PLANNING AND DESIGNING OF HORIZONTAL WELLS

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

Bachelor of Technology

(Applied Petroleum Engineering)

By

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CERTIFICATE

This is to certify that the Project Report on **"PLANNING AND DESIGNING OF HORIZONTAL WELLS"** submitted to University of Petroleum & Energy Studies, Dehradun, by Mr. K V Koundinya in partial fulfillment of the requirement for the award of Degree of Bachelor of Technology in Applied Petroleum Engineering (Academic Session 2004 - 08) is a bonafide work carried out by them under my supervision and guidance. This work has not been submitted anywhere else by anyone for any other degree or diploma.

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Abstract

The use of horizontal drilling technology in oil exploration, development, and production operations has grown rapidly over the past 5 years. This report reviews the technology, its history, and its current domestic application. It also considers related technologies that will increasingly affect horizontal drilling's future.

Horizontal drilling technology achieved commercial viability during the late 1980's. Its successful employment, particularly in the Bakken Shale of North Dakota and the Austin Chalk of Texas, has encouraged testing of it in many domestic geographic regions and geologic situations. Of the three major categories of horizontal drilling, short-, medium-, and long-radius, the medium-radius well has been most widely used and productive. Achievable horizontal bore hole length grew rapidly as familiarity with the technique increased; horizontal displacements have now been extended to over 8,000 feet. Some wells have featured multiple horizontal bores.

Completion and production techniques have been modified for the horizontal environment, with more change required as the well radius decreases; the specific geologic environment and production history of the reservoir also determine the completion methods employed.
Most horizontal wells have targeted crude oil reservoirs. The commercial viability of horizontal wells for production of natural gas has not been well demonstrated yet, although some horizontal wells have been used to produce coal seam gas. The Department of Energy has provided funding for several experimental horizontal gas wells.

The technical objective of horizontal drilling is to expose significantly more reservoir rock to the well bore surface than can be achieved via drilling of a conventional vertical well. The desire to achieve this objective stems from the intended achievement of other, more important technical objectives that relate to specific physical characteristics of the target reservoir, and that provide economic benefits. Examples of these technical objectives are the need to intersect multiple fracture systems within a reservoir and the need to avoid unnecessarily premature water or gas intrusion that would interfere with oil production. In both examples, an economic benefit of horizontal drilling success is increased productivity of the reservoir.
In the latter example, prolongation of the reservoir's commercial life is also an economic benefit.

Chapter 1

WELL PLANNING and TYPES OF HORIZONTAL WELLS

Introduction

There are many aspects involved in well planning, and many individuals from various companies and disciplines are involved in designing various programs for the well (mud program, casing program, drill string design, bit program, etc). A novel approach to well planning is one where the service contractors become equally involved in their area of expertise. This section will concentrate on those aspects of well planning which have always been the provinces of directional drilling companies.

1.1 Reference Systems and Coordinates.

With the exception of Inertial Navigation Systems, all survey systems measure inclination and azimuth at a particular measured depth (depths measured "along hole"). These measurements are tied to fixed reference systems so that the course of the borehole can be calculated and recorded. These reference systems include:

a. *Depth References*

During the course of a directional well, there are two kinds of depths:

- Measured Depth (MD) is the distance measured along the actual course of the borehole from the surface reference point to the survey point. This depth is always measured in some way, for example, pipe tally, wire line depth counter, or mud loggers depth counter.
- True Vertical Depth (TVD) is the vertical distance from the depth reference level to a point on the borehole course. This depth is always calculated from the deviation survey data.

In most drilling operations the rotary table elevation is used as the working depth reference. The abbreviation BRT (below rotary table) and RKB (rotary kelly bushing) are used to indicate depths measured from the rotary table. This can also be referred to as derrick floor elevation. For floating drilling rigs the rotary table elevation is not fixed and hence a mean rotary table elevation has to be used. In order to compare individual wells within the same field, a common depth reference must be defined and referred to (e.g. When drilling a relief well into a blow-out well, the difference in elevation between the wellheads has to be accurately known). Offshore, mean sea level (MSL) is sometimes used. Variations in actual sea level from MSL can be read from tide tables or can be measured.

b. *Inclination References*

The inclination of a well-bore is the angle (in degrees) between the vertical and the well bore axis at a particular point. The vertical reference is the direction of the local gravity vector and could be indicated by a plumb bob.

c. *Azimuth Reference Systems*

For directional surveying there are three azimuth reference systems:

- Magnetic North
- True (Geographic) North
- Grid North

All "magnetic-type" tools give an azimuth (hole direction) referenced to Magnetic North. However, the final calculated coordinates are always referenced to either True or Grid North.

True (Geographic) North

This is the direction of the geographic North Pole which lies on the Earth's axis of rotation. Direction is shown on maps using meridians of longitude.

Grid North

Drilling operations occur on a curved surface (i.e, the surface of the Earth) but when calculating horizontal plane coordinates a flat surface is assumed. Since it is not possible to exactly represent part of the surface of a sphere on a flat well plan, corrections must be applied to the measurements. To do this, different projection systems which can be used are:

1.1.1 UTM System

One example of a grid system is the Universal Transverse Mercator (UTM) System. In transverse mercator projection, the surface of the spheroid chosen to represent the Earth is wrapped in a cylinder which touches the spheroid along a chosen meridian. (A meridian is a

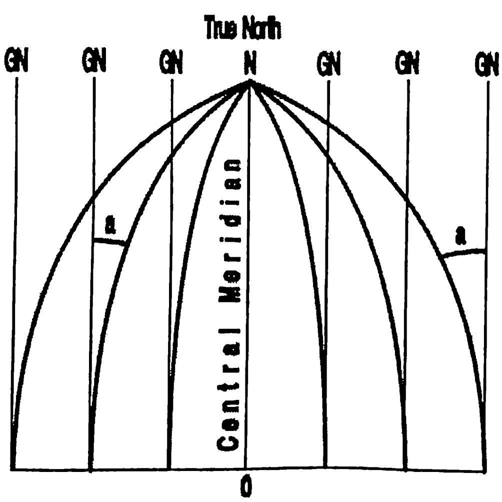


Fig 1.1- Grid

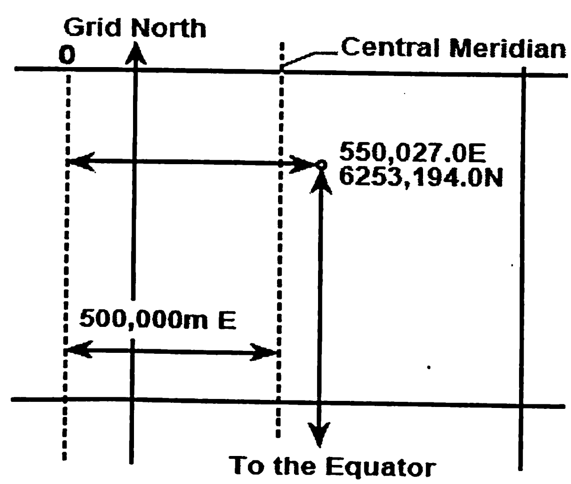


Fig 1.2- Northings and Eastings

circle running around the Earth passing through both North and South geographic poles.)These meridians of longitude converge towards the North Pole and do not produce a rectangular grid system. The grid lines on a map form the rectangular grid system, the Northerly direction of which is determined by one specified meridian of longitude. This "Grid North" direction will only be identical to "True North" on a specified meridian.

The relationship between True North and Grid North is indicated by the angles 'a' in the Figure. Convergence is the angle difference between grid north and true north for the location being considered. The reference meridians are 6 degrees apart, starting at the Greenwich meridian, which means the world is divided into 60 zones. The zones are numbered 0 to 60 with zone 31 having the 0 degree meridian (Greenwich) on the left and the 6 degree East on.the right. Each zone is then further divided into grid sectors - a grid sector covering 8 degrees latitude starting from the equator and ranging from 80° South to 80° North.

Coordinates in the UTM system are measured in meters. North coordinates being measured from the equator. For the Northern hemisphere, the equator is taken as 0.00m North whereas for the Southern hemisphere the equator is 10,000,000m North (to avoid negative numbers). East coordinates for each sector are measured from a line 500,000m west of the central meridian for that sector. In other words, the central meridian for each zone is arbitrarily given the coordinate 500,000m East. Again, this avoids negative numbers.
So UTM coordinates are always Northings and Eastings, and are always positive numbers.

1.1.2 Lambert Projection

Another projection system, used in some parts of the world, is the conical projection or Lambert system. A cone as opposed to a cylinder covers the spheroid under consideration. This produces a representation with meridians as convergent lines and parallels as arcs of circles.

The Lambert azimuthal equal-area projection is a map projection having transformation equations

$$x = k' \cos\phi \sin(\lambda - \lambda_0)$$
$$y = k' [\cos\phi_1 \sin\phi - \sin\phi_1 \cos\phi \cos(\lambda - \lambda_0)],$$

Where ϕ_1 is the standard parallel, λ_0 is the central longitude, and

$$k' = \sqrt{\frac{2}{1 + \sin\phi_1 \sin\phi + \cos\phi_1 \cos\phi \cos(\lambda - \lambda_0)}}.$$

The inverse formulas are

$$\phi = \sin^{-1}\left(\cos c \sin\phi_1 + \frac{y \sin c \cos\phi_1}{\rho}\right)$$

$$\lambda = \lambda_0 + \tan^{-1}\left(\frac{x \sin c}{\rho \cos\phi_1 \cos c - y \sin\phi_1 \sin c}\right),$$

where

$$\rho = \sqrt{x^2 + y^2}$$

$$c = 2\sin^{-1}\left(\tfrac{1}{2}\rho\right).$$

1.1.3 Field Coordinates

Although the coordinates of points on a well path could be expressed as UTM coordinates, it is not normal practice. Instead, a reference point on the platform or rig is chosen as the local origin and given the coordinates (0, 0). On offshore platforms this point is usually the center of the platform. The Northings and Eastings points on the wells drilled from the platform are referenced to this single origin. This is important when comparing positions of wells, in particular for anti-collision analysis.

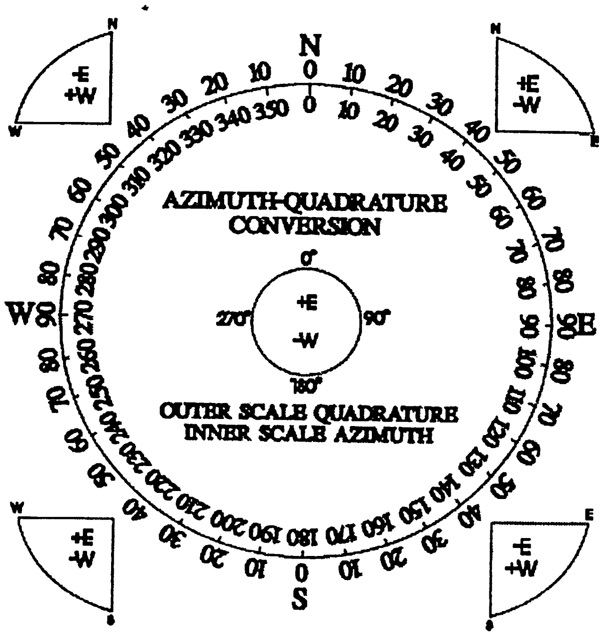


Fig 1.3 Azimuth reference systems

Direction Measurements

Survey tools measure the direction of the wellbore on the horizontal plane with respect to North reference, whether it is True or Grid North. There are two systems:

a. Azimuth

In the azimuth system, directions are expressed as a clockwise angle from 0° to 359.99°, with North being 0°.

b. Quadrant Bearings

In the quadrant system, the directions are expressed as angles from 0°-90° measured from North in the two Northern quadrants and from South in the Southern quadrants. The diagram here illustrates how to convert from the quadrant system to azimuth, and vice versa.

1.2 Planning the Well Trajectory

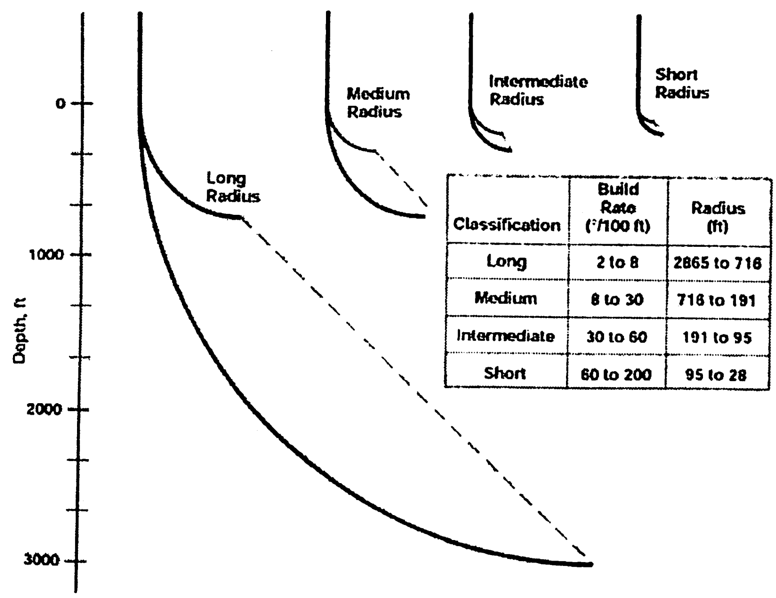
One area of well planning in which directional companies are closely involved is the planning of the well trajectory. Again, this is not as simple a task as it might seem at first glance, particularly on a congested multi-well platform. There area number of aspects that must be carefully considered before calculating the final well path.

a. The Target

The target is usually specified by the geologist, who will not merely define a certain point as the target but also specify the acceptable tolerance (e.g. a circle of radius 100 feet having the exact target as its center). Target zones should be selected as large as possible to achieve the objective. If multiple zones are to be penetrated, they should be selected so that the planned pattern is reasonable and can be achieved without causing drilling problems.

b. Types of Directional Patterns

The advent of steerable systems has resulted in wells that are planned and drilled with complex paths involving 3-dimensional turns. This is particularly true in the case of re-drills, where old wells are sidetracked and drilled to new targets. Common patterns for vertical projections are



Classification	Build Rate (°/100 ft)	Radius (ft)
Long	2 to 8	2865 to 716
Medium	8 to 30	716 to 191
Intermediate	30 to 60	191 to 95
Short	60 to 200	95 to 28

Fig 1.4 Directional patterns

c. Kick-off Point and Build-Up Rate

The selection of both the kick-off point and the build-up rate depends on many factors. Several being hole pattern, casing program, mud program, required horizontal displacement and maximum tolerable inclination. Choice of kick-off points can be limited by requirements to keep the well path at a safe distance from existing wells. The shallower the KOP and the higher the build-up rate used, the lower the maximum inclination.

