DRILL STRING DESIGN AND MEASUREMENT WHILE DRILLING IN HORIZONTAL WELLS

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Dehradun
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DRILL STRING DESIGN AND MEASUREMENT WHILE DRILLING IN HORIZONTAL WELLS

A thesis submitted in partial fulfilment of the requirements for the Degree of

Master of Technology

(Gas Engineering)

By

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Under the guidance of

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Approved

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May, 2008

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CERTIFICATE

This is to certify that Mr. Soumya Ranjan Mishra student of M. Tech (Gas engineering) has successfully completed his project "Drill String Design And Measurement While Drilling In Horizontal Wells" for 8 weeks period starting from 15th march 2008, MEHESANA ASSET (ONGC) under guidance of directional drillers.

During the summer training he had excelled to learn the direction drilling operation at MEHESANA ASSET.

He was found sincere, regular, hardworking and good in learning. His conduct was good during the training period.

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Abstract

In petroleum industry, drilling is the only method by which oil and gas can be brought from subsurface to the surface. This makes drilling vital and indispensable for exploration and exploitation of hydrocarbons. Keeping in view, the ever increasing global energy demand where oil prices are touching new heights everyday, innovative and cost effective methods in oil well drilling is becoming crucial to meet the demand keeping the overall operational cost low. Mehsana Asset, the highest on land oil producing project of ONGC in India, is putting its sincere efforts to fulfill this ever increasing demand with an aim to put on more profit to the organization. As the oil pay zones are at shallow depth in most of the fields, vertical wells are preferred in Mehsana Asset. However, keeping in view the strenuous & time consuming process of land acquisition, to increase the production and considering the techno-economics, a number of high-tech wells such as Horizontal and ERD wells are also being drilled. The horizontal well drilling is a costly operation hence the problem free drilling would optimize the drilling cost and it need

- good well planning
- adequate BHA (bottom hole assembly design)
- Proper measurement while drilling operation

Hence, in this project an approach has been given towards the drilling string design optimization and the measurement while drilling in horizontal wells.

Acknowledgement

This is to acknowledge with thanks the help, guidance and support I have received during the training.

I have no words to express a deep sense of gratitude to the management of JINDAL DRILLING INDUSTRIES & ONGC, MEHESANA ASSET for their valuable guidance and support.

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SOUMYA RANJAN MISHRA

M. TECH (GE)

UPES

CONTAINS **PAGES**

LIST OF FIGURES PAGES

HORIZONAL WELL DRILL STRING DESING

INTRODUCTION

The drill string performs the following functions:-

- Transfer and support axial loads (weight on bit)
- Transfer and support torsional loads (rotation)
- Transfer hydraulics

Note:-One of the main differences between horizontal drilling and conventional well is that the BHA (BOTTOM HOLE ASSEMBELY) lies on its side. For this reason, the drillstring must be run in compression to transfer weight to the bit through the horizontal section. The weight of the horizontal portion of the drillstring must also be minimized to reduce the effects of friction. This is usually achieved by using drill pipe in the horizontal section with heavyweight drill pipe in the near-vertical section of the well to produce the required weight to drill.

Reduction of the effects of friction is the primary goal in designing a drillstring for a horizontal well.

The main elements which lead to drill string failure are

Group 1 Mechanisms (can be controlled)

- Buckling
- Tension (drag)
- Torsion (torque)
- Combination of Tension and Torsion
- Collapse Pressure
- Burst Pressure

Group 2 Mechanisms (can not be controlled):

- Fatigue
- Split Box
- Sulfide Stress Cracking
- Stress Corrosion Cracking

BUCKLING FORCE:-

Some part of the drill string is in compression in horizontal well. Hence there is a chance of the buckling increase due to the compression force (negative tension force).

THERE ARE DIFFERENT STAGES OF THE BUCKLING DESCRIBED BELOW

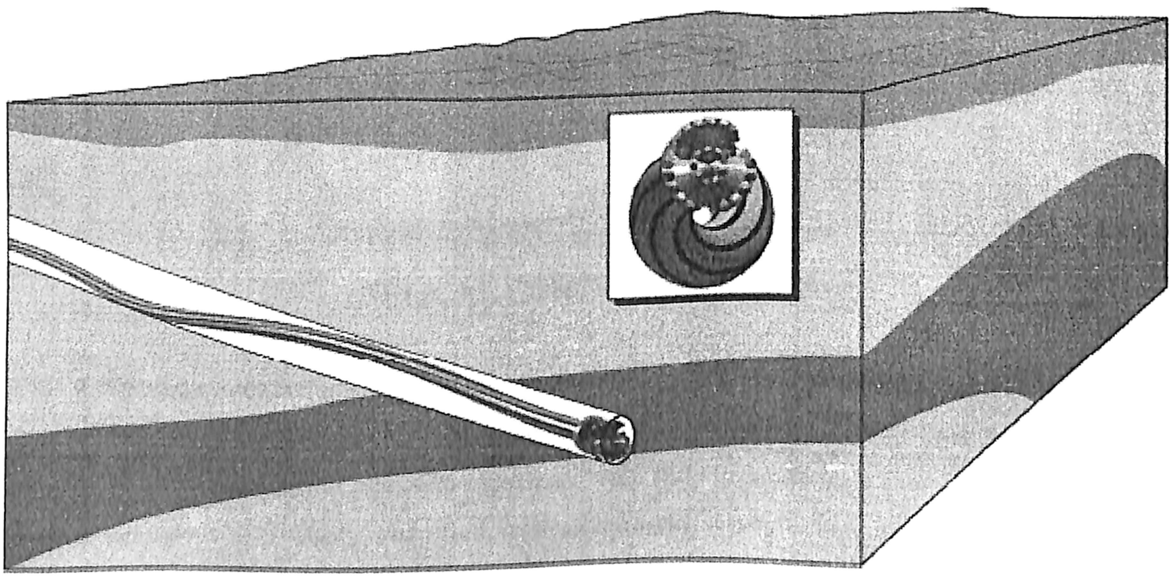
FIRST STAGE:-

It is the sinusoidal buckling. The pipe form a 2-dimensional wave shape resembling a sine wave, winding back and forth along the bottom of the well bore.

SECOND STAGE:-

It is the helical post buckling. This causes the pipe to ride up the sides of the well bore in the shape of a helix.

The increase in the wall contact area increases drag, there by requiring more axial load to maintain the same bit weight. The additional axial load causes higher well contact force, which further increases drag. Therefore, helical post buckling should be avoided.

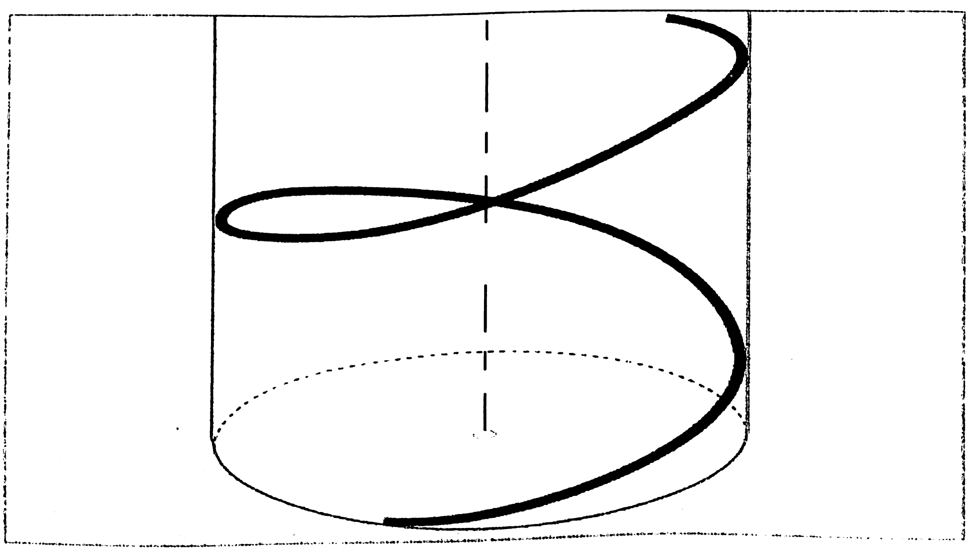


(HELICAL POST BUCKLING)

THIRD STAGE:-

When the compressive forces are increased further, the increased wall contact force will generate so much drag that no amount of slacking off will move the pipe. At this point, a change is required for drilling to continue.

NOTE:-When the drillstring is rotated, most of the axial drag present while sliding is converted to rotational drag. This increases torque and decreases axial drag. The decrease in drag allows the pipe to move down the wellbore more freely. Therefore, rotary drilling is usually possible beyond the point where a BHA would "lock-up" in the sliding mode. The critical force required to helically buckle the pipe remains unchanged, but a greater bit weight is necessary in the rotary mode to reach this critical force.



(HELICAL CONFIGURATION)

The main difference between rotating and sliding from a buckling standpoint is that substantial fatigue damage occurs when the string is rotated while buckled. This greatly increases the risk of fatigue failure. In the sliding mode, the pipe will experience very little or no damage even if buckling occurs (as long as the pipe is not rotated). Therefore, from an operational perspective, it is important to pick up off bottom before starting to rotate if the drillstring is buckled. To avoid fatigue failures due to rotation of buckled drillpipe, heavyweight drillpipe is usually run over the interval where compressive loads exceed the drillpipe's critical buckling load. The drillstring will be in compression (while drilling) from the bit to the neutral point, which usually occurs somewhere above the kickoff point. The interval of potential buckling for the drillpipe is from below the neutral point to about midway through the curve (40° – 60°).

THE HELICAL POST BUCKLING EQUATION DEVELOPED BY CHEN, LIN, AND CHEATHAM

Metric Units

$$F_{crit} = 2\times10^{-6}\sqrt{\frac{2EIW_m 9.806\sin\theta}{(D_h \times D_p)}}$$

Customary Units

$$F_{crit} = 2\sqrt{\frac{2EIW_m\sin\theta}{12(D_h \times D_p)}}$$

where:

$$I = \frac{\pi}{64}(OD^4 - ID^4)$$

Note: OD and ID are of drillpipe

$$W_m = \frac{PipeWeight}{UnitLength}\times\left(1 - \frac{MudDensity}{PipeMaterialDensity}\right)$$

Var	Definition	Metric		US
F_{crit}	= Critical Buckling Force	kN		lbf
E	= Young's Modulus of Elasticity			
	steel: 206,843	MPa	steel: 30,000,000	psi
	aluminum: 73,085	MPa	aluminum: 10,600,000	psi
I	= Moment of Inertia	mm^4		in^4
W_m	= Buoyed weight of pipe/unit length	kg/m		lbm/ft
q	= Inclination angle	degrees		degrees
D_h	= Diameter of hole	mm		in
D_p	= Outside diameter of pipe	mm		in

(Helical Post Buckling Equation)

RESISTANCE TO BUCKLING INCREASES AS:-

- Hole inclination increases
- Radial clearance decreases (smaller hole size, larger pipe size)
- Stiffness (EI) increases
- Weight per foot increases

THE PARAMETER NEGLECTED IN ABOVE EQUATION:-

- The effects of tool joints, which tend to centralize the drillpipe in the hole and reduce the tendency to buckle. Neglecting the tool joints results in a conservative design since the calculated helical post buckling axial force is less than the actual force required to buckle the pipe.

NOTE:-

The use of aluminum drillpipe has been proposed as a means to reduce torque and drag because of its light weight. However, the buckling resistance of aluminum pipe is very low compared to steel drillpipe for two main reasons:

• Young's Modulus (E) for aluminum is one-third that of steel

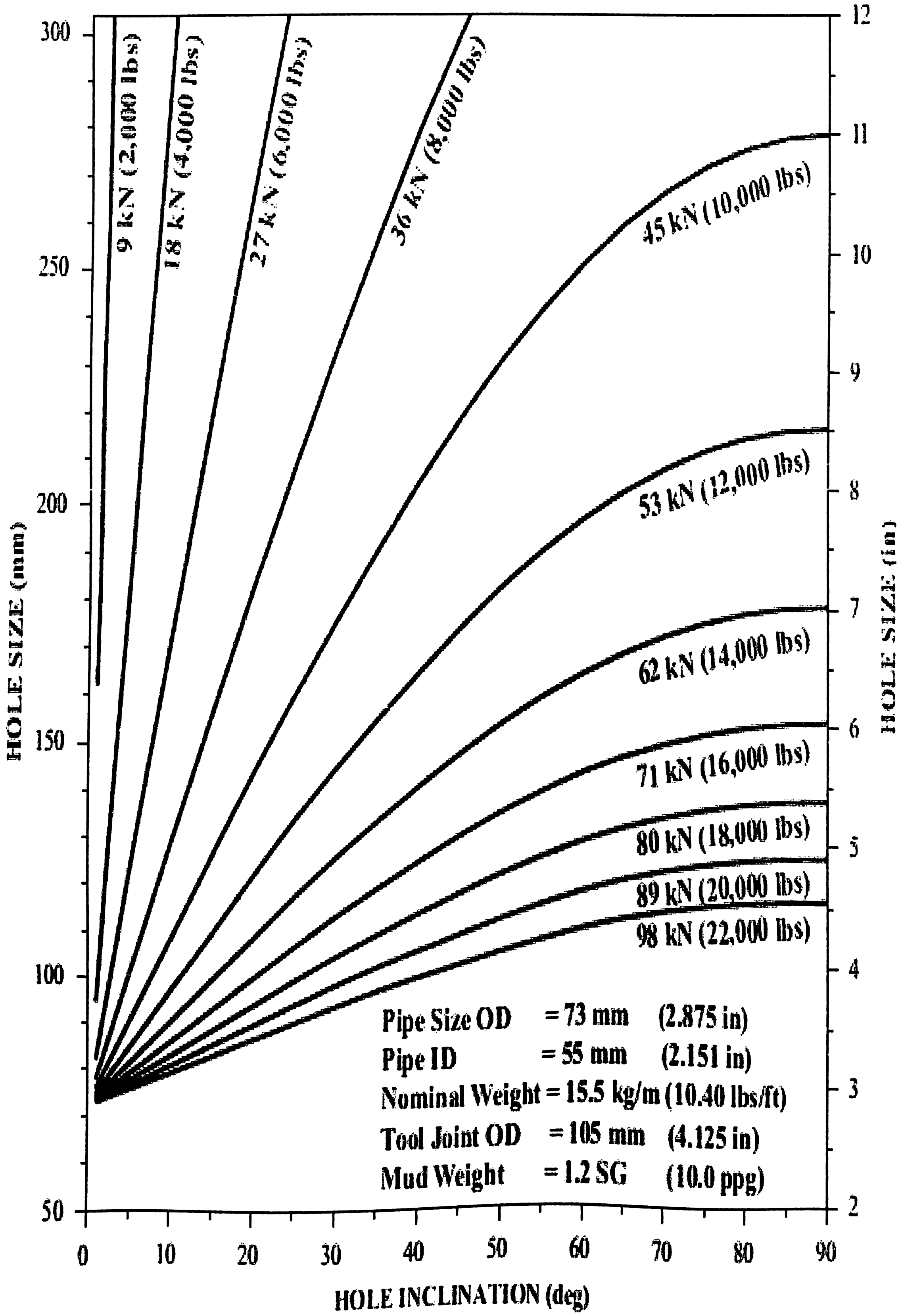
• The light weight which makes aluminum pipe good for torque and drag reduction also adversely affects its buckling resistance. So aluminum drillpipe is not recommended for drilling in compression.

FRICTION / TORQUE & DRAG

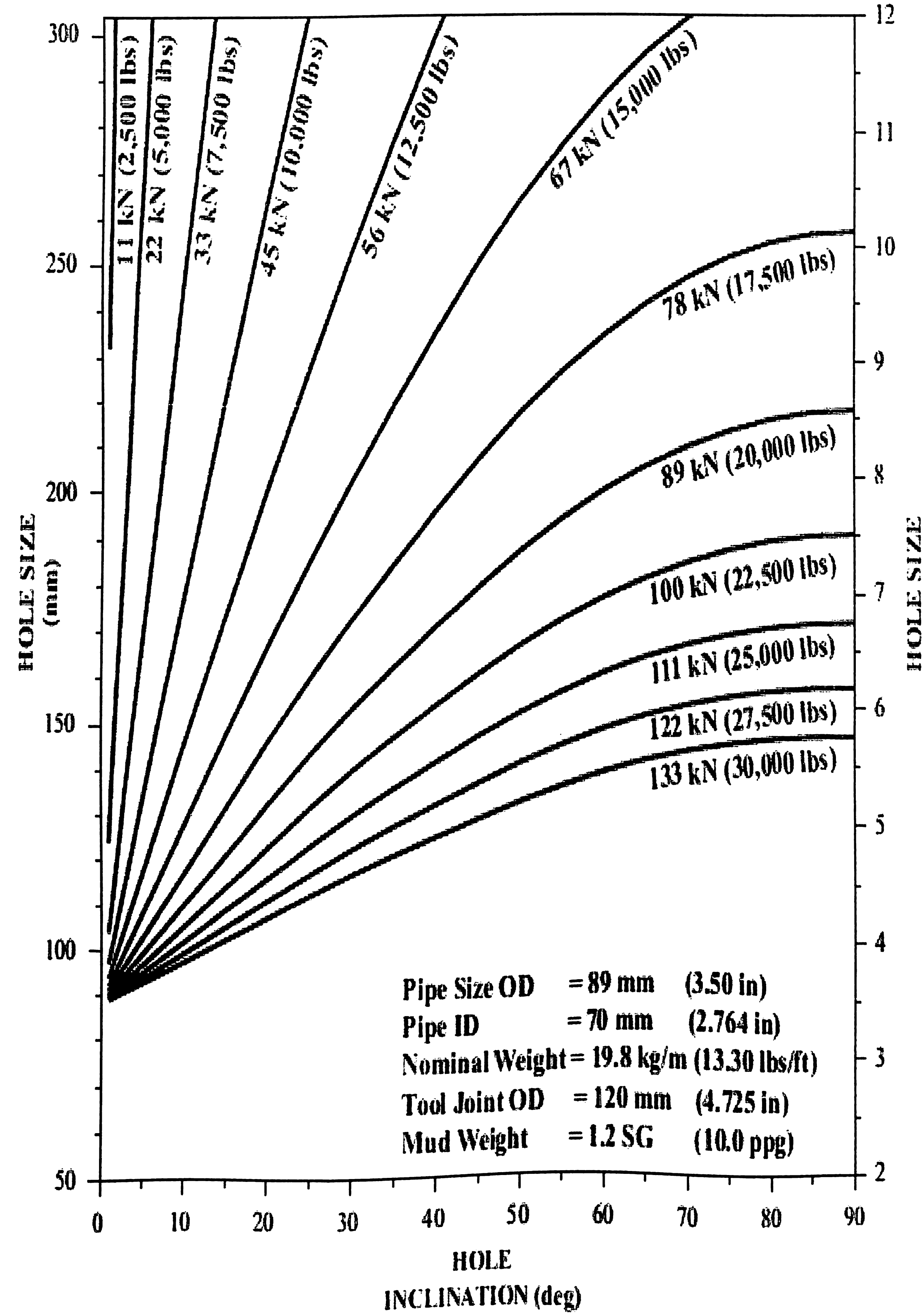
A torque and drag program is used to calculate different factor in the drillstring

- Compressive
- Tensile
- Torsional forces.

