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Drilling Data Analysis and Evaluation for Agbada 1 and Soku 56 Wells Using 'Matching the Area Average' Performance Approach

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Abstract

In order to achieve the purpose of improving the understanding of drilling bits performance at a particular depth in the Niger Delta region of Nigeria, a simple performance optimization model – 'Matching the Area Average Performance' was used to ascertain the actual performances of selected drilling bits used in the region against their prevailing drilling variables in terms cost evaluation. In this model, Cost per Foot equation was used to compare the performances of the selected drilling bits on the basis of minimum Cost Drilling for two case study wells - Agbada 1 and Soku 56, located in the heart of the region with depth range of 3,000 feet to 20,000 feet respectively. The interpretation of graphs of the relationships between Depth, Cost per Foot and Total Run Cost of a particular drilling bit size gave a proper downhole drilling analysis of two the two wells in the region hence, illuminating the behavior of a drilling bit at a particular depth amidst the prevailing drilling variables in the region. The selected drilling bit sizes were 17½, 12¼ and 8½ inches of predominantly PDC bit types representing surface, intermediate and production casing stages respectively. The prevalent formation/lithology of the region is Agbada formation. The evaluated drilling variables include the Rotational Hours, Rate of Penetration (ROP), and Weight on Bit (WOB). The effect of these important variables was used to determine the Cost per Foot Drilled and Total Run Cost (TRC) for the two Wells. The result obtained from the work was recorded and presented as an organized graphical analysis of the cost performance record of the selected bits used for the two wells. This is believed to be an invaluable tool that will enable stakeholders in the drilling business to make an informed and economically viable decision on the selection of a drilling bit run conditions and the drilling system design that will minimize economic downtime when drilling a new well in the region.

Keywords

Drilling Optimization, Polycrystalline Diamond Compact (PDC) Bit, Cost Per Foot, Rotational Hours, Drilling Variables/Parameters

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1. General Introduction

While drilling a well, crucial decisions are made on the basis of what is believed to be happening downhole. There are a large number of factors that can affect drilling performance from the drilling rig itself and associated surface equipment to the downhole equipment; from run parameters and formation type to their consequential effect on drill string dynamics and bit life. This study improves the understanding of these factors and provides guidelines for management and optimization procedures. With better identification and understanding of drilling problems, informed decisions can be made to improve drilling performance and significantly reduce the drilling costs.

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1.1. Objective

The main objective of this article is to analyze, evaluate and compare the cost implications of the performance of a PDC drilling bit run at a particular depth for two wells in the Niger Delta geomechanical environment. Other evaluation and comparisons such as the relationship between ROP vs. WOB, ROP vs. Depth, and Rotational Hours vs. Depth for the two wells was done to demonstrate the behavior of bits run in this environment. With the drilling record data collated from SOKU 56 and AGBADA 1 wells, detailed evaluation, analysis and comparisons were made using the MATCHING THE AREA AVERAGE PERFORMANCE METHOD. This involves using the Cost per Foot equation to compare graphically the performances of the selected drilling bits for the two wells on the basis of minimum Cost Drilling. The result obtained shows the actual performances of the selected drilling bits run at a particular depth amidst prevailing drilling variables. Intelligent recommendations was however offered following the outcome of the whole process in terms of the selection of a drilling system design and a drilling bit run conditions that will minimize economic downtime while drilling a prospect well in the region.

1.2. Limitation

This study's limitation is the lack of current bit records to reflect the present day bit and rig costs. The bit record used in the study was recorded since 2010. The bit performance was evaluated based on the information given in the bit record data. Other bit record data may include hole deviation information and so directional drilling technique will have been mentioned.

1.3. Justification

This study, a research contribution to investigation, evaluation, analysis, comparisons and interpretation of field data, is of immense benefit to indigenous engineers and drillers intending to venture into drilling business. It is a quick reference guide for field engineers for selecting the appropriate bit type, design and run conditions as well as the best drilling method that will optimize the bit performance and save cost. The fact that the conclusion drawn from the two offset wells is consistent to some degree with other wells drilled in the Niger Delta region made this study justifiable and this is applicable in drilling a prospect well in the region.

2. The Niger Delta Lithology Make Up

Briefly, the Niger Delta lithology is a clastic sequence of sediments described as an upward and updip (south-to-north) transition from marine dip and pro-delta sediments (Akata formation), through alternating sand/shale paralic deposits (Agbada formation), to continental deposits (Benin formation) [1] (Ejedawe et al., 1984). Production thus far has been principally from the Agbaba formation which is at least 3000 m thick. It is an alternating sequence of sands, silts and clays deposited. Principally in delta-front, tidal/estuarine, distributing channel, and delta-plain environments. Reservoir quality has been shown to be related to depositional environment (in association with lithology and geometry) and burial depth. The underlying and interbedded Akata formation which is reportedly up to 7000 m thick includes clays, silts and sands deposited in deeper water environments by slump/slide/debris flow, bottom current, and turbidity current and pelagic/hemipelagic processes, also locally exhibits reservoir potential. The overlying and interfingering Benin formation is composed of fluviatile sands and conglomerates with locally contains (heavy) oil and gas stringers, where the oil-bearing sands are associated with coal [2] (Avbovbo A. A, 1978).

The Niger Delta depositional sequence is a regressive sequence of clastic sediments developed in a series of offlap cycles. All deep wells in the basin record a tripartite lithostratigraphic succession in which the regressive sequence is demonstrated. The base of the sequence consists of massive and monotonous marine shales. These grade upward into interbedded shallow-marine and fluvial sands, silts and clays, which form the typical paralicfacies portion of the delta. The uppermost part of the sequence is a massive non-marine sand section. [3] (Doust and Omatsola, 1990). The overall sequence is, as in all deltas, strongly diachronous, *(see figure 1)* although marine shales as old as Paleocene may underlie the entire complex, the deltaic facies range in age from Eocene to in the North to Miocene-Pliocene in the South.

