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Mud programs and drilling problems pertaining to the tertiary Clays and Shales, Norwegian Northsea

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ABSTRACT

Problems encountered in drilling Tertiary clays and shales in the southern part of the Norwegian Continental Shelf and the mud system most frequently used in this area, are reviewed in this paper.

Severe viscosity problems frequently arise while drilling the top 10,000 feet of hole, which predominantly consists of clays and shales, and are the direct cause of several problems like swabbing formation; blocking of flowlines and shaker screens by very soft sticky clay; sticking of drill pipe; and bit and collar balling.

The viscosity problems are the result of lack of solids removal equipment, the dispersing type drilling fluid used which makes the solid separation more difficult, and the facts that the lower 5,000 feet of formation is overpressured, behaves plastically, and has a high montmorillonite content.

A salt solution base mud is discussed as an alternative to the commonly used lignosulfonate system. Hydration tests of formation samples in various salt solutions indicate that low density solid content in the drilling fluid might be controlled more economically by the use of a salt water base mud and centrifuges and fine screen shakers. To date mud properties have partially been controlled in the unsatisfactory manner of discarding old mud and making up new mud.

It is concluded that a saving of 25% on the cost of barite alone seems possible with a salt solution base mud. More important however, are the potentials for reducing rig time and consequently cost.

References and illustrations at end of paper.

INTRODUCTION

This study presents mud programs and drilling problems pertaining to the Tertiary clays and shales in the southern part of the Norwegian Continental Shelf (see Fig. I).

Difficulties in maintaining desired drilling fluid properties have frequently been experienced, and controlled drilling with limited penetration rate has consequently been necessary. This results in increased rig time, which is costly, in addition to the mud system, which in itself is expensive due to continuous dumping and dilution of mud and addition of chemicals and weight materials. The fluid properties of the mud system most commonly used, are presented in this paper.

Factors affecting the fluid properties are the chemical composition of the drilling fluid, formation characteristics and solids removal equipment available. These factors are discussed with reference to the area mentioned above, and suggestions for improvements are made.

The latter portion of this paper presents average cost figures for the type mud used to date, and an estimate of probable savings that can be achieved taking new equipment and chemicals into consideration.

MUD PROPERTIES

The drilling fluid most commonly used to penetrate the Tertiary shales and clays in the southern part of the Norwegian North Sea consist of a weighted sea water base lignosulfonate system. Lignite has been added to help stabilize the system where bottom hole temperatures increase abnormally (generally below 5,000 feet) and caustic soda has been added to control the pH (Table I and II).

Fluid properties versus depth, for 15 wells, were plotted to obtain the average characteristics for this type of system and are considered separately in the following paragraphs.

A. Mud Weight

The mud weights now used are the results of a progressive development from lower to higher values, the outcome of which has been a reduction in the frequency of hole trouble. Using representative wells a curve has been constructed which provides an indication of the mud weights required in this area, (Fig. No. 3)

B. Solids Content

Based on the total solids content, and the corresponding mud weights of the drilling fluid, the fractions of low density solids (formation cuttings and bentonite) and high density solids (barite) were calculated and the following observations are made:* Firstly, the low density solids content was generally higher than desirable (i.e. 60 lbs/bbl. to 200 lbs/bbl.). Secondly, when correlating solids content data with mud weights for each individual well it was noted that increases and decreases in mud weights and solids content were found to follow each other fairly closely. The similarity between the solids content curve and the mud weight curve indicates constant low density solids content. Conversely, when the total solids content increases without a corresponding change in mud weight, an increase in low density solids, and a decrease in barite, occurred. The similarity between curves for the wells in the area of this study is generally not due to good mud control (i.e. continuous removal of low density solids) but is a result obtained by discarding large quantities of drilling fluid, dilution of the remaining drilling fluid with water, and the addition of barite. A solids content versus depth graph for a representative will is shown in Fig. 4.

C. Plastic Viscosity

A fluctuation of plastic viscosity and yield point values is mostly a reflection of the treatment of the mud at the surface and is not an indication of changes in the drilling fluid due to the formations penetrated. Generally plastic viscosity and yield point measurements show acceptable values, not because of good mud control, but are probably the result of water dilution and addition of mud materials to the system. Plastic viscosity and yield point are presented in graphical form in Figs. 5 and 6.

D. Gel Strength

Gel strength values have generally been higher than desirable. Values for the

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* A specific gravity for the low density solids of 2.65 and for the barite of 4.2 was assumed.

10 seconds/10 minutes gel strength have been in the order of 5/20 lbs/sq.ft. These higher gel strength values indicate a progressive gel, and have undoubtedly contributed to pressure surges and the swabbing in of shale when tripping and making connections.

E. Chloride Content

Generally wells have been drilled using a sea water base drilling fluid and the chloride content has averaged 25,000 and 30,000 p.p.m. A few wells have been drilled with pre-hydrated bentonite in fresh water having a chloride content of about 10,000 p.p.m. Drilling fluids in the wells drilled with a fresh water base mud show a noticeable increase in plastic viscosity below 5,000 feet, indicating a mud making formation. This hypothesis is confirmed by X-ray diffraction analysis of lower Tertiary shales (table III) which shows the montmorillonite content of the clays and shales to be approximately thirty-five percent.