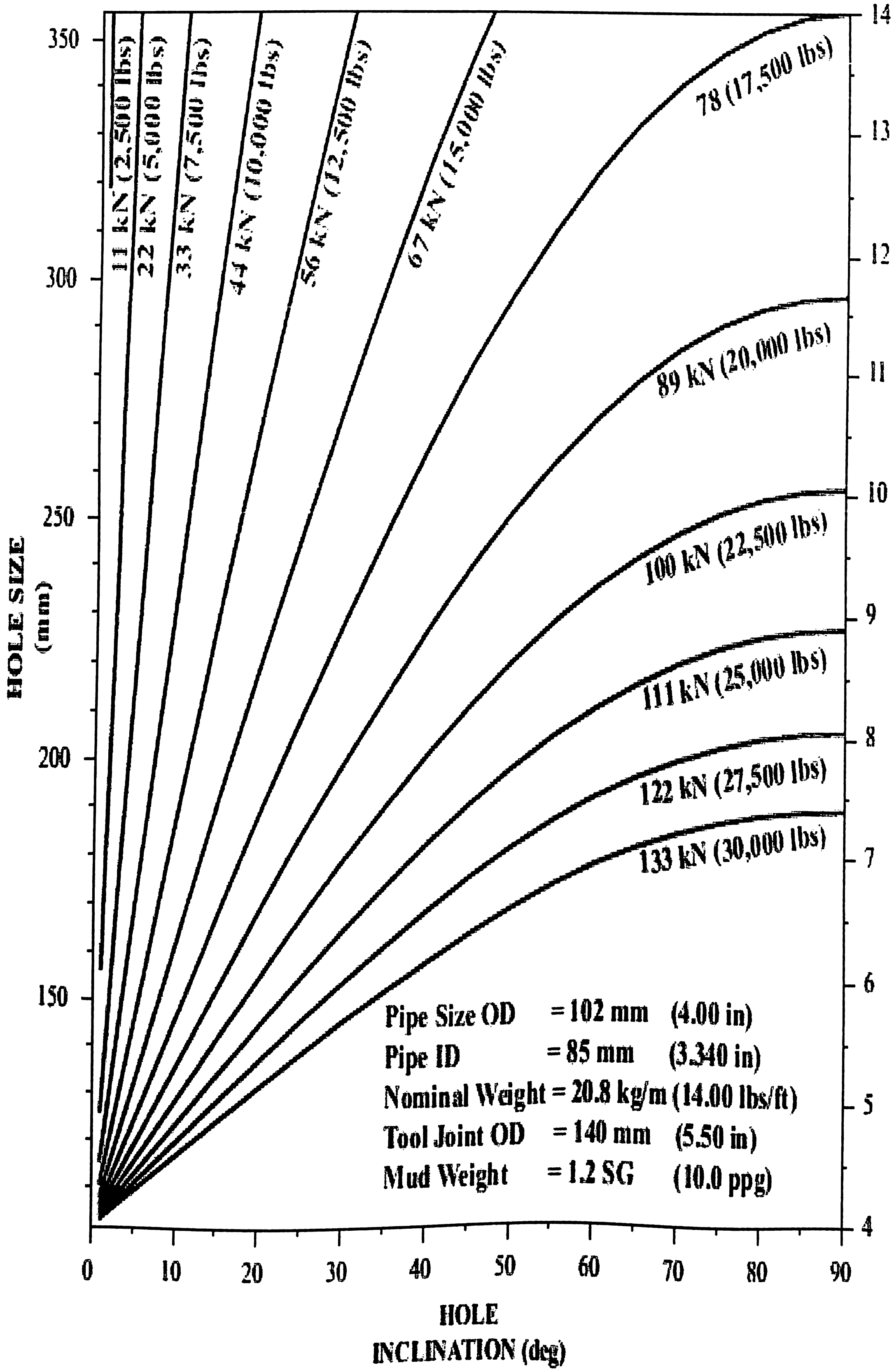
These programs also calculate the incremental change in the relationship between pipe weight, pipe geometry, friction, and hole inclination with azimuth. The "friction factor" or "coefficient of friction" is a pseudo-friction coefficient. It is used by these programs to account for many different parameters, including contacting surfaces, degree of lubrication, well path tortuosity, and effectiveness of hole cleaning.



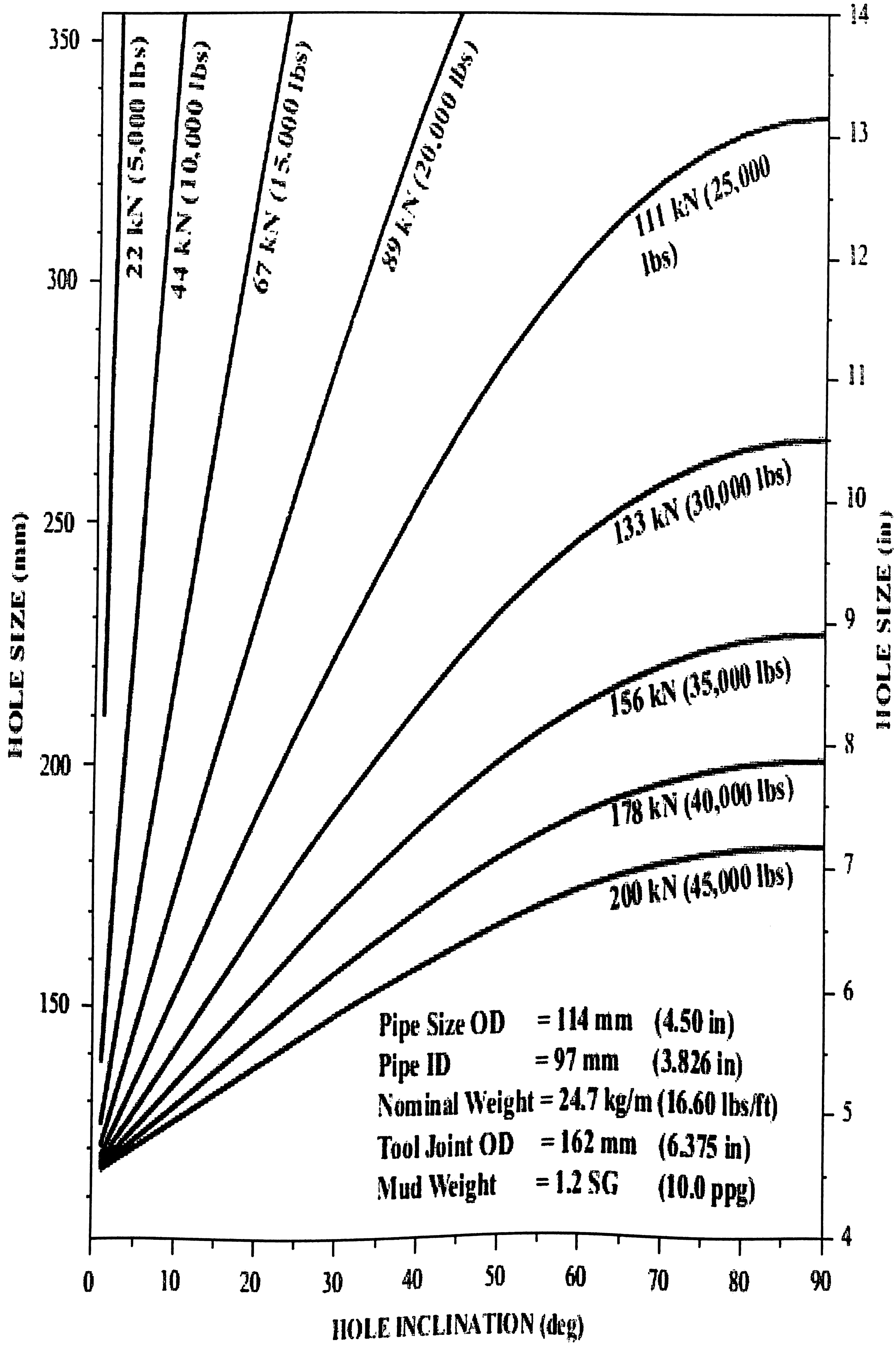
(HELICAL POST BUCKLING LOAD FOR 2-7/8" DRILLPIPE – STEEL 10.40 LBS/FT)



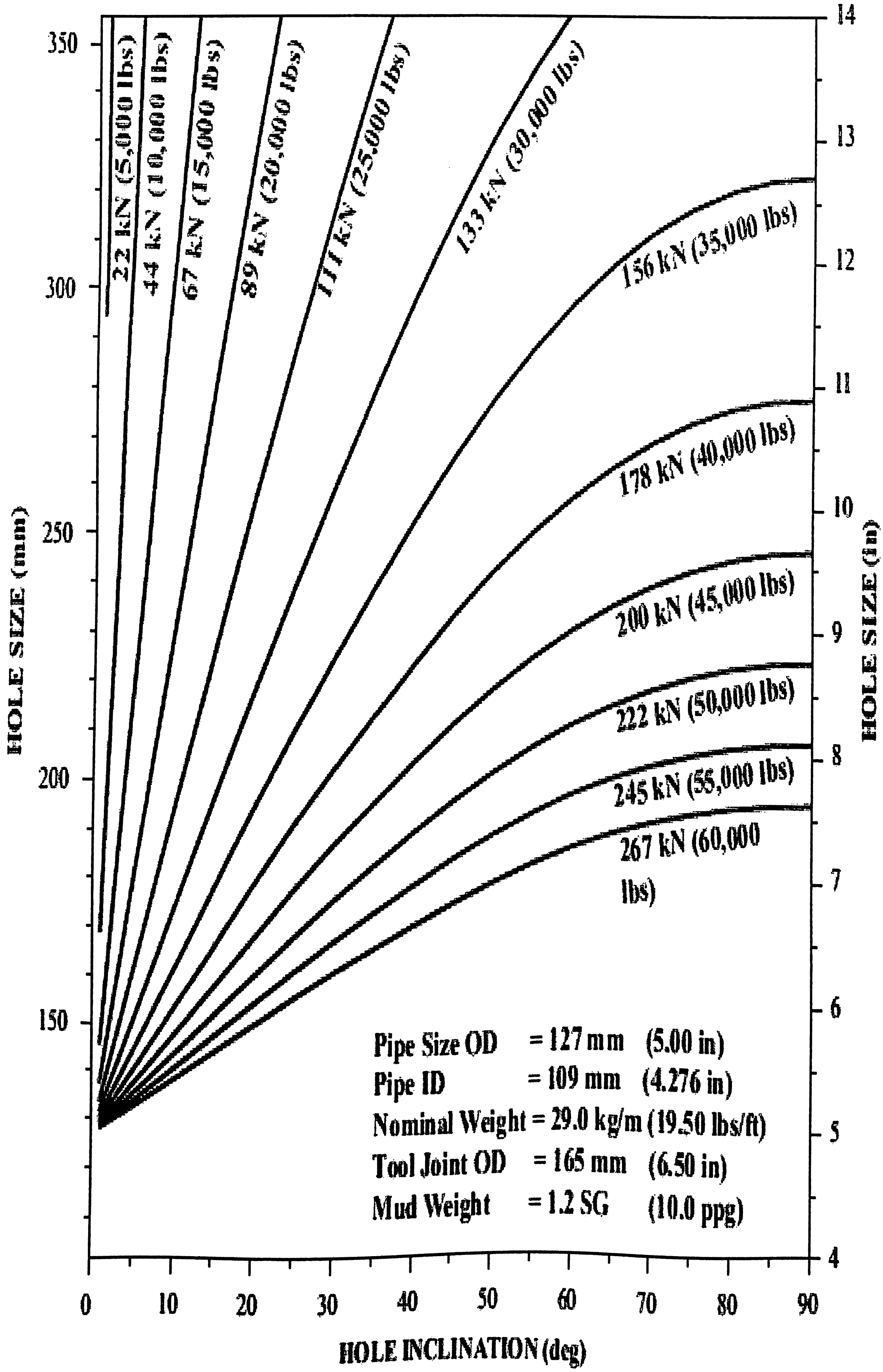
(HELICAL POST BUCKLING LOAD FOR 3-1/2" DRILLPIPE – STEEL 13.30 LBS/FT)



(HELICAL POST BUCKLING LOAD FOR 4" DRILLPIPE – STEEL 14.00 LBS/FT)



(HELICAL POST BUCKLING LOAD FOR 4-1/2" DRILLPIPE – STEEL 16.60 LBS/FT)



(HELICAL POST BUCKLING LOAD FOR 5" DRILLPIPE – STEEL 19.50 LBS/FT)

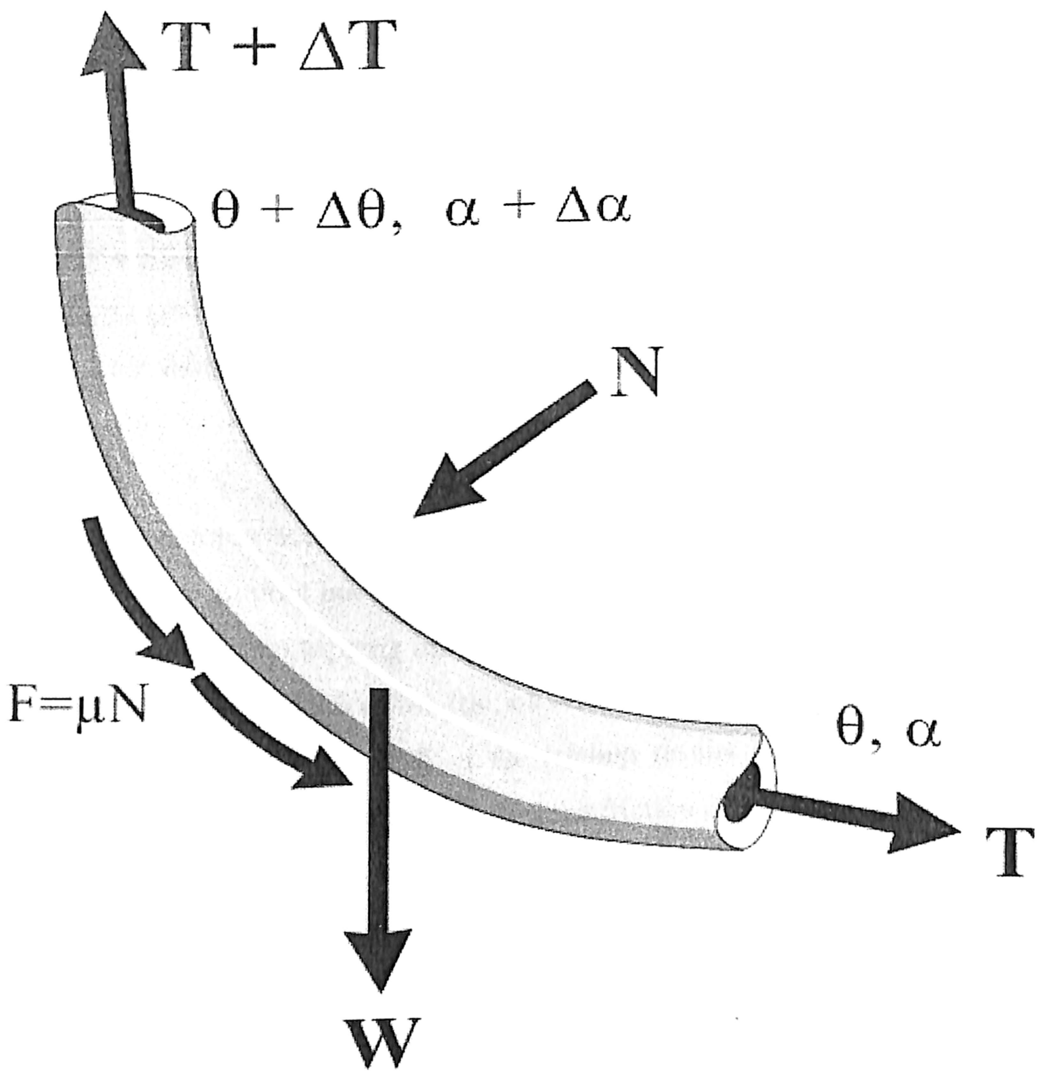
NOTE:-

The friction coefficient is affected by many parameters; its value will change as a function of time and hole conditions when the well is actually drilled. Buildup of cuttings on the low side of the hole will frequently cause a dramatic increase in drag. It can also make the friction coefficient for pickup appear different from the slackoff or rotating friction coefficients. Friction inside casing is typically less than open hole friction; although a new casing string can initially have higher friction. This is due to rough surfaces which usually become smoother after some pipe rotation, which reduces the friction. Keyseating and other sticking mechanisms will also cause anomalies in the friction coefficient. Different formation types can have different friction coefficients (i.e., sandstone versus limestone). Torque and drag programs have been used to diagnose hole problems.