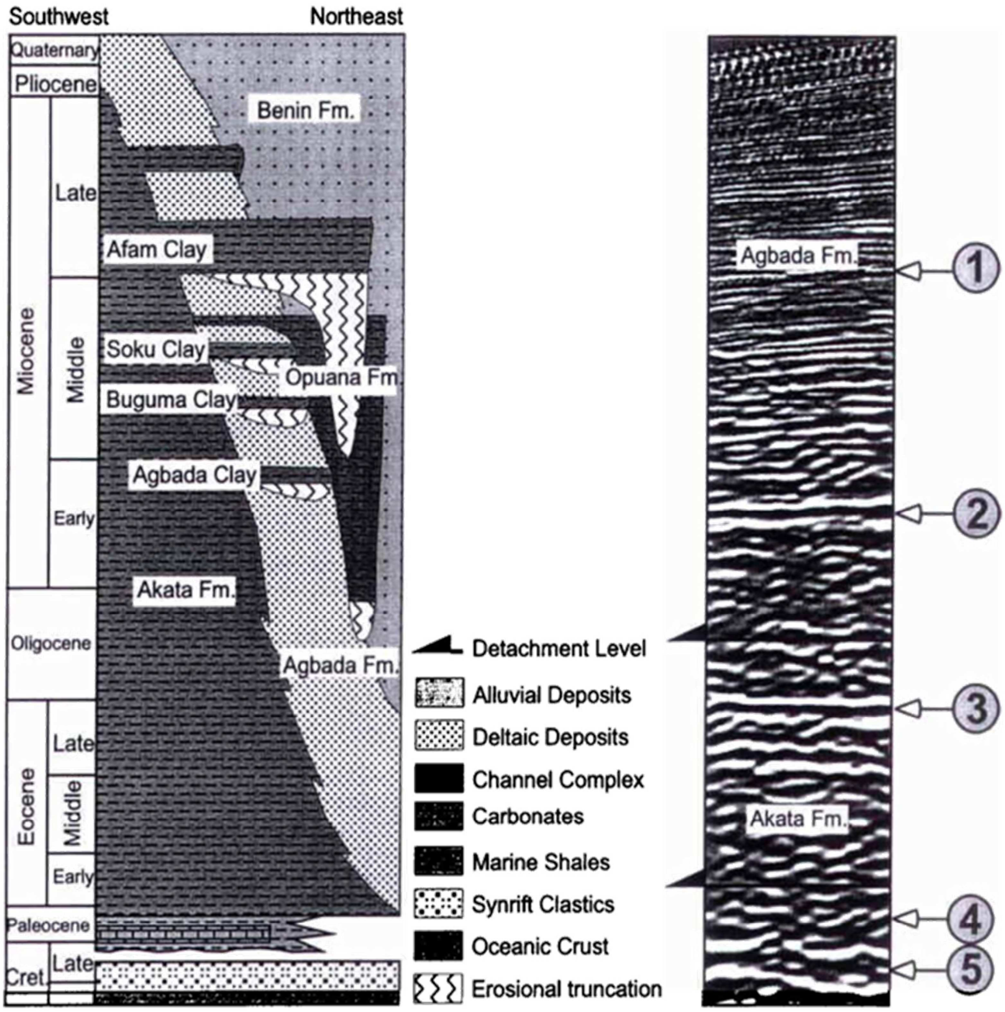

Figure 1. The diachronous nature of major lithofacies units, and the stratigraphic relationships of clay-filled channels on the delta flank (Doust et al, 2004).

The progradation of the deltaic sequence has been controlled by synsedimentary faults and the interplay between subsidence and sediment supply. The delta can be divided into a number of major growth-fault-bounded sedimentary units or "depobelts," which as the delta prograded, succeeded one another in a southward direction. In each depobelt, a tripartite regressive sequence forms an integral delta unit of a distinct age, becoming more argillaceous in a distal (southward) direction. (Doust et al 1990). From the shoreline to the shelf break, the submarine topography of the Niger Delta is almost flat. Submarine terraces on the shelf are crossed by several shallow channels, believed to be former distributaries that were incised during the sea level lowstand during the last glaciation. Major submarine canyons have been carved into the shelf and continental slope off the Niger Delta. Turbidity currents in submarine canyons off the delta have deposited deep-sea fans on the continental rise of the delta. The continental slope off the delta comprises a gentle upper slope, and hilly, steep lower slope known as the Nigeria Escarpment. A belt of mud diapirs occurs along the seaward side of the Nigeria Escarpment. These fluvial, coastal and marine depositional processes, coupled with the eustatic rises and falls of sea level, have determined the stratigraphic fill of the Cenozoic Niger Delta. [4] (Reijers et al, 1996).

3. Drilling Bits Performance Evaluation

The performance of a bit may be judged on the following criteria:

1. How much footage it drilled (ft)
2. How fast it drilled (ROP)
3. How much it cost to run (the capital cost of the bit plus the operating costs of running it in hole) per foot of hole drilled. [5] (Nwani O. J 2012)

Since the aim of bit selection is to achieve the lowest cost per foot of hole drilled the best method of assessing the bits' performance is the last of the above. This method is applied by calculating the cost per foot ratio, using the following equation:

$$C = \frac{C_b + (R_t + T_t)C_r}{F} \quad (1)$$

Where:

C = overall cost per foot ($/foot)

C_b = cost of bit ($)

R_t = rotating time with bit on bottom (hrs)

T_t= round trip time (hrs)

C_r = cost of operating rig ($/hrs)

F = footage drilled (ft)

This equation relates the cost per foot of the bit run to the cost of the bit, the rate of penetration and the length of the bit run. It can be used for:

1. Post drilling analysis to compare one bit run with another in a similar well.
2. Real-time analysis to decide when to pull the bit.
3. The bit should be pulled theoretically when the cost per foot is at its minimum.

Rate of Penetration (ROP) is one of the most significant factors in the assessment of bit performance.

The ROP of the rotary bit through rock is expressed is units of distance per unit time. It is considered as one of the primary factors which affect drilling costs and hence it is given a prior consideration when planning for optimized drilling.

The subject of drilling rate has been studied and extensively analyzed from both the theoretical standpoint and the experimental standpoint with the objective of maximizing drilling rate and improving operating efficiencies (Lummus, 1969; Eckel, 1967; Huff and Varnado, 1980; Kelsey, 1982; [6] Holester and Kipp, 1984; [7] Ambrose, 1987; Warren and Armagost, 1988; Waller, 1991; [8] Shah, 1992). The determination of the rate of penetration is one of the most important objectives, and is therefore considered and presented in detail in this study. Collectively, contributions to the understanding of these factors on the penetration rate have been greatly exploited in an effort to drill faster and more economically.

3.1. Roller Cone Bits Performance Evaluation

According to [9] Gray and Young 1973, in addition to correct bit selection; penetration rate is a function of many parameters: weight on bit (WOB), rotary speed (RPM), mud properties, and hydraulic efficiency.

1. Weight on Bit

A certain minimum WOB is required to overcome the compressibility of the formation. It has been found experimentally [10] that once this threshold is exceeded, penetration rate increases linearly with WOB *(figure 2)*.

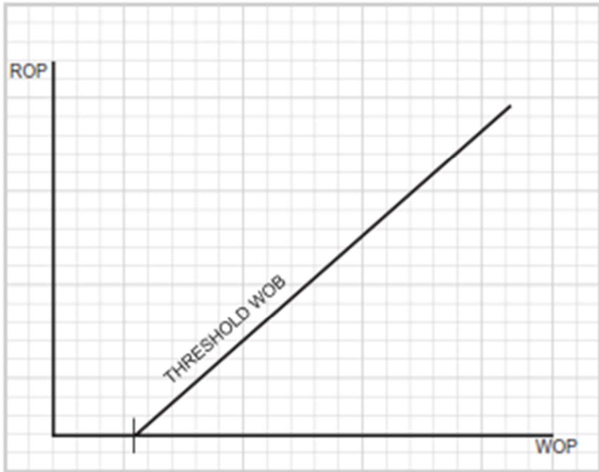

Figure 2. Rate of Penetration vs. Weight on Bit.

There are however certain limitations to the WOB which can be applied:

a) Hydraulic horsepower (HHP) at the bit: If the HHP at the bit is not sufficient to ensure good bit cleaning the ROP is reduced either by:

i. Bit balling where the grooves between the teeth of the bit are clogged by formation cuttings (occurs mostly with soft formation bits), or

ii. Bottom hole balling where the hole gets clogged up with fine particles (occurs mostly with the grinding action of hard formation bits).

If this situation occurs no increase in ROP results from an increase in WOB unless the hydraulic horsepower (HHP) generated by the fluid flowing through the bit is improved *(Figure 3)*.

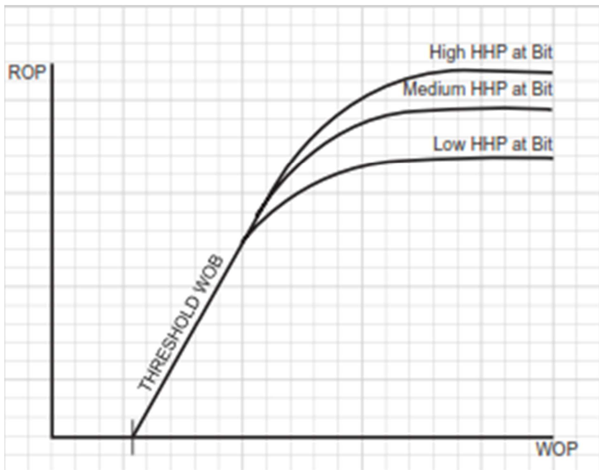

Figure 3. Penetration rate variation due to hole cleaning.

