smaller jet nozzles clearly effect the rate of penetration. The results indicate that smaller nozzle diameters provide higher jet velocities which are needed to clean loose chips from the hole between tooth impacts and help dislodge chips that are held in place by differential pressure. The primary cause of this effect is a higher turbulence levels at the jet boundary caused by a higher jet velocity obtainable by the smaller nozzle diameters. Smaller nozzles can deliver more hydraulic energy to the bottom of the hole more efficiently than larger nozzles. Also there is a destructive interference between the jets issuing from the nozzles and the fluid returning from under the bit.

The parameters most commonly used to quantify the effect of hydraulics is the jet impact force at the bit. The optimum bit hydraulics conditions are considered to be those which gave maximum impact force at the bit while keeping the annular velocity within limits established by the borehole erosion and cuttings transport conditions.

This study of field investigation confirm the comprehensive laboratory study published by Winter and Warren, 1986, which indicated to the effect of bit hydraulics on the rate of penetration and concluded that ROP is a function of nozzle diameters.

Figure 5.22. shows the interactive effects of jet horsepower and crossflow; i.e., flow of fluid across the bit on 12 1/4 in. soft and hard formation bits, which are the correct type of bits for the particular formations being drilled. The soft formation bit has drilled (7.97 m/h) with 366 jet horsepower (hp)

and flow rate of 570 gpm. Increasing the jet hp by 19 % to 437 hp, has increased the drilling rate by 37% to (11 19 m/h).

The conclusion is that this bit was not drilling its potential because the teeth were not being cleaned. The penetration rate of this bit could not increase significantly with higher weights or rotary speeds at the low jet horsepower, but at higher jet horsepower, additional weights on bit and rotary speed, would cause this bit to drill quite effectively. A minor increase in operating cost for the hydraulics can yield a major reduction in overall cost in soft to medium hard formations.

Also, the penetration rate of the hard Dolmite formation bit was not affected when the flow rate and jet horsepower were increased. This insensitivity is probably due both to low jet velocity and to the interference effect of the high flowrate around the short teeth.

6.5 Core Bit Design and Performance at Sellafield and Dounreay

In the Sellafield's investigative core drilling, the initial design of core bits was based on the anticipated geology and previous experience in similar formations. The only data available was from general geological descriptions so it was necessary to carry out some experimentation in the initial holes. At Sellafield, the sandstones were more accommodating to a range of bit settings and profiles, but at Dounreay, the strong crystalline rocks posed the usual problems of bit type and achieving an acceptable trade off between penetration rate and bit life. In this initial borehole, the

consequences of having to lay down pipe without the facility of a pipe handling device were significant in terms of the overall performance.
In the first borehole at Sellafield, 19 bits were used with 12 different specifications, 14 of which were impregnated and five surface set. Design changes were implemented by a constant feed back of information from bit site to the manufactures. Overall at Sellafield site, bit usage was as shown in Table 6.1.

Borehole No	No of bits	Average life (m/bit)
S2	19	83.0
S3	22	57.2
S4	9	94.3
S5	6	184.8

Table 6.1 Records of bits used at Sellafield.

Boreholes S2 and S3 were drilled concurrently with boreholes S4 and S5 following borehole S2 using the same rig. With more experience of the geology, the bit life has improved most notably on the last borehole where one bit still in use at the end of this study has drilled 356 m.

One aspect of the bit design that was changed was the depth of the impregnation. Initially the depth was 9 mm, but in an endeavour to increase bit-on-bottom time, the depth of impregnation in later bits was increased to 14 mm. Castellated impregnated bits performed well generally in these hard formations, but some problems were experienced with broken segments in fractured zones. A design with a matrix appropriate to the harder rocks was used in the stronger formations.

Some points from the drilling experience to date include:

- Impregnated bits were used in favour of surface set bits in the Permo-Triassic formations as higher rates of penetration were achieved.
- Poor performance of surface set bits was experienced in the Borrowdale volcanics.
- Gauge reinforcement by increasing the diamond concentration and increasing the number of tungsten carbide inserts increased bit life significantly.
- Pump pressure fluctuations maintained the waterway size by preventing the possibility of a build up of fines or slithers of rock jamming the waterways.
- In the harder, fine grained formation, the inclusion of silica in the matrix formation improved the self sharpening characteristics to maintain penetration rates at an acceptable level over a sustained period.
- A further measure to increase the self sharpening characteristic was to lower the density of the matrix at the sintering stage which improved the performance in the more silicfied, fine grained materials.