F. Water Loss

Maintaining a low water loss as a precaution against swelling and sloughing of the formation into the bore-hole has not been a problem. Information available to the author indicates that High Temperature-High Pressure tests have not been routinely run in this area consequently no suppositions regarding the effects of these parameters can be made at this time.

G. Other Mud Characteristics

The oil content, pH and calcium ion concentration varies considerably from well to well and no specific correlation of these variables has been possible. It has been observed however, that there is apparently no correlation between drilling fluid problems and pH or calcium ion concentration.

SOLIDS SEPARATION

Using the conventional shale shaker alone is not adequate for solids removal Drilling experience has shown that when drilling soft and incompetent formations or 'gumbo' clays, fine screens tend to plug allowing a subsequent loss of drilling fluid and coarse screens allow the fines to be re-circulated in the mud system.

The introduction of fine and/or multiple screen shakers has generally improved solids separation. The motion generated by these types of shakers is such that finer screens may be used without being plugged. Mud centrifuges have gained wider usage during the last few years and have at times been found to be very effective for the reclamation of barite from drilling fluids.

FORMATION CHARACTERISTICS

Sonic, conductivity and density logs were plotted on a convenient format with measured shale densities. A very close correspondence was found between these plots, and they indicate that a low density/high pressure zone exists in the lower Tertiary (below 4,000-5,000 feet) and averages some 4,000 feet in thickness.[1,2] Figs. 7 and 8 are plots of the sonic and conductivity log readings through the shale and clay sections for a representative well. Gauge or under gauge holes, as evidenced by caliper curves, and high conductivity readings which are indicative of high liquid content in the shales and clays, support the belief that the formation has had a tendency to flow or swell resulting in tight hole and spalling.

LOW DENSITY SOLIDS BUILD UP

Three major factors contribute to the build up of low density solids in the drilling fluid.

Firstly, the hydration and swelling of montmorillonite in the formation, and the extrusion of shale into the well bore, increase the amount of solids that must be removed from the mud. Secondly, highly pressurized shale and clay cuttings circulated to the surface tend to expand and disintegrate due to a reduction of hydrostatic pressure. Thirdly, chemcially aided disintegration of cuttings occurs due to dispersants used in the drilling fluid.

GENERAL OBSERVATIONS

Several types of problems have been experienced in using a lignosulfonate mud system to drill lower Tertiary shales. The most prevalent difficulty encountered has been the control of mud properties because of rapid build up of low density solids, the immediate consequences of which are: high yield points and high plastic viscosities; swabbing in of shales and/or clays; partial collapse of the wellbore when tripping; and the blocking of flowlines and shaker screens by very soft sticky clay. The net result of this has generally been a considerable loss of mud through the bell nipple, and over the shale shaker. Other related problems are: the sticking of drill pipe; bit and collar balling; and pipe drag. These problems are generally reduced by:

(a) Using higher mud weights

(b) Limiting penetration rate.

(c) Discarding large quantities of mud and adding water, chemicals and weight material to the remaining system.

Higher mud weights have been employed to stabilize the well-bore. While this method is often effective, it generally results in slower penetration rates. Reducing penetration rate in order to allow more time to conveniently condition the drilling fluid and treat out low density solids may partially alleviate the problem at hand. However, subsequent mud costs are generally higher, and valuable rig time may be lost. Discarding mud and adding water and chemicals to the remaining system would appear to be the least desirable method of controlling low density solids in the drilling fluid. Not only is this method expensive, but possible problems regarding the sensitive area of pollution must also be considered.

OTHER MUD SYSTEMS

The effect of different mud systems on hydration and swelling of various types of shales has been discussed in previous literature.[3-6] Kelly recommends that an oil-phase mud be used for the soft, pliable formation with few fractures and containing moderate to large amounts of sodium or calcium montmorillonite. In retrospect however, the use of an oil-phase mud introduces a new problem inasmuch as the cuttings cannot be dumped overboard without a treatment that will prevent pollution. The cost of this treatment added to the cost of the oil-phase system would be prohibitive.

Of the various drilling fluids studied, an inhibitive system appears to be the most applicable. Various salt solutions were pilot tested (Table IV) to find a suitable chemical inhibitor. Due to a lack of cores in this interval, large cuttings and sidewall cores were used for these tests. The best inhibitor (Table IV) appears to be a sodium chloride saturated salt water solution. Potassium chloride and ammonium sulfate also gave good results, whereas diammonium phosphate did not. At this time further investigations regarding the use of various salts as inhibitors are being carried out.

A bio-polymer, prehydrated bentonite or attapulgite could be used to obtain viscosity with a salt solution mud. The bio-polymer would probably be the least expensive and the easiest to use from a mixing standpoint. However, the performance of the polymer as well as the various salts, can only be properly assessed under actual field conditions.

These systems can be tried out at very little extra cost or risk because they can easily be converted to the old type of system should they be considered unsatisfactory.

Stabilization of the well-bore has been partially achieved by the use of higher mud weights. An adjusted mud weight versus depth curve can be derived based on previous mud weights (Fig. 3) and electric log interpretations (Figs. 7 and 8). However, the geographical limits for the application of such a mud weight versus depth curve have not yet been determined. The abnormal pressure begins in the lower part of the Miocene and may be related to the thickness of the Miocene deposits. Abnormal pressure may be explained by assuming a fast rate of deposition and burial[7-10] during early Miocene time and in fact, the Miocene section is thicker in the high pressure wells than in the low pressure wells investigated for this study.