The HHP at the bit is given by:

$$HHP_b = \frac{P_B \, X \, Q}{1714} \quad (2)$$

Where:

P_B = pressure drop across the nozzles of the bit (psi)

Q = flow rate through the bit (gpm)

To increase HHP therefore requires an increase in P (smaller nozzles) or Q (faster pump speed or larger liners). This may mean a radical change to other drilling factors (e.g. annular velocity) which may not be beneficial. Hole cleaning may be improved by using extended nozzles to bring the fluid stream nearer to the bottom of the hole. Bit balling can be alleviated by using a fourth nozzle at the center of the bit.

b) Type of formation: WOB is often limited in soft formations, where excessive weight will only bury the teeth into the rock and cause increased torque, with no increase in ROP.

c) Hole deviation: In some areas, WOB will produce bending in the drillstring, leading to a crooked hole. The drillstring should be properly stabilized to prevent this happening.

d) Bearing life: The greater the load on the bearings the shorter their operational life. Optimizing ROP will depend on a compromise between WOB and bearing wear.

e) Tooth life: In hard formations, with high compressive strength, excessive WOB will cause the teeth to break. This will become evident when the bit is retrieved. Broken teeth are, for example, a clear sign that a bit with shorter, more closely packed teeth or inserts is required.

2. Rotary Speed

The ROP will also be affected by the rotary speed of the bit and an optimum speed must be determined. The RPM influences the ROP because the teeth must have time to penetrate and sweep the cuttings into the hole.

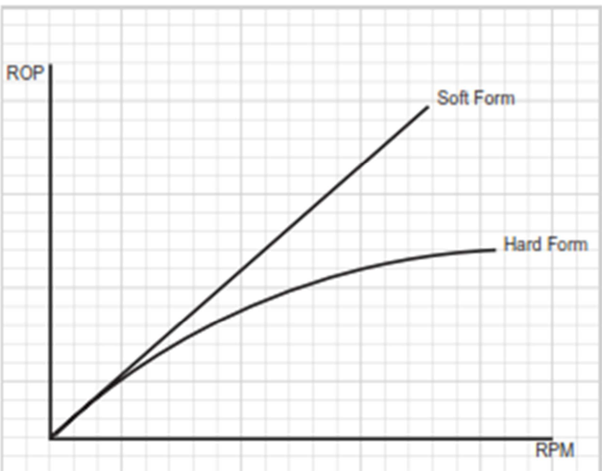

Figure 4. Penetration Rate versus Rotary Speed.

shows how ROP varies with RPM for different formations. The non-linearity in hard formations is due to the time required to break down rocks of higher compressive strength. Experience plays a large part in selecting the correct rotary speed in any given situation.

The RPM applied to a bit will be a function of:

a) Type of bit: In general lower RPMs are used for insert bits than for milled tooth bits. This is to allow the inserts more time to penetrate the formation. The insert crushes a wedge of rock and then forms a crack which loosens the fragment of rock.

b) Type of formation: Harder formations are less easily penetrated and so require low RPM. A high RPM may cause damage to the bit or the drill string.

3.2. Mud Properties

WOP In order to prevent an influx of formation fluids into the wellbore the hydrostatic mud pressure must be slightly greater than the formation (pore) pressure. This overbalance, or positive pressure differential, forces the liquid portion of the mud (filtrate) into the formation, leaving the solids to form a filter cake on the wall of the borehole. In porous formations this filter cake prevents any further entry of mud into the formation. This overbalance and filter cake also exists at the bottom of the hole where it affects the removal of cuttings. [11] When a tooth penetrates the surface of the rock the compressive strength of the rock is exceeded and cracks develop, which loosen small fragments or chips from the formation. Between successive teeth the filter cake covers up the cracks and prevents mud pressure being exerted below the chip. The differential pressure on the chip tends to keep the chip against the formation. This is known as the static chip hold down effect, *(figure 5)* and leads to lower penetration rates.

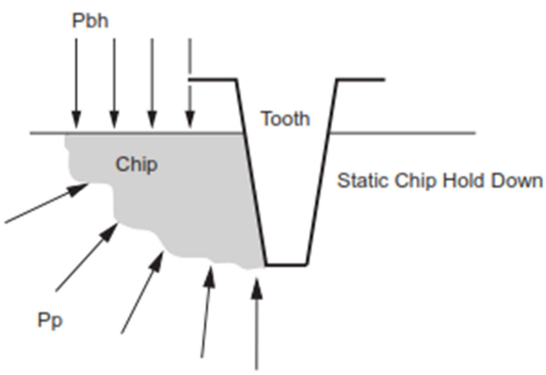

Figure 5. Static chip hold down effect.

The amount of plastering which occurs depends on mud properties. To reduce the hold down effect:

Reduce the positive differential pressure by lowering the mud weight (i.e. reduce the overbalance to the minimum acceptable level to prevent a kick).

Reduce the solids content of the mud (both clay and drilled solids). Solids removal is essential to increase drilling efficiency. In less porous formations the effect is not so significant since the filter cake is much thinner. However dynamic chip hold down effect may occur (*Figure 6*).

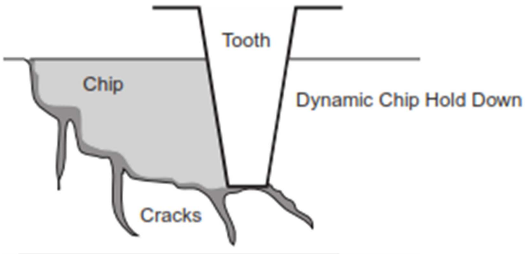

Figure 6. Dynamic hold down effect.

This occurs because when cracks form around the chip mud enters the cracks to equalize the pressure. In doing so, however, a pressure drop is created which tends to fix the chip against the bottom of the hole. The longer the tooth penetration, the greater the hold down pressure. Both static and dynamic hold down effects causes bit balling and bottom hole balling. This can be prevented by ensuring correct mud properties (e.g. mud weight and solids content).

3.3. PDC Bits Performance Evaluation

1. WOB/RPM

PDC bits tend to drill faster with low WOB and high RPM. They are also found to require higher torque than roller cone bits. The general recommendation is that the highest RPM that can be achieved should be used. Although the torque is fairly constant in shale sections the bit will tend to dig in and torque up in sandy sections. When drilling in these sandy sections, or when the bit drills into hard sections and penetration rate drops, the WOB should be reduced but should be maintained to produce a rotary torque at least equal to that of a roller cone bit. Too low a WOB will cause premature cutter wear, possible diamond chipping and a slow rate of penetration.

2. Mud Properties

The best ROP results have been achieved with oil based muds but a good deal of success has been achieved with water based muds. Reasons for the improved performance in oil based muds has been attributed to increased lubricity, decreased cutter wear temperature and preferential oil wetting of the bit body. The performance of PDC bits in respect to other mud properties is consistent with that found with roller cone bits i.e. increase in mud solids content or mud weight decreases ROP.

3. Hydraulic Efficiency

The effects of increased hydraulic horsepower at the bit are similar to their effect on roller cone bits. However manufacturers will often recommend a minimum flowrate in an attempt to ensure that the bit face is kept clean and cutter temperature is kept to a minimum. This requirement for flowrate may adversely affect optimization of HHP.

3.4. Drilling Bits Performance Optimization

Drilling bits performance optimization is the logical process of analyzing the effects and interaction of drilling variables through mathematical modeling to achieve maximum drilling efficiency (Nwani O. J 2011). The process involves the post appraisal of offset well record to determine the cost effectiveness of selected control variables, which include mud type, hydraulics, bit type, weight on bit and rotary speed. The variables that offer the best potential for improving the drilling process are identified. A final optimized drilling program is prepared and then will be implemented in the field. Flexibility should be built into the program to allow field application changes that may be dictated when unexpected problems are encountered. There is no such thing as a 'true' optimum drilling program; invariably compromises must be made because of limitations beyond our control that result in something less than optimum. Perhaps it can be explained this way; for years it has been known that rate of penetration could be increased by drilling with water, by rotating the bit faster, and by increasing flow velocity through jets in the bit. Lack of sufficient mechanical and hydraulic horsepower, however, often prevents the proper balancing of variables to obtain maximum drilling efficiency (Nwani O. J 2011).