THE PHYSICS BEHIND THE TORQUE DRAG PROGRAMME:-

$$F = \mu N$$

F =	Friction force, lbf
μ =	Friction coefficient, dimensionless
N =	Normal contact force, lbf



(FORCES ON A DRILLSTRING)

T =	Tension on Drillstring
W =	Weight of Drillstring

0

FRICTION COEFFICIENT DETERMINATION:-

The friction coefficient determined by taking **the ratio of the friction force to the Normal contact force**. Normally that for water base mud systems, typical friction coefficients range from 0.20 – 0.40. For oil base mud systems, typical friction coefficients range from 0.14 – 0.22.

NOTE:-

In the field, the friction coefficient is determined by acquiring pickup hookload, slackoff hookload, and/or torque readings from the rig floor at a given depth. Initially, a guess is made at the friction coefficient. The computer model is run for this depth, and the results are compared to the observed hookload and torques. The friction coefficient is adjusted up or down until the predicted hookload/torque values match well with the rig values.

This is because hookload is a direct measurement of tension, while torque is an indirect indication based on amperage measurements and is affected by the inefficiencies in the rig motors.

The normal force due to gravity is the major contributor to torque and drag in any long section of wellbore which has high inclination and low curvature, such as the lateral section of a horizontal well. At 90° inclination, all the buoyed weight of the pipe becomes normal force, contributing nothing to the string tension. To minimize drag in this interval, the lightest weight pipe should be used (providing no other adverse effects occur, such as buckling).

The friction force acts in the opposite direction of motion. This results in a downward drag when tripping out of the hole, increasing the string tension. Conversely, an upward drag occurs when tripping in, which decreases the indicated string weight. As long as the pipe is not rotated, all of the friction results in drag. Similarly, when the pipe is rotated without axial movement, all of the friction results in torque. If the pipe is rotated and moved axially at the same time, then the friction acts in the opposite direction of the resultant motion. This concept is very important and can be used to reduce the axial friction (or drag) if the pipe is rotated while moving into or out of the hole. Because the pipe rotational velocity is large compared to the axial velocity (rate of penetration or trip speed), almost all of the friction results in torque with very little axial drag.

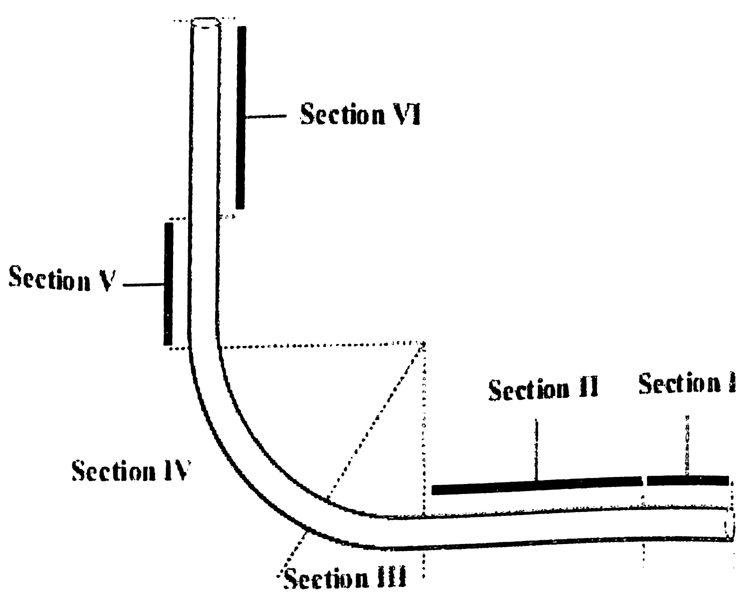
DESIGN CRITERIA

The drill string design should satisfy the criteria mentioned below.

- The drillstring has sufficient tension capacity. Conventional drillstring design calls for at least 100,000 lbs of margin between the anticipated weight of the string (indicated hookload minus travelling block and kelly) and the tensile capacity of the top section of drillpipe (specified in API codes). An alternate approach to tension design is to model the drillstring with 50,000 lbs tension at the bit to simulate the load required to activate the jars, and to allow 50,000 lbs margin of overpull at the surface, instead of 100,000 lbs.

- The drillstring has sufficient torsional capacity. A safe design practice is to use 80% of the make-up torque for the connections being used as the maximum allowable torque. This will provide a 20% safety margin and prevent downhole makeup.
- The drillstring has sufficient buckling resistance. Buckling can be avoided by using the proper size/type of pipe in the compressive intervals. Drillstring design for horizontal wells is complex and requires running drillstring components in compression to transmit weight to the bit through the horizontal section. The drillstring should be designed to provide the required weight on bit, produce minimum torque and drag, and provide for adequate hydraulics. An optimum drillstring design for long and medium radius horizontal wells may have as many as 6 separate sections.

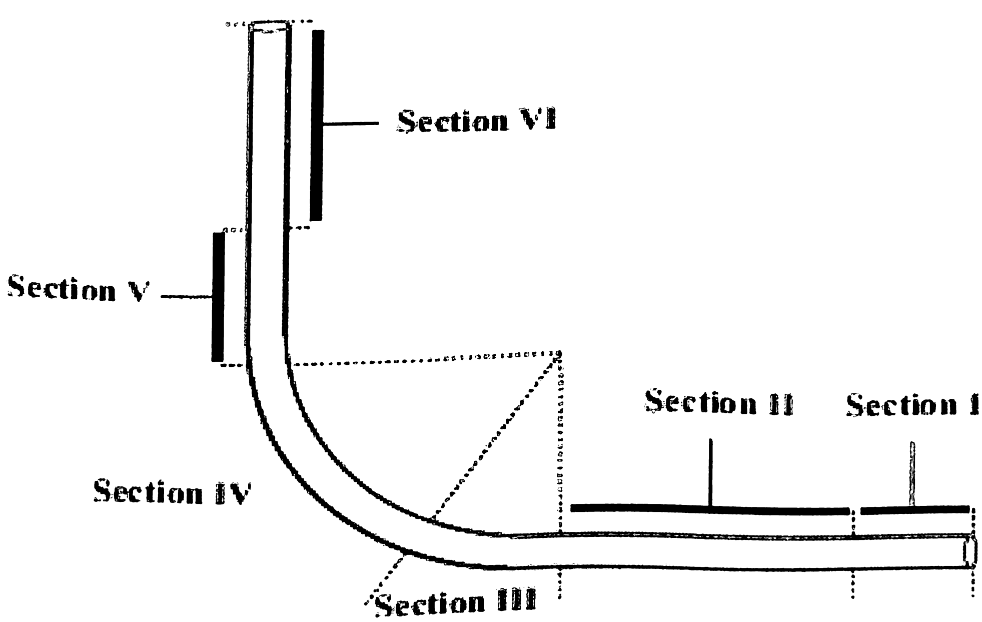
Drillstring Design Sections



Section	Type	Function	Desired Characteristics	Desired Consideration
I	BH	Directional Control	Stiff, Lightweight	Minimize Torque and Drag
I	DP	Transfer Weight	Stiff, Lightweight	Minimize Torque and Drag providing adequate buckling resistance
II	Heavy DP or HWDP	Transfer Weight	Stiff, Lightweight	Minimize Torque and Drag increase buckling resistance
I	HWDP	Transfer and Provide Weight	Stiff, Moderate Weight	Increased Buckling Resistance
V	HWDP or DC	Provide Weight	Concentrated Weight	Transition Component (compression to tension)
V	DP	Support Weight	High Tensile, Torsion Limits	Provide Adequate Tensile Torsion Margins

(Drillstring Design Sections)

Drillstring Design Sections



(DRILLSTRING DESIGN SECTIONS)

SECTION I

Bottom hole assembly, including bit, motor, non-magnetic collars, and MWD tool. This section controls the hole trajectory, but does not contribute to weight on bit. This section should be kept as lightweight as possible to minimize torque and drag.

SECTION II

Horizontal section transmits axial and torsional loads during drilling/tripping. This section must support compressive loads without buckling, but must also be lightweight to minimize torque and drag. This section is the largest OD conventional drillpipe available.

SECTION III

Lower build section, 60° – 90°. The pipe here must also be able to transmit axial and torsional loads, while sustaining potentially large bending stresses induced by rotating in up sections rate. Most of the pipe weight in this high inclination section lies on the side of the hole and therefore contributes very little to weight on bit. This is usually heavy drillpipe or heavyweight.

SECTION IV

Upper build section, from 0° – 60°. The pipe in this section must be able to resist buckling and withstand the bending stresses imposed by rotation in the build up section. Buckling is more of a concern in this section since the pipe does not benefit from sidewall support available at the higher angles of hole inclination. The pipe weight in this section can contribute significantly to bit weight. Heavyweight drillpipe is usually used here. However, drillpipe can be used if there is a tangent section. However, drillpipe can be used if there is a tangent section.

SECTION V

Vertical well bore above kickoff point. This section produces the remaining required weight on bit (after accounting for Section IV) and is usually drill collars or heavyweight drillpipe. If collars are used, they are kept above the kickoff point to reduce their exposure to high doglegs and minimize the risk of fatigue failure. Hydraulics must be analyzed closely when using drill collars in this section. Since this interval is vertical and the drillstring tension is low, it contributes very little to torque and drag.

SECTION VI

Vertical portion to surface. The drillstring in this section will be in tension... The pipe must support the tensile and torsional loads of drilling and tripping, with adequate over pull margin. The pipe used here is usually determined by considerations of torque and drag, hydraulics, and convenience of rig operations.

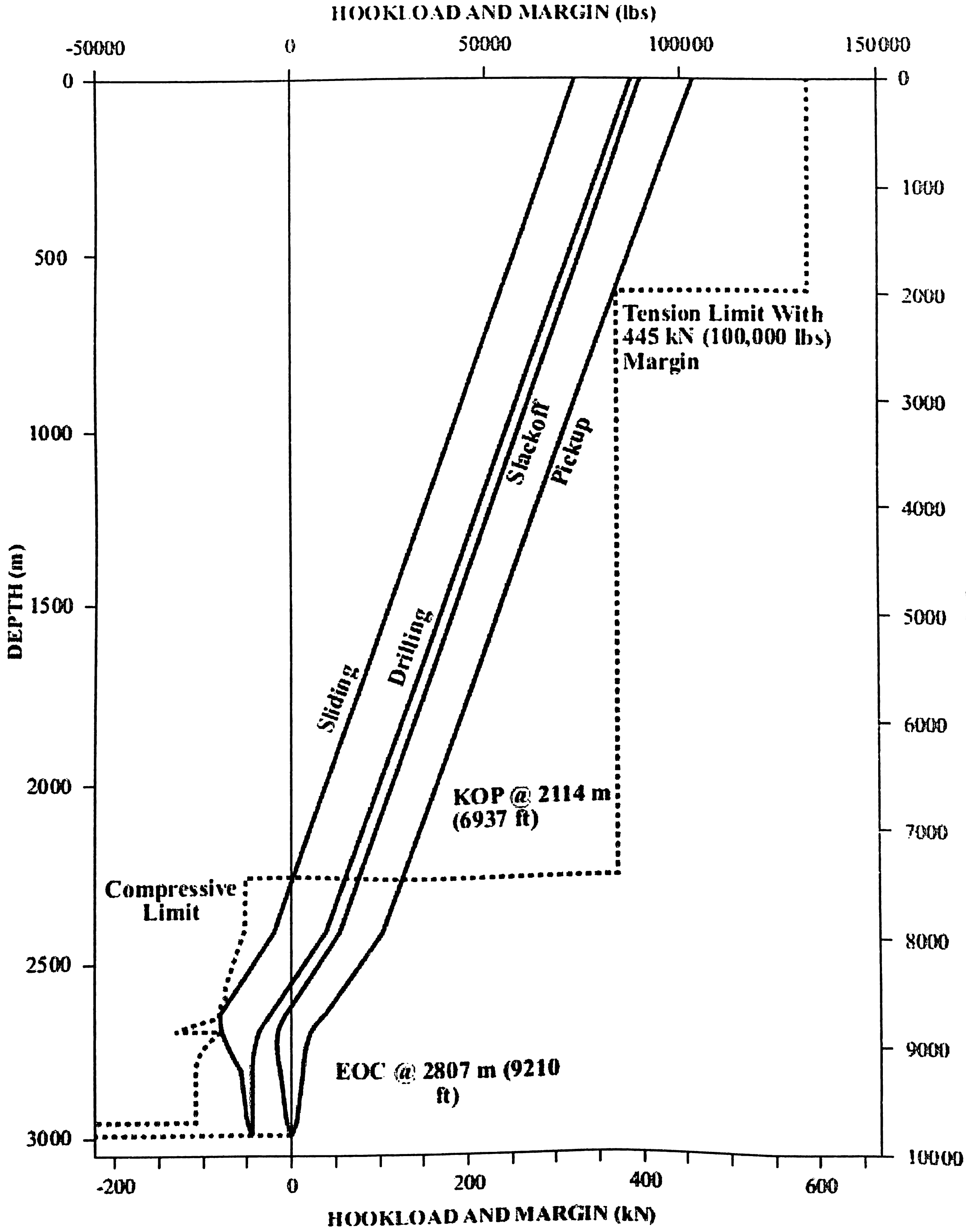
DRILLSTRING DESIGN

The information needed for the torque drag programme

- A survey file containing depth, inclination, and azimuth
- BHA and drillstring ODs, weights per foot, and lengths for each unique section
- Weight on bit, torque at bit, mud weight, friction coefficient, and calculation interval

The output shows the parameter like

- pickup hookload (tripping out)
- slack off hookload (tripping in)
- rotating off bottom hookload and torque
- Drilling hookload and torque.
- sliding hookload and torque
- Reaming and backreaming hookload/torque.



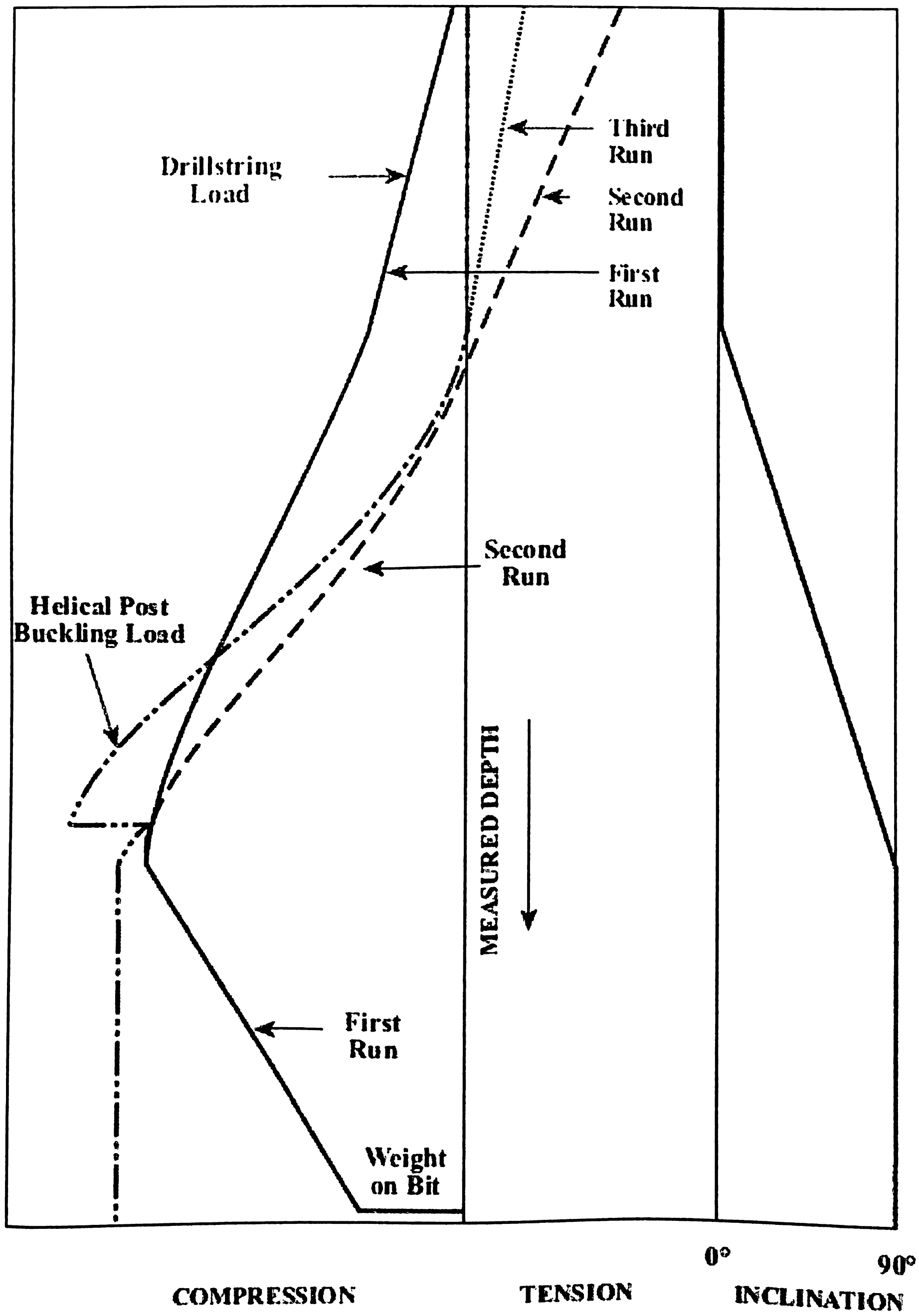
(TYPICAL HOOKLOAD PLOT FROM TORQUE & DRAG)

The first step in the design is to calculate the torque and drag for the deepest bit run. A drillstring should be used consisting of the BHA followed by drillpipe all the way back to the surface. The oriented drilling mode (sliding) will create the highest compressive forces, so this is analyzed first. The string is designed from the bottom up since the friction is cumulative from the bottom up. The output will show the total cumulative axial load at specified increments from the bit back to the surface. At the bit, these compressive forces will be equal to the desired weight on bit, and will increase to a maximum (negative) at some point in the curve section. These forces will then decrease back to zero at the neutral point and increase positively to the surface.