Some experimentation has been carried out with PDC bits in the Permo-Triassic sandstones, but some oscillation in torque and associated string vibration effects were experienced. Typically, penetration rates at Sellafield during coring ranged from 0.7 m/hr to 3.0 m/hr with an average of about 1.6 m/hr.

At Dounreay, surface set bits performed reasonably well in the interbedded siltstones and sandstones of the Devonian sequence. The majority of bits used through the Moinian series were impregnated and a preference for castellated design evolved after some initial experimentation. These materials were broadly similar to the suite of rocks penetrated in the KTB super-deep pilot hole to 4000 m in Germany where progressive coring bit development in a similar size resulted in an average bit performance of 48 m planned (Rischmuller, 1990). Bit performance at Dounreay is shown in Table 6.2.

Borehole No	No of bits	Average life (m/bit)
D1	37	35.3
D2	22	43.9

Table 6.2. Records of bits used at Dounreay.

Design improvements at Dounreay were similar to Sellafield with enlargement of waterways, improvement in gauge protection and an increase of the self sharpening characteristics of the bits being adopted as standard. In view of the higher gauge wear experience at Dounreay and damage or loss of segments, there was a tendency to reduce impregnation thickness to minimise costs as bits were being discarded on other criteria with significant depth of impregnation remaining.

Penetration rates at Dounreay ranged from about 0.4 m/h to 1.8 m/h in the different lithologies with an average of 1.0 m/h.

Coring bit design followed the normal path of tailoring the bits to the formations. This is particularly important in strong abrasive rocks where the formations are less accommodating to poor bit selection or design as against weaker non abrasive rocks where a wide range of bits often give satisfactory performance.

In the stronger materials, one factor which was important in the trade off between rate of penetration rate and bit life was the need to select or design a bit that would drill the 50 m interval between test points to avoid unnecessary tripping and by and large this was achieved except in the early days while the bit design was being adjusted and refined.

6.6 Operational Performance

This investigative drilling programme has provided an opportunity to acquire data on similar drilling operations using two very different types of drilling rigs. In particular, time breakdowns provide a useful guide when trying to assess the merits of different equipment and systems for other applications.

As expected, the singles mining rig was much slower in tripping than the conventional oilfield units which was significant in a programme that involved so much additional tripping necessary for testing. The ability to rack pipe in the mast proved to be a significant advantage in allowing coring and testing strings to be changed out more quickly than the cumbersome procedure of laying down and picking up different strings necessary with the singles rig. Normalised time breakdowns for the boreholes completed to date show a marked improvement with time in performance which is to be expected as the crews became more familiar with the integrated systems. The data show that while the recovery of the corebarrel inner tubes is consistent over all rigs as would be expected with wireline systems, coring and testing string trip times with the triples rigs are about double those with the mining even after installation of the pipe handling device. A graph of tripping time versus depth for singles and triples rig is shown in Figure 6.1. However, the robotic pipe handling device when fitted roughly halved tripping times on the mining rig.