4. Model Discussion

4.1. Matching the Area Average Performance Method of Drilling Bits Performance Optimization

Cost per Foot Equation

Cost calculations are necessary when comparing less expensive milled tooth bits with tungsten carbide insert bits. The basic cost per foot equation can be presented as follows:

$$C_1 = \frac{B1 + R1\,(T1 + t)}{F1} \tag{3}$$

Where:

C_1= cost per foot using control bit (dollars/ft)

B_1 = cost of control bit (dollars)

R_1 = rig cost or operating rate (dollars/hr)

T_1 = rotating time for control bit (hr)

T = round trip time (hr)

F_1 = footage drilled by control bit (ft).

According to [12] Wardlaw 1981, the average area performance is an easy, beneficial approach to optimizing drilling performance by selecting drilling parameters such as bit type, weight, and rotary speed to ensure that drilling rates and cost per foot will match the area average.

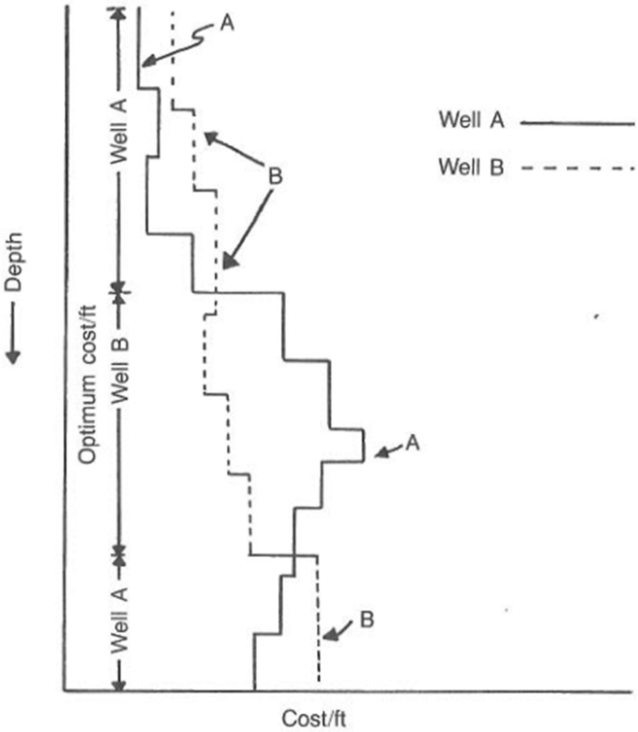

Figure 7. Bit selection based on minimum cost analysis from offset wells A & B after Wardlaw 1981.

The procedure for this technique is given below:

1. Select the offset control wells.
2. Obtain bit records from the offset wells.
3. Determine the rig cost for the prospect well.
4. Calculate the drilling cost for each bit run on the offset wells with equation 3 above
5. Select the conditions that gave the lowest cost-per-foot results.

Computer programs, such as [13] Adams and Rountree Technology's CSTSUM (cost sum) program can reduce the required time for the calculations to a few minutes. A plot of the COST SUM results is very useful. As an example, assume that Wells A and B are the offset control wells for a prospect. The cost calculations are made and plotted in *Figure 7* above. From the plot, it is clear that Well A had lower drilling costs in the upper and lower sections of the well, while Well B was optimum in the middle sections of the well. Therefore, the bit types, weight, and rotary speeds for the prospect well should be similar to Wells A and B in the respective hole segments in which they had the lowest cost-per-foot results.

4.2. General Optimized Drilling Assumptions and Guidelines

According to Wardlaw 1981, the concept of optimization is based on the following guidelines and assumptions:

All drilling variables are interrelated; changes in one variable affect all the others.

The type, amount and colloidal size of clay solids are the factors on which all other variables depend.

For effective optimization, variable analysis should be approached in the following order:

1. Mud solids and type
2. Mud flow properties for hole cleaning and stabilization
3. Hydraulics (bit cleaning, hole cleaning stability)
4. Bit type
5. Weight – rotary speed conditions for bit selected.
6. Consistent application of optimization techniques during drilling operations.

Mathematically, the drilling variables can be classified as alterable or unalterable in the table below.

Table 1. Alterable and Unalterable Drilling Variables.

Alterable	Unalterable
Mud	Weather
Type	Location
Solids Content	Rig Conditions
Viscosity	Rig Flexibility
Fluid Loss	Corrosive Borehole Gases
Density	Bottom-hole Temperature
Hydraulics	Round-trip Time
Pump Pressure	Rock Properties
Jet Velocity	Characteristic Hole Problems
Circulating Rate	Water Availability
Annular Velocity	Formation to be Drilled
Bit Type	Crew Efficiency
Weight-on-bit	Depth
Rotary Speed	

The classification is not strict, as some of the unalterable ones may be altered by a change in the alterable ones. For example, changes in bit type, resulting in a faster penetration rate through a particular formation. Changing the drilling fluid and bit type has altered the compressive and tensile strength of the rock-drilled remains constant, but the rock's drilling properties. Of course, there is considerable interdependence among the alterable variables. For instance, the type and amount of solids considerably influence mud viscosity and fluid loss. The weight-rpm combination is interrelated; an increase in one may necessitate a reduction in the other for smooth economical operation. In considering which variables to choose for mathematical optimization, experience and research suggest six: four alterable ones and two unalterable ones.

Table 2. Variables for Drilling Optimization.

Alterable	Unalterable
Mud	Formation to be Drilled
Hydraulics	Depth
Bit Type	
Weight-rpm	

The basic interactive effects between these variables were determined by factorial design experiments. Variable interactions exist when the simultaneous increase of two or more variables does not produce an additive effect as compared with the individual effects.

5. Data Design

The bit record data used in this article is offset drilling information containing data relative to the actual drilling operation that took place in both SOKU 56 and AGBADA 1 wells located at southeastern on-shore of the Niger Delta region of Nigeria. The main body of the bit record provides the following details: Number and type of bits, Jet sizes, Footage and drill rates per bit, Bit weight and rotary operating conditions, Hole deviation, Pump data mud properties, Dull bit grading, and Comments. The data was sourced from interaction with the industrial personnel of Annajul Rosari Nigeria Limited and from their bit record data documentation. Other sources of data include: industrial journals, newsletters, textbooks internet and general reference material.

In order to realize the objective of this article, footage and drill rates per bit, bit weight and rotary operating conditions will be used to analytically optimize the drilling performance and so save cost during drilling campaign in the Niger Delta region. The procedure to be used is MATCHING THE AREA AVERAGE PERFORMANCE already mentioned earlier.

The bit records from these wells will be used to select an optimum bit program for minimum cost drilling for any prospect well in the region.

5.1. Data Sampling Procedure

The bit record obtained from Annajul Rosari Nigeria Limited is a documented record of bits used in the company and their performances in various wells drilled in the Niger Delta region. The information gathered from the two wells is summarized in the table below.

Table 3. Bit Record Summary of the two offset wells.

S/N	Operator	Well Name	Depth (Ft)	Bit Sizes (Inches)	Rig Cost ($/Day)	Date Run
1	Shell	Soku 56	16,000	17.5, 12.25, 8.50	6,900	Aug. To Dec. 2010.
2	Shell	Agbada 1	17,654	17.5, 12.25, 8.50	6,900	Feb. To June 2010.

(Source: [14] Annajul Rosari Nigeria Limited 2001)

5.2. Data Analysis

As earlier mentioned, matching the area average performance method – a drilling optimization technique is used for the data evaluation, analysis and interpretation in this study (Wardlaw, H. W. R. 1981). Computer programs such as Adams and Rountree Technology's CSTSUM (cost sum) program can be used to reduce the required time for the calculations. This method requires less effort and can save up to 10 – 30% in actual rotating costs.

