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BIT PERFORMANCE EVALUATION: A CASE STUDY OF FIELD A, NIGER DELTA, NIGERIA

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ABSTRACT

The evaluation of the performance of drilling bits used to drill the top hole section in well-1 and well-2 of Field A, Niger Delta was carried out. The evaluation methods used in this study are the cost per foot and drilling specific energy. From the evaluation, the Smith bit used in drilling well-2 has the least cost per foot of $27.3, while the Hughes bit used to drill well-1 has a cost per foot of $30.36. Also, the drilling specific energy of the Smith bit for well-2 is 371MJ/m^3 and the value for the Hughes bit used to drill well-1 is 545.3MJ/m^3. From the analysis, both the cost per foot and drilling specific energy evaluation show that the Smith used in drilling well-2 in the most economical as it has the least cost per foot and drilling specific energy.

Keywords: *Drilling bits, Niger Delta, Evaluation, Performace, Penetration*

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. 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 intuitional 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.

AIM OF THE STUDY

The aim of this work is to deduce the best choice of bit that gives the lowest price per foot of hole drilled under good technical conditions.

LITERATURE REVIEW

The evaluation of bit performance in oil and gas drilling has been extensively analysed for different performance criteria such as total rotating hours, total footage or maximum rate of penetration (Mohammed, 1997; Oloro et. al. 2011). The use of these parameters provides a possible way to achieving an optimum relationship between penetration rate, rig cost, trip time and bit cost (Peter, 2007). The drilling parameters, or variables, associated with rotary drilling have been analysed and divided in two groups as independent and dependent parameters (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.

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. 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, Kelsey, 1982, Holester and Kipp, 1984). 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.

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, 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.

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

(a) 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.

(b) 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 results 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.

(c). 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.

AVAILABLE BIT TYPES:

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.

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 (See figure 1. 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.

Figure 1: Carbide Insert Drag Bit

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 (See figure 2). 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 carbid, 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.

Figure 2: PDC bits

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. 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 cannot 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.

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.

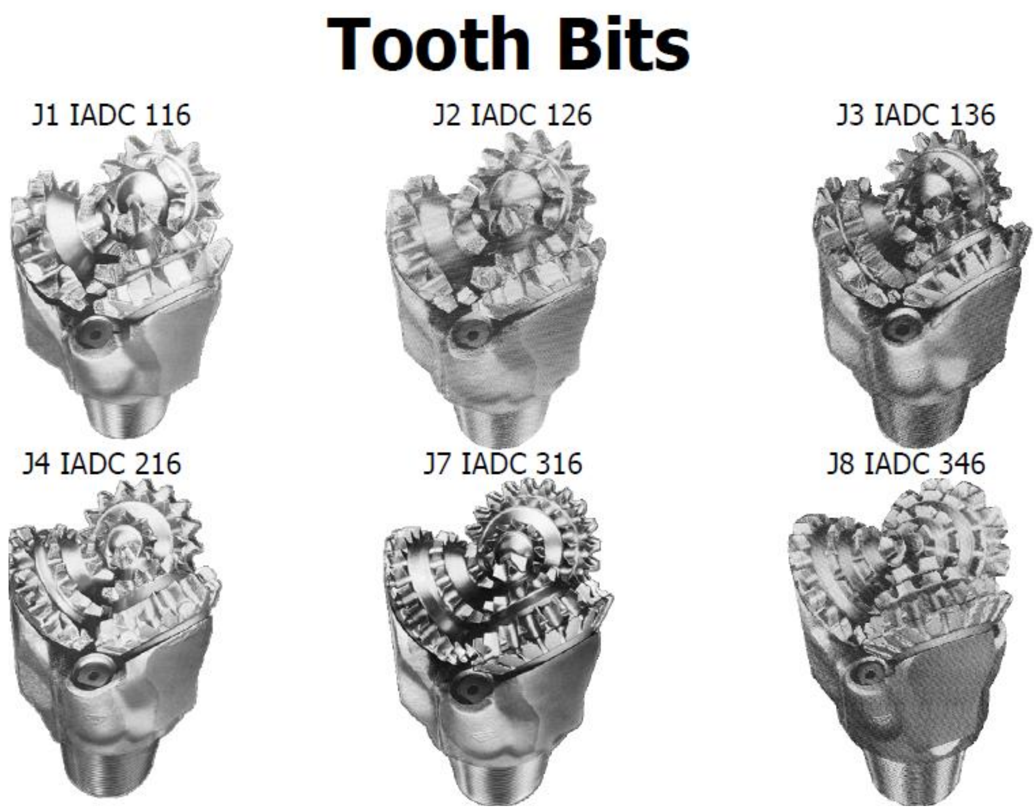
The shape of the bit teeth also has a large effect on the drilling action of a roller cutter bit. Long, widely spaced, steel teeth are used for drilling soft formations. The long teeth easily penetrate the soft rock, and the scraping/twisting action provided by alternate rotation and blowing action of 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 (See figures 3), 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 3, this case-hardened steel should wear by chipping and tends to keep the bit sharp.