Stabilization of the well-bore may also be achieved by using an asphaltic fluid-loss control agent, Gilsonite has been used as such a agent by Amoco through similar formations** with very good results, A primary criticism concerning the use of gilsonite is that it adversely affects source rock measurements.

A fresh water base mud would be costly and probably could be avoided except in areas where its use is considered indispensable for formation evaluation purposes. Montmorillonite content in the high pressure zone can be in excess of 30% and the formation will be more likely to swell and create viscosity problems if a fresh water base mud is used.

COST CONSIDERATIONS

The installation of a fine or double screen shaker and a centrifuge will definitely improve solids control and can easily be economically justified. A centrifuge can be rented for less than $70 per day or approximately $4,200 for the time required to drill an average well. This additional cost would be offset by the savings in barite alone over a 24 hour period and pay for the entire rental cost.*

Maintaining low active surface volumes will reduce the amount of drilling fluid that will need treatment and also reducing cost, Reserve volumes of mud should be kept high for safety purposes.

The cost of barite for an average well to a depth of 10,000 feet is $84,000 (Fig. No. 9). This amount constitutes 65% - 80% of the total mud bill. Barite costs for a hypothetical well to the same depth with the proposed mud system are estimated at $62,000 (Appendix A). This figure represents a saving of $22,000 (or 26%) on the barite.

* A centrifuge could reclaim 1400 sacks of barite from a 13 lb/gal drilling fluid with 24% solids (160 lb/bbl. barite) in 24 hours.

** Hackberry Field, Louisiana

CONCLUSIONS

The proposed mud system will permit an increase of penetration rate and simultaneously reduce time needed to condition the drilling fluid. Savings in cost will result by reducing the barite consumption, but also from installing suitable solids removal equipment and using a salt base mud and avoiding dispersing agents.

More significantly however, are the possibilities for reducing rig time. The cost of drilling a well offshore (rig service equipment, workboats, etc.) ranges from $20,000 to $30,000 per day. The importance of saving one day of rig time to lower total well cost is vital to any exploration program.

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APPENDIX A

An estimate of the amount of barite needed to penetrate 10,000 feet of clays and shales in the southern portion of the Norwegian Continental Shelf (Fig. 1) is presented below. The estimate is based on the time it takes to drill an average well (Fig. 2). The following three assumptions are made:

1. Good solids control is achieved mechanically and a salt water base mud is used.

2. No Barite is used until 20" casing is set.

3. Maintenance mud volume for one section* will average 5% per day of the maximum mud volume needed in that section. This assumption has given good results in other areas.

1. ESTIMATED MUD VOLUMES

A. Drilling $17\frac{1}{2}$" hole to 5100 feet. 20" casing set at 1200 feet.

1200' of 20" casing	500 barrels
3900' of $17\frac{1}{2}$" hole	1300 barrels
Surface system	600 barrels
Volume at 5100'	2400 barrels
Maintenance- 5% per day for 6 days	700 barrels
	3100 barrels
Total volume needed Section A	3100 barrels

B. Drilling 12 1/4" hole to 10100 feet
13 3/8" casing set at 5000 feet

5000' of 13 3/8" casing	800 barrels
5100' of 12 1/4" hole	900 barrels
Surface mud	500 barrels
Volume at 10100 feet	2200 barrels
Maintenance 5% per day for 10 days	1100 barrels
Total volume needed Section B	3300 barrels

* A section meaning a portion of the hole between two casing shoes.

II. ESTIMATED BARITE CONSUMPTION

A 13 lbs/gal mud is assumed for Section A and a 14.5 lbs/gal mud for Section B.

Furthermore it is assumed that 1000 barrels of the mud from Section A (13 lbs/gal) can be weighed up and used in Section B.

	Barite needed (1sack=100 lbs)
A. 3100 bbl weighted up from 9 - 13 lbs/gal	8200 sacks
B. 1000 bbl weighted up from 13 - 14.5 lbs/gal	1100 sacks
2300 bbl weighted up from 9 - 14.5 lbs/gal	8900 sacks
	18200 sacks
Total A and B	19000 sacks

III. ESTIMATED BARITE COST

The average cost of barite to 10,000 feet using the lignosulfonate system is \$84.000.* The cost of barite to the same depth using the proposed system is \$62,000.** Therefore, a saving of \$22,000 on the cost of barite can be realized.

* Assuming a cost of barite of \$3.00 per sack.

** \$57,000 + \$5.000. \$5,000 is the approximate rental cost of a centrifuge and a fine or double screen shaker for the time required to drill 10,000 feet.

TABLE III

X-Ray Diffraction Analysis

Mineralogy	Sample No. 1	Sample No. 2
Quartz	15-20%	5-10%
Feldspar	5-10	Trace
Carbonate	1-2	Trace
Barite	-	Trace
Gypsum	-	Trace
Illite	35-40	30-35
Expandable Clay (*)	10-15	30-35
Kaolinite	10-15	10-15
Chlorite	5-10	5-10

Sample No. 1 is from the top part of Miocene (-3000')

Sample No. 2 is from the top part of Oligocene (-6700')

(*) Expandable type clay in Sample No. 1 appears to be a mixed layer of illite-montmorillonite, and in Sample No. 2 appears to be mostly montmorillonite.