Build-up rates are usually in the range 1.5°/100' M.D. to 4.0°/100' M.D. In practice, well trajectory can be calculated for several KOPs and build-up rates and the results compared. The optimum choice is one which gives a safe clearance from all existing wells, keeps the maximum inclination within desired limits and avoids unnecessarily high dogleg severities.

d. Tangent Section

If wells are drilled at inclinations (up to 80°), the area which can be covered from a single platform is approximately 8 times that covered when maximum inclination of the wells is limited to 60°. However, high inclination angles can result in excessive torque and drag on the drill string and present hole cleaning, logging, casing, cementing and production problems.

Experience over the years has shown that directional control problems are aggravated when tangent inclinations are less than 15°. This is because there is more tendency for the bit to walk (i.e. change in azimuth) so more time is spent keeping the well on course. As such, most run-of-the-mill directional wells are still planned with inclinations in the range 15° - 60°.

e. The horizontal projection

On many well plans, horizontal projection is just a straight line drawn from the slot to the target. On multi-well platforms however, it is sometimes necessary to start the well in a different direction to avoid other wells. Once clear of these, the well is turned to aim at the target. This is a 3-dimensional turn, but on the horizontal plan it would typically look like this

The path of the drilled well is plotted on the horizontal projection by plotting total North/South coordinates (Northings) versus total East/West coordinates (Eastings). These coordinates are calculated from surveys.

1.3 Well Trajectory Prediction System of Directional Well and Geological Effects on Drilling

This system was designed to be applied for DHM (down hole motor) drilling and for rotary drilling. Computer programs of the system have been developed based on equations of equilibrium for BHA (bottom hole assembly) (Jogi *et al.*, 1988) to calculate the force acting on a bit, definition to determine the direction of drilling (Ho, 1987) and equation to find resonant RPM (Yew and Zhang, 1994).

Well trajectory was seriously affected by geological effect at the geological boundary. If one can estimate the geology of a new well from other nearby well data, it will be possible to improve drilling efficiency by this system

1.3.1 Introduction

In order to improve drilling efficiency, the drilling support system was developed,which consists of the directional control support system, and well evaluation support system.

As one part of the directional control support system, a well trajectory prediction system has been developed and tested. Main functions of this trajectory prediction system are:

- Well trajectory prediction while drilling in rotary and DHM drilling
- Design of adequate BHA drilling parameters
- Evaluation of the geological effect on well trajectory.

MWD must result in effective directional drilling. However, effective directional drilling with MWD operation should be based on proper directional well trajectory planning, and adequate BHA and drilling parameter design.

1.3.2 Well Trajectory Prediction System

A static BHA model program for Down Hole Motor drilling has been developed based on the equations of equilibrium for BHA to calculate the force acting on bit (Jogi *et al.*, 1988). These equations of equilibrium for BHA have the following form:

$$EIy^{iv} = Tx^{iii} - Wy^{ii} - \omega_\theta\, w_1\, z \sin\beta$$

$$EIx^{iv} = -Ty^{iii} - Wx^{ii} + w_1 \sin\beta$$

$$GJ\omega_\theta = T = \left[1 - 2\left(\frac{EI}{GJ}\right)\right]Ta$$

Where,

E_I is the bending stiffness; GJ is the torsional stiffness;

T_a is torque on the bit (TOB); W is weight on bit (WOB);

w_l is effective weight per inch of BHA including buoyancy due to drill mud;

b	is angle of inclination
w_q	is the angle of twist per unit length

The proper boundary conditions for the above equations are omitted.
Also, a drilling ahead criterion for calculating the wellpath is developed (refer to Fig.). The angle change between well trajectory and drill path is written as:

$$\tan\theta_1^{(b)} = i_b \frac{F_L^{(b)}}{F_a^{(b)}}$$

$$\gamma = \theta_{bt} + \tan^{-1}\left[i_b \frac{F_L^{(b)}}{F_{a(b)}} \right]$$

Where,

G	is the angle of drill ahead change (angle between well trajectory and drill ahead)
q_{bt}	is the angle between bit axis and well trajectory
ib	is bit anisotropy;
$F_a^{(b)}$	is force on bit along the bit direction;
$F_L^{(b)}$	is force on bit; force on bit perpendicular to the bit access direction.

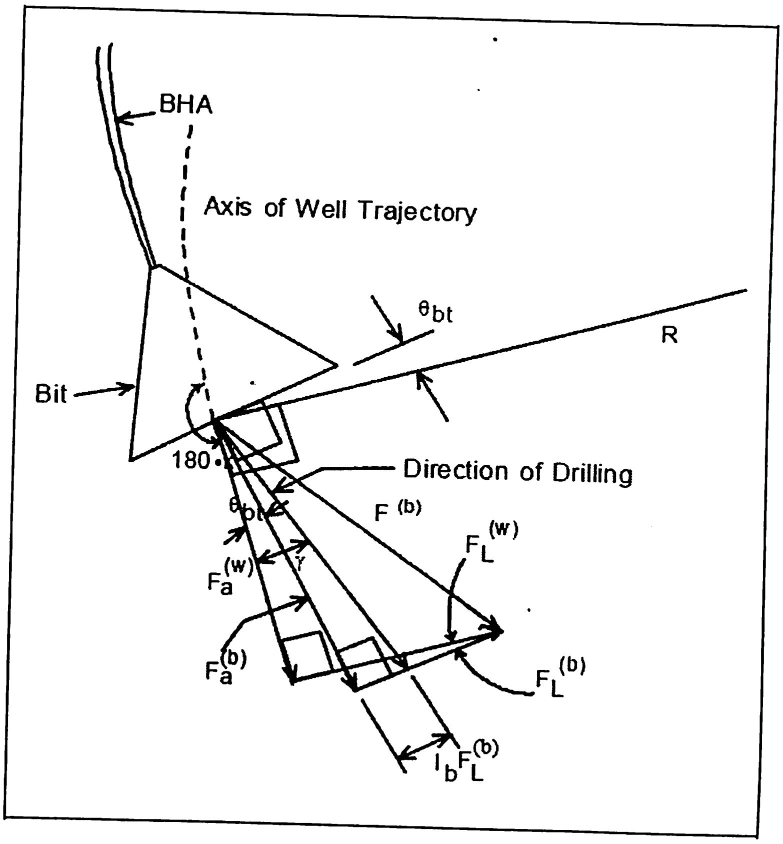


Fig 1.5 Drilling Ahead Model

Program for Rotary Drilling
If the rotary speed of drilling does not reach the resonant RPM of the drill string, the above-mentioned theory for static BHA model can be applied for a rotary drilling. However, if the rotary speed of BHA reaches the resonant RPM of drill string, lateral motion of drill collar would occur and it becomes impossible to apply static BHA model. And, in this case, drilling itself becomes more hazardous and downhole tool problems would occur.
To avoid such limitations and problems, resonant RPM is found during rotary drilling based on Yew's equations

$$\omega res = \frac{1}{2m}\left[\sqrt{-\mu^2 + 4m\left(EIn_i^4 + Tn_i^3 - Wn_i^2\right)}\right]$$

where:

$$n_i = \frac{\pi}{L} - \frac{T}{4EI}$$

w_{res}	is the resonant RPM
EI	is the bending stiffness
m	is the unit weight of drill collar
T	is torque onbit
W	is weight on bit
L	is length of drill collar.

But considering the actual parameters, it is necessary to consider both bit and rock anisotropy for applying the prediction system for rotary drilling. Thus comes the concept of anisotropic index. Direction of drilling with anisotropy index of rock and bit

$$r_n \vec{e_r} = Ir\left[Ib\vec{e_f} + (1 - Ib)\cos\theta_{af}\vec{e_a}\right]$$
$$+ Ib(1 - Ir)r_n \cos\theta_{rd}\vec{e_d}$$

e_r	is the unit vector along the drilling direction
e_f	is the unit vector along the resultant bit force on the formation
e_a	is unit vector along the bit direction
e_d	is unit vector normal to formation bedding
r_n	is coefficient; $q\ a_f$ is angle between vectors e_a and e_f
q_{rd}	is angle between vectors e_f and e_d .

With

Ir (anisotropy index of rock) $= \dfrac{\textit{drilling rate parallel to bedding}}{\textit{drilling rate normal to bedding}}$

Ib (anisotropy index of bit) $= \dfrac{\textit{drilling rate in bit's lateral direction}}{\textit{drilling rate in bits axial direction}}$

Although it was expected that this theory improved the accuracy of the simulation of well trajectory prediction, there has been a limitation to the application because it is not possible to acquire actual downhole anisotropy index of rock and bit for input to the system before drilling.

Based on this situation, a new program has been developed to calculate anisotropy index of rock and bit reflecting downhole condition by inversion technique and Ho's definition using actual drilling data, and tested to apply these indexes to the prediction of other wells.
The actual well trajectory (survey data) is the result reflected by BHA configuration and drilling parameter relating to BHA equilibrium equations, and definitions for direction of drilling with anisotropy index (bit and rock). By applying inversion (method of least squares) with the above equations and actual data, anisotropy index is calculated. The anisotropy index calculated with prior well data will be able to improve the well trajectory prediction of a new well, if the distance between old and new wells is close and geological tendency is expected to be similar.

1.3.3 Geological Effect in Directional Drilling

There exists a distinct correlation has been observed between calculated bit anisotropy indexes and geological boundary as confirmed by drilling in and geological boundary
Bit anisotropy index of more than 0.7 can be observed as a distinct correlation:

Bit anisotropy index, when indicates larger values compared to other sections, it is considered that force on bit perpendicular to the bit direction becomes much larger at the geological boundary which seems to have large physical difference as relating to intrusive rock, for example, and it makes drilling rate in the bit lateral direction much bigger.
On the other hand, very large bit anisotropy index observed is not related to geological boundary. This larger value might be caused by physical heterogeneity of the rock (New-Granite) such as boundary permeability; although further study with logging and other data is necessary.

Regarding other possible geological effect such as bedding and fracture; although data to confirm scale, dip and direction is limited, such effects and relations to rock anisotropy index can be analyzed with data as FMI or BHTV logging.
From the standpoint of directional drilling, information of the geological boundary relating to large bit anisotropy index is very important and should be strongly considered. Next drilling step including BHA (rotary or DHM, hold, build and drop BHA) should be considered based upon not only the drilling plan and situation but also prediction of geological effect.
From the standpoint of well evaluation, there is the possibility for bit and rock anisotropy index to be calculated from directional drilling data to support geological evaluation; although more detailed study is necessary.

1.4 Types of Horizontal Wells and Their Application Favorabilities

For classification purposes that are related both to the involved technologies and to differential application favorabilities, petroleum engineers have developed a categorization of horizontal wells according to the radius of the arc described by the wellbore as it passes from the vertical to the horizontal. The required horizontal displacement, the required length of the horizontal section, the position of the kickoff point, and completion constraints are generally considered when selecting a radius of curvature. Most new wells are drilled with longer radii, while recompletions of existing wells most often employ medium or short radii. Longer radii tend to be conducive to the development of longer horizontal sections and to easier completion for production.

1.4.1 Conventional (Long-Radius) Wells

Conventional, or long-radius, wells are typically defined as those with build rates from 1 to approximately 8°/100 ft. However, the definition can vary with hole size. A better definition may be that the steerable motor that is used in the sliding mode to drill the build section may also be safely rotated in that section, and that the hole curvature in the build section is not high enough to cause drill pipe failure from fatigue. This definition suggests that the maximum build rate in a large hole size will be lower than the maximum build rate of a smaller hole size. Equation 2-10 relates the stress in a tubular member that is bent through a given curvature. Clearly, for a given acceptable stress level, the smaller the tubular diameter, the higher the tolerable build rate.

$$BUR = \frac{137510\,\sigma}{E\,D}$$

BUR = build up rate, σ = allowable stress

E = Young's modulus, D = pipe diameter

Another characteristic of conventional wells is that the maximum angle of any section of the well can allow the drillstring and wireline tools to advance through that section by the force of gravity alone—that is, without being pushed or pumped down. This criterion would normally limit the maximum angle to about 65° to 80°, depending on friction factors. Friction factors are primarily a function of formation type and mud type, but overall friction factors include the effect of ledges and the effect of the geometry of stabilizers and other points at which the drillstring or BHA contacts the formation. The critical wellbore angle above which the drillstring will no longer advance down the hole under the force of gravity alone, is

$$\Theta_c = \tan^{-1}\frac{1}{f}$$

Θ_c = critical well bore angle f = coefficient of friction

1.4.1.1 Drillstring Considerations for Long-Radius Wells

In conventional directional wells, because the angle of the well is low enough to allow gravity to be used, drill collars are commonly used in the BHA to apply weight-on-bit. Unlike drillpipe, the collar's weakest part is the connection; therefore, rotating collars through high doglegs should be avoided. The American Petroleum Institute (API) has published guidelines for rotating drillpipe through doglegs, but not for rotating drill collars through doglegs. Although MWD/LWD tools and motors normally have weaker connections than drill collars, they are generally more limber and can generally tolerate the same build rates as collars of the same diameter.

If the maximum angle of conventional wells is low enough that the drillstring will advance under its own weight, then tension in the drillstring will always exist in the build section. Lubinski (1973) and Hansford and Lubinski (1973) showed the relationship of stress in drillpipe as a function of both the dogleg severity to which it is subjected and the amount of tension in the drillpipe while in that dogleg. Abrupt doglegs cause higher stress in drillpipe than gradual doglegs. As shown in Figure, with 4 ½-in. S-135 drillpipe in a 6°/100 ft dogleg, tension in the dogleg portion of the drillstring must be limited to about 80,000 lb to avoid fatigue damage.