Figures 3: Milled tooth bits

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.

MATERIALS AND METHODOLOGY

The data for this analysis was obtained from Nigerian Petroleum Development Company (NPDC) Field A in Niger Delta. The wells are well-1 and well-2.

Well-1well was drilled to a total depth of 13,450ft using a total of four (4) bits to drill the section of interest (1015ft-6080ft).

Well-2 well was drilled to a total depth of 11,610ft using a total of two (2) bits to drill the section of interest (1011ft-5996ft).

The intervals selected for the analysis was based on the fact that the aim of this work is to evaluate bit performance in sandstone formation. In the Niger delta, the Benin formation is basically composed of sandstone and ranges from 0m-2500m (0 to $\pm$8000ft) depth (Etu-Efeotor, 1996).

BIT RECORD:

In the field, the bit record serves as the most reliable source of information (Table 1), they are important when it comes to estimating the drilling cost of the next well to be drilled within a given area. They indicate the type of bit to be used in a given formation for the greatest footage per hour of the rig time. The bit record should include a statement of the bit when it is pulled out so that in planning future wells, it will be possible to select bit for maximum footage in each formation drilled.

N/O.	BIT TYPE	BIT SIZE (INCH)	DEPTH DRILLED (FT)	HRS	FT/HR	WOB (KIPS)	BIT CONDITION	REMARKS
1	HUGHES	17-1/2	2458	76	94.5	2-6	3-4-1/8	DRILLING
2	HUGHES	17-1/2	1095	22.5	48.7	6-13	2-4-1	DRILLING
3	HUGHES	17-1/2	752	32	23.5	10-20	2-5-1	DRILLING
RR2	HUGHES	17-1/2	642	19	33.7	10-20	2-6-1	DRILLING
4	SMITH	17-1/2	118	10.5	11.2	10-20	5-3-1	DRILLING

Table 1: BIT RECORD FOR WELL-1

N/O.	BIT TYPE	BIT SIZE (INCH)	DEPTH DRILLED (FT)	HRS	FT/HR	WOB (KIPS)	BIT CONDITION	REMARKS
1	SMITH	17-1/2	500	8	62.5	6-10	1-1-1	DRILLING
RR1	SMITH	17-1/2	3567	78.5	45.5	6-10	4-3-2	DRILLING
2	SMITH	17-1/2	830	48	17	5-10	4-5-2	DRILLING
RR1	SMITH	17-1/2	579	31.5	18	5-10	5-4-2	DRILLING

Table 2: BIT RECORD FOR WELL-2

The two bit evaluation methods used in this work are the cost per foot and drilling specific energy and are described below.

1. Cost per Foot 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:

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

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 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.

2. SPECIFIC ENERGY METHOD

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 bit that gives the lowest value of specific energy in a given section is the most economical bit. The drilling specific energy equation has been derived by considering the mechanical energy expanded at the bit and is calculated from the following equation:

$$SE = \frac{20WN}{DF} \times t$$

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)

Research 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.

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.

RESULTS, FINDING AND DISCUSSION

WELL-1

A total of four (4) bits were used to drill the 17 ½" hole section of well-1. The bits are three (3) Hughes bits with one (1) Smith bit. Hughes bit number two was re-run after it was pulled out of hole for bottom hole assembly (BHA) change. The average values of Hughes bits used in well-1 were shown in tables 3 and average values for Smith bits of Well-2 were shown on table 5, the value for Smith bit used in well-1 is given in table 4,. The values were obtained by summing the individual bit values and dividing by 4.

Bit No.	Make	Footage (ft)	Time on Bottom (hr)	ROP (ft/hr)	Trip Time (hr)	Bit Cost ($)
1	Hughes	2,458	76	94.5	6	18,000
2	Hughes	1,095	22.5	48.7	6	18,000
3	Hughes	752	32	23.5	6	18,000
RR2	Hughes	642	19	33.7	6	18,000
Total		4,947	149.5	200.4	24	72,000
Average		1,237	37.4	50.1	6	18,000

Table 3: Average value of Hughes Bits used in well-1

Bit No.	Make	Footage (ft)	Time on Bottom (hr)	ROP (ft/hr)	Trip Time (hr)	Bit Cost ($)
4	Smith	118	10.5	11.2	6	16,000

Table 4: Value of Smith Bit used in well-1

WELL-2

A total of two (2) bits were used to drill the 17 ½" hole section of well-2. The bits are two (2) Smith bits. Bit number one (1) was re-run twice after it was pulled out of hole for bottom hole assembly (BHA) change and section

Bit No.	Make	Footage (ft)	Time on Bottom (hr)	ROP (ft/hr)	Trip Time (hr)	Bit Cost ($)
1	Smith	500	8	62.5	6	16,000
RR1	Smith	3,567	78.5	45.5	6	16,000
2	Smith	830	48	17	6	16,000
RR1	Smith	579	31.5	186	6	16,000
Total		5,476	166	311	24	64,000
Average		1,369	41.5	77.75	6	16,000

Table 5: Average value of Smith Bits used in well-2

COST PER FOOT EVALUATION

The average drilling cost per foot for the bits used in both wells are calculated below using the formula; $C=\frac{B+(T+t)R}{F}$ and a summary given in Table 6.