TABLE I

CONCENTRATION OF MATERIALS USED

Lignosulfonate	10 lbs/bbl
Lignite (when used)	5 lbs/bbl
Caustic	2-2.5 lbs/bbl
Barite	As needed for desired mud weight
Bentonite / Attapulgite	As needed for viscosity
Diesel Oil	2-5% by volume

TABLE II

AVERAGE CONSUMPTION OF MUD MATERIALS DOWN TO APPROX. 10,000 FT SUBSEA

Material	Sacks	Sack Size (lbs)	Lbs
Barite	29,642	100	2,964,200
Bentonite	2,750	56	154,000
Attapulgite	345	50	17,450
Asbestos	70	50	3,500
Lignosulfonate	2,144	50	107,200
Lignite	647	50	32,350
Caustic Soda	281	112	31,472
Soda Ash	281	112	31,472
Lime	106	56	5,936
CMC	105	56	5,880
Diesel Oil	373 bbl		

TABLE IV

THE RESULTS OF EXPOSING SIDEWALL CORES AND CUTTING SAMPLES TO VARIOUS SALT SOLUTIONS FOR 24 HOURS

SALT ADDED CONCENTRATION	BASE LIQUID: TAP WATER	BASE LIQUID: TAP WATER+ 1 ppb XC-POLYMER	BASE LIQUID: SEA WATER+ 1ppb XC-POLYMER
Sodium Chloride, 100 ppb (ppb = pounds per barrel)	1.1 Hard, no visible change during time of observation	2.1 Hard, no visible change during time of observation	3.1 Hard, no visible change during time of observation
Potassium Chloride, 10ppb	1.2 Little change to the sample. Apparently this salt prevented breakup of the shale. Possibly slightly better than 1.3	2.2 Hard, no cracks, slightly softer than 2.1 above	3.2 Slightly softening no cracks.
Ammonium Sulphate, 20ppb	1.3 Little change to the sample. See 1.2	2.3 Hard, no cracks, no visible difference from 2.2 above	3.3 Softening slightly more than 3.2 above, no cracks.
Calcium Chloride, 20 ppb	1.4 Started to fall apart in about 30 minutes, but not as bad as 1.5		
Diammonium Phosphate, 10ppb	1.5 Started to disintegrate in 15 minutes. No swelling occurred but plates split off in hard pieces	2.4 Somewhat sticky and with a few cracks, but not disintegrated	3.4 Sample broke up into relatively hard pieces No apparent softening
No salt added	1.6 Swelled and became soft and mushy in 15 minutes		3.5 Softened, but not disintegrated or cracked. Sample more intact than 3.4 above