The location of the neutral point is a function of the well profile. For long radius wells with a tangent, it will usually occur in the tangent. For medium radius wells, it will usually occur somewhere in the vertical portion of the well (above the kickoff point). The critical buckling load is calculated for drillpipe in the proper hole size and with the appropriate mud weight. Starting at the bit, the compressive forces from the torque and drag output are compared to the critical buckling force for the appropriate inclination until the critical buckling force is exceeded. This defines the depth where heavier drillpipe is used (usually heavyweight).

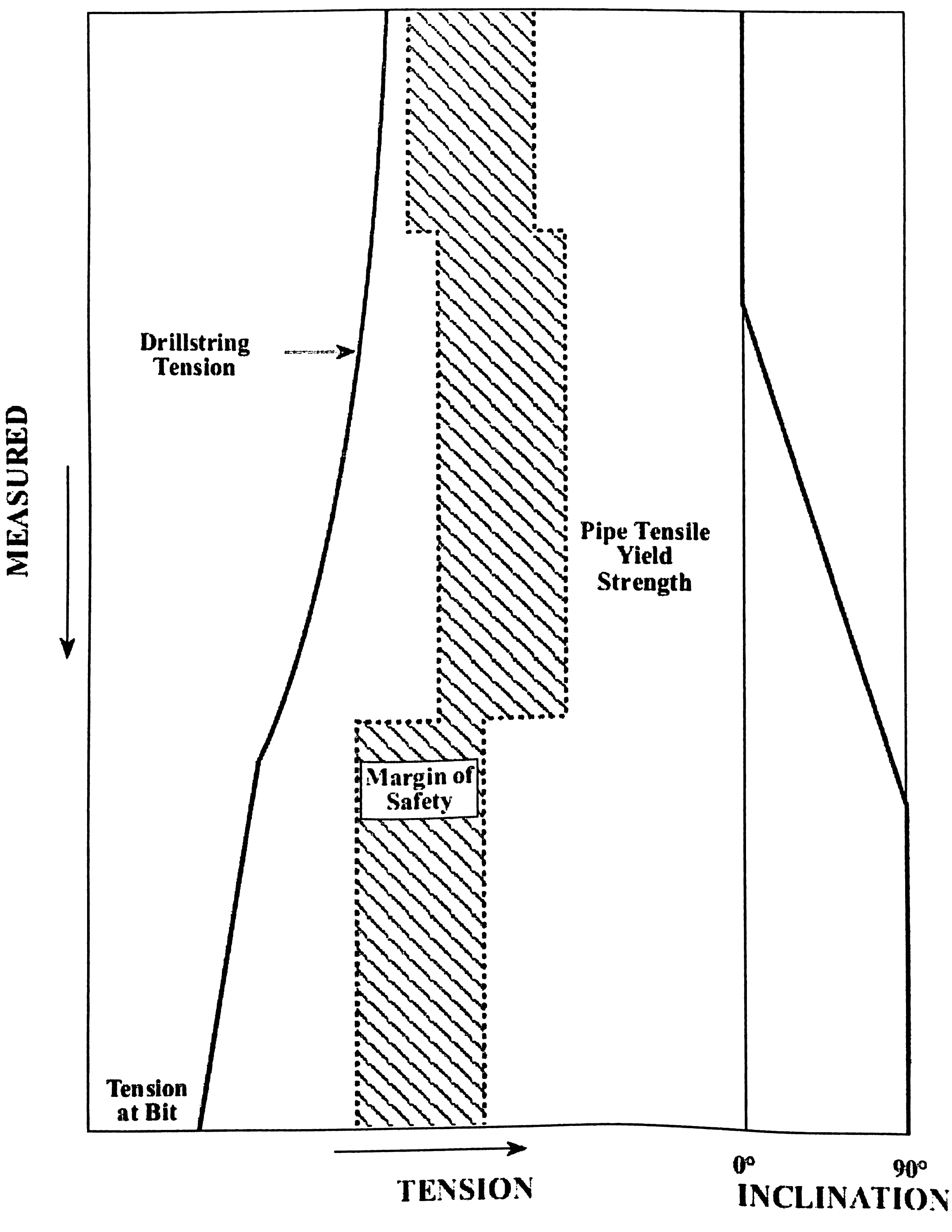
This depth is then increased by the anticipated length of the bit run. This insures that the heavier pipe is in this interval at the beginning of the run as well as at the end. The next step is to replace the drillpipe from this critical depth (adjusted for bit run length) to the surface with heavyweight drillpipe. This is done to determine in one step how far up the heavyweight must be run. The program is rerun, and the output is inspected to determine the location of the new neutral point. Since the heavyweight contributes significantly to the overall string weight, the neutral point will move down the string.

For critical buckling load, use the heaviest mud weight. For the purposes of torque and drag, use the lightest expected mud weight.



(COMPRESSION)

The final step in this initial phase of design is to replace the heavyweight with drillpipe from the neutral point to the surface and rerun the program. This will leave the neutral point unchanged but reduce the total hookload at the surface. At this point, the designer must consider whether to replace some of the heavyweight with drill collars in the vertical section of the hole. This may be necessary if the amount of heavyweight available on the rig is insufficient. This will cost him nothing to use and can typically provide the same weight in roughly half the number of joints. However, proper consideration must then be given to the impact this will have on hydraulics. Prevent the drill collars from entering the curve section during the bit run, due to the high bending stresses.



(TENSION)

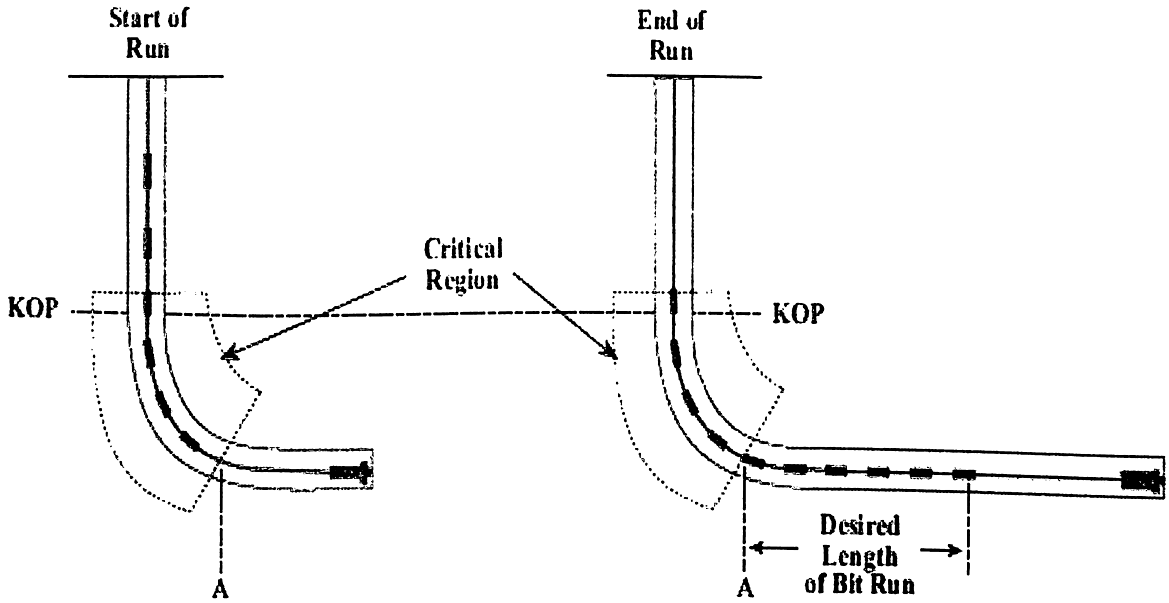
Tension margin. The calculated total pickup hookload is increased by 100,000 lbs (or 50,000 lbs if modeling stuck pipe with 50,000 lbs tension at the bit). This new value must not exceed the tensile strength for the particular grade and class of pipe used to ensure adequate tension capability. If the adjusted value of hookload exceeds the tensile strength, determine the depth at which the limit is exceeded. Replace the drillpipe from that point to the surface with a higher grade/class or larger size of drillpipe; or reconsider the well profile plan.

Torque margin. The drilling torque must not exceed 80% of the make-up torque anywhere in the string for the connections at that depth.

Slackoff hookload. The slack off hookload must be a positive value to allow sufficient weight to get to bottom. The weight of the traveling assembly can be used to push the pipe down.

NOTE:-

- A maximum allowable weight on bit must be specified for rotary drilling to ensure the drillstring is not buckled while rotating. Consideration must be given to the length of the bit run. The location of the heavyweight drillpipe in the well must be monitored and predetermines the length of the bit run. In conventional drilling, more pipes are simply added at the surface as depth increases. The number of different grades of pipe should be kept to a minimum since the increased pipe handling required by the heavyweight will be exacerbated by a design calling for several grades of drillpipe. Should this phase of the design determine that the well cannot be drilled for any reason; the well plan may need to be rethought. Consideration should be given to reducing the build rate and/or horizontal displacement required.



The length of heavyweight must be increased so that heavyweight drillpipe is at point A at the beginning of the run, as well as the end. At the end of this run, compressive forces at point A may have increased to the critical buckling force, and drillpipe will buckle. Therefore, heavyweight drillpipe should be used here.

If the well design calls for running the drillpipe at the surface close to the design limits for tension and/or torsion, further calculations should be done to determine the reduction in tensile strength due to torque and vice versa.

The next phase of the design should look at the planned casing depths. Both casing and drillpipe should be modeled at each depth (including TD) to determine if the wellplan is achievable. The same design criteria listed above should be applied to insure that adequate tensile and torsional margins are built into the design.

CASE

STYUDY

DRILL STRING DESIGN FOR MEDIUM RADIUS HORIZONTAL WELL

WELL PLANNING:-

WELL NAME: - MNO

TRUE VERTICAL DEPTH:-8000ft

NAME OF THE RIG- E-760-XI

TYPE OF RIG- ELECTRICAL

DRAW WORKS (BHEL) - 1000 HP

POWERTO DRAW WORKS – ELECTRICAL

WELL HEAD SET- 2 CASING POLICY (9 5/8"x 7")

TYPE OF THE WELL- DEVEPOLEMENT

SLUSH PUMP- ELECTRICAL

ORIENTATION OF THE WELL- HORIZONTAL

ELEVATION KELLY BUSH- 98.65m

ELEVATION GROUND LEVEL- 91.03m

OBJECTIVE TO DEVELOPE KS-II-SAND

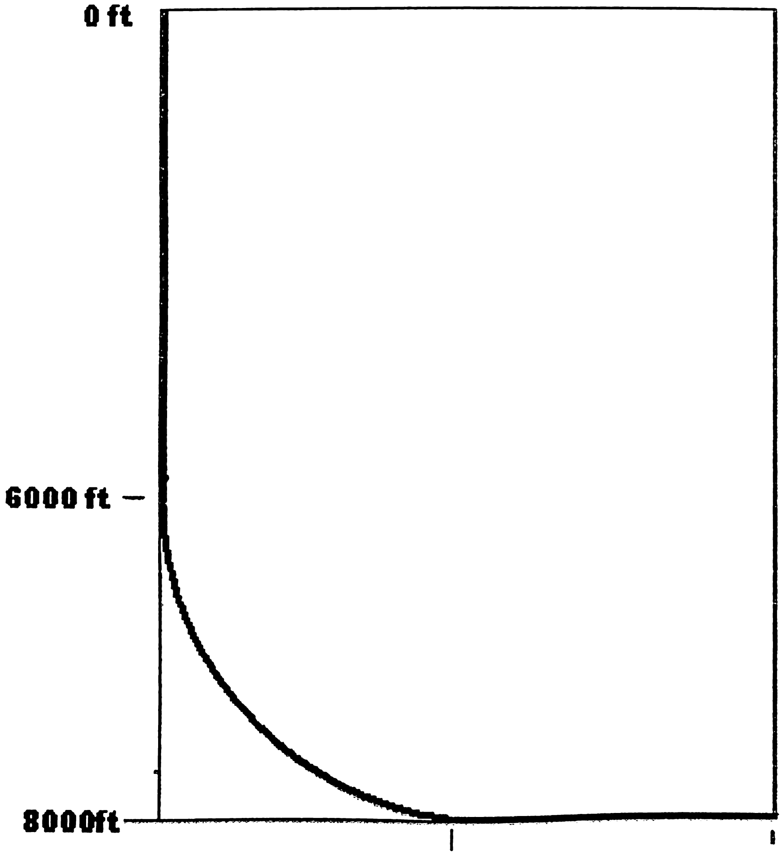
Well Plan

Kickoff at 6,000 ft	Hole size at TD:	8.5 in
Build 10°/100 ft to 90°	Mud weight:	10 ppg
Hold for 1,100 ft	Coeff. of friction:	0.20
TD = 8000 ft MD	Max. mud motor torque:	3,000 lbs

BHA and Available Pipe

BHA:	240 ft	6.75 in	101.0 lbs/ft
HWDP available:	3,000 ft	5.00 in	49.3 lbs/ft
Drillpipe:	15,000 ft	5.00 in	19.5 lbs/ft Grade E Class 2
	3,000 ft	5.00 in	19.5 lbs/ft Grade G Class 2

WELL TREJECTORY

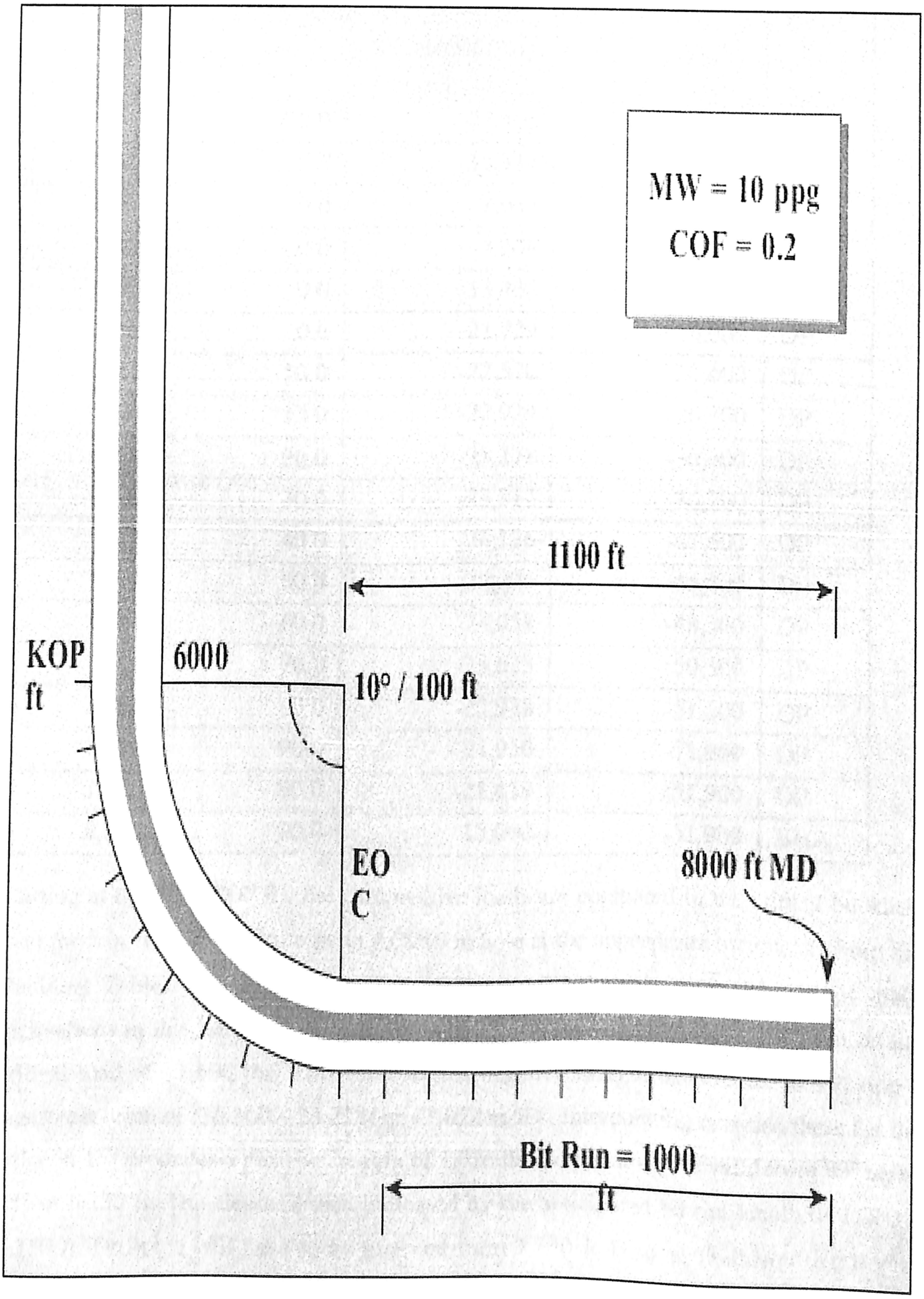


THE DRILL STRING DESIGN OF THE WELL:-

STEP 1

The first drillstring to run should include only the BHA and drillpipe to reach the proposed TD.