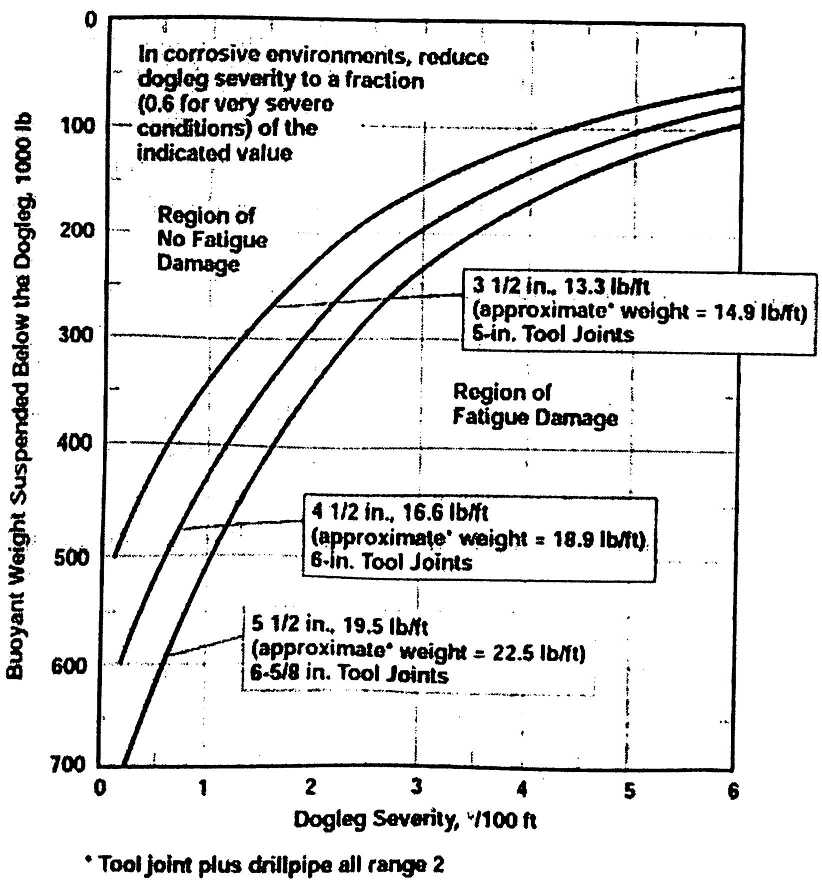


Fig 1.6 Dogleg severity limits for S-135 drillpipe (after Lubinski, 1973)

1.4.1.2 Drilling the Build Section

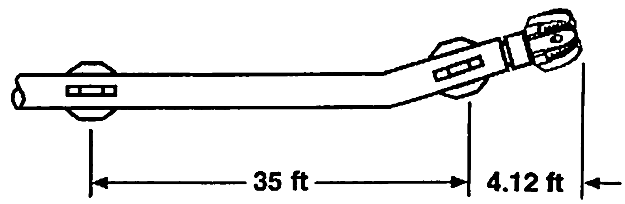
Steerable motors are normally run in the build section because they can compensate for almost any variation from plan. General well planning guidelines are to design the steerable motor with a dogleg capability of about 25% to 50% more than the planned build rate; the motor is then rotated as required to eliminate the excess build rate. In the build section, however, the greatest fear is falling "behind the curve." To ensure that this situation will not occur, the tendency is to design the steerable motor for a greater build rate than needed. Cases have been seen where the actual dogleg capability of a steerable motor is two to three times the planned build rate. Such a selection can result in the creation of excessive doglegs in the build section as the assembly repeatedly builds more than is needed; then, the motor must be rotated to reduce the overall build rate. When the motor is first rotated after each interval of oriented drilling, it will also encounter high bit side-loads that may reduce its life.

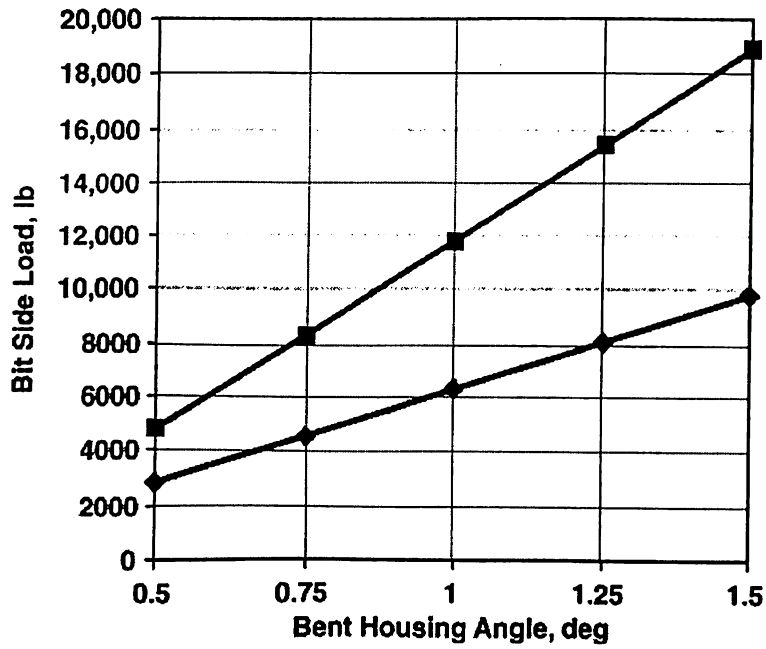
Figure in next page shows build-rate capabilities and bit side-loads for a 7 ¾-in. steerable motor for various bend angles. The highest bend angle shown (1.5°) can build about 10°/100 ft.

However, when the motor is rotated in this curvature, the resulting bit side-load is about 19,000 lb. If the desired build rate is 4°/100 ft, the use of a 1° bend should result in a 6°/100 ft dogleg capability. The build-rate safety factor is 50%, but bit side-loads will have been reduced to about 12,000 lb, a reduction of 32%. In addition, since the actual build rate is closer to the necessary build rate, fewer slide/rotate sets will have to be used, resulting in a smoother wellbore.

High bit side loads can cause damage to the gauge or bearings of the bit and limit motor life by causing driveshaft fatigue, radial bearing wear, and stator damage. Stabilizer loads and associated wear also increase. The high doglegs resulting from excessive bend angles can cause drillpipe fatigue and difficulty in sliding the drillstring or running logging tools, casing strings, or completion equipment in the well in the future.

The preferred well planning strategy for most wells is to ensure that the build assembly will have a sufficient build-rate safety margin to cover any contingency while maximizing the life of other BHA components and minimizing doglegs. As a rule of thumb, a build assembly with a dogleg capability of 25% greater than the desired build rate is adequate.





Bend Angle (°)	Dogleg Severity of Curved Hole (°/100 ft)
0.5	2.6
0.75	4.34
1	6.08
1.25	7.85
1.5	9.57

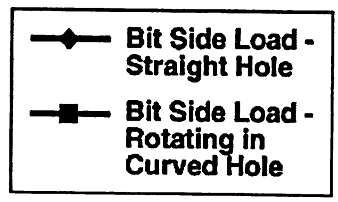


Fig 1.7 Effect of bent housing angle on build rates and bit side-loads

1.4.2 Medium-Radius Wells

Medium-radius wells use many of the same BHA components and well planning tools used in long-radius wells. The main difference is that medium-radius build rates place some limitations on the ability to rotate, and that these limitations can affect the well profile. Medium-radius wells can be broadly characterized by the following:

- The BHA used for drilling the build section cannot be rotated in that section because of stresses in motor and MWD housings and connections. At best, limited rotation is allowed.
- Because of the hole curvature in the build section, the component of drillpipe stress caused by bending is high enough that either drillstring rotation must be limited while in tension, or the stress component resulting from tension must be limited by well profile design.

- To eliminate any tension in the drillstring in the build section, any footage drilled beyond the build must be at or above the critical angle. As a general rule, medium-radius build rates are used only for wells with high-angle or horizontal laterals.

The definition of medium-radius wells, like that of long-radius wells, will vary with hole size.

The build/tangent/build profile is less preferred because it requires a trip to change the BHA at the end of each of the three sections. A build/tangent/build profile also sacrifices some potential pay zone exposure. The dual build rate, as compared to the build/tangent/build rate, saves a trip or, if the well planner is fortunate, two trips if the first build rate is on target and the second BHA can be avoided

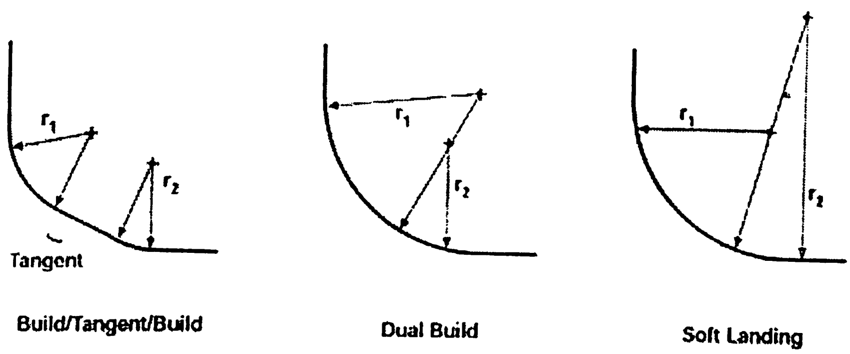


Fig 1.8 well profiles for medium radius wells

The best well profile is usually the "soft landing," in which a medium-radius BHA is used to drill most of the build section, and the remainder of the build section is then drilled, mostly in the sliding mode, with the same steerable assembly that will be used for drilling the lateral. The length of this final section should be at least as long as that of the BHA, so that all BHA components will be through the high build-rate section before they encounter significant rotation. This well profile minimizes the number of trips, applies the least stress on motors, and allows precise TVD control at the EOB.

1.4.2.1 Drillstring Design for Medium-Radius Wells

In vertical wells and conventional directional wells, WOB is provided by the weight of the collars directly above the bit, and most of the drillstring is in tension. In the lateral section of medium-radius/horizontal wells, however, the weight of the drillstring is supported by the side of the hole and it cannot contribute to advancing the drillstring. The force to advance (push) the drillstring in the lateral must come from the vertical portion of the well, or at least from some section of the well that is above the critical angle. To provide this force, drill collars or heavy-wall drillpipe (HWDP), which can be run in compression, are usually run in the vertical portion of the well.

Some well profiles require a KOP so close to the surface that the limited amount of vertical hole will not allow the use of enough drill collars or HWDP to provide the necessary force. In such a case, either traveling block weight or a hydraulic pull-down system must be used for applying the force needed to push the drillstring into the hole.

Drill collars serve no purpose in the horizontal lateral. In fact, the weight of collars in the lateral only increases torque and drag and hinders the drillstring from advancing. Conventional drillpipe will buckle with low axial loads in near-vertical holes, but drillpipe can transmit substantial compressive loads without buckling in high-angle wellbores.

Common practice is to run conventional drillpipe in compression in the lateral of horizontal wells to transmit axial loads to the bit. Two or three joints of nonmagnetic compressive-service drillpipe are frequently used above the MWD/LWD tools for magnetic spacing.

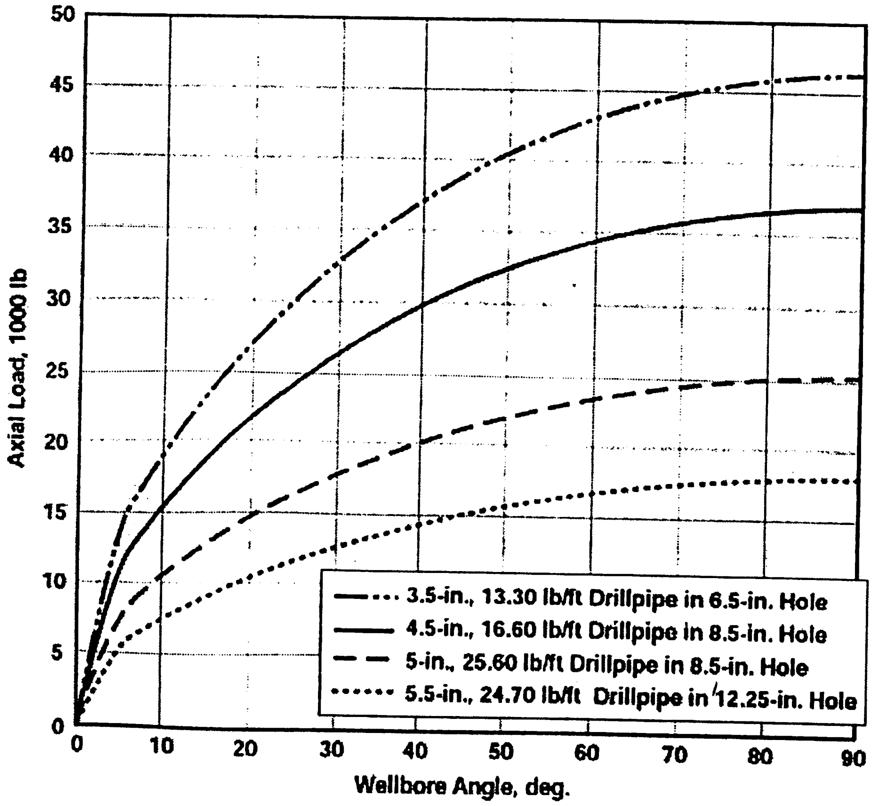


Fig 1.9 Compressive load capability of drillpipe that increases with wellbore angle

The torque required to rotate the drill string in deviated holes is a function of drill string weight, hole angle, the diameter of tool joints and tubulars, and the coefficient of friction. In high-angle holes, the torque required for rotating the drillstring can be substantial. Torque/drag modeling should be performed to ensure that the torsional strength of tool joints and tubulars exceeds the maximum anticipated drilling torque. The ability to rotate is extremely important because in some high-angle wells, the drillstring cannot be advanced—or even withdrawn—without rotation. This condition is especially true when poor hole cleaning or differential sticking becomes a problem. Torque/drag modeling should also be used during drillstring design to ensure that the drillstring can withstand the tension that occurs during pick-up and the buckling that occurs during slack off. Maximum loads, both tensile and compressive, should be plotted along the length of the drillstring, and sections of the drillstring should be optimized based on those loads.