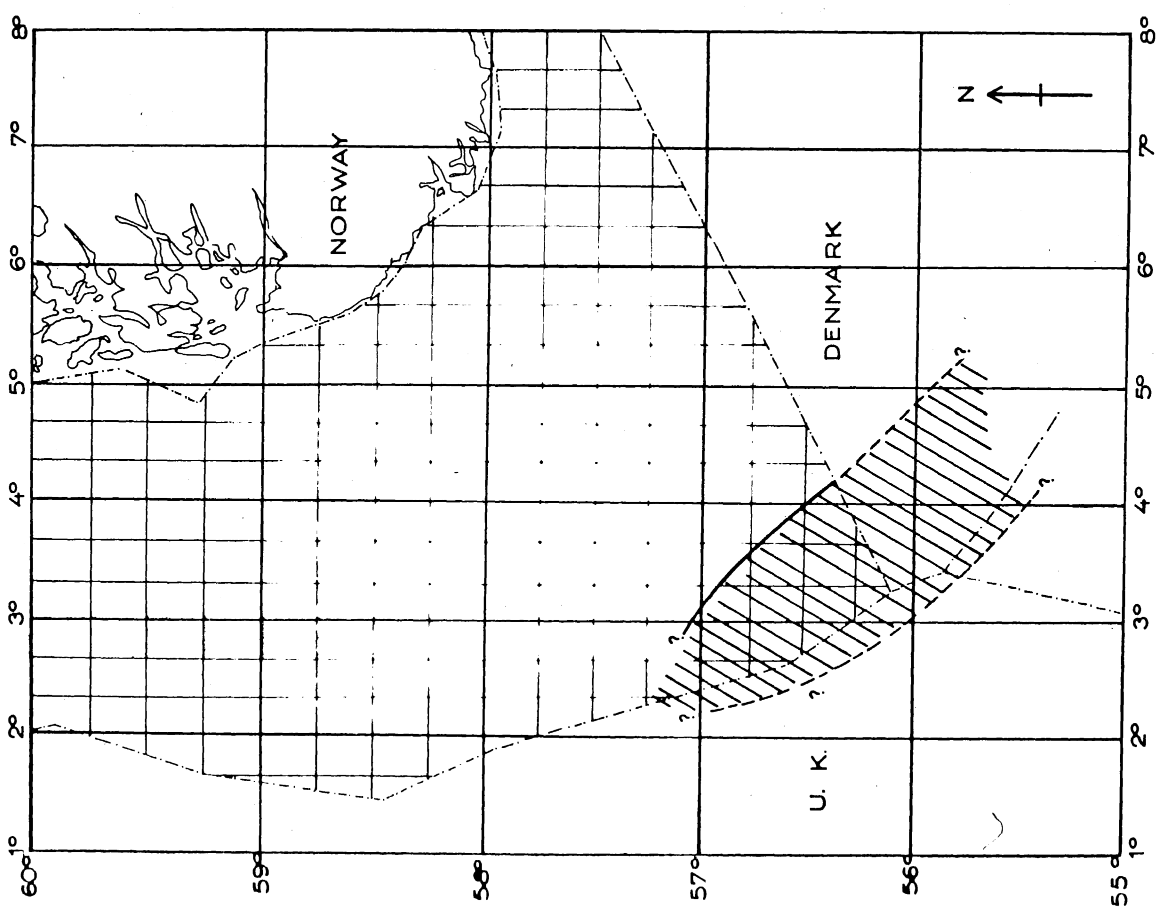


FIGURE 1. LOCATION MAP

ABNORMAL FORMATION PRESSURE AREA STUDIED.

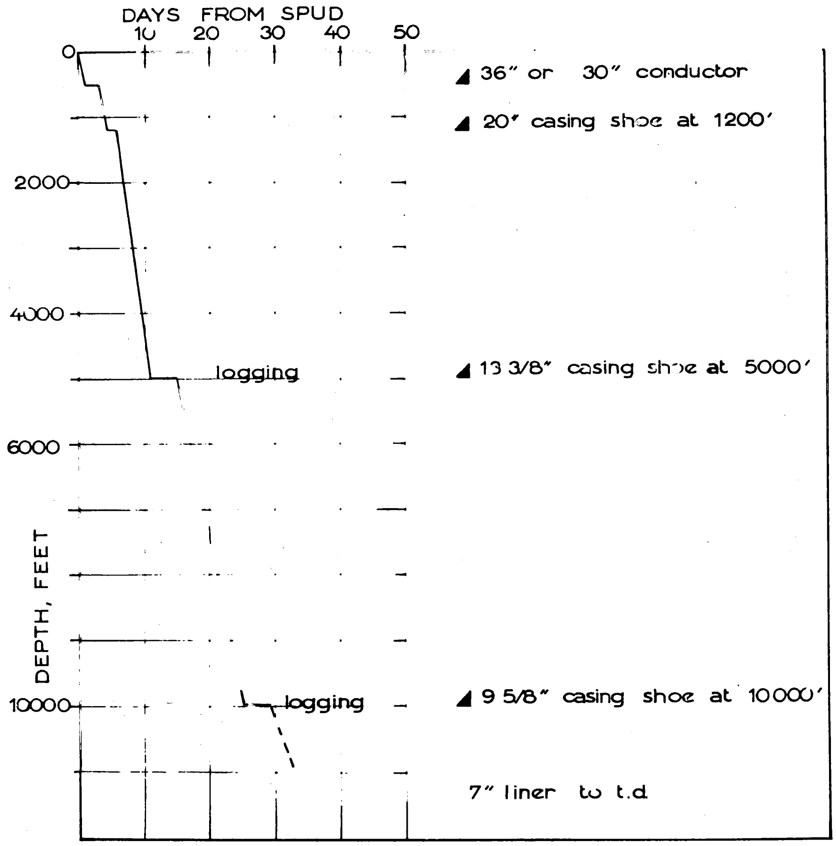
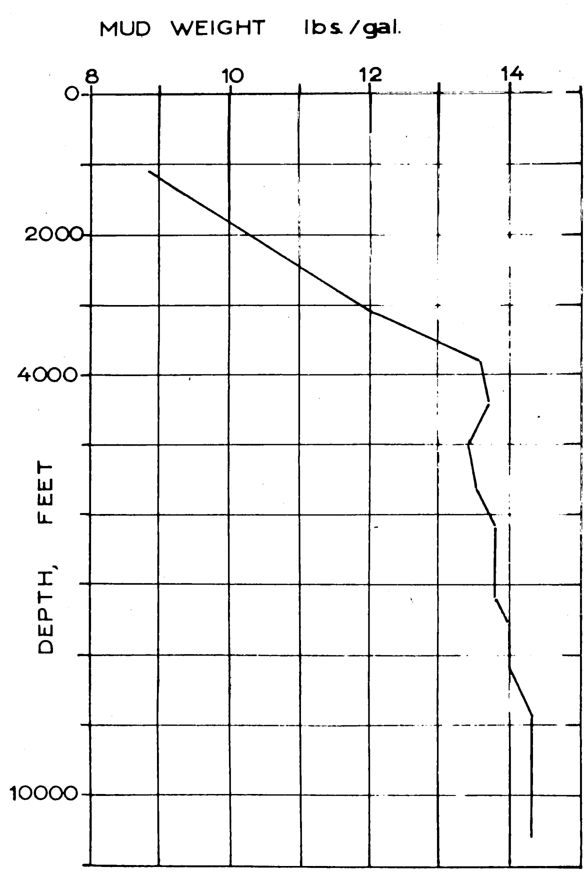


FIGURE 2. DRILLING TIME CURVE FOR AN AVERAGE WELL.