Length	Name	OD	ID	Wt/Length	Depth Range
7760 ft	Drillpipe	5.00 in	4.276 in	19.5 lbs/ft	0 - 7760 ft
240 ft	BHA	6.75 in	2.813 in	101.0 lbs/ft	7760 - 8000 ft


MW = 10 ppg
COF = 0.2
1100 ft
KOP
ft
6000
10° / 100 ft
EO
C
8000 ft MD
Bit Run = 1000
ft

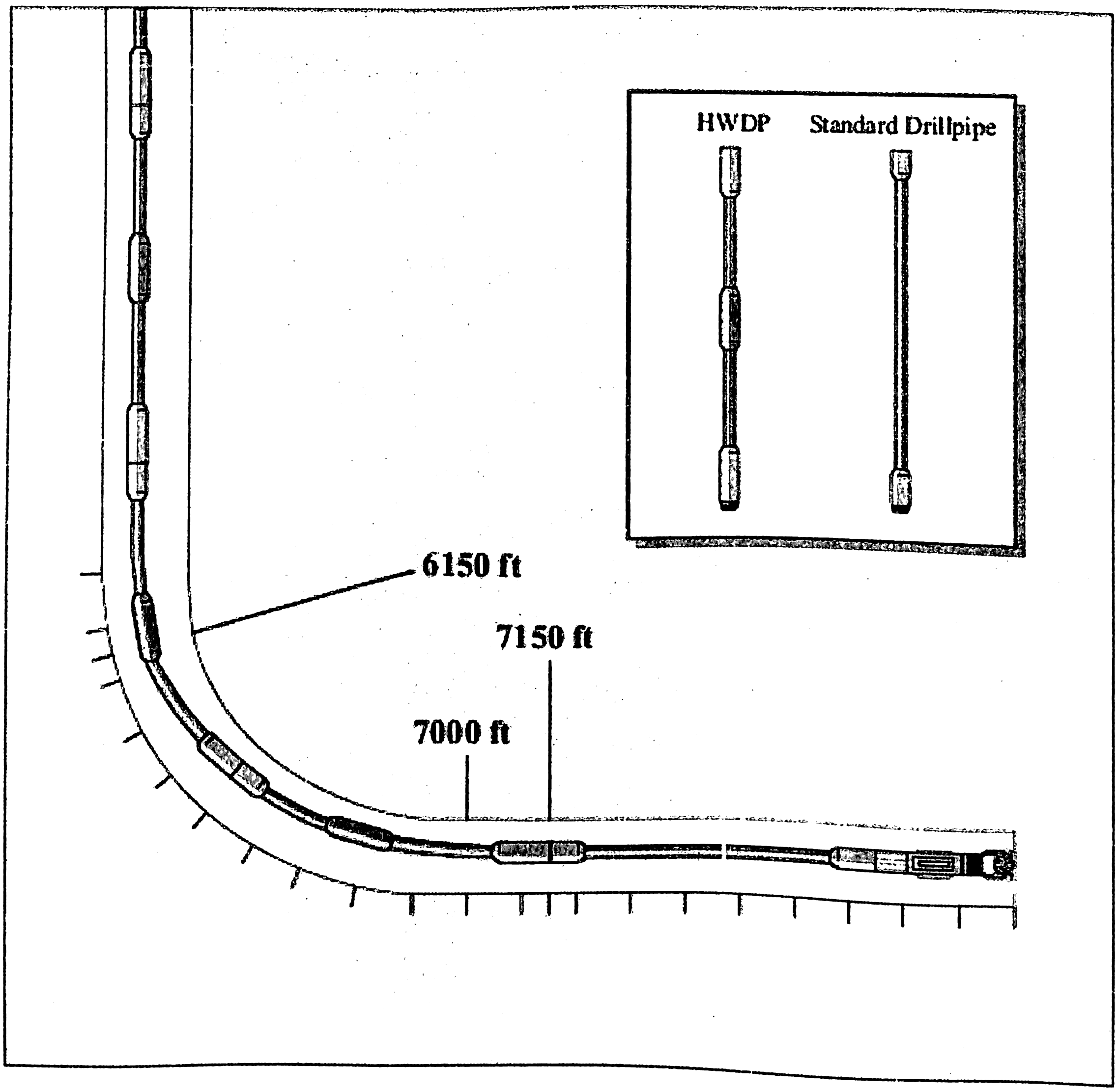
TH (ft)	INC. (deg)	TENSION (lbs)	CRITICAL BUCKLING LOAD (lbs)	
0	0.0	77,405	——	
4,000	0.0	11,315	——	
4,500	0.0	3,055	——	
5,000	0.0	-5,206	-6,900	DP
5,500	0.0	-13,468	-6,900	DP
6,000	0.0	-21,729	-6,900	DP
6,100	10.0	-22,570	-21,600	DP
6,150	15.0	-22,924	-26,300	DP
6,200	20.0	-23,278	-30,400	DP
6,300	30.0	-23,812	-36,700	DP
6,400	40.0	-24,136	-41,600	DP
6,500	50.0	-24,225	-45,400	DP
6,600	60.0	-24,058	-48,300	DP
6,700	70.0	-23,623	-50,300	DP
6,800	80.0	-22,918	-51,500	DP
6,900	90.0	-21,950	-51,900	DP
7,000	90.0	-21,619	-51,900	DP
8,000	90.0	-15,000	-51,900	BHA

Starting at the bit (8,000 ft), the compressive loads are compared to the critical buckling load for 5 in, 19.5 lbs/ft drillpipe in an 8.50 in hole at the appropriate inclination from the Buckling Tables. The loads from 20° – 90° are all below the critical loads for these inclinations in this hole size, but the value of 22,570 lbs compression at 10° exceeds the critical load of 21,600 lbs. This represents a negative margin of -970 lbs at 10° and a positive margin of (30,300 – 23,278) or +7,022 at 20°. Interpolating between these for the value at 15° produces a positive margin of 3,026 lbs, so the design is valid from 90° up to 15° or 6,150 ft. This depth is then increased by the anticipated bit run length of 1,000 – 7,150 ft. Drillpipe will have to be replaced from 7,150 ft to some shallower depth with heavyweight drillpipe.

STEP 2

Replace the 5 in drillpipe from 7,150 ft to surface with heavyweight drillpipe

Length	Name	OD	ID	Wt/Length	Depth Range
7150 ft	HW Drillpipe	5.00 in	3.000 in	49.3 lbs/ft	0 - 7150 ft
610 ft	Drillpipe	5.00 in	4.276 in	19.5 lbs/ft	7150 - 7760 ft
240 ft	BHA	6.75 in	2.813 in	101.0 lbs/ft	7760 - 8000 ft



The output generated from this run is summarized below.

DEPTH (ft)	INC. (deg)	TENSION (lbs)	CRITICAL BUCKLING LOAD (lbs)	
0	0.0	239,893	——	HW
4,000	0.0	72,805	——	HW
4,500	0.0	51,919	——	HW
5,000	0.0	31,033	——	HW
5,500	0.0	10,147	——	HW
5,700	0.0	1,793	——	HW
5,800	0.0	-2,384	-14,900	HW
5,900	0.0	-6,562	-14,900	HW
6,000	0.0	-10,739	-14,900	HW
6,100	10.0	-14,382	-47,000	HW
6,200	20.0	-17,636	-66,000	HW
6,300	30.0	-20,399	-79,800	HW
6,400	40.0	-22,586	-90,500	HW
6,500	50.0	-24,128	-98,800	HW
6,600	60.0	-24,978	-105,100	HW
6,700	70.0	-25,109	-109,400	HW
6,800	80.0	-24,515	-112,000	HW
6,900	90.0	-23,212	-112,900	HW
7,000	90.0	-22,377	-112,900	HW
7,150	90.0	-21,123	-51,900	DP
8,000	90.0	-15,000	-51,900	BHA

Again, the compressive limits are compared to the calculated results. The drillpipe interval from 7,150 – 7,760 ft is at 90°. According to the buckling table, the 5 in drillpipe can withstand 51,900 lbs of compression at 90° before helically buckling. The maximum value calculated, 21,123 lbs compression, which occurs at the top of the section, is well below this limit.

Then compare the results over the heavyweight interval from 0 – 7,150 ft. An assumption about true hole inclination is made to get around the fact that at 0° inclination, the solution of the buckling equation is always zero (sine of 0° = 0).

The hole is assumed to have some inclination, and the value of 1° is used as the minimum hole inclination. The highest compression seen in the vertical portion of the well, -10,739 lbs is less than the limit of the heavyweight, which is -14,900 lbs. This output also identifies the point at which the heavyweight can be replaced with drillpipe to the surface.

The drillpipe can tolerate 6,900 lbs compression in a vertical hole At 5,900 ft, the compression is only -6,562 lbs, so drillpipe can be run in the interval from surface to 5,900 ft.

STEP 3

Replace the heavyweight from 5,900 ft to surface with drillpipe.

Length	Name	OD	ID	Wt/Length	Depth Range
5900 ft	Drillpipe	5.00 in	4.276 in	19.5 lbs/ft	0 - 5900 ft
1250 ft	HW Drillpipe	5.00 in	3.000 in	49.3 lbs/ft	5900 - 7150 ft
610 ft	Drillpipe	5.00 in	4.276 in	19.5 lbs/ft	7150 - 7760 ft
240 ft	BHA	6.75 in	2.813 in	101.0 lbs/ft	7760 - 8000 ft

Summarized output is given below.

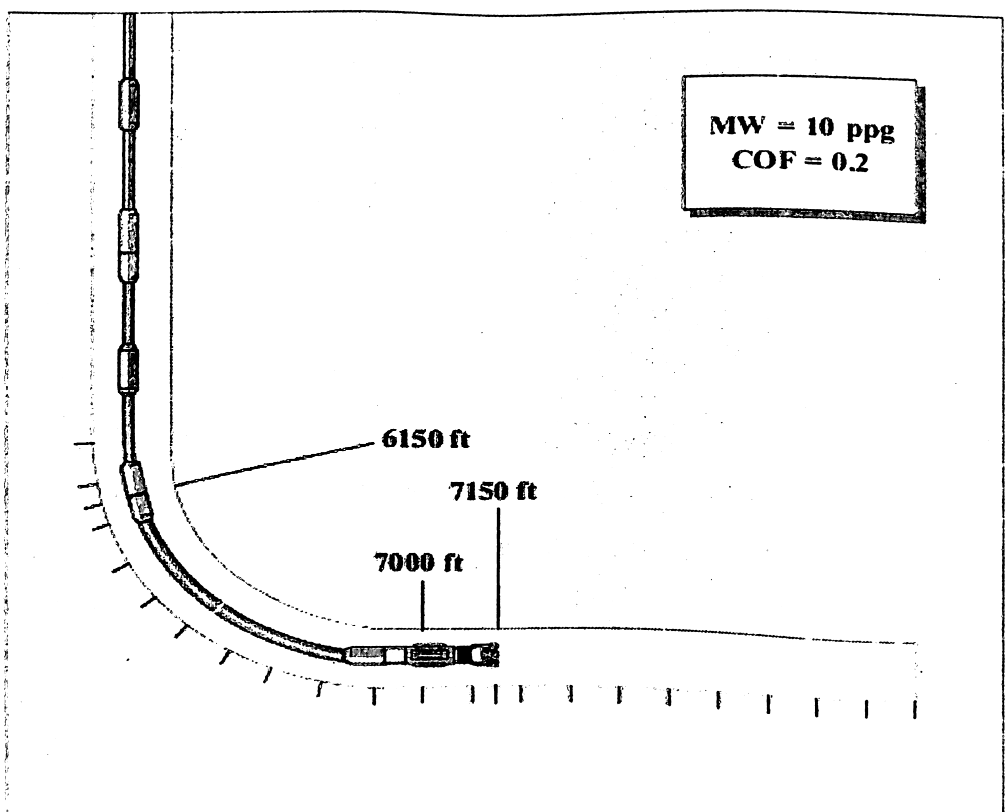
DEPTH (ft)	INC. (deg)	TENSION (lbs)	CRITICAL BUCKLING LOAD (lbs)	
0	0.0	90,920	270,432	DP
4,000	0.0	24,831	270,432	DP
5,000	0.0	8,309	270,432	DP
5,500	0.0	47	270,432	DP
5,700	0.0	-3,257	-6,900	DP
5,800	0.0	-4,909	-6,900	DP
5,900	0.0	-6,562	-6,900	DP
6,000	0.0	-10,739	-14,900	HW
6,100	10.0	-14,383	-47,000	HW
6,200	20.0	-17,636	-66,000	HW
6,300	30.0	-20,399	-79,800	HW
6,400	40.0	-22,586	-90,500	HW
6,500	50.0	-24,128	-98,800	HW
6,600	60.0	-24,979	-105,100	HW
6,700	70.0	-25,109	-109,400	HW
6,800	80.0	-24,515	-112,000	HW
6,900	90.0	-23,212	-112,900	HW
7,000	90.0	-22,377	-112,900	HW
7,150	90.0	-21,123	-51,900	DP
8,000	90.0	-15,000	——	BHA

This output is again checked for high compressive loads. The heavyweight covers the critical interval from 5,900 – 7,150 ft, where buckling is likely if drillpipe were used. No buckling occurs in the heavyweight. The drillpipe sees a maximum of -6,562 lbs, which is below the limit of -6,900 lbs for a vertical hole. A quick comparison is made between the maximum tension at surface, 90,920 lbs, and the specification for tensile load in API RP7G. Table 6 show the maximum allowable tension for 5 in, 19.50 lbs/ft Grade E used pipe is 270,432, which gives in excess of 100,000 lbs safety margin. The total tension at surface will be highest when tripping out of the hole (pickup hookload).

STEP 4

Run the program at 7,000 ft to analyze the beginning of the bit run.

Length	Name	OD	ID	Wt/Length	Depth Range
4900 ft	Drillpipe	5.00 in	4.276 in	19.5 lbs/ft	0 - 4900 ft
1250 ft	HW Drillpipe	5.00 in	3.000 in	49.3 lbs/ft	4900 - 6150 ft
610 ft	Drillpipe	5.00 in	4.276 in	19.5 lbs/ft	6150 - 6760 ft
240 ft	BHA	6.75 in	2.813 in	101.0 lbs/ft	6760 - 7000 ft



DEPTH (ft)	INC. (deg)	TENSION (lbs)	CRITICAL BUCKLING LOAD (lbs)		
0	0.0	115,093	270,432	DP	Tensile Capacities
4,000	0.0	49,004	270,432	DP	
4,500	0.0	40,743	270,432	DP	
4,900	0.0	32,114	691,185	HW	
5,000	0.0	29,957	691,185	HW	
5,500	0.0	9,071	691,185	HW	
5,600	0.0	4,893	691,185	HW	
5,700	0.0	716	691,185	HW	
5,800	0.0	-3,461	-14,900	HW	
5,900	0.0	-7,638	-14,900	HW	
6,000	0.0	-11,815	-14,900	HW	
6,100	10.0	-15,422	-47,000	HW	
6,150	15.0	-16,472	-26,400	DP	
6,200	20.0	-17,522	-30,400	DP	
6,300	30.0	-18,253	-36,700	DP	
6,400	40.0	-18,769	-41,600	DP	
6,500	50.0	-19,042	-45,400	DP	
6,600	60.0	-19,052	-48,300	DP	
6,700	70.0	-18,789	-50,300	DP	
6,800	80.0	-18,285	-138,000	BHA	
6,900	90.0	-16,712	-139,000	BHA	
7,000	90.0	-15,000	-139,000	BHA	

The lower interval of drillpipe is now between the depths of 6150 – 6,760 ft. The critical buckling load at 15° is 26,400 lbs for the 5 in drillpipe and increases with inclination. Nowhere in the lower drillpipe interval does the compression exceed this value, so the design is still valid. The heavyweight is in the interval from 4,900 – 6,150 ft and covers the interval of compressive force at inclinations less than 15°. The heavyweight can tolerate -149, 00 lbs in a vertical hole, which exceeds the highest calculated value of 11,815 lbs. The majority of heavyweight is in the vertical portion of the well where the greatest weight-on-bit contribution is realized.

STEP 5:-

Analyze the cases of pickup, slack off, and drilling at TD.

	Depth (ft)	Inc. (deg)	Pickup Tension (lbs)	Slackoff Tension (lbs)	Drilling Tension (lbs) 35k WOB	Drilling Tension (lbs) 40k WOB
DP	0	0.0	137,991	111,070	90,535	85,530
HW	5,900	0.0	40,509	13,588	-6,947	-11,951
DP	7,150	90.0	6,123	-6,123	-35,014	-40,014
BHA	7,760	90.0	3,776	-3,776	-35,008	-40,008
TD	8,000	90.0	0	0	-35,000	-40,000

The maximum tension at the surface, 137,991 lbs occurs during pickup. This represents the tension actually seen by the drillpipe (traveling block weight is not included). This value must be compared to the API RP7G specification for this grade and size of pipe. According to API SG7G Table 6, 5 in, 19.50 lbs/ft Grade E used pipe is rated for 270,432 lbs in tension. This represents a 132,441 lbs safety margin (270,432 – 137,991), 32% greater than the 100,000 lbs required by the design. Had this grade of pipe not met the 100,000 lbs margin requirement, the pipe would be replaced with a higher grade, but only over the interval where necessary. At some depth the tension in the pipe will be low enough to use Grade E and still maintain a 100,000 lbs margin. Multiple grades of pipe do increase pipe handling difficulty. Because the design has already been optimized for sliding and because slacking off is less demanding than sliding, the results for slacking off are expected to meet the design requirements automatically. The maximum slack off compression in the drillpipe is -6,123 lbs at 90°, far below the critical load of -51,900 lbs. Two cases of drilling are presented. The first shows results for drilling with 35,000 lbs weight on bit, the second for 40,000 lbs WOB. In the first case, the compressive load of -6,947 lbs at 5,900 ft occurs at the junction of the upper section of drillpipe and the heavyweight. This indicates that any further weight applied to the bit will result in helical buckling in the upper section of drillpipe. The output for 40,000 lbs WOB indicates an increase to -11,951 lbs, roughly 5,000 lbs higher, at this depth. Therefore the maximum weight on bit should be limited to 35,000 lbs while rotary drilling. The torque in the drillstring is analyzed next. The cases of drilling and rotating off bottom are analyzed.