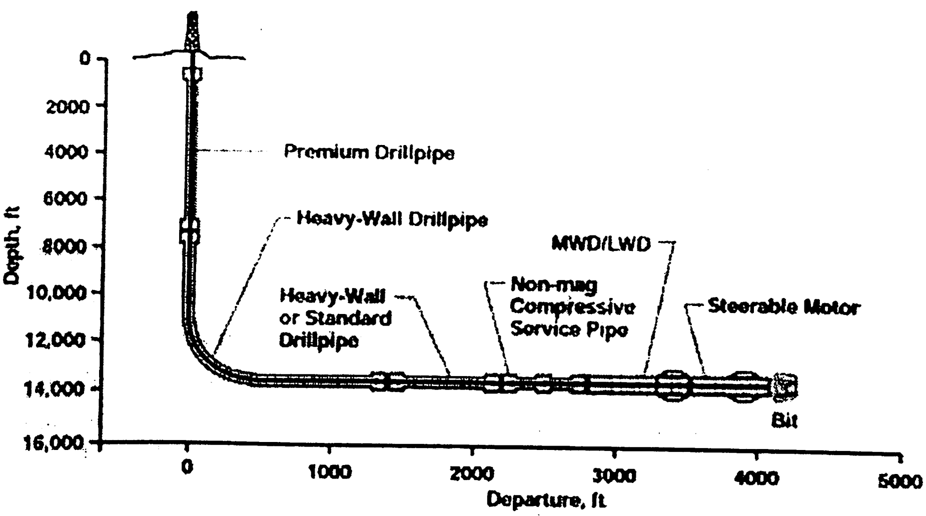
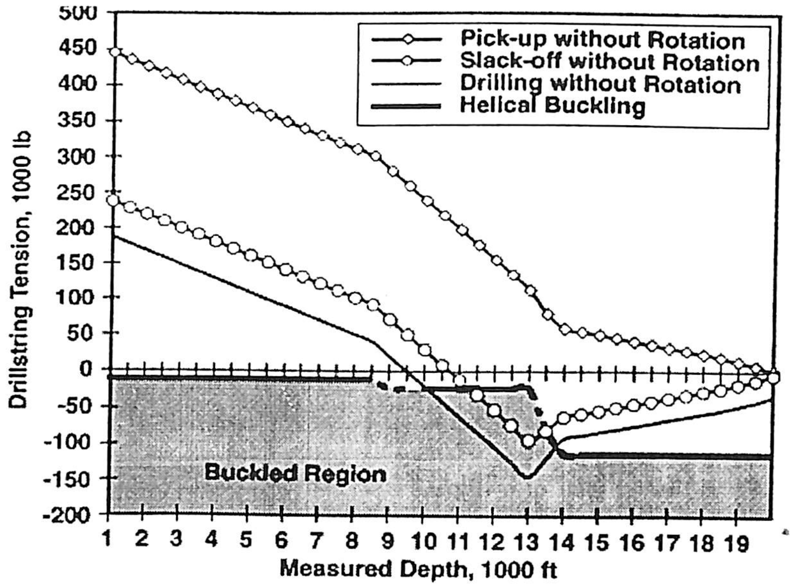


Fig 1.10 Typical drill string for medium-radius well

The profile and drillstring of a sample medium-radius well is shown in above Figure. The drillstring sections have been sized to withstand the torsional and tensile loads derived by torque-and-drag modeling. From the surface to about 8500 ft, the drillstring is in tension, so drillpipe is used. However, suppose that the maximum drillstring tension at the surface is 446,000 lb. According to standards, S-135 drillpipe is required to provide a reasonable safety margin.

In the vertical part of the subject well, HWDP is used instead of drill collars to apply weight. HWDP is easier to handle on the rig floor than drill collars, and unlike collars, it can withstand passing through a medium-radius build section. If collars were used, an extra trip would be necessary so that the collars could be removed from the string before they reached the curve. For modeling purposes, HWDP is used from 7500 ft to total depth (TD) based on the assumption that a single PDC bit will drill the entire lateral section, and that the HWDP used to drill the build section will advance into the lateral. If a trip for a worn bit were necessary in the lateral, torque and drag could be reduced with the substitution of standard drill pipe for some of the HWDP in the lateral. A 5-in. drill pipe in an 8 ½-in. hole can transmit approximately 45,000 lb without buckling. As shown in Figure 1.11, during sliding with 30,000-lb WOB, the drillstring



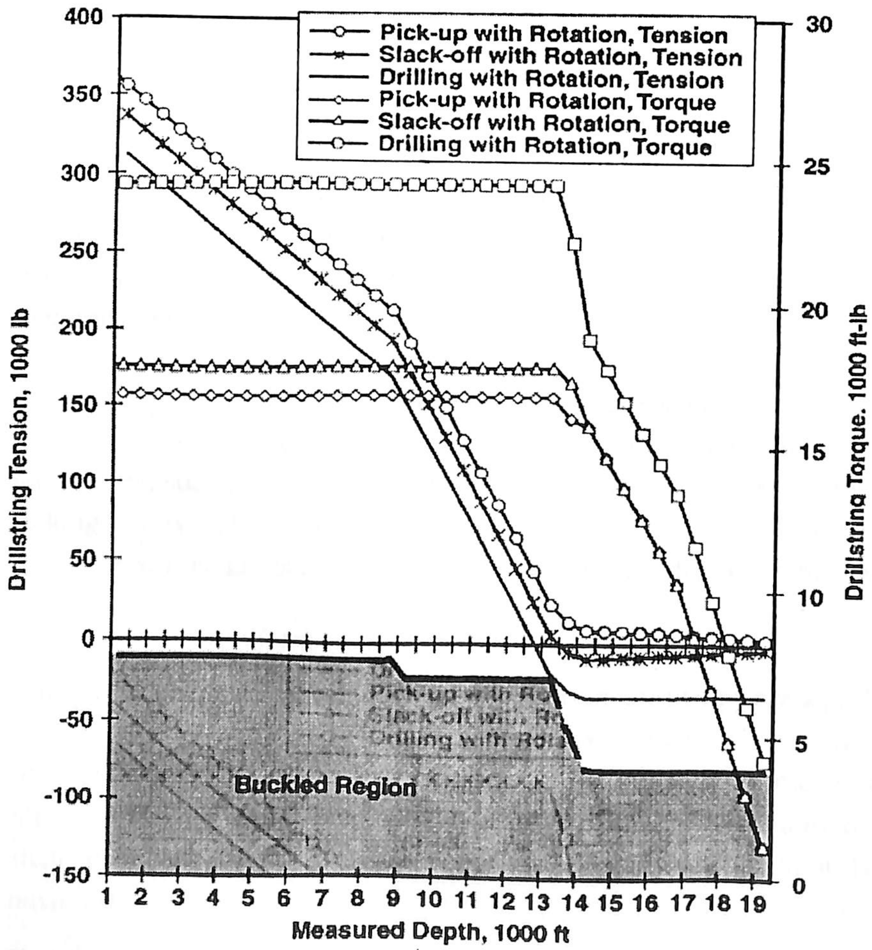


Fig 1.11 Drillstring loads for Figure 1.10 well

compression reaches 45,000 lb approximately 1000 ft from the bit. Thus, the last 1000 ft of HWDP could be replaced by drill pipe without buckling.

Note that during drilling without rotation (i.e., sliding), drag is 126,000 lb greater (surface-indicated weight is 126,000 lb less) than drilling with rotation. In this well, the HWDP in the vertical section of the hole provides sufficient axial force to overcome drag when sliding.

To reduce drillstring cost, drillpipe could be run in place of the top 2000 ft or so of HWDP, although some of this pipe would buckle when sliding. Some buckling is acceptable during sliding because fatigue will not occur if the pipe is not rotating. However, severe buckling can create a "lock-up" condition in which additional weight only serves to increase buckling and side forces. When lock-up does occur, it may be alleviated by the use of stiffer pipe or by a reduction of drag in the lateral. Near the TD of such a well, a lighter pipe may have to be substituted for HWDP in the lateral so that drilling can progress.

1.4.2.2 BHA Configuration in the Build

Since the motor for drilling the build section is not intended to be rotated, its configuration is somewhat different from that of a steerable motor. The stabilizers that give a steerable motor its rotating-mode directional tendencies are not needed; in fact, they reduce the ability of the motor to slide, so they are typically not used. The first contact point of a medium-radius BHA is generally a pad or sleeve instead of a stabilizer, and it is usually designed close to the bend to maximize the build rate capability.

Eliminating the possibility of using drillstring rotation to vary build rate means that more emphasis must be placed on accurate trajectory prediction. The effects of variation of downhole parameters, such as hole erosion or formation anisotropy, must be more carefully evaluated than in long-radius wells. Moving the first contact point further from the bit has a beneficial effect if hole erosion is an issue, but it can also make the assembly more sensitive to formation anisotropy.

If unpredictable build rates caused by formation anisotropy are a problem, the best approach may be to reduce the planned build rate enough that limited rotation can be used so that some degree of steerability is allowed. If casing shoe depth and geology dictate build rates that are too high for rotation to be feasible, the best solution may be the use of a motor with a lower contact point, such as a stabilized bearing pack. This assembly will exhibit less sensitivity to formation anisotropy.

A second bend at the top of the motor can also be used as a means of improving build-rate capability and predictability. The second bend establishes a definitive contact point and ensures that the top of the motor will stay on the low side of the hole in a near-vertical wellbore. These factors make the build rate more predictable at kickoff and reduce the sensitivity of the assembly to variations in down hole parameters. However, the second bend (1) greatly reduces the chances of rotating the BHA, (2) reduces the ability to configure the motor at the rig site, and (3) makes it more difficult for the motor to pass through the blowout preventer (BOP) stack. For these reasons, the use of double-bend motors is declining, but they should still be considered where high build rates are required in anisotropic or unconsolidated formations and when a predictable build rate is critical.

1.4.3 Short-Radius Wells

Short-radius wells have the following characteristics:

- Hole curvature is so high that the BHA must be articulated so it can pass through the build section.
- Drillpipe in the build section is stressed beyond the endurance limit—and in some cases beyond the yield strength—of the material, so that even in the lateral section, the allowable rotation ranges from limited to almost zero.
- Horizontal lateral length capability is reduced by eliminating the possibility of drillstring rotation.

The decision to drill a short-radius well may be driven by the need to (1) set casing very close to the payzone, (2) place artificial lift as close as possible to the payzone, (3) maximize the length of the horizontal lateral in the payzone in fields with close well spacing, or (4) minimize the amount of directionally drilled footage. Frequently, short-radius wells are drilled by re-entering existing wells, and the radius of the well is simply defined by the distance from the existing casing seat to the payzone.

Although the reasons for drilling short-radius wells usually are based on a physical constraint of some sort, there is frequently some choice about just how short the radius is. This decision is critical, not just because it affects how the build section is drilled, but because the radius affects how the rest of the well can be designed and drilled. Drilling efficiency in the lateral and lateral-reach capability are the factors that are most affected by the radius of curvature in the build section.

The lateral section of a short-radius well is drilled either in the sliding mode or with very slow drillstring rotation. If build rate and the resulting pipe stresses preclude rotation, the lateral must be drilled entirely in the oriented mode. Though the motor used to drill the lateral has a fixed build rate, the well can be kept within a small TVD plane by alternating orientations to the right and left, resulting in a sinusoidal profile when viewed in the horizontal plane. This procedure is acceptable in many cases, but the increased drillstring drag resulting from this technique will eventually limit the length of lateral that can be drilled. Oriented drilling will also progress at a much slower ROP than when the drillstring is rotated.

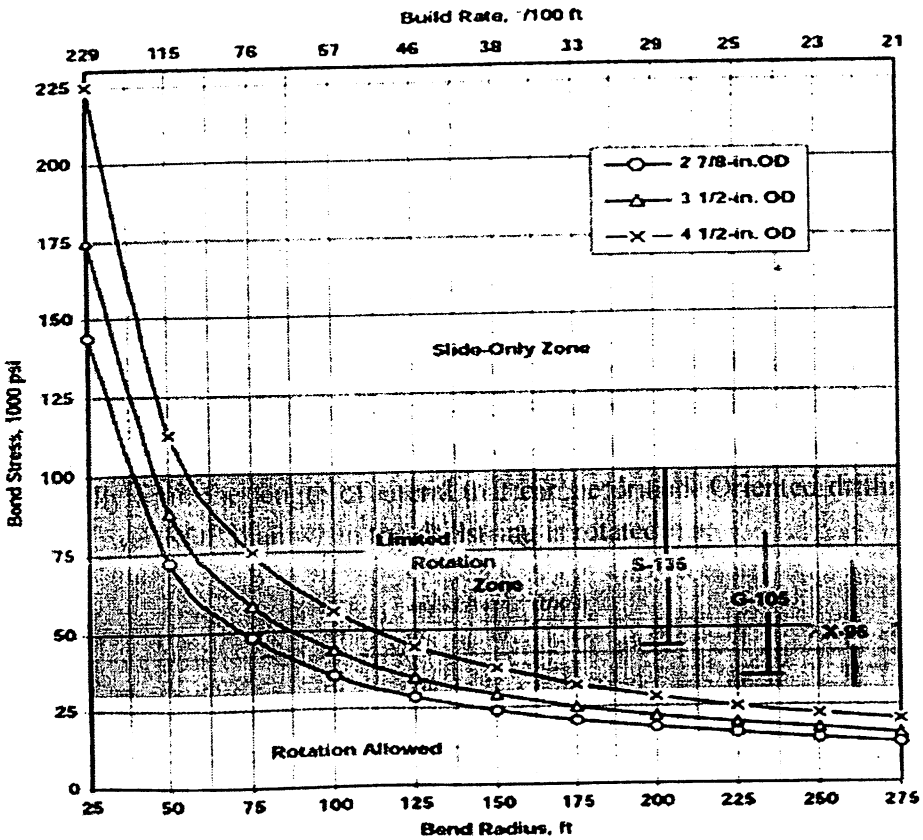


Fig 1.12 General guidelines for limited drillpipe rotation in high-build-rate wellbores

If the build rate and the resulting drillpipe stresses are low enough to allow limited rotation, drilling the lateral with rotation is certainly preferable to sliding. In addition to improved ROP and reach capability and the ability to drill a straight hole, rotating results in better hole cleaning and a reduced chance of stuck pipe. However, depending on drillpipe size and the radius of the curvature, the pipe is stressed somewhere between its endurance limit and its yield point. Since damage from fatigue is a function of the stress level and the accumulated number of cycles, at some number of cycles, the drillstring will fail. Figure 13 provides guidelines for limited rotation for various radii of curvature and drillpipe sizes and grades, based on both calculations and historical data. However, cycles-to-failure are difficult to quantify because of variations in material strength, previous stress history, corrosion, surface finish, and wear.

While cycles-to-failure cannot be predicted precisely, one thing is certain: the longer the radius of the well, the lower the chance of failure, and the more contingency options that are available. The radius of the build section directly affects the motor's ability to rotate, and thereby affects drilling efficiency in the lateral. Since the lateral comprises 80% to 90% of footage drilled in short-radius wells, it is the main factor in drilling costs.