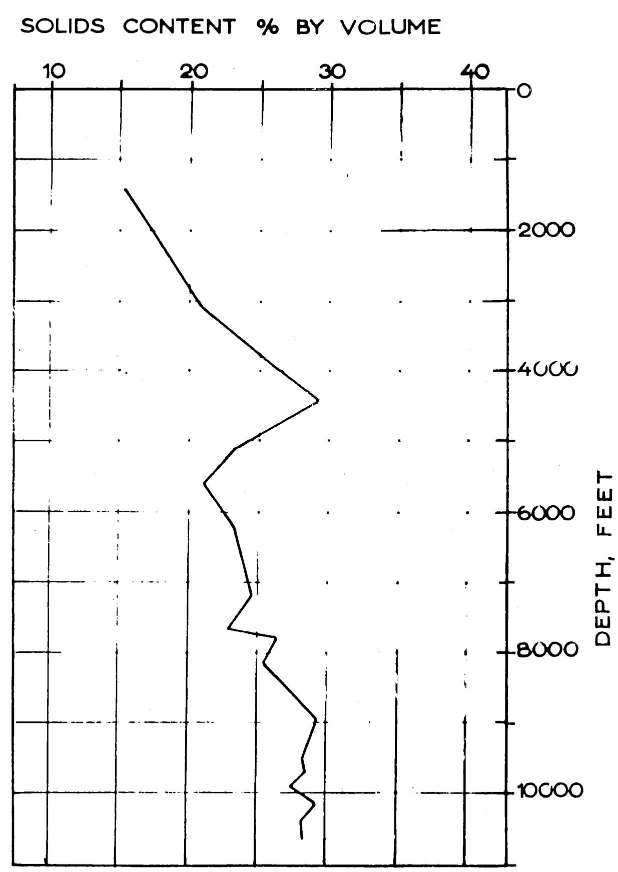


FIGURE 3. MUD WEIGHT VS DEPTH FIGURE 4. SOLIDS CONTENT VS. DEPTH

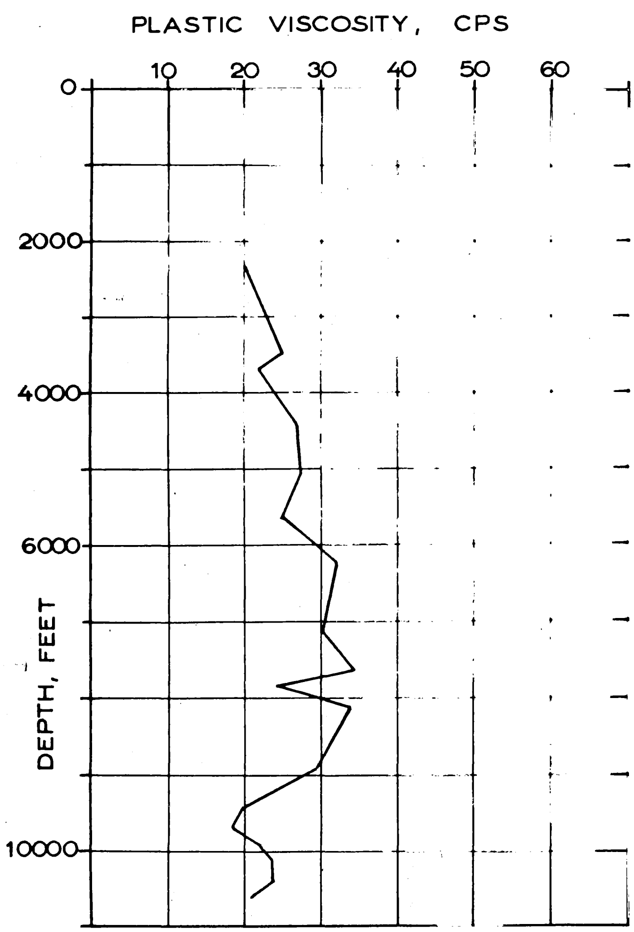