	Depth (ft)	Inc. (deg)	Drilling Torque (ft-lbs)	Rotating Off Bottom Torque (ft-lbs)
DP	0	0.0	7,748	2,949
HW	5,900	0.0	7,748	2,949
DP	7,150	90.0	4,575	1,575
BHA	7,760	90.0	4,055	1,055
TD	8,000	90.0	3,000	0

According to API RP7G Table 10, the torque rating on 5 in 19.50 lbs/ft Grade E drillpipe with NC-50 connections is 14,082 ft-lbs. Taking 80% of this value gives 11,266 ft-lbs. All cases fall below this value, and the drillpipe is the weakest member in the drillstring, hence the design is satisfied.

<u>HENCE THE FINAL DESIGN OF THE DRILL STRING IS GIVEN BELOW</u>

	Depth (ft)
DP	0
HW	5,900
DP	7,150
BHA	7,760
TD	8,000

MEASUREMENT WHILE DRILLING IN HORIZONTAL WELL

MEASUREMENT WHILE DRILLING

CONCEPT OF MAGNETICS

COULMB'S LAW

$F = (1/u) * (P_1 * P_2)/r^2$

F – Force Acting On Two Poles
u - Magnetic permeability. (It is the properties of the medium where the magnets are placed)
P_1 - pole strength

P_2 – pole strength

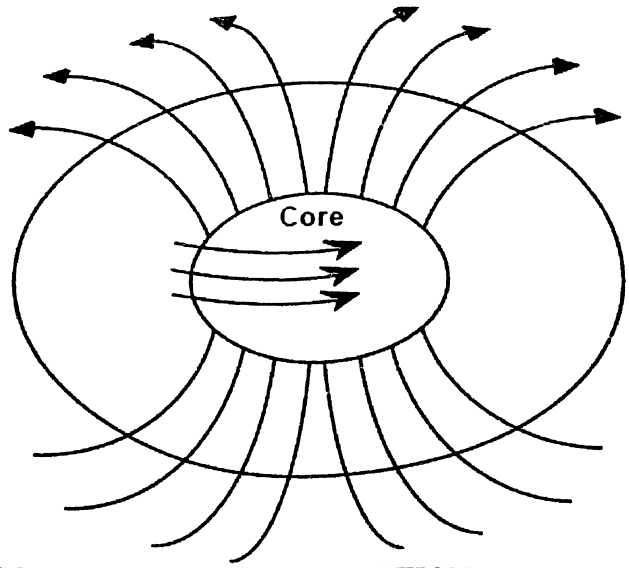
FACTS ABOUT THE MAGNETS:-

- The two poles of a magnet are opposite in nature but of equal pole strength.
- It is not possible to separate two poles. When breaks it produce independent two new magnets.
- Two equal poles repeal each other but two unequal poles attract each other.
- Metal that are attract by the magnet called the FERROMEGNETICS and induced magnetism in them when the brought close to the magnet and loose the magnetism when take away form the magnets. The metal when come close to the north pole of the magnet the south pole induced at the part and the vice versa. Some metal do not loose the magnetism is called permanent magnets.
- The magnet produces the magnetic fields that act as the agent of the magnetic forces.
- The direction of the magnetic field can be known by the direction of the north pole of the compass needle.
- Our mother **earth** also act as a **bar magnet**.

THEORIES TO EXPLAIN THE EARTH'S MAGNETIC FIELD:-

THEORY -1:

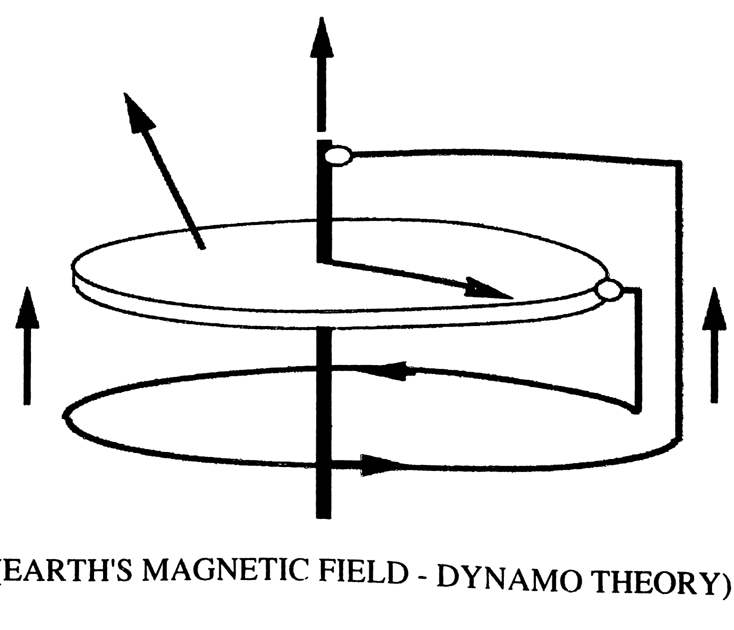
Rotation of the Earth's solid exterior relative to its liquid iron core is believed to induce a slow rotation of the core. A magnetic field results from the electrical currents generated by the relative motion between the liquid core and the mantle.



(EARTH'S MAGNETIC FIELD - ROTATION OF LIQUID CORE)

THEORY -2:

The center portion of the Earth is largely composed of iron and has the mechanical properties of a fluid. These fluids are subjected to internal circulation currents similar to phenomena observed at the periphery of the sun. The internal circulation of these fluids acts as the source of the Earth's magnetic field according to the principle of a self excited **dynamo**.



(EARTH'S MAGNETIC FIELD - DYNAMO THEORY)

MAGNETIC FIELD STRENGTH

The total magnetic field strength may be referred to as the H value, HFH magnetic field strength or total field. The different units of the magnetic field strength is

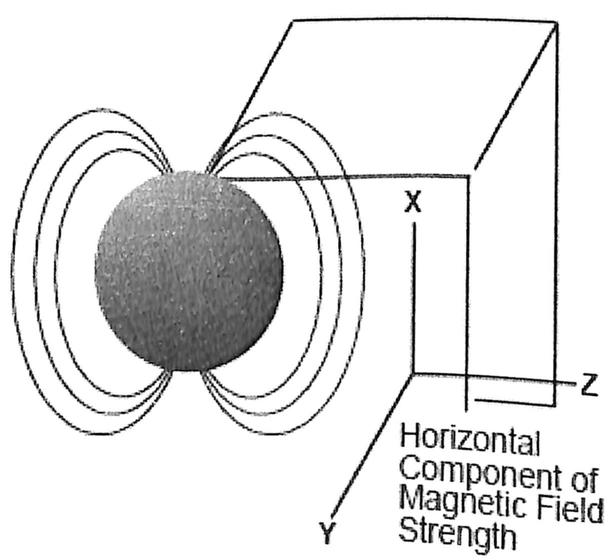
- Tesla
- gauss

The magnetic field intensity recorded at ground level is of a much smaller magnitude than that prevailing around the Earth's core.

The total magnetic field intensity is the vector sum of its horizontal component and its vertical component (Figure 4-5). The vertical component of the magnetic field points toward the ground and therefore contributes nothing to the determination of the direction of magnetic north.

The horizontal component can be computed from the following equation:

MAGNETIC FIELD STRENGTH (HFH) X COS (MAGNETIC DIP ANGLE) = HORIZONTAL COMPONENT OF EARTH MANGETIC FIELD



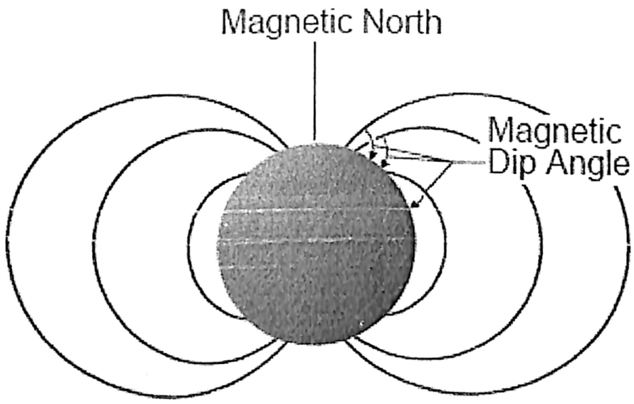
(MAGNETIC FIELD STRENGTH)

MAGNETIC DIP ANGLE:-

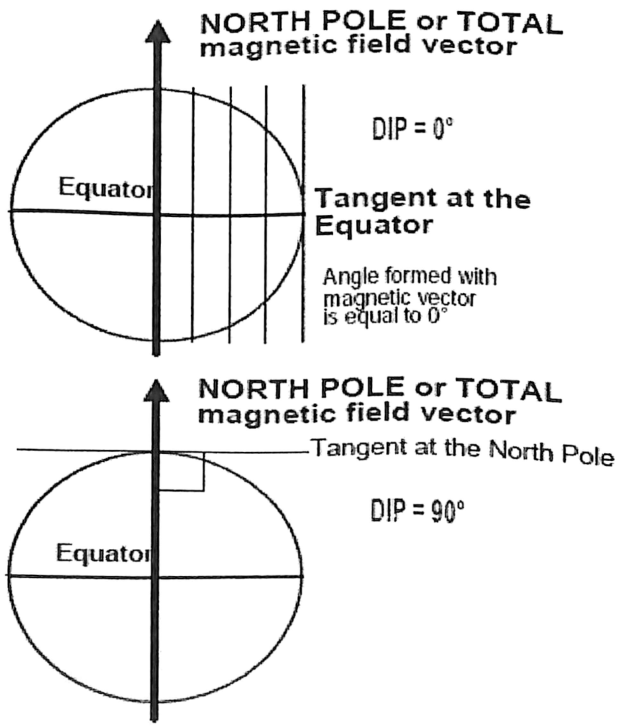
The magnetic dip angle is equal to the angle between the tangent to the Earth's surface and the magnetic field vector. This is also the angle formed between the total magnetic field vector (HFH) and the horizontal vector.

NOTE:

Dip angle is 90 degrees close to the North Pole zero degrees at the equator. There are also several other points on the Earth's surface where the dip is equal to 90 degrees. These are due to local anomalies and are called "dip holes".



(MAGNETIC DIP ANGLE)



(MAGNETIC DIP ANGLES AT POLES AND EQUATOR)

Common relative values for dip angle

Gulf of Mexico	East Canada	Beaufort sea	North sea
59 degrees	70 degrees	84 degrees	70 degrees

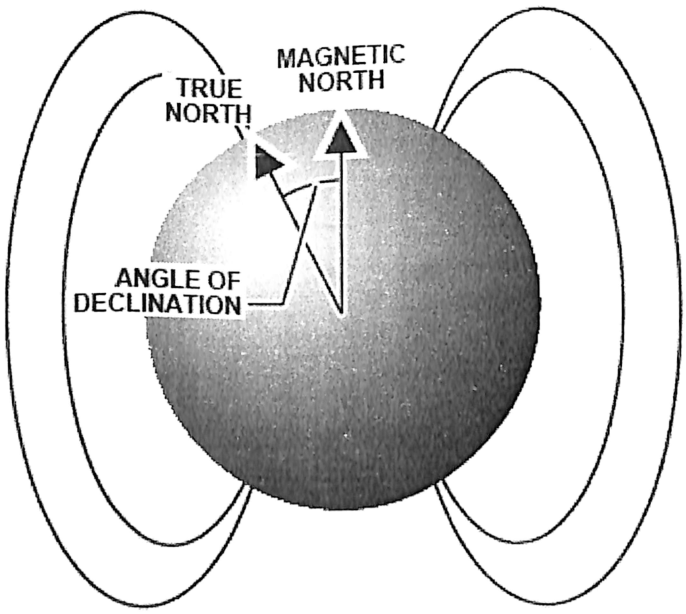
MAGNETIC DECLINATION ANGLE

The angle between magnetic north and geographic north (true north) is defined as the magnetic declination or the angle of declination. This is dependent upon the location (both in latitude and longitude) All magnetic surveys require a conversion to geographic direction by adding or subtracting this angle. If magnetic declination is known, then the direction of the Earth's magnetic field relative to true north can be calculated.

True magnetic north = measured azi ± declination angle

"+" if location in west

"-" if location in east



(MAGNETIC DECLINATION ANGLE)

MAGNETIC INTERFERENCE:

In this section we deal with the interference of the magnets with the survey instruments

There are two types of magnetic interference:

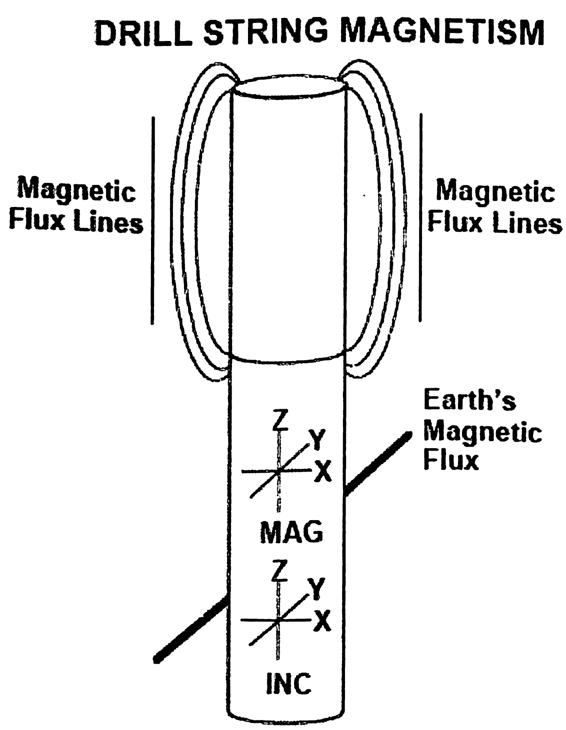
- DRILL STRING MAGNETIC INTERFERENCE.
- EXTERNAL MAGNETIC INTERFERENCE

(Some of the cause is listed below)

- ✓ A fish left in the hole.
- ✓ Nearby casing.
- ✓ A magnetic "hot spot" in the drill collar
- ✓ Fluctuation in the Earth's magnetic field.
- ✓ Certain formations (iron pyrite, hematite and possibly hematite mud).

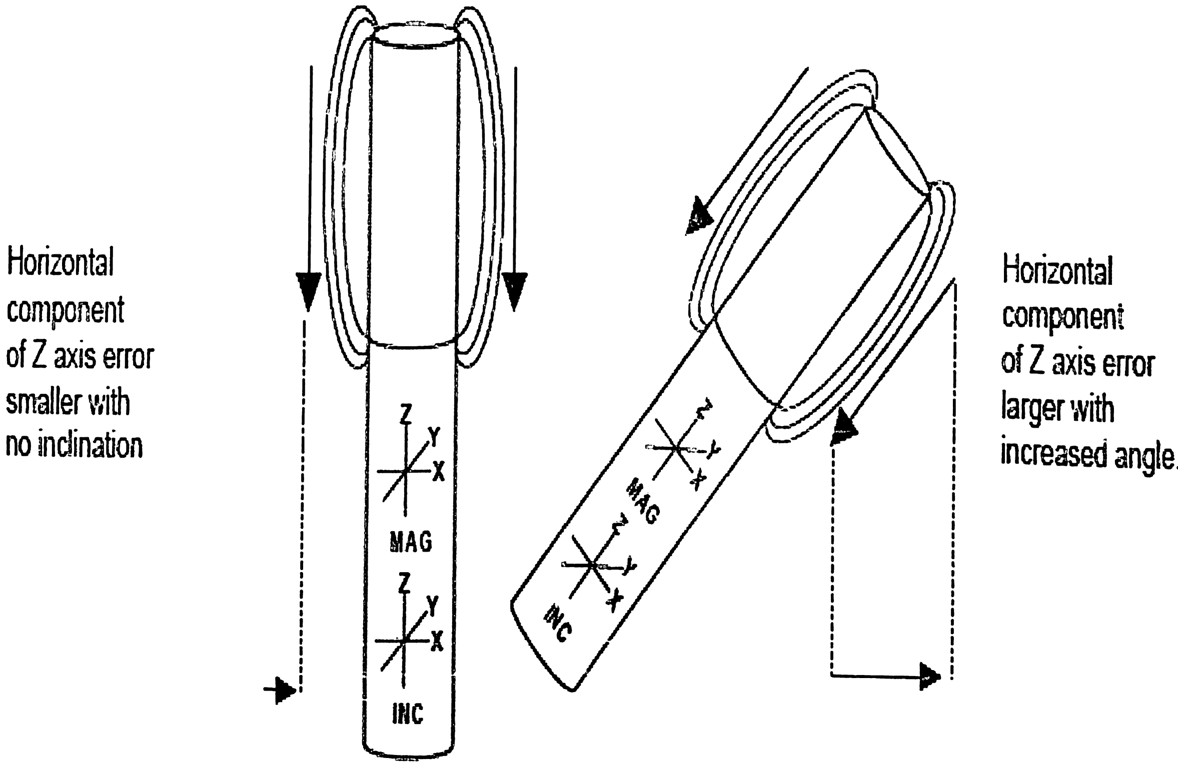
DRILL STRING MAGNETIC INTERFERENCE:

The drill string can be compared to a long slender magnet with its lower end comprising one of the magnetic poles. Even if the components of a drilling assembly have been demagnetized after inspection, the steel section of the drill string will become magnetized by the presence of the Earth's field.