Drillpipe damage, ROP, and trouble time all factor heavily into short-radius economics. Some operators have settled on an established radius of about 75 ft or greater as optimum from the viewpoint of overall economics.. At or above a 75-ft radius, drillstring damage is normally minimal, and limited rotation can be used to maximize ROP and minimize hole problems. Also, above a 75-ft radius, some completion equipment, such as screens or packers can also be used. Even if the build rate allows limited rotation, the length of the lateral that can be drilled will eventually be limited by drillstring drag, which is normally exacerbated by buckling.

1.4.3.1 Drillstring Design and Maintenance for Short-Radius Wells

Drillstring design for short-radius wells is similar to that of medium-radius wells in that drillpipe is run in compression through the build section and in the lateral. In short-radius wells, drillpipe run in compression can be expected to buckle, often inelastically. The length of drillpipe to be run in compression should be no more than the combined length of the lateral and build section so that the amount of damaged pipe section is minimized. If available, heavy-wall drillpipe can be run above the build so that the rest of the string is in tension.

Drillpipe size and grade should be selected relative to stresses in the build section. Generally, if there is uncertainty regarding which of two grades to use, the stronger drillpipe grade should be chosen. However, because high-strength steel is more prone to attack by H_2S, the lower strength material may be necessary in such an environment. Torque-and-drag modeling should be used for calculating drillstring loads during sliding and rotating. If any rotation of the drillstring is intended, stress should be limited to 75% of yield. The strongest tool joint for a given pipe grade should be selected relative to torsional capacity as given in API RP 7G (1995).

Torsional capacity can be assumed to be an approximate indicator of bending strength. If retrievable wireline steering tools will be used, the tool joint ID must be larger than the steering tool OD, which is typically 1 ¾-in. In this section, the term drillpipe refers to either drillpipe or tubing. For example, 2 7/6-in. P110 tubing with premium connections has been used as the drillstring in a 4 3/4-in. hole size. Dimensions and torsional specifications of tubing connections are usually proprietary and must be provided by the manufacturer.

The drillstring used in short-radius work should be in new or good condition. After each well, all drillpipe that has been run in compression should be subjected to a comprehensive program of inspection, stress relieving, and if necessary, straightening.

Threaded connections should frequently be inspected, through the use of wet magnetic particle or dye penetrant inspection. A system of tracking stress cycles should be implemented, and high-risk pipe should be set aside. Depending on the extent of damage or rework cost, drillpipe that has been run in compression in short-radius wells should either be considered for retirement after use in a few wells, or it should be used as line pipe or production tubing.

Pipe run in tension in the vertical part of the well should also be inspected at regular intervals like any drillstring, even though it will avoid the damage of pipe run in a buckled state.

Drill pipe used in short radius holes has a finite fatigue life; that is, sooner or later it will fail. The amplitude of the bending stress induced in the pipe can be estimated with the formula

$$\sigma = \frac{D*E}{2R}$$

And, the radius of curvature can be calculated by: $R = \frac{5730}{BR}$

BR Build Rate (degrees per 100 ft)
D Diameter of Pipe (inches)
E Modulus of Elasticity of Pipe (psi)
R Radius of Curvature of Hole (inches)
σ Stress (psi)

The equation for stress is an approximation that does not take into account the diameter of the tool joints or the axial tensile or compressive load on the pipe. The equation can be an indication of whether the stresses are approaching the endurance limit of the pipe.
The endurance limit of pipe, in this context, is defined as the cyclic stress amplitude below which a fatigue failure will not occur. The endurance limit for drill pipe with no axial load, regardless of grade, is about 30,000 psi. The radius of curvature needed to induce this bending stress in 2-7/8 pipe is 120 ft. This assumes that the pipe has the same radius of curvature as the hole. A radius of curvature of 120 ft is equal to a build rate of 48 degrees per 100 ft.

1.4.3.2 Short Radius Drill Pipe Assembly

Most short radius holes are drilled with tubing. Tubing is relatively inexpensive but tubing threads do not have the durability desired for repeated makes and breaks needed in a drill pipe connection and the fatigue strength of tubing threads is lower than that of a drill pipe tool joint. Many tubing connections are also limited in torsional strength.

Early this year, Grant Prideco initiated a project to develop small diameter drill pipe specifically for short radius drilling. The objective was to develop a drill pipe assembly that had maximum resistance to fatigue and could be manufactured with the lowest possible cost; in other words, a fatigue resistant disposable drill pipe assembly. The pipe is designed to be used in applications where fatigue failures are eminent; therefore, when the fatigue life of the pipe has.been expended, the pipe can be laid down.

a. Pipe Description

The objectives in designing the pipe are to maximize fatigue resistance so the pipe will last longer than conventional pipe and to minimize cost so the pipe can be retired with a minimum financial impact.

The pipe will be 2-7/8 in, 10.40 lb/ft, Range 3, S-135 or X-95. When there are no special material requirements, the pipe will be made from standard drill pipe steel. Grant Prideco produces all four API grades of pipe from the same chrome-moly steel. The four different strengths are achieved with different tempering temperatures. All four grades are quenched and tempered. If there are special requirements for the pipe such as operating in H_2S or if greater toughness is required, special chemistry steels and special heat treatment processes are available to meet these needs.

2-7/8 in 10.40 lb/ft was chosen because there are many applications for this size pipe in 4-3/4 in diameter holes. The pipe can be produced in other sizes such as 3-1/2 in and 4 in. The pipe weight of 10.40 lb/ft was chosen to maximize fatigue life, strength, buckling resistance and penetration rate. Operating in like conditions, the bending stress in 10.40 lb/ft is the same as the bending stress in lighter weights; however, the mean stress in the pipe caused by tensile or compressive loads will be less in 10.40 lb/ft than lighter weight pipe because of the increased wall thickness. The lower the mean stress about which the alternating stresses fluctuate, the longer the fatigue life.

The thicker wall of the 10.40 lb/ft compared to lighter weights also gives the pipe more buckling resistance. The buckling strength of 2-7/8 in 10.40 lb/ft pipe is about 43% greater than that of 2-7/8 in. 6.85 lb/ft pipe based on the pipe's moment of inertia. This translates to more bit weight and faster penetration rates.

Pipe Length: Range three pipe was chosen to minimize the number of connections thereby minimizing the manufacturing cost and minimizing the time required to pick the string up and lay it down. However, Range 2 pipe will be available. The factors that could influence the selection of pipe length for short radius drilling operations are:

- Whether or not the pipe contacts the wall of the hole or has "wrap contact" with the wall of the hole. This is not only a function of the pipe size and length, but of axial tensile or compressive load as well.
- The bending stresses in the pipe from axial tensile or compressive loading in the curved portion of the hole and cost

Predictions regarding how the pipe contacts the wall of the hole and pipe stresses were made using Frank Schuh's equations. According to Schuh's equations, 2-7/8 in pipe with an axial compressive load of about 1,500 lbs or greater will have wrap contact in holes with build rates greater than 50-degrees/100 ft. For all practical purposes, 2-7/8 in pipe is going to contact the wall of the hole when drilling short radius horizontal or extended reach holes. If the goal is to eliminate contact with the hole, methods other than pipe length such as drill pipe rubbers are recommended.

b. Threaded Connections:

Rather than welding tool joints to the pipe, tool joint threads are machined directly onto the drill pipe upset. This reduces cost. While many connection types with a selection of outside and inside diameters are available, the first joints produced will have a special fatigue resistant SST thread. The pin will have a stress relief groove and will be free of other features such as benchmarks or pin base marking that do not contribute to longer lifer or reduced cost.
The SST thread is machined on the pin only and is completely interchangeable with API threads. The SST thread has two unique features that increase its resistance to fatigue. First, the thread has a root radius of 0.052 in versus an API NC connection root radius of
0.038 in. The larger root radius decreases the stress concentration factor of the thread and gives the thread greater fatigue life.

The second feature is a pin taper slightly less than the box taper. The difference in taper causes the axial load induced in the threads from make-up to be more evenly distributed along the length of the pin. The first thread on an API connection carries about 29% of the axial load from make-up: whereas the first thread of the SST connection carries only about 25%. This results in a lower mean stress at the root of the last engaged thread, which makes the connection more resistant to fatigue.
A third feature on the connection not related to the SST thread is the 15-degree torque shoulder. The torque shoulder on conventional tool joints is perpendicular to the axis of the connection. On this pipe, the torque shoulder is at an angle of 15 from perpendicular. This will resist loosing the seal as the pipe is bent through high angle build zones.

c. Drill Pipe Upsets

The upsets on the pipe will include a smooth transition between the tool joint and the pipe body. The smooth transition will minimize the stresses where most washouts occur. The tong length of the connections will be short because of the limited length of the upsets; however, when pipe is continually used in short radius holes, it will be retired before recuts are necessary.
The pipe will have an 18-degree elevator shoulder on the box and pin to decrease drag and to allow the pipe to be run with the pin up. A conventional pin has a 35-degree shoulder and can cause more drag than an 18-degree shoulder as the pipe is pushed or pulled in the hole.

Calculated Stress Concentration Factors In Tension And Bending.

Loading Condition	Location	Stress Concentration Factor (SCF)	Comments
Tension	Upset	1.103	Highest stress in bore at transition from pipe to upset.
Tension	Threads	2.112	Highest stress at root of last engaged thread of pin. SCF for API tool joint is about 3.6.
Bending	Upset	1.006	Highest stress at outside surface near transition from pipe to upset.
Bending	Threads	1.981	Highest stress at root of last engaged thread of pin. SCF for API Tool joint is about 3.6.

Table 1.1 calculated stress concentration factors in drill pipes for ultra short radius wells

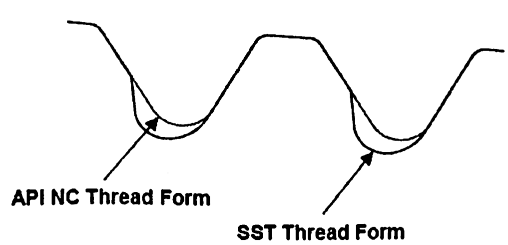


Fig 1.13 Comparison between API and specially designed SST thread form

1.4.3.3 Drilling the Short-Radius Build Section

The build rate of short-radius wells requires that large-diameter tubulars (motors or survey collars) must be articulated to pass through the build section. Articulations are knuckle joints or hinge points that transmit axial loads and torque, but not bending moment. BHA components are shortened into lengths that will traverse through the build section without interference (Figure 14). Without articulations, excessive bending stress and high side-loads would result.

Since the articulated joints decouple the bending moment from one section of the BHA to another, the build rate of the steering section is unaffected by the stiffness or weight of the sections above it. Build rate is completely defined by three contact points: the bit, the first stabilizer or pad, and the first articulation point.

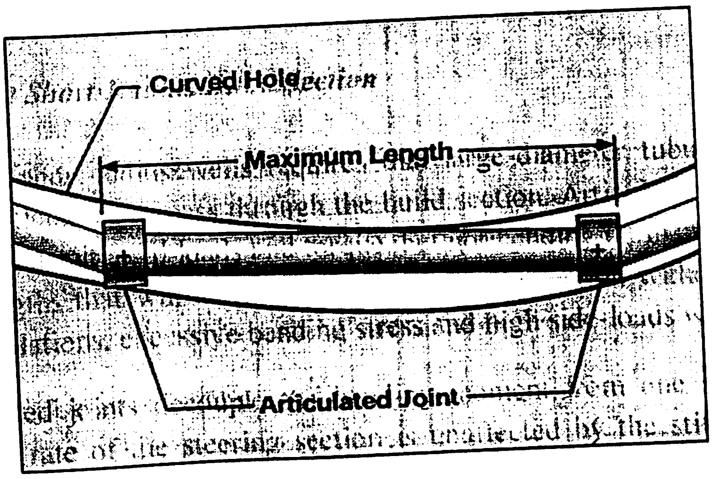


Fig 1.14 Short-radius BHA components must be short to prevent binding in the well bore

For the same reasons that other BHA components must pass through the build section without interference, the overall length and offset of these components must allow the assembly to pass through the casing without interference. For this reason, a bit at least 1/8 in. smaller than the casing drift diameter is normally specified.

Because of the relatively short length of short-radius BHA components, slight interference with the borehole will cause high contact loads. The geometry of some short-radius BHAs may allow them to be rotated in the intermediate-radius hole curvature range without exceeding critical loads or stresses. However, the manufacturer's engineering guidelines should be strictly followed; if short-radius in-hole curvatures are rotated in excess of design guidelines, they can bind in the wellbore or immediately break

1.4.3.4 Drilling the Short-Radius Lateral

Although articulated motors may be run in the lateral, non articulated tools can be expected to provide more predictable control. Motors with flexible housings, may be required for passing through the build section without yielding or getting stuck. At the beginning of the build section, the lateral motor may need to be oriented so that it can be tripped through that section without binding. To minimize stress cycles, top drives or power swivels should be used to turn the drillstring as slowly as possible, preferably at 1 to 10 rpm. Drilling operators should particularly avoid picking up the drillstring or tripping out of the hole, since the combined stress in the build section will be maximum in this condition. Drillpipe fatigue cracks can usually be detected as washouts before the cracks part, so the drillstring should be tripped at the first sign of a loss in pump pressure.

Because most short-radius footage is drilled oriented or at a low rate, the drillstring cannot be relied upon to agitate the cuttings beds and lift cuttings into the annular flowstream. High annular velocities and drilling-fluid rheology must remove cuttings; sliding wiper trips may also be necessary.

Chapter 2

Directional Control with Rotary Assemblies

INTRODUCTION

An important aspect of drilling horizontal well is the BHA design which is to drill the planned trajectory. Now the basic principles used in directional control when drilling with rotary assemblies and the typical assemblies will be described. The effects of drilling parameters (weight-on-bit) and formation (anisotropy) will be considered.

Historically, it has always been possible to control the angle (inclination) of directional wells during rotary drilling by correct design of the assembly and use of suitable drilling parameters. However, the control of hole direction has traditionally been poor. Roller cone bits usually walk to the right, and directional control was formerly limited to using well-stabilized assemblies to reduce this tendency.

2.1 Side Force and Tilt Angle

Directional trends are partly related to the direction of the resultant force at the bit. It has also been shown that bit tilt (the angle between the bit axis and the hole axis) influences the direction of drilling. This is because a drill bit is designed to drill parallel to its axis. In rotary assemblies where there is a near bit stabilizer, the bit tilt angle is small causing the magnitude of side force at the bit to be a key factor.