FIGURE 5. PLASTIC VISCOSITY VS. DEPTH

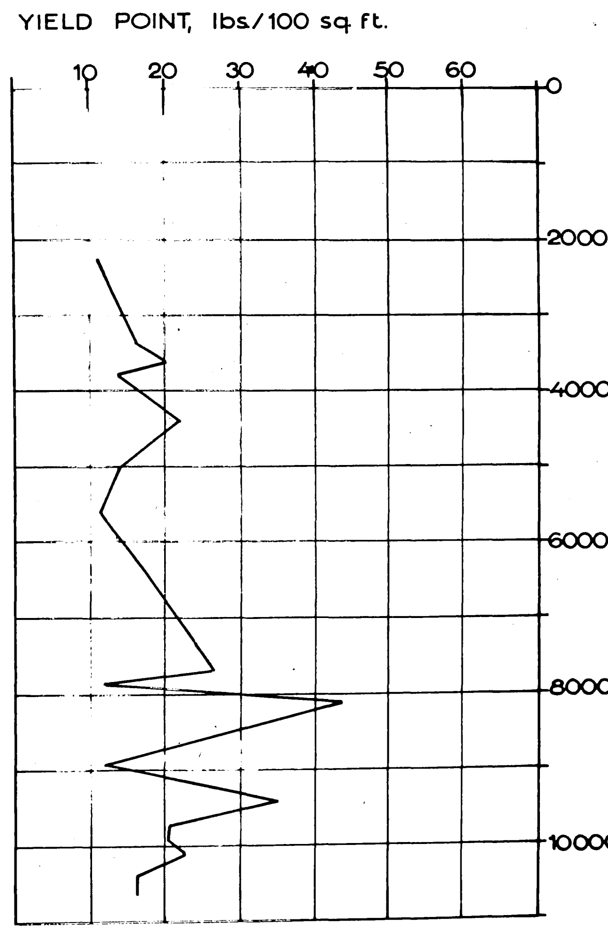


FIGURE 6. YIELD POINT VS. DEPTH

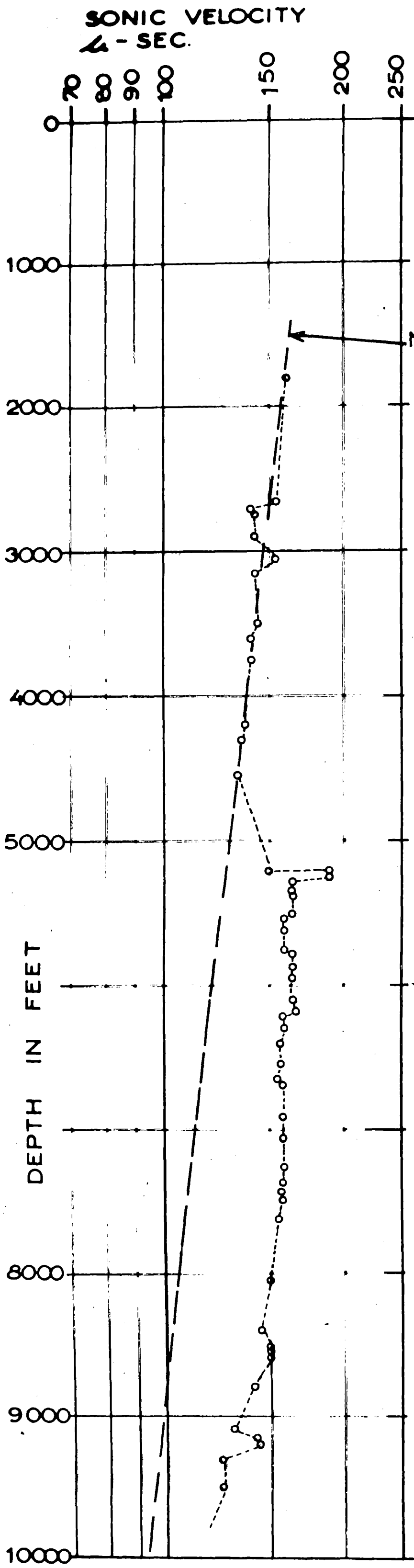


FIGURE 7. SONIC LOG