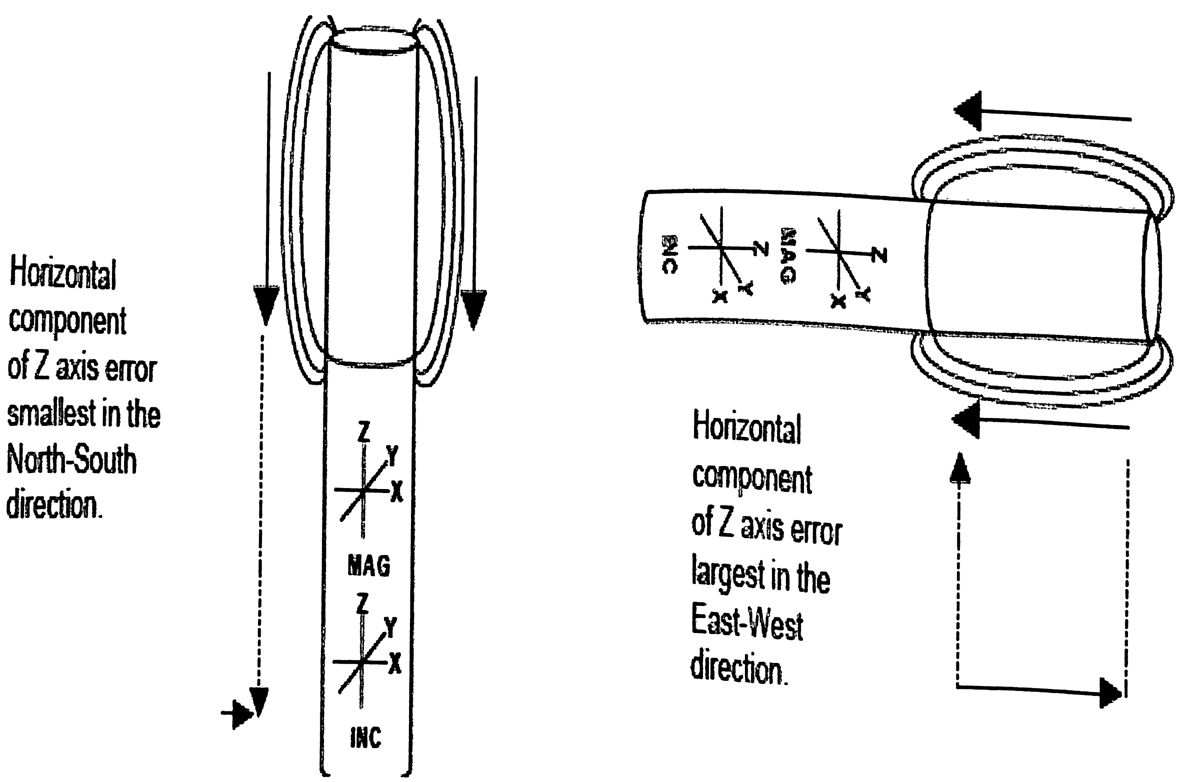


(DRILL STRING MAGNETISM)

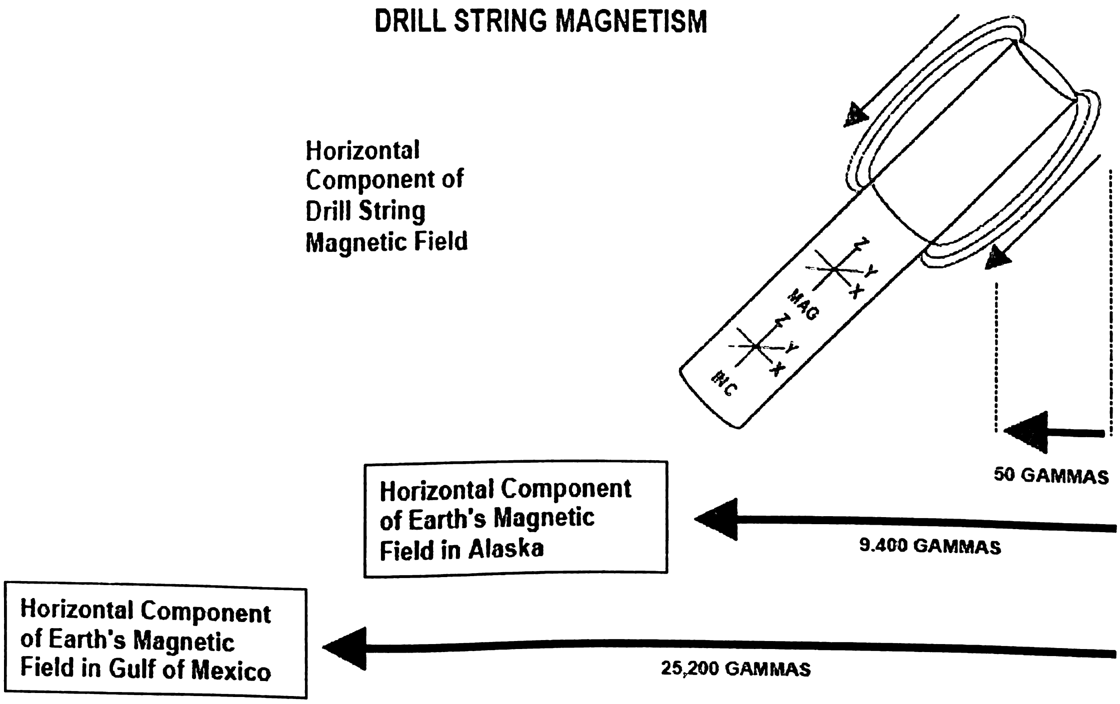
Drill string magnetism can be a source of error in calculations made from the supplied magnetometer data. This may happen as the angle builds from vertical or as the azimuth moves away from a north/south axis. Also, changing the composition of the BHA between runs may change the effects of the drill string.



(EFFECT OF HOLE ANGLE ON DRILLSTRING MAGNETIC INTERFERENCE)



(EFFECT OF AZIMUTH ON DRILLSTRING MAGNETIC INTERFERENCE)



(DRILLSTRING MAGNETIC INTERFERENCE AT DIFFERENT LATITUDES)

It is because of drill string magnetism that non-magnetic drill collars are needed. Non-magnetic drill collars are used to position the compass or D&I package out of the magnetic influence of the drill string.

The magnetometers are measuring the resultant vector of the Earth's magnetic field and the drill string. Since this is in effect one long dipole magnet with its flux lines parallel to the drill string, only the Z-axis of the magnetometer package (Z-axis is usually the axis of the surveying tool). Is affected, normally creating a greater magnetic field effect along this axis. The magnitude of this error is dependent on the pole strength of the magnetized drill string components and their distance from the MWD tool. The error will normally appear in the calculated survey as an increased total HFH value (higher total field strength than the Earth alone). This increase is due to the larger value of the Z-axis magnetometer. The total H value should remain constant regardless of the tool face orientation or depth as long as the hole inclination, azimuth and BHA remain relatively constant.

When drill string magnetism is causing an error on the Z-axis magnetometer, only the horizontal component of that error can interfere with the measurement of the Earth's magnetic field. The horizontal component of the Z-axis error is equal to the Z-axis error multiplied by the <u>sine of the hole deviation</u>.

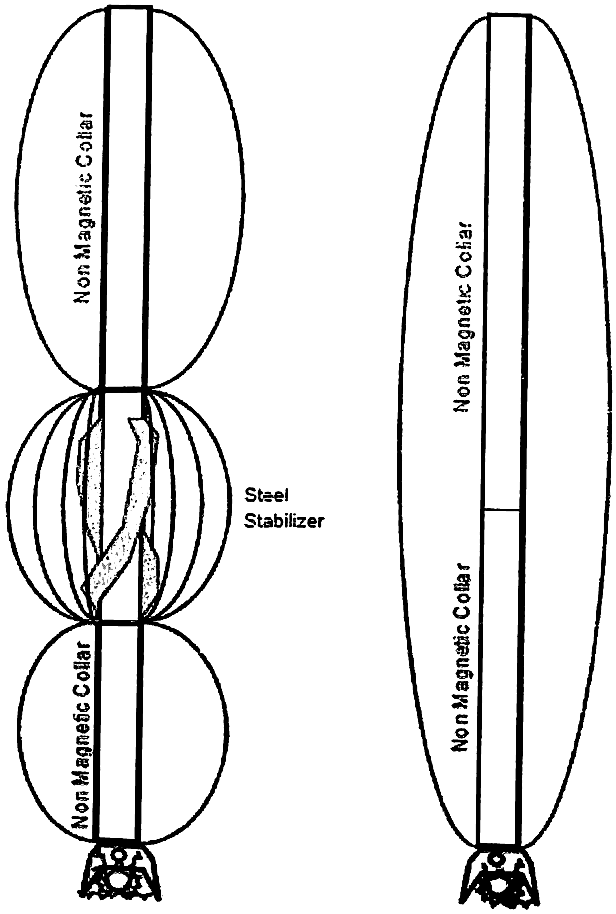
The horizontal component of the Z-axis error is equal to:

– [(Z-axis error) x sin (drift)].

MINIMIZING ERRORS

- Minimize the error caused by the drill string by eliminating as much of the magnetism as possible from the drill string.
- Isolate the magnetometer package with as many non-magnetic drill collars as possible. The length of the non-magnetic collars implies a uniform and non-interrupted non-magnetic environment.
- Each connection in a drill string, whether magnetic or not, is magnetic due to the effects of the mechanical torque of the pin in the box. This mechanical stress causes the local metal around the connection change its magnetic properties and can actually cause a survey azimuth reading error. Therefore, never space within 2 feet of a connection.
- Does not space exactly in the center of a nonmagnetic collar. When a collar has been bored from both ends, there is a very slight ridge at the point where the two bores come together. This becomes magnetically hot due to the cyclic rotation stresses to which the collar is subjected during rotary drilling. Usually, this effect can be removed by trepanning the collar bore. This leads to reading error.
- The presence of a steel stabilizer or steel component between two non-magnetic collars results on a pinching of the lines of force. This is detrimental to the accuracy of the survey.

The figure below illustrated the effect of a steel stabilizer or steel component between two non-magnetic collars



Length of Non Magnetic Collars
implies a uniform, non-interrupted
non-magnetic environment.

(MAGNETIC LINES OF FORCE IN THE DRILLSTRING)

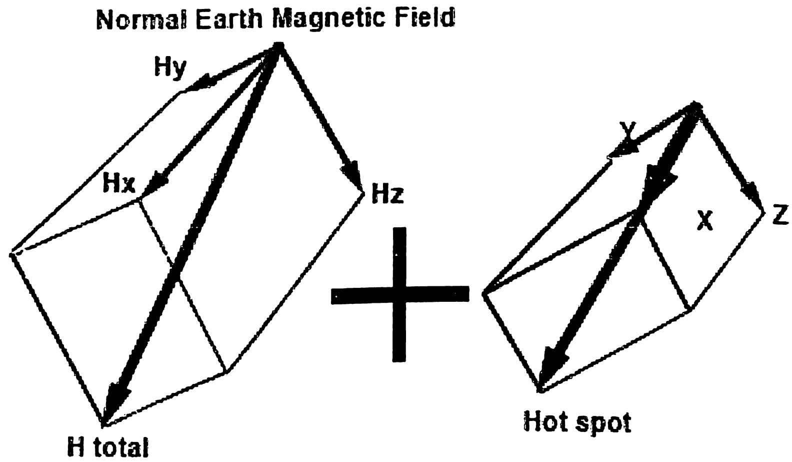
- Non-magnetic stabilizers are actually magnetic near the blades due to the hard metal facing and matrix used on stabilizers can be very magnetic. Hence never space a MWD tool inside a non-magnetic stabilizer.

N OTE:

If magnetic interference is encountered from the drill string, the total H value should remain constant regardless of tool face orientation or depth as long as the hole inclination, azimuth and BHA remain constant.

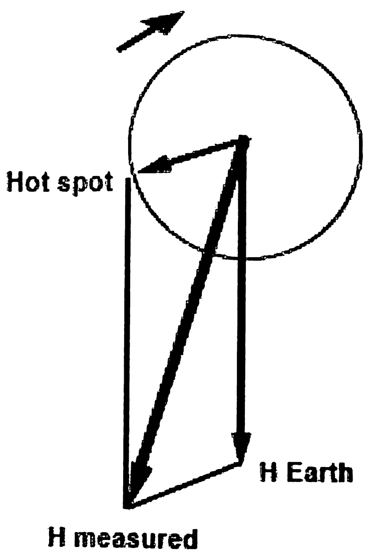
EXTERNAL MAGNETIC INTERFERENCE

- When magnetic interference from external sources is encountered (such as from a fish in the hole or from nearby casing), all three axis of the D&I package will be affected. Therefore, the total magnetic field will vary. The total H value will also vary when the D&I package is close to casing joints.
- If a hot spot occurs on a non-magnetic collar, our total H value will change with varying tool face settings.



Magnetic Hot Spot Rotating With MWD Collar

On thisdrawing hot spot is perfectly aligned with X axis.

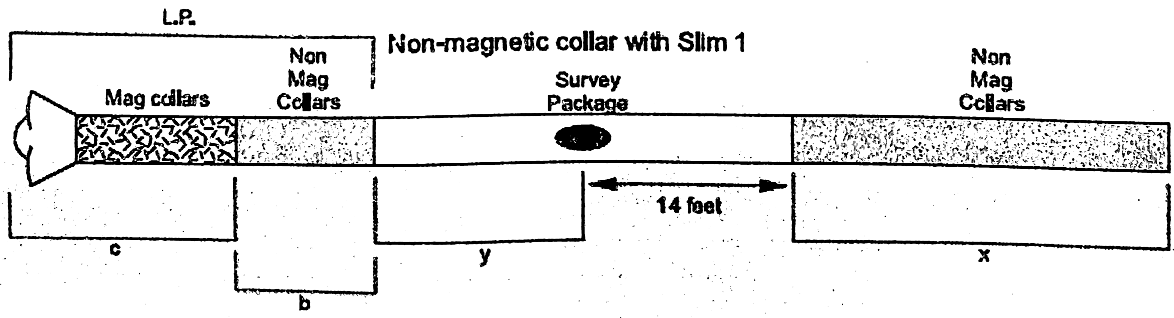


All 3 axis measurements are affected. Fluctuation in total field is observed when MWD tool is rotated. Calculated azimuth will be wrong but will be repeatable with the same tool face.

(EFFECT OF MAGNETIC HOT SPOT IN MWD COLLAR)

DIRECTIONAL PACKAGE SPACING

To avoid magnetic interference, non-magnetic drill collars are used. Charts were valid at the time because most wells were kicked off to less than 10 degrees of inclination and often without a mud motor (whip stock, jetting). Mud motors produce a magnetic field from 3 to 10 times greater than components such as steel stabilizers and short drill collars, So a non-magnetic short drill collar (of 10 to 15 feet) should be placed between the motor and D&I package..



(NMDC REQUIREMENTS)

$$IF = [770 / (z + x)^2] + [L^* P / (y + b)^2] - [LP / (y + b + c)^2] \mu T$$

$$AE = (57300 * IF * \sin I * \sin Az - MD) / H * \cos Dip$$

IF = the calculated interfering field (in micro Tesla)

LP = Pole strength of components below the MWD

AE = Predicted azimuth error due to interfering field

H = Total magnetic field strength in gammas

Az = Azimuth of the well (relative to True North)

I = Inclination of the well

MD= Magnetic declination

Dip = Magnetic dip angle

x = Length of non-magnetic collar above MWD

y = Length of MWD collar below D&I sensor point

z = Length of MWD collar above D&I sensor point

b = Length of non-magnetic collar below MWD

c = Length of magnetic material below MWD

N.B: All lengths are in feet

NOTE:

- For LP use the following values:

  Stabilizer and bit = 77

  30 ft or more DC or other BHA = 260

  Mud motor or turbine = 860

- Azimuth error (AE) should be less than 0.5 degrees. If it is not, continue adding lengths of non-magnetic drill collars both above and below the MWD collar until the AE value is below 0.5 degrees.

BASIC MWD THEORY:-

MWD Systems use two type of Telemetry to transmit survey data from down hole to surface

- Mud Pulse Telemetry
- electromagnetic transmission

Mud Pulse Telemetry:-

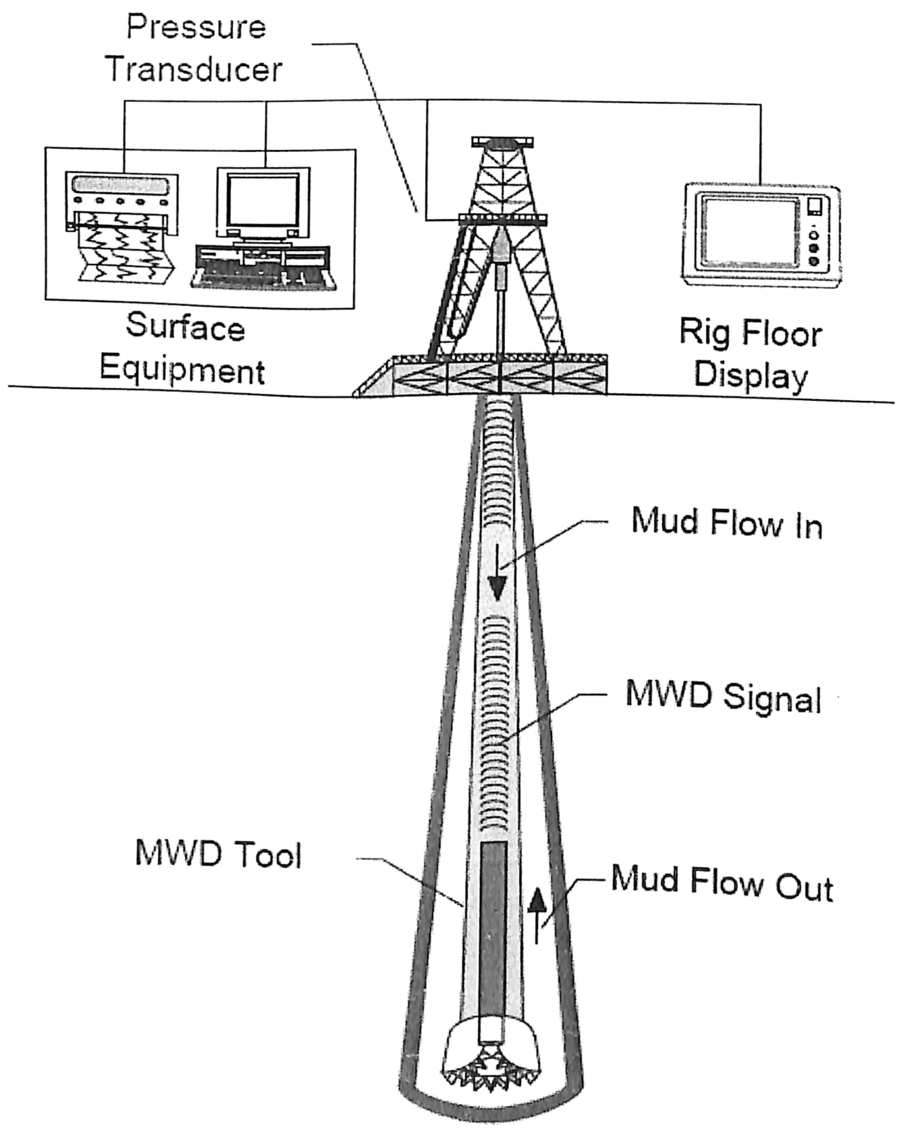


Figure 4-33 Mud pulse telemetry

In Mud Pulse Telemetry the mud pressure in the drill string is modulated to carry information in digital form. Tool measurements are digitized down hole. The measured values are transmitted to the surface as a series of zeroes and ones in the form of pressure variations.