1. Average drilling cost per foot for well-1 using Hughes Bit:

$$= \frac{18{,}000 + 450\,(37.4+6)}{1{,}236}$$

$$= \frac{18{,}000 + 19{,}530}{1{,}236}$$

$$= \frac{37{,}530}{1{,}236}$$

$$= \mathbf{\$30.36/ft}$$

2. Average drilling cost per foot for well-1 using Smith Bit:

$$= \frac{16{,}000 + 450\,(10.5+6)}{118}$$

$$= \frac{16{,}000 + 7{,}425}{118}$$

$$= \frac{23,425}{118}$$

$$= \mathbf{\$198/ft}$$

3. Average drilling cost per foot for well-2 using Smith Bit:

$$= \frac{16,000 + 450\,(41.5+6)}{1,369}$$

$$= \frac{16,000 + 21,375}{1,369}$$

$$= \frac{37,375}{1,369}$$

$$= \mathbf{\$27.3/ft}$$

RIG RATE ($/HR)		450					
TRIP TIME (HR)		6					
Make	Well	Average Footage (ft)	Time on Bottom (hr)	ROP (ft/hr)	Trip Time (hr)	Bit Cost ($)	Average Cost/Foot ($/Ft)
Hughes	Well-1	1,237	37.4	50.1	6	18,000	$30.36/ft
Smith	Well-1	118	10.5	11.2	6	16,000	$198/ft
Smith	Well-2	1,369	41.5	77.75	6	16,000	$27.3/ft

Table 6: Bit Cost Evaluation

DRILLING SPECIFIC ENERGY

From the cost per foot analysis carried out on the bits used in drilling both wells (table 6), the average footage for Hughes bit used in drilling well-1 is 1,237 ft; rotating time is 37.4 hours; rate of penetration is 50.1 feet per hour; trip time of six (6) hours; bit cost of $18,000 USD, which gave an average cost per foot of $30.36/ft. The Smith bit used for this well made a footage of 118ft, time on bottom of 10.5 hours, rate of penetration of 11.2 feet per hour, trip time of 6 hours, bit cost of $16,000USD which gave a cost per foot of $198/ft. For well-2, the average footage drilled is 1,369ft, rotating time of 41.5 hours, rate of penetration of 77.75 feet per hour, trip time of 6 hours, bit cost of $16,000USD which gave an average cost per foot of $27.3/ft.

It can be seen from the analysis above that the Smith bit used in well-2 has the lowest cost per foot of \$27.3/ft compared to the Hughes bit used in drilling well-1 with a cost per foot of \$30.36/ft. Also, only two Smith bits were used to drill this hole section of about 5,476ft as against the four bits that were used to drill the similar section in well-1 even though it is shorter (5,065ft). Therefore the cost of drilling the section of well-2 using the Smith bit will be \$149,495USD (27.3x5476) and that for drilling well-1 using the Hughes bit will be \$153,773USD (30.36x5065). By using the Smith bit in drilling well-1 the cost saved is \$4,278USD.

The specific energy evaluation of the drilling bits used in both well (table 10) shows that the Hughes bit used in well-1 had an average weight on of 6,691 kg, rotation per minute of 120, hole diameter of 445mm, footage drilled of 1,237ft, rotating time of 2,243min with a specific energy of 545.3MJ/m^3. The Smith bit used for the well had a weight on bit of 9,072 kg, rotation per minute of 120, hole diameter of 445mm; footage drilled 118ft, rotating time 630minutes with a specific energy of 2,176.9MJ/m^3. The Smith bits used in drilling well-2 well had a weight on bit of 4,536kg, RPM of 120, hole diameter of 445mm, footage drilled of 1,369ft, rotating time of 2,490minutes with a drilling specific energy of 371MJ/m^3.

The drilling specific energy of the bits show that the Smith bits used in drilling well-2 has the least specific energy value of 371MJ/m^3 followed by the Hughes bit used in well-1 with value of 545.3MJ/m^3 and finally the Smith bit used in well-1 with value of 2,176.9MJ/m^3. From the forgoing, the Smith bit used in drilling well-2 is most economical been the bit that gives the lowest value of specific energy.

From the analysis, both the cost per foot and drilling specific energy evaluation show that the Smith bit used in drilling well-2 is the most economical as it has the least cost per foot and drilling specific energy. The high cost per foot and high specific energy of the Smith bit used in drilling well-1 may be attributed to the fact that from the bit record it is of a different make from that used in well-2.

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