6. Presentation, Analysis and Interpretation

This section shows the tabulation and graphical presentation, analysis, comparisons and interpretations of the sample bit records of the two wells: Soku 56 and Agbada 1.

6.1. Data Presentation

The data presentation for SOKU 56 well is shown in the table below:

Table 4. The Offset Bit Record for Soku 56 Well.

ANNAJUL ROSARI BIT RECORDS									
OPERATOR: SHELL			WELL NAME: SOKU 56			DATE RUN: AUG 8, 2010 TO DEC 12, 2010			
Bit run	Size (in)	Type	Cost ($)	Depth out (ft)	Interval (ft)	Rotating Hours	Wob (lb)	Trip time (hr)	Remarks
1	17.50	OSC3A	5,062	4,435	4,435	78.50	5	4.6	
2	12.25	X3A	2,516	5,867	1,432	37.50	10	6.2	
3	12.25	X3A	2,516	6,907	1,040	18	20	7.0	
4	12.25	SII	2,516	7,752	845	27.50	15	7.5	
5	12.25	FDT	3,052	9,048	1,296	46.50	10	8.1	
6	12.25	FDT	8,399	9,509	461	22	40	8.6	
7	12.25	884F	4,377	11,005	1,496	88	20	9.2	
8	8.50	J22	4,377	12,769	1,764	104.50	30	7.2	
9	8.50	FP53	4,377	12,985	216	33	22	7.7	
10	8.50	F20	4,377	13,230	245	30	10	7.9	
11	8.50	Y12	1,101	13,595	365	32	15	8.0	

ANNAJUL ROSARI BIT RECORDS									
OPERATOR: SHELL			WELL NAME: SOKU 56			DATE RUN: AUG 8, 2010 TO DEC 12, 2010			
Bit run	Size (in)	Type	Cost ($)	Depth out (ft)	Interval (ft)	Rotating Hours	Wob (lb)	Trip time (hr)	Remarks
12	8.50	J22	4,377	13,714	119	11.50	10	8.2	
13	8.50	J22	4,377	14,519	805	75	12	8.5	
14	8.50	J22	4,377	14,797	278	21	10	8.8	
15	8.50	J22	4,377	15,600	803	63.50	12	9.1	
16	8.50	J22	4,377	15900	300	29	10	9.4	
17	8.50	J22	4,377	16714	814	86.50	12	9.7	
18	8.50	J22	4,377	16716	2	5	10	10.0	
19	8.50	J22	4,377	17171	455	77	3	10.1	
20	8.50	J22	4,377	17,654	483	53	3	10.4	

B. AGBADA 1: The offset bit record for this well shows the operating conditions of the bits used in drilling the well from February 10, 2010 to June 23, 2010.

Table 5. The Offset Bit Record for Agbada 1 Well.

ANNAJUL ROSARI BIT RECORDS									
OPERATOR: SHELL			WELL NAME: AGBADA 1			DATE RUN: FEB. 8, 2010 TO JUN. 23, 2010			
Bit Run	Size (in)	Type	Cost ($)	Depth (ft)	Interval (Ft)	Rotating hours	WOB (lb)	Trip Time (hr)	Remarks
1	17.50	X3A	7422	3500	3500	36	10	4.3	
2	12.25	X3A	2,516	5320	1820	26	15	5.8	
3	12.25	X3A	2,516	6748	1428	28	20	6.7	
4	12.25	X3A	2,516	6837	89	6	10	7.2	
5	12.25	X3A	2,516	7573	736	32	15	7.4	
6	12.25	X3A	2,516	8097	525	30	20	7.8	
7	12.25	J22	8333	9442	1344	80	25	8.3	
8	12.25	J22	8333	10600	1158	82	10	9.0	
9	8.50	J22	4,377	11387	787	78	10	6.6	
10	8.50	J22	4,377	11407	20	10	5	6.9	
11	8.50	J22	1,101	12252	845	95	15	7.1	
12	8.50	J22	4,377	12720	468	45	10	7.5	
13	8.50	J22	4,377	13103	383	45	5	7.8	
14	8.50	J22	4,377	13470	367	40	5	8.0	
15	8.50	J22	4,377	13655	185	20	5	8.1	
16	8.50	J22	4,377	13745	90	18	10	8.2	
17	8.50	J22	4,377	14017	272	30	15	8.3	
18	8.50	Diamond	14,875	14469	450	150	10	8.5	
19	8.50	Diamond	14,875	15139	672	160	5	8.9	
20	8.50	J22	4,377	16000	861	98	5	9.3	

A. SOKU 56: The bit record for the well shows the operating conditions of the bits used in drilling the well from August 8, 2010 to December 12, 2010.

6.2. Data Analysis

Data A and B can be analyzed by using Cost per foot equation and also obtaining the cumulative section costs:

Cost per foot:

Cost per foot for each bit is

$$\$/\text{ft} = \frac{C_B + C_R T_R + C_R T_T}{Y}$$

Where: $/ft =cost per foot, dollars

C_B = bit cost, dollars

C_R = rig cost, dollars/hr

T_R = rotating time, hr

T_T = trip time, hr

Y = footage per bit run.

For Soku 56

The cost for the first bit run of the Soku 56 well is:

$$\$/\text{ft} = \frac{5{,}062 + (6900/24)(78.5) + (6900/24)(4.6)}{4{,}435}$$

$$= \$6.53/\text{ft}$$

The cumulative cost for the first bit = $6.53/ft x 4435

= $28961.

For Agbada 1

The cost for the first bit run of the Agbada 1 well is:

$$\$/\text{ft} = \frac{7422 + (6900/24)(36) + (6900/24)(4.3)}{3500}$$

$$= \$5.43/\text{ft}$$

The cumulative cost for the first bit = $5.43/ft x 3500

= \$19009.

Penetration Rates:

The required penetration rate can also be obtained from the cost per foot equation below:

$$C = \frac{C_B + C_R T_T + C_R T_R}{(\text{Rotating hours})(PR)}$$

Where: PR = penetration rate in ft/hr

R_T = rotary time in hours

$$PR = \frac{C_B + C_R T_T + C_R T_R}{C \times (\text{Rotating hours})} \text{ft/hr}$$

For the first bit in Soku 56 well, penetration rate is:

$$PR = \frac{5062 + (6900/24)(78.5) + (6900/24)(4.6)}{6.54 \times 78.5}$$

PR = 56.5 ft/hr.

For the first bit in Agbada 1 well, penetration rate is:

$$PR = \frac{7422 + (6900/24)(36) + (6900/24)(4.3)}{5.43 \times 36}$$

PR = 97.23 ft/hr.

The cost per foot and penetration rates obtained per bit for the selected 20 bit runs in both offset wells are summarized for the final analyses and presented below.

Table 6. Cost per foot Summary for Soku 56 Well.