Pressure pulses are converted to electric voltages by a transducer installed in the pump discharge circuit. This information representing tool measurements is decoded by the surface equipment.

There are three telemetry systems used for transmitting the data from down-hole to surface.

- Positive pulser
- Negative pulser
- Standing (or continuous) wave pulsers

POSITIVE PULSER

Positive pulse telemetry uses a flow restrictor which when activated increases stand pipe pressure and sends the data to the transducer.

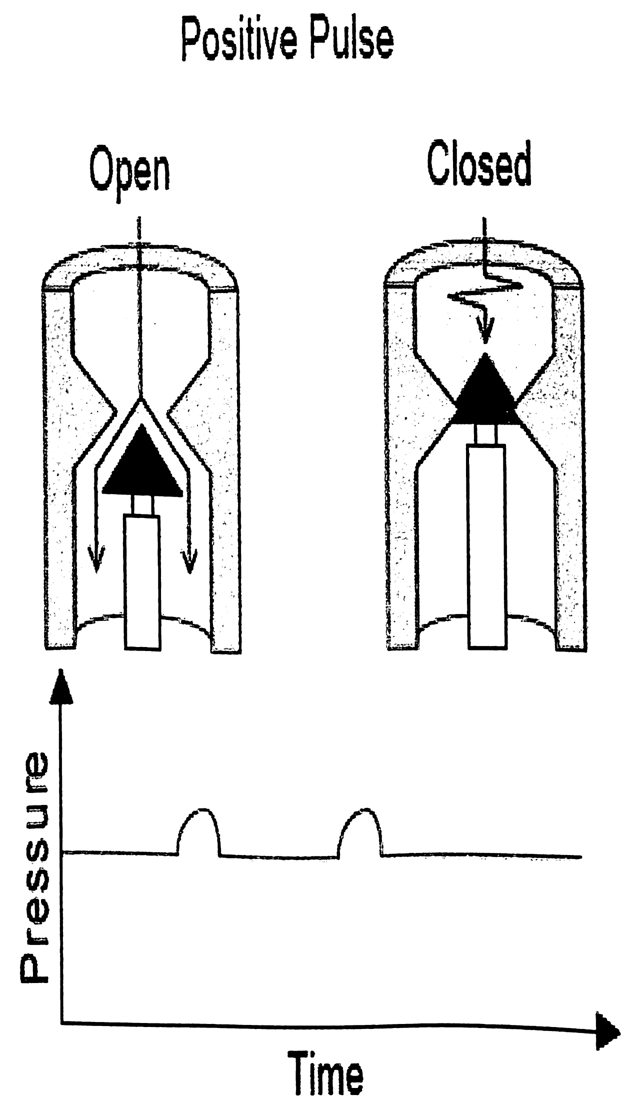
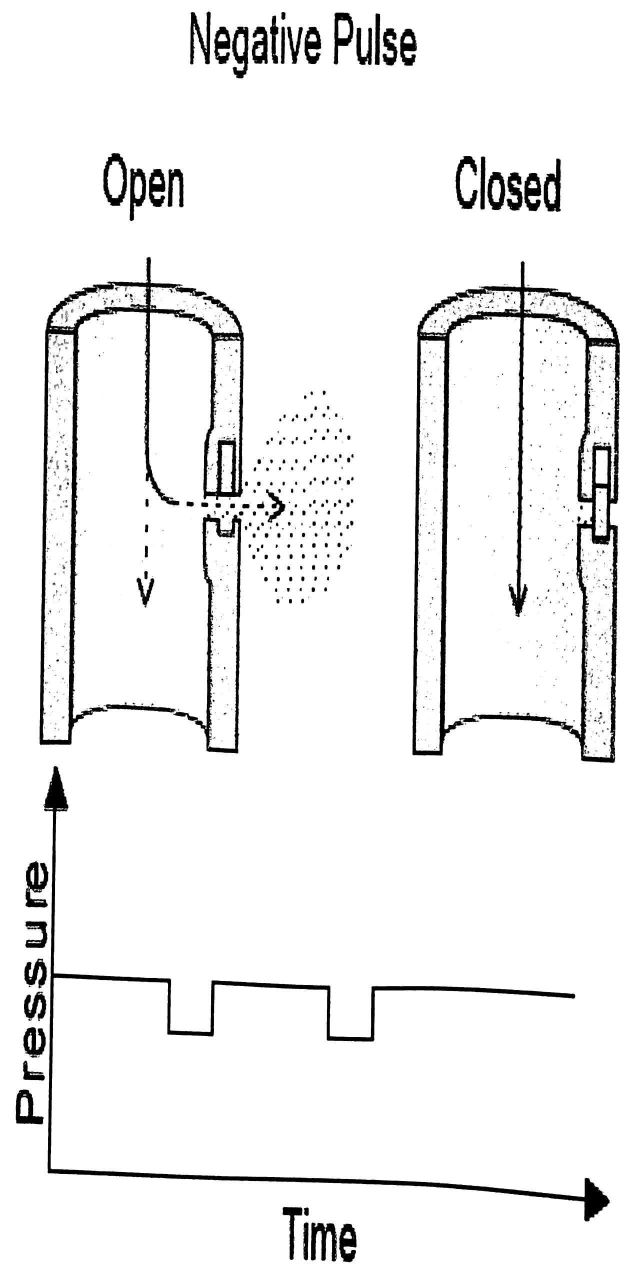


Figure 4-35 Positive pulse telemetry

NEGATIVE PULSE

Negative pulse telemetry system has having a diverter valve that vents a small amount of mud flow to the annulus when activated. This decreases standpipe pressure momentarily. Hence produce the signal and transmitted it to the transducer.

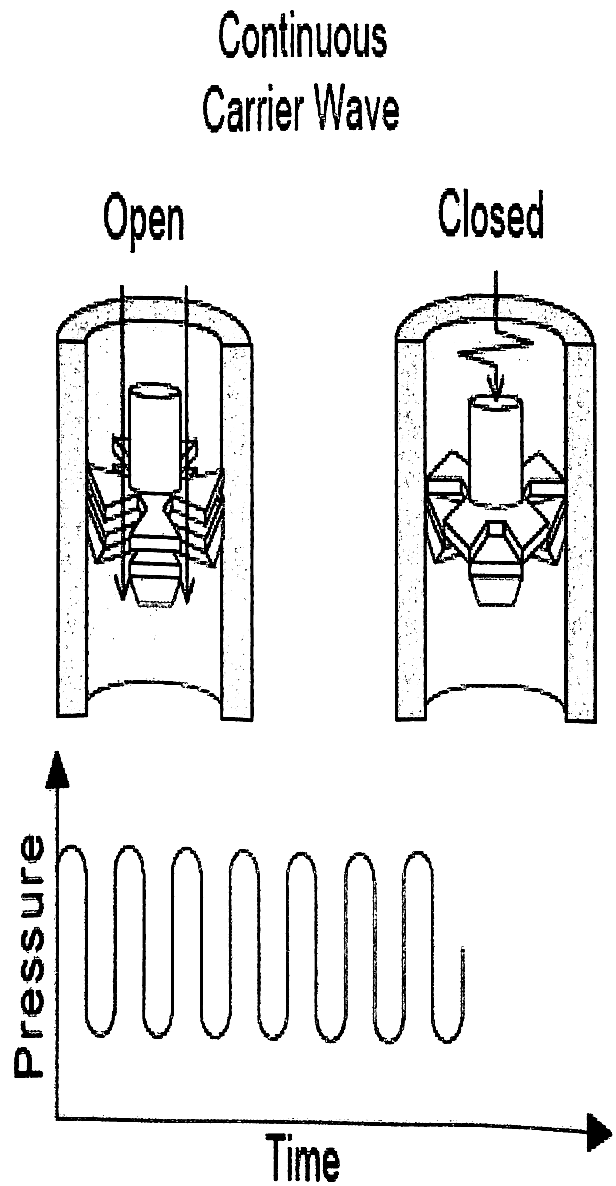


(STANDING (OR CONTINUOUS) WAVE PULSERS (MUD SIRENS)

STANDING (OR CONTINUOUS) WAVE PULSERS (MUD SIRENS):-

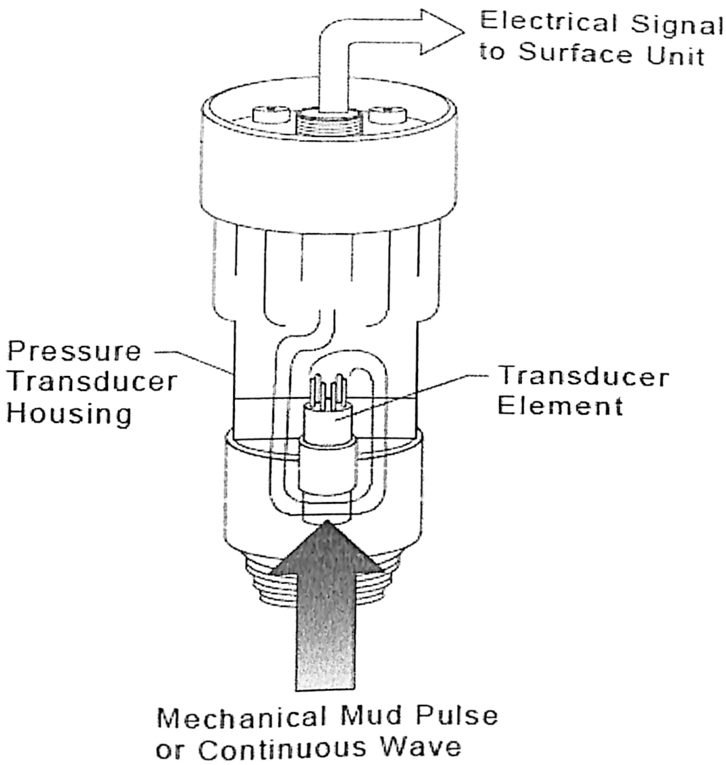
Standing (or continuous) wave pulsers use rotating baffled plates which temporarily interrupt mud flow, creating a pressure wave in the standpipe.

Changes in relative rotation speed of the plates changes the wave phasing. This phase changes are identified at the surface and decoded.



TRANSDUSERS:-

Pressure pulses are converted to electric voltages by a transducer installed in the pump discharge circuit.



HYDRAULIC CONSIDERATIONS:-

The drilling fluid system introduces noise during pump operation which can make MWD surface equipment inefficient to decode the tool signal from down hole. MWD performance can be improved by careful attention to the mud system.

- Keep the pump rate as high as possible for the needed flow rates. Mud pump pressure pulses at increased pump frequency are filtered out by MWD surface computer. This reduces the effect of pump noise on the MWD signal.

- Make sure the pump liners are in good condition. Damaged liners cause so much noise they even have an identifiable signature on the surface pressure record. If the MWD engineer mentions a bad liner signature - at least check it out.

- Keep the pulsation dampeners charged to the percent of rated pressure specified by the MWD vendor. The ideal mud flow would be at constant pressure, the only changes in system pressure are those of the MWD pulser.

- Maintain as constant weight on bit as possible, when drilling with mud motors. Changes in motor torque will cause changes in standpipe pressure.

- Mud additives should be mixed as uniformly as possible. Changes in viscosity and suspended solids concentration can attenuate the MWD signals

- Duplex mud pumps should be avoided. Their noise is particularly difficult to filter.

DIRECTIONAL SENSOR PACKAGE:-

The D&I sensor of any MWD tool consists of a set of tri-axial inclinometers and tri-axial magnetometers to measure respectively hole inclination (drift) and hole direction (azimuth).

The triaxial inclinometer measures the 3 orthogonal axes components of the earth gravity vector G. The triaxial magnetometer measures the three orthogonal axes components of the earth magnetic field vector H.

TOOL ALLINGMENT

- "Z axis" along the tool axis and positive toward surface
- "Y axis" in a plane perpendicular to the tool axis and used as reference for angular tool faces measurements.
- "X axis" orthogonal to both Y and X axis

Accelerometers and Magnetometers are effectively measuring the G (earth gravitational vector) and H (earth magnetic vector) vectors at the survey point.

$$G^2=G_x^2+G_y^2+G_z^2$$

$$H^2=H_x^2+H_y^2+H_z^2$$

NOTE:

All collar materials must be "non magnetic" to avoid drill string magnetism interference with magnetometer measurements. The calibration process is best achieved in a controlled magnetic environment.

The magnetic declination and the magnetic field strength of the field should be entered correctly otherwise it leads to the survey error.

NOTE:

Tool Face (TF) is an angular measurement of the orientation of the BHA versus the top of the hole (gravity tool face) or magnetic north (magnetic tool face). Reference for tool face is the "Scribe mark" on the collar.

Usually the magnetic tool face is measured for the inclination less than 5^0

The gravity tool face is used for the inclination more than the 5^0

<u>POWER SUPPLIES</u>

Tool power is supplied by battery or by down hole alternator Smith use a battery only. Others use alternators alone or alternator with a battery backup.

- Batteries:
  - ✓ Batteries allow tool operation without mud flow. However their energy is limited. This means that the operating time is limited, and the sensor power output is limited.
  - ✓ Batteries have limitations in temperature.

- Alternator:
  - ✓ Alternators don't have energy limit but there is a pressure drop in it.
  - ✓ When the mud flow is stopped the energy production also stopped hence there is a problem if LWD information is their.

SURFACE EQUIPMENT

The surface instrument consists of the a display screen that is shows

- Azimuth
- Inclination
- Tool face
- Gamma ray logging signatures

The direction driller made his decision like

- Drilling with orient mode (to increase the inclination).
- Drilling wit the sliding mode (to hold the angle)
- Rotate to set the tool face
- recognize any tool error

DATA TRANSMISSION FORMATS

MWD tool data are sent to the surface as a series of 0's and 1's. The tools are programmed to begin a data sequence with a distinct marker recognizable by the surface decoder. Data are then transmitted in order, with a certain number of 0's and 1's representing a "word'- or frame of information.

Transmission formats are programmable at the surface to send data in different styles. For example, tool face becomes very important while slide drilling with a mud motor. Since an entire sequence may take several minutes to transmit, it would be wise to use a format that sends several tool faces per sequence, particularly during rapid drilling. Conversely, for pore pressure detection, high rates of gamma ray and resistivity are needed. The tool programming needs to be planned according to the objective of the bit\ Run. Tools often detect rotation by measuring the x and y (normal to tool axis) magnetic Fields. If change exceeds 240 over a 10 second period, the tool switches to rotating mode. Rotating mode data will be sent uphold if the tool is programmed to do so. Synchronization of data bits is important! If the surface computer loses communication with the down hole tool for even a short time, whole timing sequences of data will be lost, as the surface computer cannot re-establish which bits represent which down hole data. In the slower data rate formats, much information will be lost should the sequence be interrupted by hydraulic or electronic noise. This could be a serious problem during fast drilling. Careful attention to the suggestions mentioned in the hydraulics section will assist getting a good MWD job. Sometimes the existing rig hydraulics and necessary drilling program makes detection at higher data rates difficult. Several of the MWD tools can be reprogrammed to transmit at lower speeds. While this will increase the time between surface readings, it certainly is better than no surface readout at all.

SURFACE EQUIPMENT

The surface computer performs the pressure pulse decoding and survey computations. All vendors use an operator console which is electrically connected to the transducer and rig power, and a remote driller's or rig floor display. The operator's console has digital readouts for azimuth, inclination and tool face. Operator console tool face as displayed will usually be referenced to the MWD scribe line.

The driller's dial, or rig floor display, has digital indicators for azimuth and inclination. They also have an analog display for tool face orientation. Bent sub corrections must be correctly entered in the operator console for this display to read bit orientation correctly. Tool face readings on the driller's dial can be selected to read magnetic or gravity tool face by the driller. Surface gear is available in IS (intrinsically safe) explosion-proof cases or standard non-IS types.

CONCLUSION

The drilling technology is very vast science but he report tries to focus on the drill string design and the measurement while drilling effective manner.

The study developed is efficient to display the design effect of the horizontal wells. This study report serves the allocated purpose of familiarization with technology and related factors used in the oil well drilling, the different factors of earth magnetization. The different magnetic effect on measurement while drilling and the error minimization

In addition to that due to systematic and programmed approach in the presenting, this study can be used in further studies.

REFERANCE

- Drilling tools data and the different properties from the book by oil and natural organisation drilling data book.

- Explanatory part from different book listed below

  ONGC training manuals
  Oman oil corporation traing manual
  Jindal drilling training manual

- Calculation of the torque drag of the well and the dring assembly by the software "T & D CALCULATOR" developed by WINSURVE FRANCE.

- Different figures and data from the verious web sites www.slb.com