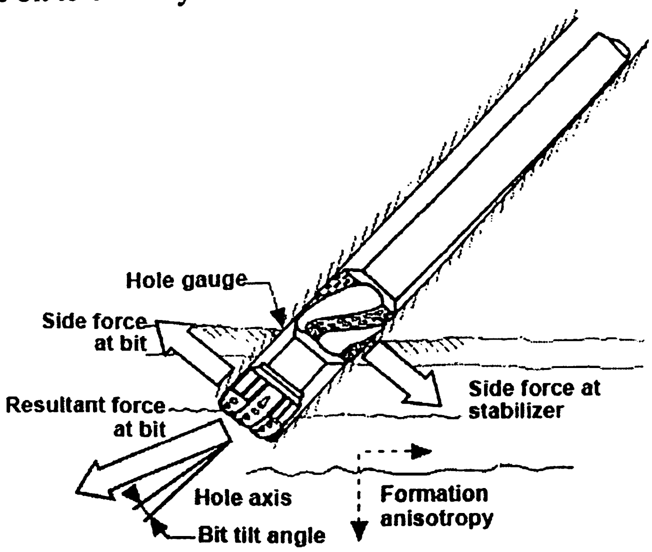


Fig 2.1 - Forces acting at the bit which influence the direction of the borehole.

Factors which can affect the directional behavior of rotary assemblies include:

- Gauge and placement of stabilizers
- Diameter and length of drill collars
- Weight -on-bit and Rotary speed
- Bit type, Flow rate, Rate of penetration

- Formation anisotropy and dip angle of the bedding planes
- Formation hardness

2.2 Basic Directional Control Principles

- The Fulcrum Principle is used to build angle (increase borehole inclination)
- The Stabilization Principle is used to hold (maintain) angle and direction.
- The Pendulum Principle is used to drop (reduce) angle.

2.2.1 The Fulcrum Principle

An assembly with a full gauge near-bit stabilizer, followed by 40 to 120 feet of drill collars, before the first string stabilizer, or no string stabilizer at all, will build angle when weight-on bit is applied. The collars above the near-bit stabilizer bend, partly due to their own weight and partly because of the applied WOB. The near-bit stabilizer acts as the pivot, or fulcrum of a lever and the bit is pushed to the high side of the hole. The bit therefore drills a path which is gradually curving upwards (the assembly builds angle).

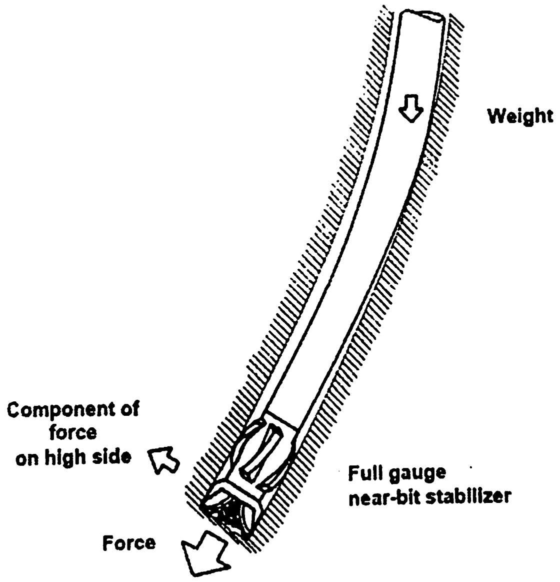


Fig 2.2 BHA using the fulcrum principle

The rate of build will be increased by the following:

- Increasing the distance from the near-bit stabilizer to the first string stabilizer
- Increase in hole inclination
- Reduction of drill collar diameter
- Increase in weight on bit

- Reduction in rotary speed
- Reduction in flow rate (in soft formations)

The distance from the near-bit stabilizer to the first string stabilizer is the main design feature in a fulcrum assembly which will affect the build rate. The build rate increases as this distance is increased, because a longer fulcrum section will bend more, which will increase the fulcrum effect and the side force on high side. There is a limit, however. Once the upper stabilizer is more than 120 feet from the near-bit stabilizer (depending on hole size, collar OD, etc.), the collars are contacting the low side of the hole and any further increase in this distance will have no additional effect on build rate.

The rate of build increases as the inclination increases because there is a larger component of the collars own weight causing them to bend. The mechanics involved predicts that the rate of build should increase in direct proportion to the sine of the inclination. In reality, the situation and the actual response is more complicated. Example, a strong build assembly which built at a rate of 1.5°/100' when the inclination was only 15° might build at 4°/100' when the inclination was 60°.

- Drill Collar Diameter: The stiffness of a drill collar is proportional to the fourth power of its diameter. A small reduction in the OD of the drill collars used in the fulcrum section considerably increases their limberness and hence the rate of build. However, it is not common practice to pick drill collar diameter according to build rate requirements. Usually, standard collar sizes for the given hole size are used.
- Weight-on-Bit: Increasing the weight on bit will bend the drill collars behind the near-bit stabilizer more, so the rate of build will increase.
- Rotary Speed: A higher rotary speed will tend to 'straighten' the drill collars and hence reduce the rate of build. For this reason, low rotary speeds (70 - 100 RPM) are generally used with fulcrum assemblies.
- Flow Rate: In soft formations, a high flow rate can lead to washing out the formation ahead of the bit which reduces the build tendency.

2.2.2 The Stabilization (Packed Hole) Principle

This principle states that if there are three stabilizers in quick succession behind the bit separated by short, stiff drill collar sections, then the three stabilizers will resist going around a curve and force the bit to drill a reasonably straight path.

The first of the three stabilizers should be immediately behind the bit (a near-bit stabilizer) and should be full gauge. Assemblies which utilize this principle are called packed hole assemblies and are used to drill the tangent sections of directional wells, maintaining angle and direction. High rotary speed (120-160+) will assist the tendency to drill straight.

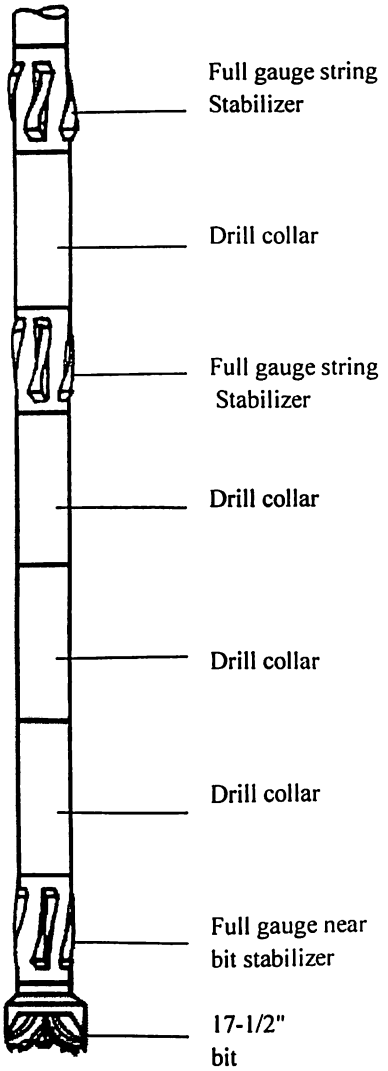


fig 2.3a

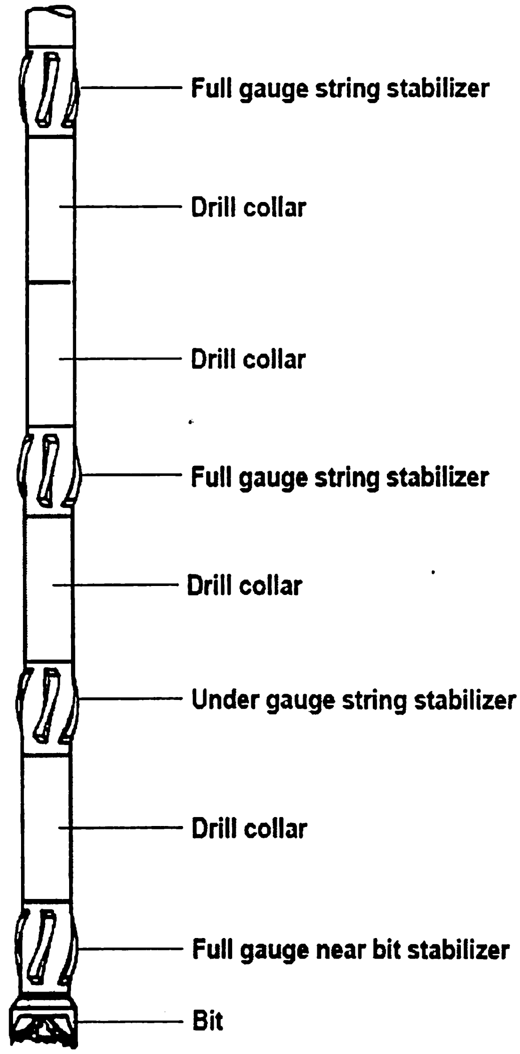


Fig 2.3b

fig 2.3a A 90 ft Build Assembly 17½" bit / 17½" NB stab 3 x 9½ x 30' DCs / 17½" stab / 9½" x 30' DCs as needed. This assembly will build angle rapidly, typically at 2.0° - 3.5°/100', depending on the inclination and the drilling parameters.

Fig 2.3b A Gradual Angle Build Assembly 12¼" bit / 12¼" NB stab / 8" x 30' DC / 12¼" stab / 8" x 30' DCs as needed / etc. This assembly would be used in the tangent section when it was necessary to build angle gradually. It would build typically at 0.5° - 1.0°/100'

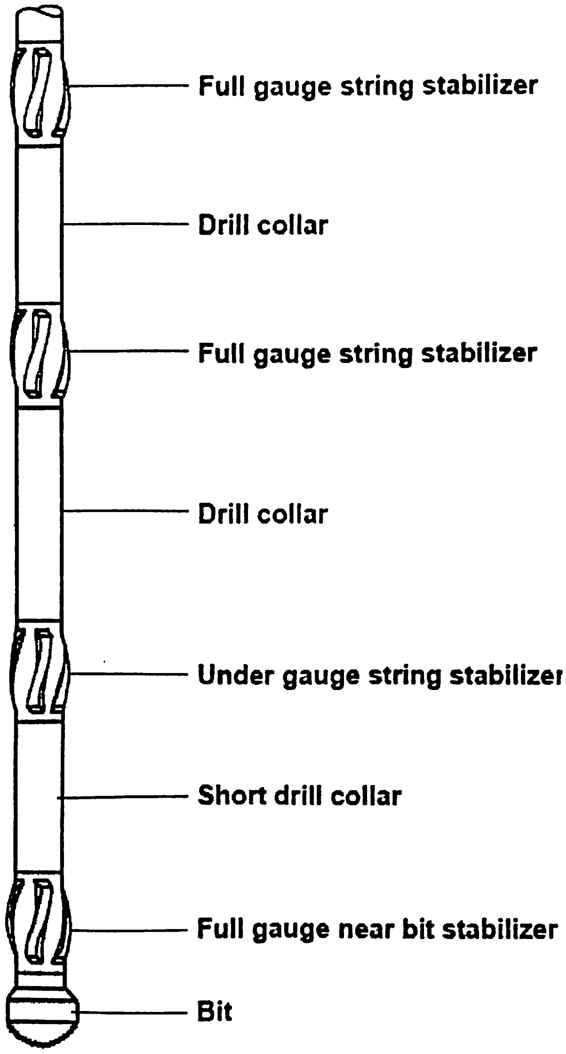


Fig 2.4a

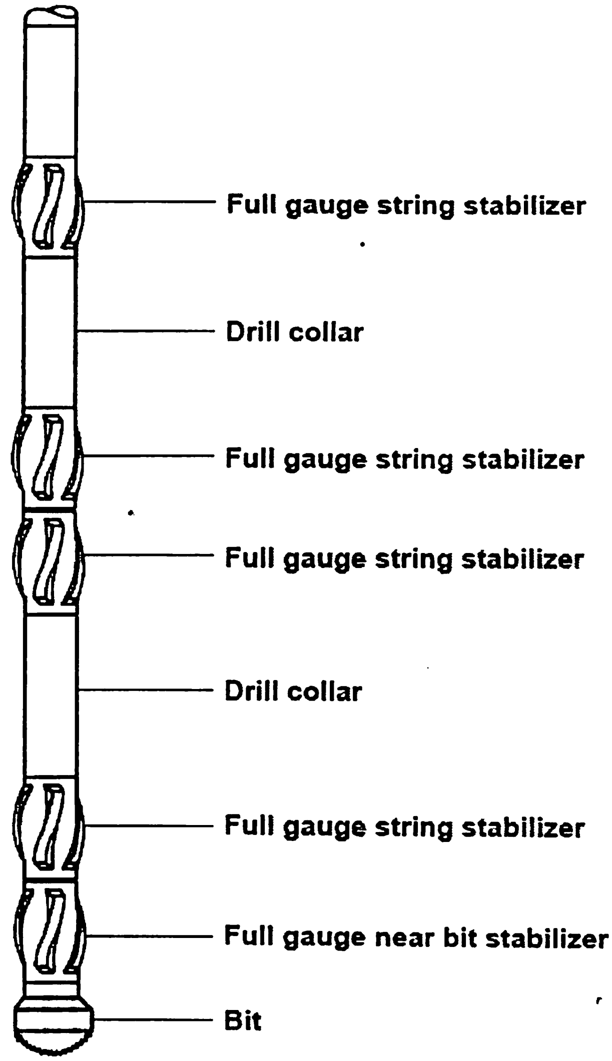
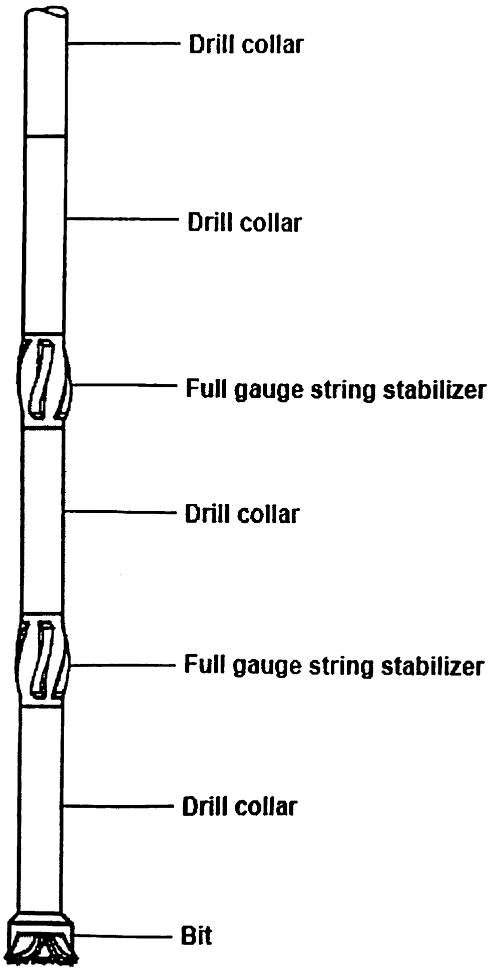


Fig 2.4b

Fig 2.4a This assembly should hold angle Depending of the exact gauge of the first string stabilizer

Fig 2.4b The tandem stabilizers make this assembly very rigid. In the past it was more common to use tandem stabilizers to control the bit walk of roller cone bits. Presently, its use is limited to areas where extreme bit walk is common. Rotation of an assembly such as this will generate high rotary torque. Generally, as the number of stabilizers in the BHA increases, so does the possibility of hole sticking.