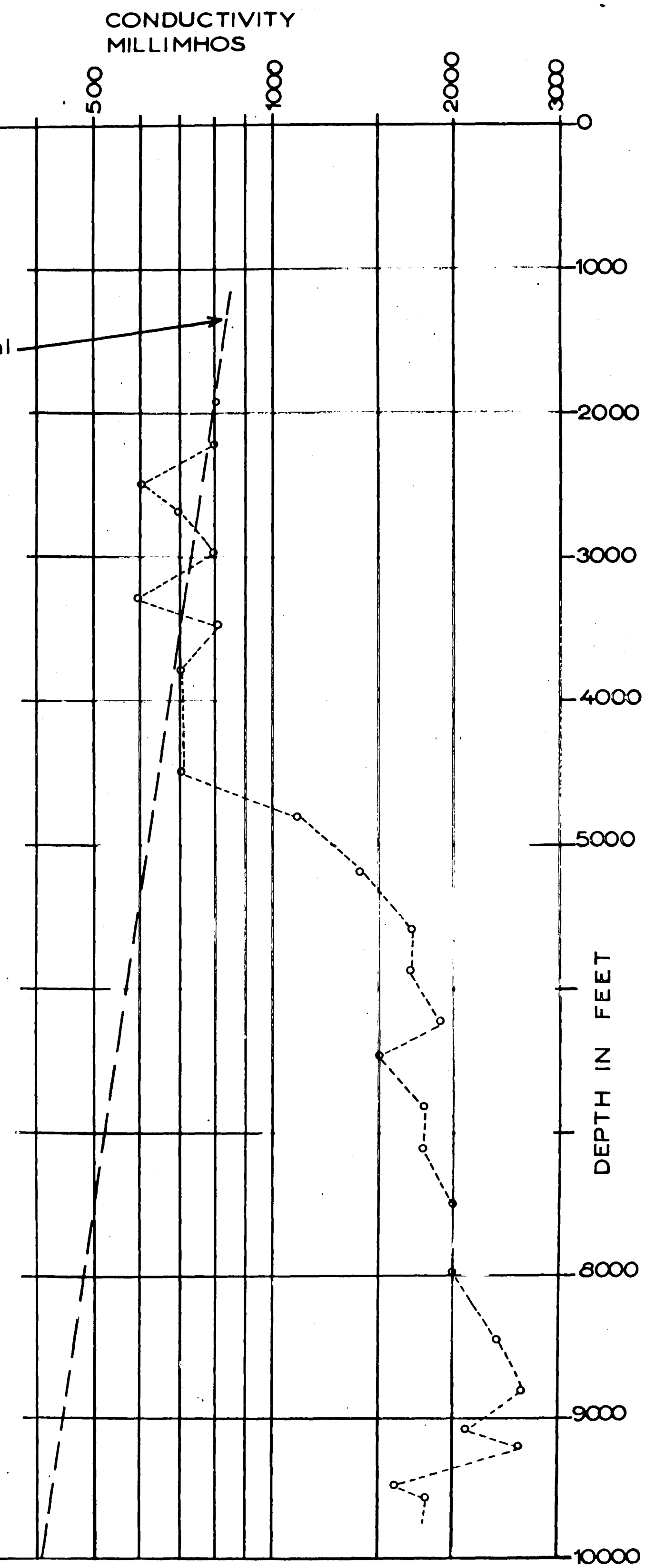


FIGURE 8. CONDUCTIVITY LOG.

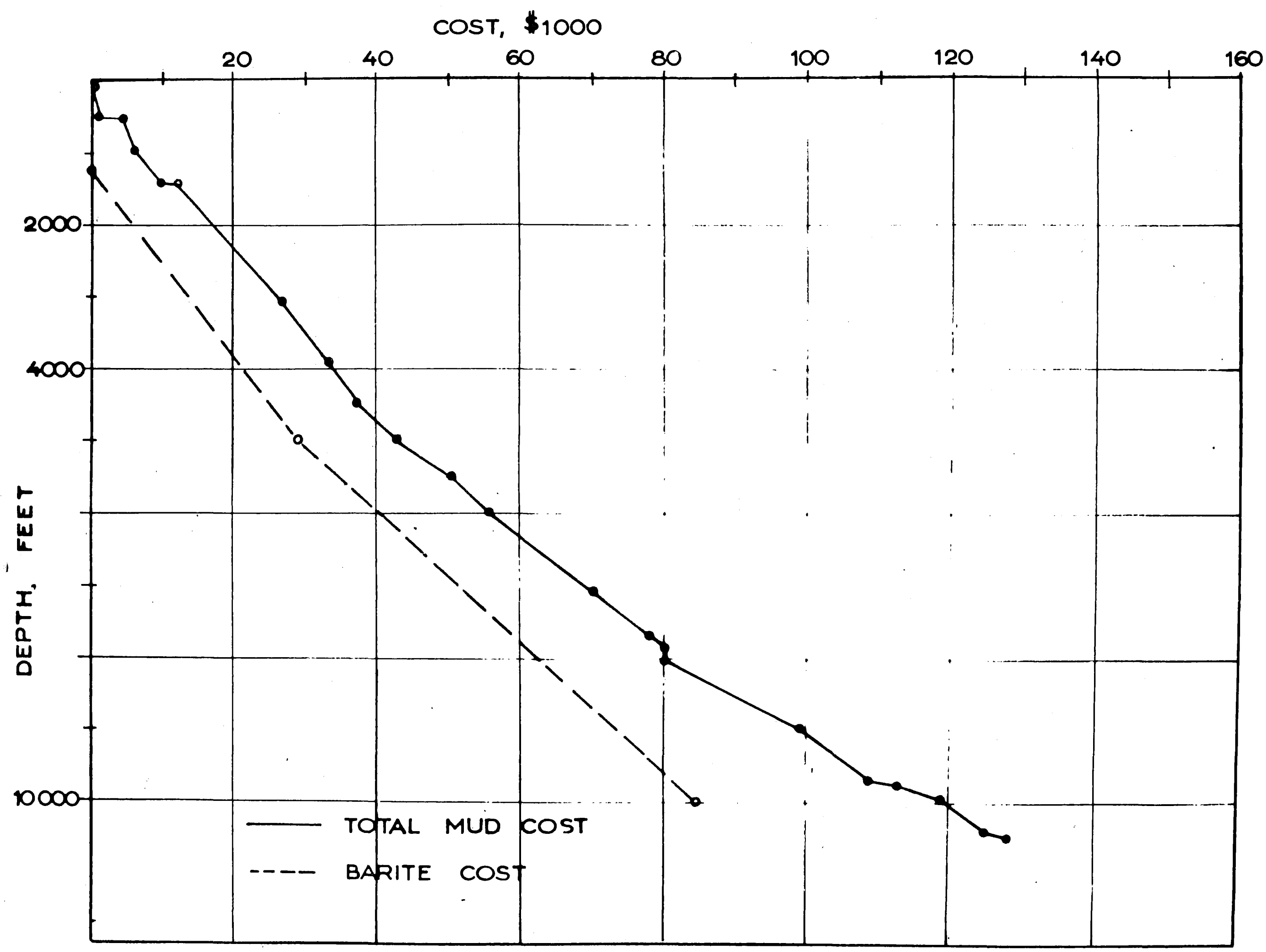


FIGURE 9. TOTAL MUD AND BARITE COSTS VS. DEPTH FOR AN AVERAGE WELL.