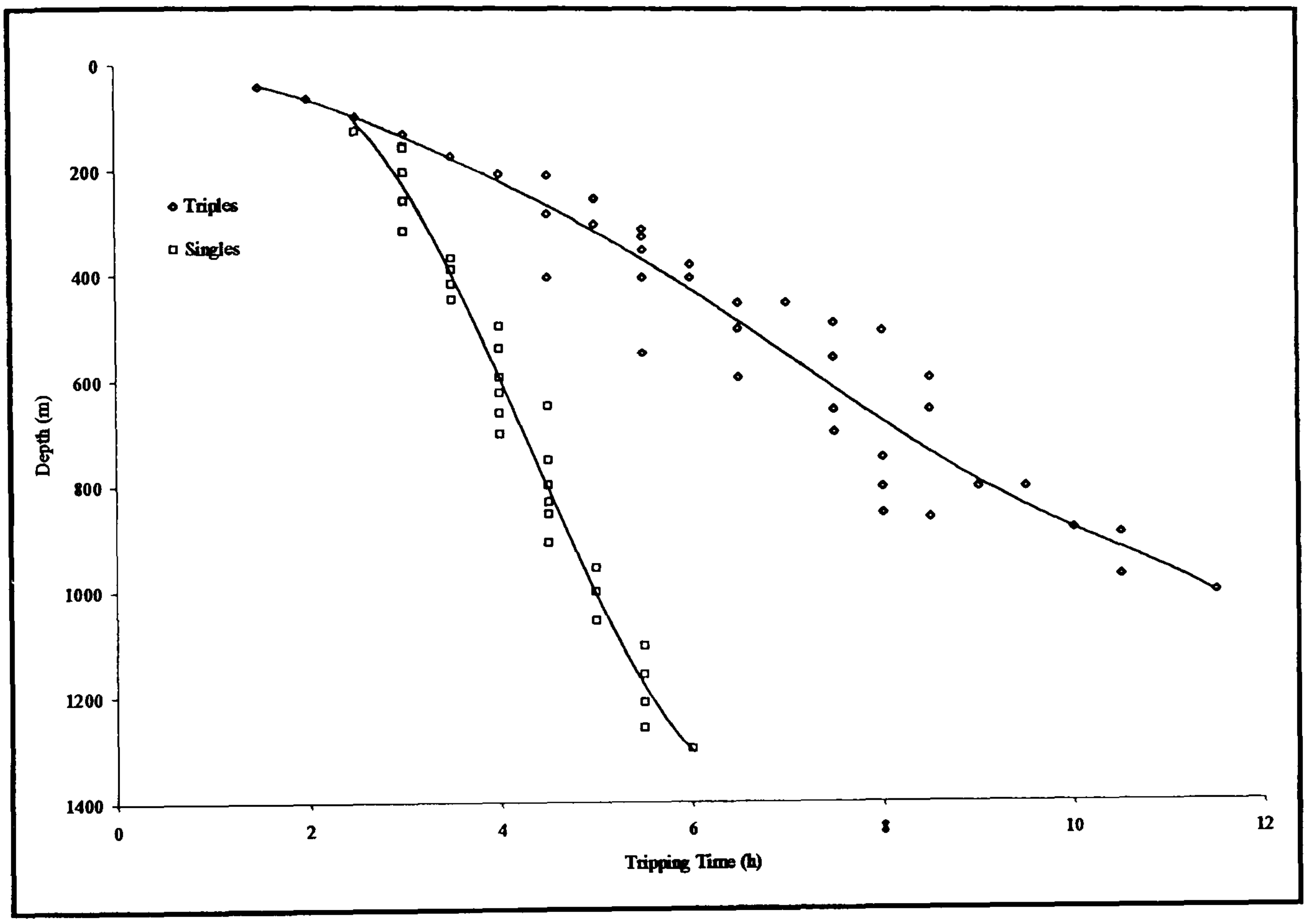


Figure 6.1. Tripping time of singles rig Vs triples rig during coring and testing.

A considerable database is being generated as the project progresses which will allow detailed analysis of several key elements including rig and equipment performance and pipe wear statistics as well as a range of cost assessments for all aspects of the programme.

The automatic drilling modifications to the drawworks winch control on the conventional rigs were adequate for the relatively large diameter wireline coring, but the hydraulic mining rig incorporated a superior fine feed system which was more suitable for coring. For smaller diameters where bit weight control is more sensitive, the mining rig approach is desirable.

Chapter Seven

CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

The effects of the operating parameters on the performance of the bits in field drilling were examined. The relationship of the operating parameters with each other were also determined. Increasing WOB gave an increase in ROP up to some yielding point, at which, the rate of increase in ROP was at a lesser rate. The results have also shown that ROP increase with RPM. The interactive effects of jet horsepower and fluid flow across the bit was determined and illustrated.

The findings of this field investigation of drilling parameters confirm the comprehensive laboratory study by previous investigations which indicated to the effect of these operating parameters on the drilling performance.

An analysis of a highly successful geotechnical investigation drilling programme has been presented. This project has given an opportunity to evaluate the advantages and disadvantages, merits and limitations of applying different drilling and associated technologies for deep hole construction to safely and routinely provide high quality geoscientific information. Several elements are included in this special investigation drilling programme, which are important to the application of slim hole methods for the oil and gas industry and gives some confidence that with the right approach there are benefits to be realised in an integrated technology approach. Many of the technical issues associated with a slim hole approach were addressed.

In the search for ways to reduce costs in exploration and exploitation of oil and gas resources, currently there is renewed interest in 'slim hole' and 'ultra slim hole' methods. The term 'slim hole' is widely used to refer to a range of drilling applications ranging from a small size conventional rotary drilling approach using destructive bits to small diameter high speed coring systems similar to those used in deep mining exploration where depths up to 5000 m have been achieved. In the case mentioned in chapter four , the final hole diameter is relatively large and more consistent with the smaller range of normal drilling, but the use of a wireline coring as a means of advancing a hole and providing high quality data addresses many of the issues which are currently under debate by the various groups working in this field.

The objective in applying slim hole methods to oil and gas exploration is principally to reduce cost, but there is also a secondary potential benefit in areas where geological control data is not available provided by the option to continuous core at a lower cost penalty than with conventional oilfield exploration methods.