Dropping Assemblies



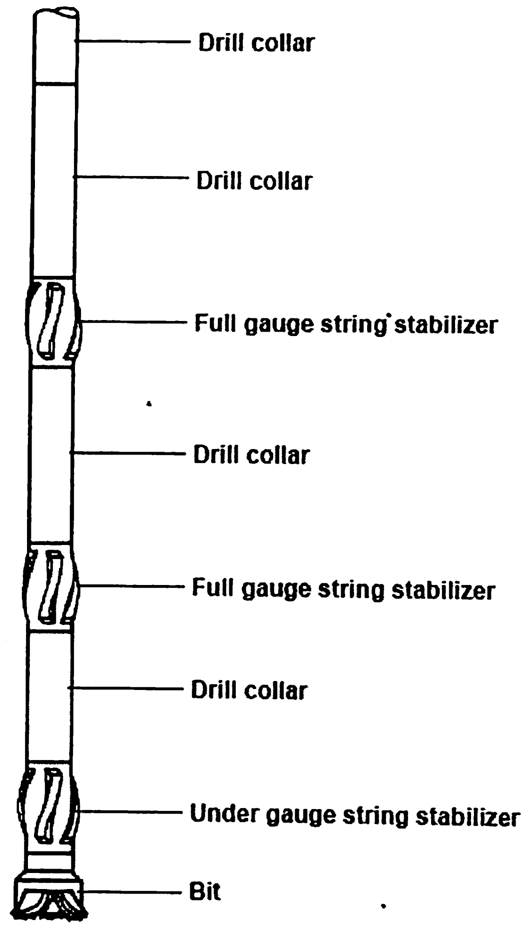


Fig 2.5a A 30 foot Pendulum Assembly. The rate of drop depends on the wellbore inclination and the diameter and weight of the bottom drill collar, as well as the drilling parameters. At 45° inclination, this assembly would typically drop at 1.5° - 2.0°/100'.

Fig 2.5b A 30 foot Pendulum Assembly with under-gauge near bit stabilizer. This will give a slightly lower rate of drop than the previous BHA, but should reduce bit walk and thereby give better azimuth control.

2.2.3 The Pendulum Principle

This was the first directional control principle to be formulated and was originally analyzed for slick assemblies drilling straight holes. The portion of the BHA from the bit to the first string stabilizer hangs like a pendulum and, because of its own weight, presses the bit towards the low side of the hole. The major design feature of a pendulum assembly is that there is either no near-bit stabilizer or an undergauge near- bit stabilizer. In most cases where a pendulum assembly is used, the main factor causing deviation is the force at the bit acting on the low side of the hole. The length of collars from the bit to the first string stabilizer (the "pendulum") must not be allowed to bend too much towards the low side of the hole. If the collars make contact with low side, then the effective length of the pendulum and the side force on low side are both reduced. This situation is also undesirable because the bit axis has been tilted upwards in relation to the hole axis which will reduce the dropping tendency.

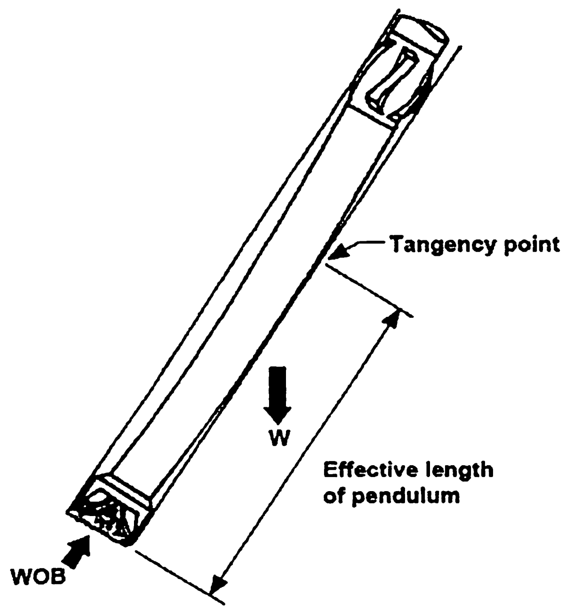


Fig 2.6 Reduction of Pendulum force due to wall contact

Careful selection of drilling parameters is required to prevent this. High rotary speed (120 - 160+) helps keep the pendulum straight to avoid the above situation. Initially, low weight-on-bit should be used, again to avoid bending the pendulum towards the low side of the hole. Once the dropping trend has been established, moderate weight can be used to achieve a respectable penetration rate.

The safest approach to designing and using a pendulum assembly is concentrating on producing a side force at the bit on the low side of the hole. This is achieved by running an assembly where the pendulum portion will be as stiff and straight as possible. It is also desirable that the section

immediately above the first string stabilizer be stiff and straight and that a second string stabilizer be within 30 feet of the first.
Omit the near-bit stabilizer when azimuth control is not a concern or when drilling with a PDC bit. When drilling with a roller cone bit, use an under-gauge near-bit stabilizer if azimuth control is a consideration. Typically, the near-bit stabilizer need only be 1/4" to 1/ 2" undergauge in order to produce a dropping tendency.

The assembly should have two string stabilizers with the second stabilizer not more than 30 feet above the first. Initially using low WOB until the dropping tendency is established, then gradually increasing bit weight until an acceptable penetration rate is achieved.

2.3 Bit Type Effects on Rotary Assemblies

2.3.1 Roller Cone Bits

When rotary drilling with roller cone bits, the type of bit makes very little difference to whether an assembly builds, holds or drops angle. Directional control is determined by the configuration of stabilizers and collars and by varying the drilling parameters.
However, the type of bit has a significant influence on walk rates.
Conventional tri-cone bits cause right-hand walk in normal rotary drilling.
Generally speaking, long tooth bits drilling soft to medium hard formations give a greater right walk tendency than short tooth bits drilling a harder formation. This is because soft formation bits have a larger cone offset and cut the rock by a gouging action.

2.3.2 PDC Bits

When rotary drilling with PDC bits, it has been found that almost no walk occurs (the assemblies hold their direction). It has also been found that inclination angle is affected by PDC bits, particularly when an angle drop assembly is used.

The gauge length of a PDC bit can significantly affect the build rate in a rotary assembly. A bit with a short gauge length can result in a build rate greater than that would be expected with a tri-cone bit. On the other hand, a longer gauge stabilizes the bit, which tends to reduce the rate of build. The low WOB typically used with PDC bits can also reduce the build rate, since collar flexure decreases with decreasing WOB. When used with packed assemblies, longer gauged PDC bits seem to aid in maintaining inclination and direction due to the increased stabilization at the bit.

When used with angle drop assemblies, PDC bits can reduce the drop rate previously obtained with a tri-cone bit. Generally, the longer the gauge length, the lower the rate of drop obtained because the bit gauge acts similar to a full gauge near-bit stabilizer. Short gauge length PDCs can be used effectively for dropping angle. When such a suitable PDC bit is used in a rotary pendulum assembly, the low WOB and high RPM, typical to most PDC bit applications, should assist in dropping angle.

2.4 Stiffness of drill collars

The behavior of bottom-hole assemblies, particularly fulcrum and pendulum assemblies is affected considerably by the stiffness of the drill collars used in the lowest portion of the BHA.
It is generally accepted that drill collars are considered as thick walled cylinders, their stiffness depending on the axial moment of inertia and the modulus of elasticity of the steel.

A collar's axial moment of inertia I, is determined by:
$I = (\pi/64) \times (OD^4 - ID^4)$
The weight per unit length, W, is calculated from:
$W = (\pi/4)\, \sigma \times (OD^2 - ID^2)$
where σ is the density of the steel.
Notice that the stiffness is proportional to the fourth power of the outside diameter, while the collar weight is proportional to the square of the outside diameter. This means that the inside diameter has very little effect on collar stiffness but has a significant effect on collar weight.

For example, the moment of inertia of a 9-1/2" collar is double than that of an 8" collar, which in turn is more than double that of a 6-1/2" collar.
The component of weight/unit length tending to bend the drill collars and contributing to the lateral forces at the bit and stabilizers is then:

$W_x = W\,(BF) \sin\theta$
Where

W	weight/foot of the drill collar in air,
BF	buoyancy factor of the drilling mud
Θ	inclination of the wellbore

For example, if the inclination was 50° and the mud density was 10 ppg then the value of W_x for 8-inch drill collars would be:
$W_x = 160 \times 0.847 \times \sin 50°$
$W_x = 160 \times 0.847 \times 0.766 = 104$ lb/ft
(Buoyancy factor for 10 ppg mud = 0.847)

The thing to notice is that most types of steel and monel which are actually used in drill collars have about the same modulus of elasticity and density.

So in practice the stiffness of a drill collar depends almost entirely on its outside diameter and is proportional to the fourth power of the OD. However, aluminum drill collars would be more limber than steel drill collars of the same dimensions whereas tungsten collars would be much stiffer. In general, it is recommended that standard drill collar diameters should be used for each hole size.

Collar OD (in)	Moment of Inertia (in^4)	Weight/Length (lb/ft)
4.75	25	45
6.5	85	100
8.0	200	160
9.5	400	235

Table 2.1- Relative Weights & Inertia of Some Common Drill Collars

Metal	Modulus of Elasticity (10^6 psi)	Density (lb/ft^3)
Steel (low carbon	29.0	491
Stainless Steel	28.0	501
K Monel	26.0	529
Aluminum	10.6	170
Tungsten	51.5	1205

Table 2.2 - Modulus of Elasticity and density of Various Metals

2.4.1 Effects of Drill Collar O.D

When using a fulcrum (build) assembly, reducing the collar OD will dramatically increase the build tendency, because the collars will be more limber and will bend more. Another factor is the clearance between the outside of the drill collars and the wall of the hole. The greater the clearance, the more the collars can bend before they contact the low side of the hole. Once the collars contact the low side of the hole, further increases in WOB will have only a marginal effect on build rate by moving the contact point down the hole.

When using a packed assembly, reducing collar OD may give a slight build tendency because the collars can bend more.

When using a pendulum assembly, it is best that the pendulum portion be as stiff as possible, so it is preferable to use large diameter collars.
Reducing collar OD increases the likelihood that the collars will bend towards the low side of the hole, which will reduce the pendulum effect and the rate of drop. Also, reducing the collar OD reduces the weight of the bottom collars which reduces the pendulum force and the rate of drop.

2.5 Formation Effects on Bit Trajectory

The nature and hardness of the rock being drilled can have a pronounced influence on directional tendencies, although in many cases the importance may be exaggerated. A main point is whether the rock is isotropic or anisotropic. An isotropic rock is one which has the same properties, or behaves in the same way, regardless of its direction. Most sand stones are isotropic. Conversely, anisotropic rocks, such as shales, do not have the same properties in all directions.

Most oilfield drilling is done in sedimentary rocks. Due to the nature of their deposition, sedimentary rocks have layers or bedding planes, causing most sedimentary rocks to show some degree of anisotropy. Drilling into dipping (tilted) formations has shown that the drill bit is forced towards a preferential direction related to the dip angle and direction of the bedding.
The trends are most prevalent in low angle, medium to hard drilling, especially in formations with pronounced structure.

- A number of explanations and models have been proposed over the years to explain these effects. In their early work on the pendulum theory, Lubinski and Woods proposed a drillability model which related an index of the rock strength when attacked perpendicular to the bedding planes to rock strength when attacked parallel to the formation. They produced tables of anisotropy indices and formation classes which could be used as a guide in selecting pendulum length, drill collar size or weight on bit.

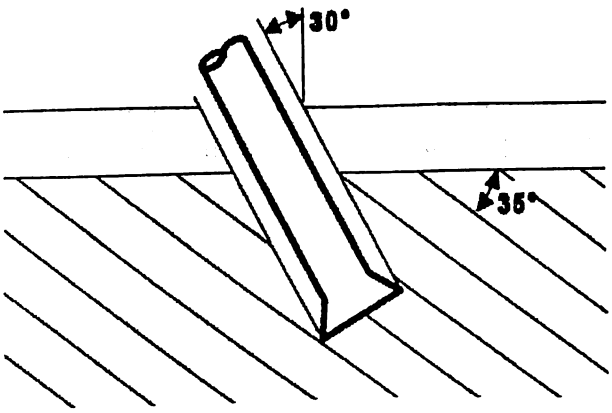
- Another theory proposes that as the bit drills into hard layers, the hard layer will fracture perpendicular to the dip. This creates a miniature whipstock which guides the bit to drill into the dip.

- Another explanation, proposed by McLamore and others, is that of preferential chip formation. This considers the mode of chip formation at a single tooth. Anisotropic formations have preferential planes of failure. As it impacts the formation, the bit tooth sets up a compressive stress in a direction perpendicular to the face of the tooth. Shear failure will then occur more readily along the bedding planes. When the bit is drilling an anisotropic rock, larger chips will be cut rapidly on one side of the bit and smaller chips will be cut more slowly on the other. Unequal chip volumes will therefore be generated on each side of a bit tooth. Using Figure as an example, the forces between the bit tooth and the rock will be greater on the right side of the tooth. Therefore, there will be a resultant force on the bit acting to the left. This is F_d, the deviation force. It follows that the deviation force will depend on the angle of dip.