Bit					Depth Out (ft)	Interval (ft)	Rotating Hours	ROP (ft/hr)	Trip Time (hr)	Run Cost \$	Cost per Foot \$/ft	WOB (lb)
Run	Size Inches	Type	IADC Code	Cost \$								
1	17.50	OSC3A	1,1,1	5062	4435	4435	78.5	56.50	4.6	28940	6.53	5
2	12.25	X3A	1,1,4	2516	5867	1432	37.5	38.2	6.2	15091	9.32	20
3	12.25	X3A	1,1,4	2516	6907	1040	18	57.8	7.0	9689	14.88	20
4	12.25	511	1,1,4	2516	7752	845	27.5	30.7	7.5	12577	14.47	15
5	12.25	FDT	1,2,6	3052	9048	1296	46.5	27.9	8.1	18752	25.71	10
6	12.25	584F	5,1,7	3052	9509	461	22	21	8.6	11854	24.28	40
7	12.25	584F	5,1,7	8388	11005	1496	88	17	9.2	36327	20.68	20
8	8.50	J22	5,1,7	4377	12769	1764	104.5	16.9	7.2	36477	20.68	30
9	8.50	FP53	5,3,7	4377	12985	216	33	6.5	7.7	16088	74.48	22
10	8.50	F20	5,1,7	4377	13230	245	30	8.2	7.9	15264	62.30	10
11	8.50	Y12	1,2,1	4377	13595	365	32	11.4	8.0	15891	43.54	15
12	8.50	J22	5,1,7	1101	13714	119	11.5	10.3	8.2	6762	56.82	10
13	8.50	F30	5,1,7	4377	14519	805	75	10.7	8.5	28372	35.24	12
14	8.50	J22	5,1,7	4377	14797	278	21	13.2	8.8	12939	46.54	10
15	8.50	J22	5,1,7	4377	15600	803	63.5	12.6	9.1	25249	31.44	12
16	8.50	J22	5,1,7	4377	15900	300	29	10.3	9.4	15423	51.41	10
17	8.50	J22	5,1,7	4377	16714	814	86.5	9.4	9.7	32048	39.37	12
18	8.50	J22	5,1,7	4377	16716	2	5	0.4	10	8686	4342.99	10
19	8.50	J22	5,1,7	4377	17171	455	77	5.9	10.1	29425	64.67	3
20	8.50	J22	5,1,7	4377	17654	483	53	9.1	10.4	22604	46.80	3

Table 7. Cost per Foot Summary for the Agbada 1 Well.

Bit					Depth Out (ft)	Interval (ft)	Rotating Hours	ROP (ft/hr)	Trip Time (hr)	Run Cost	Cost/ Foot \$/ft	WOB (lb)
Run	Size (in.)	Type	IADC Code	Cost \$								
1	17.50	X3A	1,1,4	7422	3500	3500	36.0	97.2	4.3	19008	5.43	10
2	12.25	X3A	1,1,4	2516	5320	1820	26.0	70.0	5.8	11662	6.41	15
3	12.25	X3A	1,1,4	2516	6748	1428	28.0	51.0	6.7	12506	8.76	20
4	12.25	X3A	1,1,4	2516	6837	89	6.0	14.8	7.2	6307	70.26	10
5	12.25	X3A	1,1,4	2516	7573	736	32.0	23.0	7.4	13850	18.62	15
6	12.25	X3A	1,1,4	2516	8098	525	30.0	17.5	7.8	13379	25.48	20
7	12.25	J22	5,1,7	8388	9442	1344	80.0	16.8	8.3	33781	25.13	20
8	12.25	J22	5,1,7	8388	10600	1158	82.0	14.1	9.0	34563	29.85	25
9	8.50	J22	5,1,7	4377	11387	787	78.0	10.1	6.6	28707	36.48	10
10	8.50	J22	5,1,7	4377	11407	20	10.0	2.0	6.9	9225	461.26	10
11	8.50	J22	5,1,7	4377	12252	845	95.0	8.9	7.1	33736	39.92	5
12	8.50	J23	5,3,7	4377	12720	468	45.0	10.4	7.5	19472	41.61	15
13	8.50	J23	5,3,7	4377	13103	383	45.0	8.5	7.8	19544	51.03	10
14	8.50	J23	5,3,7	4377	13470	367	40.0	9.2	8.0	18169	49.51	5
15	8.50	J23	5,3,7	4377	13655	185	20.0	9.2	8.1	12466	67.38	5
16	8.50	J55	6,3,7	4377	13745	90	18.0	5.0	8.2	11914	132.38	5
17	8.50	J33	5,3,7	4377	14017	272	30.0	9.1	8.3	15395	56.60	10
18	8.50	PDC	D,1,0,0	14875	14467	450	150.0	3.0	8.5	60454	134.34	15
19	8.50	PDC	D,1,0,0	14875	15139	672	160.0	4.2	8.9	63424	94.38	10
20	8.50	J22	5,1,7	4377	16000	861	98.0	8.8	9.3	35230	40.92	5

6.3. Data Interpretation

The data will be interpreted graphically for the two wells from the following five graphs namely:

1. Depth (feet) versus cost per foot ($/foot).
2. Depth (feet) versus Total Run Cost ($).
3. Rate of Penetration (foot/hour) versus Weight on Bit (pounds)
4. Rotating hours versus Depth (feet)
5. Depth (feet) versus Rate of Penetration (foot/hour).

Table 8. Cost per foot versus Depth.

Soku 56	Soku 56	Agbada 1	Agbada 1
Cost per foot	**Depth**	**Cost per foot**	**Depth**
6.53	4435	5.43	3500
9.32	5867	6.41	5320
14.88	6907	8.76	6748
14.47	7752	70.26	6837
25.71	9048	18.62	7573
24.28	9509	25.48	8098
20.68	11005	25.13	9442
20.68	12769	29.85	10600
74.48	12985	36.48	11387
62.3	13230	461.26	11407
43.54	13595	39.92	12252
56.82	13714	41.61	12720
35.24	14519	51.03	13103
46.54	14797	49.51	13470
31.44	15600	67.38	13655
51.41	15900	132.38	13745
39.37	16714	56.6	14017
4342.99	16716	134.34	14467
64.67	17171	94.38	15139
14.80	17654	40.92	16000

Case 1: Depth (feet) versus Cost per foot ($/ft)

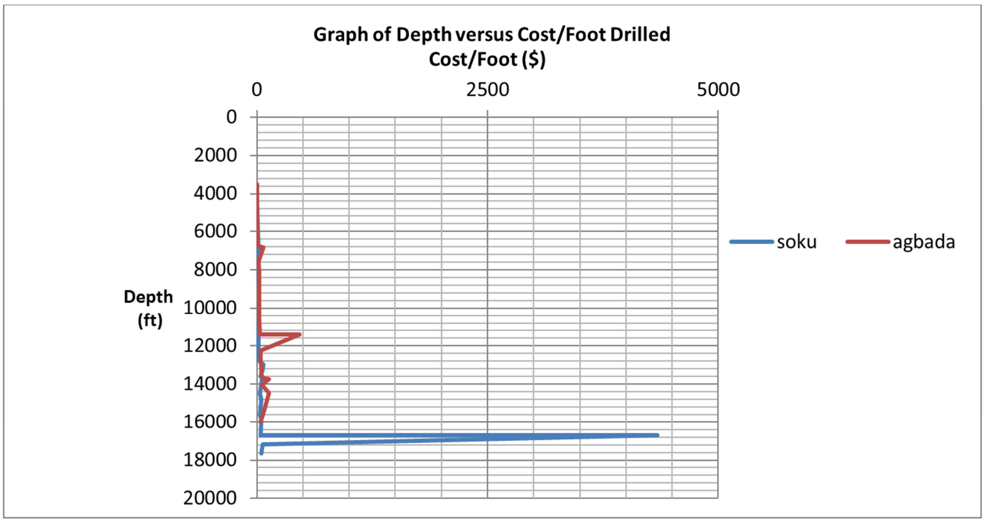

Figure 8. Cost comparison between Soku 56 and Agbada 1 Wells.

Table 9. The relationship between Depth drilled and Cumulative cost.

Soku 56	Agbada 1	Soku 56	Agbada 1
Depth (ft)	**Depth (ft)**	**Cum. Cost $**	**Cum. Cost $**
4435	3500	28940	19008
5867	5320	44031	30670

Soku 56	Agbada 1	Soku 56	Agbada 1
Depth (ft)	**Depth (ft)**	**Cum. Cost $**	**Cum. Cost $**
6907	6748	53720	43176
7752	6837	66297	49483
9048	7573	85049	63333
9509	8098	96903	76712
11005	9442	133230	110493
12769	10600	169707	145056
12985	11387	185795	173763
13230	11407	201059	182988
13595	12252	216950	216724
13714	12720	223712	236196
14519	13103	252084	255740
14797	13470	265023	273909
15600	13655	290272	286375
15900	13745	305695	298289
16714	14017	337743	313684
16716	14467	346429	374138
17171	15139	375854	437562
17654	16000	398458	472792

Case 2: Depth Out versus Cumulative cost.