Experience of slim and ultra-slim hole drilling for oilfield applications has been of mixed success with problems of mixing mining and oilfield cultures. Despite the reduced scale of the operation realising real costs savings has not always been achieved.

The experience at Sellafield has highlighted several facts of the application of wireline coring and small mining rigs which provides additional information in considering these methods for other uses.

Small rigs can be constructed that have the capability for considerable depth using small, lightweight strings providing that they are designed to provide the flexibility required to cope with both surface hole drilling in sizes up to say 445 mm (17.5 in.) even 508 mm (20 in.) and small diameter high rotational speed wireline coring systems with hole sizes down to 76 mm (3 in.) or even smaller for the lower sections of the hole.

Small rigs such as the mining units obviously occupy much smaller sites than the conventional rigs and hence there are savings in site preparation costs, although these can be insignificant if there are long access roads to construct.

Mobilisation costs with the small rigs are much reduced which is particularly important in remote location operations. Fast moving or heli-transportable units with the reduced costs of supporting consumables, materials and equipment provide the best potential for significant savings with this approach. Crews are reduced with obvious savings on costs as well as accommodation and travel expenses. The mining approach is more conducive to an integrated service philosophy with associated cost benefits.

Wireline coring in the smaller sizes can out perform small diameter destructive drilling in certain formations providing the drilling system allows the optimum parameters to be adopted. Wireline coring systems can be advantageous where formation problems occur and it is possible to leave the coring string in place as a permanent casing and drill through the string with a smaller size to continue the hole. However, some concerns remain and must be seriously addressed before the benefits of the mining approach can be translated into real savings for oil and gas exploration and exploitation.

Singles rigs are slow in tripping especially where the pipe cannot be racked in the mast even with pipe handling devices to assist and unless drilling with few bit trips or limited testing is anticipated, tripping costs will become significant. Pipe handling generally needs careful thought to optimise rig time and where possible introduction of another process such as the use of lift plugs should be avoided.

The various programmes already undertaken and currently being considered under the umbrella of 'slim hole' drilling use several different types of strings for both coring and drilling. So far there is no consistency in this area and it can be seen that there are many considerations and trade offs. Open hole drilling in small sizes is often slow. Continuous coring dictates a weaker pipe than can be successfully used for destructive drilling and the problems of well control become more acute especially in the smaller sizes. Wireline coring strings are more like casing and hence have limitations on burst strengths even assuming the connections are in ideal condition so limiting their use in highly pressured formations.

Small diameter systems provide less potential for successful fishing, indeed wireline coring pipe can only be fished with spears. The mining industry accepts hole failures and routinely side-tracks if strings are lost, but better quality control, preventative inspection and improved well planning and drilling procedures should reduce the risk of failure.

Kick detection and procedures will remain a key issue. The use of electromagnetic flowmeters is a useful method in detection, although these devices have not been extensively tested in the application reported in this thesis with a high particulate content in the mud stream which may be the case with small diameter destructive drilling.

7.2 Recommendations

What is needed is a comprehensive review of all pipe types available and safe operating limits established and presented in a consistent format. Pipe lengths also vary and this needs to be standardised to give a range of options which can be easily accommodated without changes to the rigs or the rigs configured so that they can accept different pipe lengths.

Well control methods need to be investigated more thoroughly and procedures adopted to suit the special cases which slim hole applications present.

The approach of integrating the flowmeters with the mud logging unit points to one of the key areas which needs to be developed if slim hole drilling is to become a useful cost effective method of exploration. The mud logging data, drilling parameter monitoring and kick detection and control and all other instrumentation and data acquisition should be concentrated in one unit or service and the appropriate data made available to the driller and crew on displays using the latest information technology systems. There is no merit in duplicating systems on the rig which only adds cost. Providing the information service is manned by competent personnel, this would be a discreet package within the integrated drilling system providing reliable data manned by specialists. This is especially true if the full benefit of reduced rig crews is to be realised. Rigs could include the data acquisition sensors built into the architecture with permanent wiring to a data connection box for simple hook ups on moves.

This approach lends itself to the introduction of automation and eventually artificial intelligence systems. In this connection, automatic drilling equipment and drawworks design must include comprehensive control systems independent of the braking systems.

Quality management and time efficiency must be a main feature of the application of slim hole methods to the oilfield by developing routine procedures which ensure problem free drilling and safe operations. By using both adapted oilfield equipment and heavy mining equipment for the same drilling programmes, the merits of each approach can be seen. It would appear that if slim hole concepts are to become a mainstream activity in the oil and gas industry, purpose built rigs with the flexibility to cope with the range of options available are necessary as retrofitting the architecture of a new culture or adapting existing equipment is not ideal if the real benefits of this approach are to be realised.

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