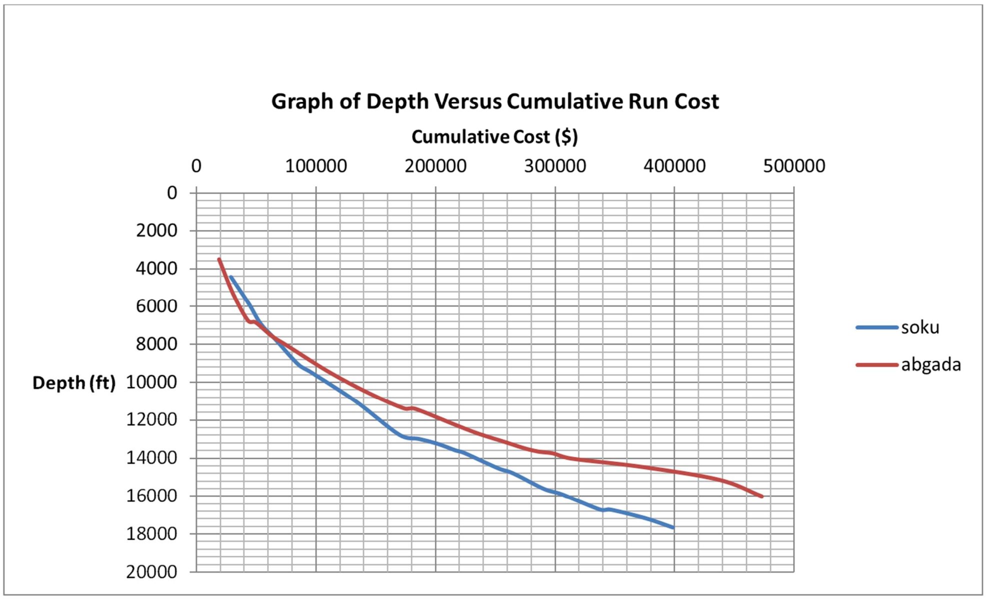

Figure 9. Depth (ft) versus Cumulative Cost ($) for the two Wells.

Table 10. Relationship between ROP and WOB for the two wells.

Soku 56	Agbada 1	Soku 56	Agbada 1
Cum. ROP	**Cum. ROP**	**Cum. WOB**	**Cum. WOB**
56.5	97.2	5	10
94.7	167.2	25	25
152.5	218.2	45	45
183.2	233	60	55
211.1	256	70	70
232.1	273.5	110	90
249.1	290.3	130	115
266.1	304.4	160	125
283	314.5	182	135
289.5	316.5	192	140
300.9	325.4	207	155
311.2	335.8	217	165

Soku 56	Agbada 1	Soku 56	Agbada 1
Cum. ROP	Cum. ROP	Cum. WOB	Cum. WOB
321.9	344.3	229	170
335.1	353.5	239	175
347.7	362.7	251	180
358	367.7	261	190
367.4	376.8	273	205
367.8	379.8	283	215
373.7	384	286	220
382.8	392.8	289	225

Case 3: Cumulative ROP versus Cumulative WOB.

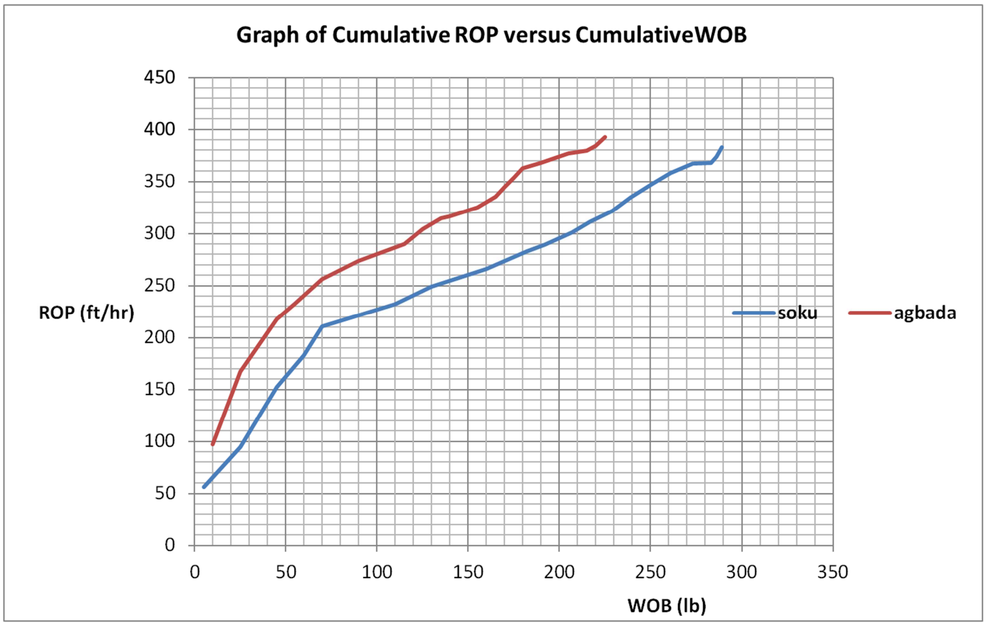

Figure 10. ROP versus WOB for the two wells.

Table 11. Relationship between Depth and ROP.

Soku 56	Agbada 1	Soku 56	Agbada 1
Depth (ft)	Depth (ft)	ROP ft/hr	ROP (ft/hr)
4435	3500	56.5	97.2
5867	5320	38.2	70
6907	6748	57.8	51
7752	6837	30.7	14.8
9048	7573	27.9	23
9509	8098	21	17.5
11005	9442	17	16.8
12769	10600	16.9	14.1
12985	11387	6.5	10.1
13230	11407	8.2	2
13595	12252	11.4	8.9
13714	12720	10.3	10.4
14519	13103	10.7	8.5
14797	13470	13.2	9.2
15600	13655	12.6	9.2
15900	13745	10.3	5
16714	14017	9.4	9.1
16716	14467	0.4	3
17171	15139	5.9	4.2
17654	16000	9.1	8.8

Case 4: Depth versus Rate of Penetration.

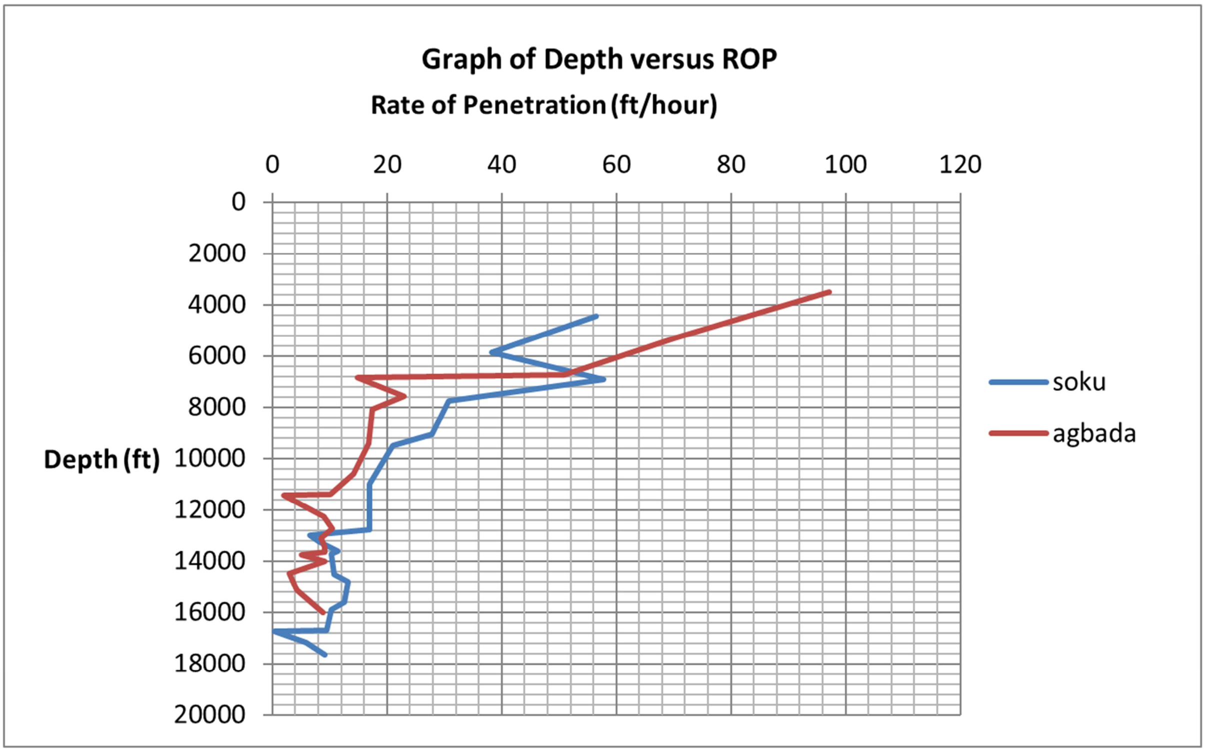

Figure 11. Depth (ft) versus Rate of Penetration (ft/ hr) for the two wells.

Table 12. Relationship between Depth and Rotational hours.

Soku 56	Agbada 1	Soku 56	Agbada 1
Rotational Hrs	**Rotational Hrs**	**Depth (ft)**	**Depth (ft)**
78.5	36	4435	3500
116	62	5867	5320
134	90	6907	6748
161.5	96	7752	6837
208	128	9048	7573
230	158	9509	8098
318	238	11005	9442
422.5	320	12769	10600
455.5	398	12985	11387
485.5	408	13230	11407
517.5	503	13595	12252
529	548	13714	12720
604	593	14519	13103
625	633	14797	13470
688.5	653	15600	13655
717.5	671	15900	13745
804	701	16714	14017
809	851	16716	14467
886	1011	17171	15139
939	1109	17654	16000

Case 5: Depth versus Rotational Hours

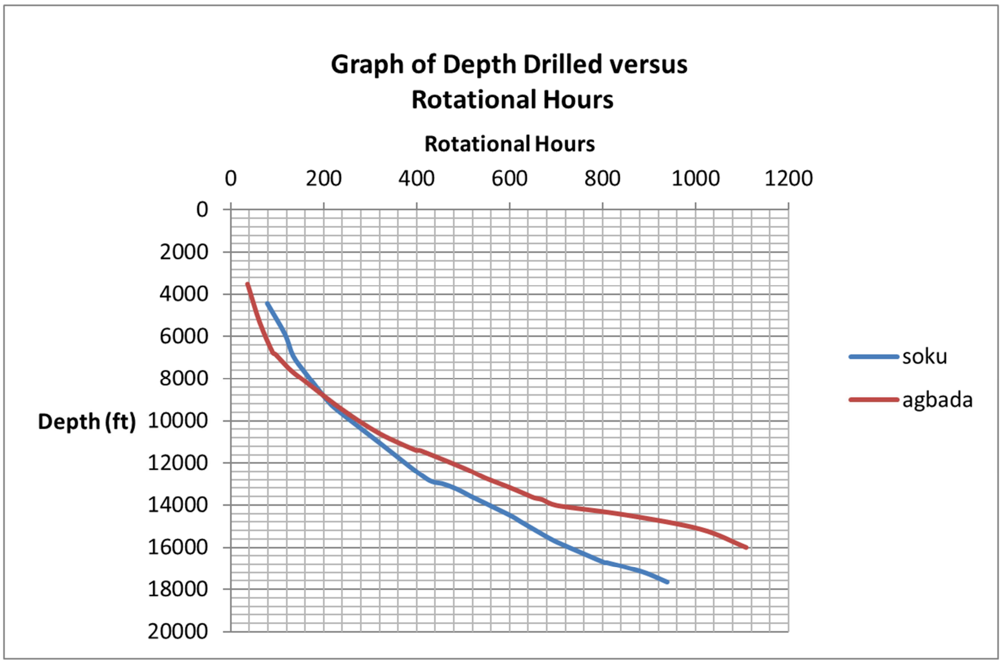

Figure 12. Depth drilled versus Rotational hours for the two wells.

7. Summary of Findings, Conclusion and Recommendations

7.1. Summary of Findings

The summary of findings from the graphs above is as follows:

Case 1: observations from the figure 8 above shows that Agbada 1 well has lower drilling costs in the upper and the lower parts of the well. Its optimum cost per foot is at the depth of 11,407 ft. The cost per foot at that depth is $461.26/ft. Therefore the total cost at the depth is $526,159.82. For Soku 56 well, it has lower drilling costs at upper part of the dwell up to a depth of 16714 ft. Its optimum cost per foot value escalated to $4342.99/ft at a depth of 16715ft, which gives a total cost of $72,588,734.86

Case 2: observations from Figure 9, shows that the Cumulative run Cost for each bit in Agbada 1 well increases in a gentle slope from the beginning of the well to the finishing. While for Soku 56, the Cumulative run Cost increases gently at the start of the well but increases uncontrollably close to the end of the well.

Case 3: observations from Figure 10 shows that operating conditions and Rotary speed (ROP) for Agbada 1 showed a uniform slope as the weight on bit (WOB) increases. This shows that the drilling was done in a more careful way. But for Soku 56 well, ROP increases linearly as the weight on bit (WOB) increases until a sharp break at ROP 2321ft/hr when the WOB was 110klbf. It then increases steeply until the end of the well.

Case 4: From figure 11, it is observed that a significant change occurred at a depth of approximately 6840 ft. It remained uniform and then disrupted up to the end of the well. For Soku 56 well, the ROP vs. Depth relationship is not uniform at all.

Case 5: the observation from Figure 12, shows that the rotational hours for Soku 56 well is uniform and increases cumulatively down the well while for that of Agdada 1 well, a trend is noticed close the end of the well at a depth of approximately 15140 ft showing a rapid increase in rotational hours.

7.2. Conclusion

Based on minimum cost analysis from offset wells, of Agbada 1 and Soku 56, bit selection, weight and rotary speeds for the next prospect well should be similar to the two wells in the respective hole segment in which they have the lowest cost. But from the analysis already carried out, it can be seen that drilling Agbada 1 well proved to be more economical and time saving. Therefore, the driller should select bit type, and run operating conditions of the next prospect well to be similar to Agbada 1 well so as to achieve the objective of drilling bits optimization.

7.3. Recommendation

Since the lithology of Niger Delta is unalterable, it is wise to use information from these offset offset wells in the same area which has been drilled economically to drill a prospect well. For a wild cat well, the driller should fully follow all the recommended operating parameters for each type of bit selected for drilling so that the bit life will be ensured.

This study is also a call on both bit manufacturers to try and digitize a program for the bit in such a way as to be able to drill alternatively through different formation, by bringing forward the soft formation teeth of the bit when it encounters soft formation, medium formation bit teeth for medium formation and hard formation teeth for a hard formation respectively. This can be achieved by in-depth study of the geology of the formation. It is also recommended that the various drilling companies/manufacturers should always make their drilling data available most especially for students and researchers for further contribution to the field drilling technology. The mind should be reoriented from the traditional method of selecting bits randomly by trial and error or by experience rather a proper guard of selection should be encouraged so as to have the best drilling bit performance for minimum cost and maximum profit.

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