2.5.1 Relationship between Dip Angle and Deviation Force.

The effective dip angle is the angle at which the bit strikes the bedding plane. The graph predicts that when the effective dip angle is less than 45°, the direction of the deviation force is up-dip. When the effective dip angle is greater than 45° the direction of the deviation force is down-dip. The meaning of up-dip and down-dip is illustrated in Figure. In practice, it has sometimes been observed that an up-dip tendency is observed at dip angles as high as 60°.
The unwanted deviation in vertical wells has borne out the predictions of the graph shown. Drilling through alternately hard and soft formations with low dip angles, using a well stabilized bit and weights high enough to cause collar flexure, usually results in a course perpendicular to the bedding planes.

The formation attitudes will have a similar effect on directional tendencies.
For dip angles less than 45°, if the direction is up-dip, the bit will tend to maintain direction, but build angle. If the borehole direction is left of up dip, the bit may tend to walk to the right; whereas if the direction is right of up-dip the bit tends to walk to the left. Both phenomena are just special cases of the up-dip tendency. When the formation dip angle is greater than 60°, the usual tendency of the bit is to drill parallel to the bedding plane or down-dip.
In cases where the dip angle is greater than 60°, if the hole direction is right of down-dip force.



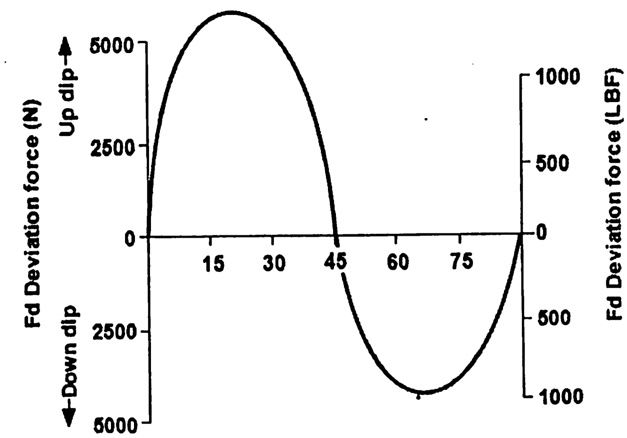


Fig 2.7 - Maximum deviation force as a Function of formation dip

Hole inclination = 30°;
Real dip angle = 35°;
Effective dip angle = 30° + 35° = 65°;

There will be a down-dip deviation direction then the bit tends to walk to the left. If the hole direction is left of down-dip direction, the bit tends to walk to the right. Again, these are simply special cases of the down-dip tendency.

There will be no deflection of the bit caused by the formation at 0° or 90° dip. This is because the bit is cutting into a structure that is essentially uniform and is constantly cutting into the same layers at the same time or constantly drilling between layers.

2.6 Formation Hardness

The preceding discussion has concentrated on the effects of rock anisotropy and changes in hardness between layers. There are a few general points concerning the effect of rock hardness on directional behavior which should be mentioned.

In very soft formations, the formation can be eroded by the drilling fluid exiting from the bit nozzles, creating an overgauge hole. This can make it hard to build angle, even with a strong build assembly. If this problem is anticipated then fairly large nozzles should be fitted into the bit. If it occurs while drilling, the pump rate should be reduced and prior to making each connection, increase the flow rate to clean the hole with the bit one joint off bottom. Hole washing or enlargement in soft formations may also cause packed assemblies to give a dropping tendency at high inclinations.

This can be counteracted by increasing WOB and reducing flow rate. If anticipated beforehand, a possible solution would be to run a mild build assembly.

BHAs tend to respond more closely to their theoretical behavior in harder formations. This is mainly because the hole is more likely to be in gauge. In medium to hard formations, building assemblies are more responsive as maximum bit weight may be applied to produce the required build. The main directional problem encountered in hard formations is getting a pendulum assembly to drop angle.

Generally speaking, the harder the formation, the longer it takes a dropping assembly to respond. There may also be a conflict between the need to reduce WOB to get the dropping trend established and the need for high WOB to maintain an acceptable penetration rate. Where possible, it is best to avoid planning a drop section in hard formation. When a drop section must be drilled in hard formation, the use of large diameter, heavy collars is recommended.

2.7 Navigation Drilling Systems

Most conventional directional drilling operations will require extra trips to change the BHA for directional control. In addition, bit performance can be reduced by those same conventional deflection techniques.

Several methods exist for continuously controlled directional drilling using "steerable downhole motors". These methods are based upon tilting the axis of the bit with respect to the axis of the hole to creating a side force at the bit. If the drill string, and the body of the motor, is rotated at the surface, the bit will tend to drill straight ahead. However, if the drill string is not rotated from surface then bit will drill a curved path determined by the orientation of the side force or the tilt of the bit axis. Most steerable systems presently being used are based on a positive displacement motor and use the principles of tilting the axis of the bit with respect to the axis of the hole. The majority of directional drilling companies use a single-tilt PDM, with a bend either on the U-joint housing or at the connection between the U-joint housing and the bearing housing.
Nowadays this single bend is typically adjustable on the rig floor, enabling the tilt angle to be set at any value between zero and some maximum.

Advantages of NDS

- Elimination of trips for directional assembly changes, saving rig time.
- More complex well paths can be drilled.
- Wells are drilled more closely to the plan at all times.
- Smaller directional targets can be hit

2.7.1 Steerable Turbines

Steerable turbines use the side force method by having an eccentric (or offset) stabilizer at the lower end of the bearing section (at the bottom end) of the turbine body, quite close to the bit. The three blade version shown below is the one most commonly used, but a single blade version exists and is used if a lot of drag (friction) is anticipated. One blade is larger in surface area and is offset by 1/8-inch. When the drill string is rotated, the offset stabilizer has no effect on the well path. When it is desired to deflect the well path, the toolface (the point opposite the center of the offset blade) is orientated using an MWD tool. Drilling continues with no rotation from surface and the turbine drills a curved path.
Steerable turbines have been used to perform various types of deflections including kick-offs. Their most successful applications have been tangent section drilling and performing correction runs as required to keep the well on course.

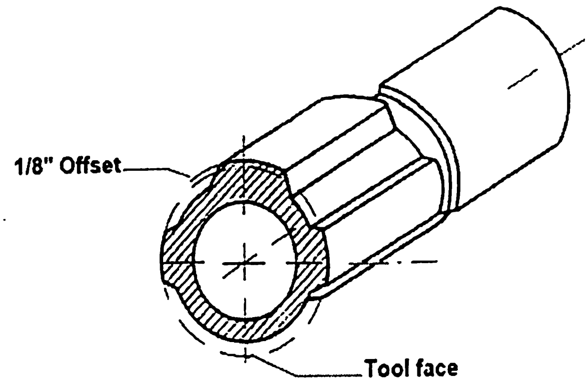


Fig 2.8 - Three blade steerable turbine

2.7.1.1 The DTU Navigation Drilling System

This drilling system consists of the following:

- Suitable drill bit
- Navi-Drill motor with a bearing housing stabilizer and DTU
- Undergauge string stabilizer just above the motor
- Survey system (usually MWD)

a. Modes of Operation

The capability to drill either oriented or rotary with the same tool is made possible by incorporating a Double-Tilted U-joint housing (DTU) and a longer U-joint assembly on a standard Mach 1 or Mach 2 PDM. The DTU creates a small tilt much closer to the bit than a conventional bent sub assembly, producing a lower bit offset.
Bit tilt and offset allow directional (azimuth and/or inclination) changes to be performed to keep the well bore on target. The low bit tilt and offset produced by the sub, means the string can be rotated when oriented drilling is not required. Rotation of the drillstring negates the bit tilt effect and the bit will usually drill a straight path.

b. DTU Basic Components

- Bypass Valve with box connection
- Navi-Drill motor section - Mach 1 or 2
- Double tilted U-joint housing
- Upper bearing housing with stabilizer (UBHS)
- Drive sub with bit box

Only the DTU housing, universal joint, and upper bearing housing components will be discussed; other components are standard Navi-Drill parts. Navi-Drill performance or operating specifications are not altered by the addition of these two special components.

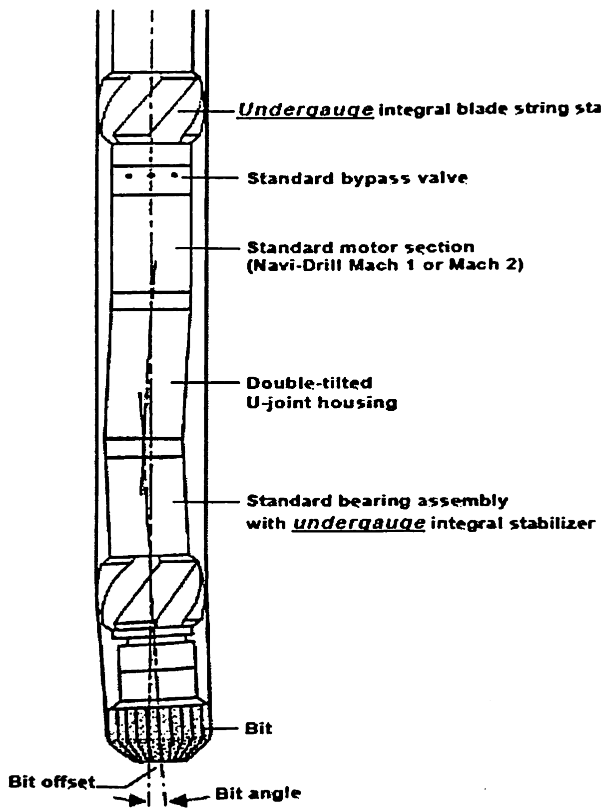


Fig 2.9a DTU and bit off-set

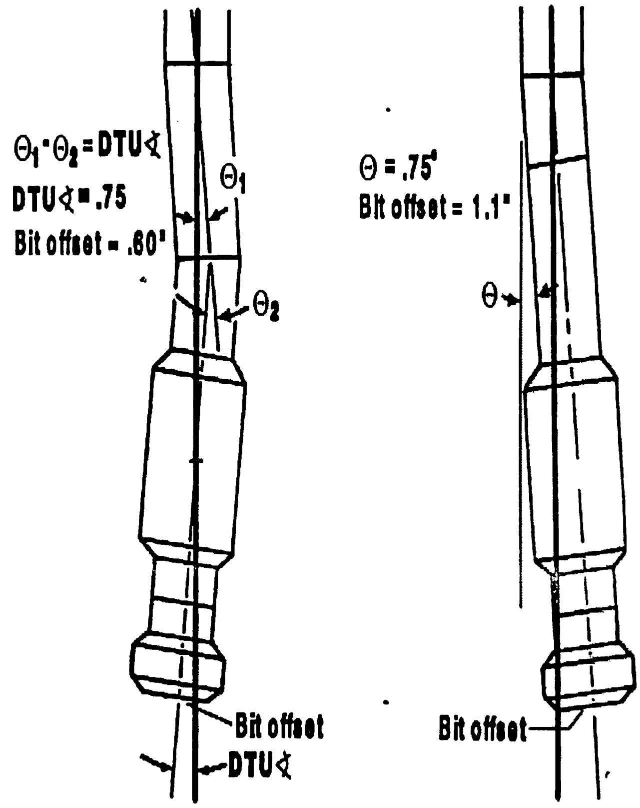


Fig 2.9b DTU Configuration

The double tilted universal joint housing:

- Replaces the straight universal joint housing on a standard Navi- Drill. The universal joint is slightly longer than the straight housing and universal joint.
- Is available in various tilt angles and identified by the tilt angle, which is the mathematical resultant angle computed from the two opposing tilt angles.
- Produces a desired bit tilt angle while reducing actual bit offset.
- Allows for extended rotation of the motor with a low eccentricity as compared to conventional bent sub or bent housing assemblies with comparable dogleg capability. Rotation of the drill string negates the effect of the bit tilt and the assembly theoretically drills a straight, slightly oversize, hole.
- Is available in various diameters ranging from 4-3/4" to 11-1/4".

With the exceptions of the 8" and the 9-1/2" tools, each diameter has three standard tilt angles designed to provide approximately 2°, 3° and 4° per hundred feet theoretical dogleg rates when configured with a Mach 2 motor. TGDS is theoretically higher when using the shorter Mach 1. The concept behind the double tilt is that by having the two tilts in the same plane but opposed (at 180°) to each other, the bit offset is minimized. Bit offset is the distance from the center of the bit to the axis of the motor section (extrapolated down to the bit).

A stabilizer can be mounted on the upper bearing housing. This stabilizer:

- Is used to centralize the motor and bit in the center of the hole.
- Is usually manufactured as an integral part of the housing and is referred to as the UBHS 9-1/2" and 11-1/4". Motors are available with either integral or sleeve type stabilizer UBHS.
- It is always under gauge.
- Has a special design to reduce drag between the blade and the wellbore, allowing sliding when the motor is drilling in the oriented mode.

The design of the UBHS includes:

- A double taper or watermelon-shape profile with rounded edges to reduce stabilizer hang up and drag.
- Blade widths of 3 to 4 inches to help prevent a cutting or ploughing action by the blade when drilling in oriented mode.
- Blade wraps varying from straight ribbed to a maximum of 30° to reduce contact area and make the stabilizer more maneuverable.
- Gauge lengths varying from 4 to 12 inches with recommended length being less than or equal to bit gauge length.
- Three blades at 1/8-inch under gauge for up to 17-1/2" hole sizes, or four blades at ¼-inch under gauge for larger hole sizes.

UBHS with 5 straight blades are now the preferred design.

Theoretical geometric dogleg severity

This angle is defined by three points on a drilled arc:

1) The bit
2) The motor stabilizer or Upper Bearing Housing Stabilizer (UBHS)
3) The first string stabilizer above the motor

TGDS (°/100 ft) = (200 x Tilt Angle) X L

Tilt angle = Bit tilt in degrees
L = length between the bit and string stabilizer = $L_1 + L_2$

2.7.2 Adjustable Kick-Off (AKO) Motor

This is a single-tilt adjustable motor, which:

- Is powered by a Navi-Drill motor section.
- Incorporates a rigsite-adjustable bent housing which can be set to achieve maximum build rates in the medium radius range (8°/30m - 20°/30m), varying with tool size and stabilizer configuration
- Allows a single AKO motor to be used for a variety of build rates
- Allows fewer tools to be transported to and from the rig, a particular advantage for remote locations

2.7.2.1 Adjustable Kick-Off Housing

The NaviDrill Mach 1 or 2 can be configured with an adjustable U-joint housing drilling motor suitable for both performance and general directional drilling applications. Steerable (mixed rotary and oriented mode) operation of the motor is possible for all well paths normally required in conventional or medium radius directional drilling operations.

The tilt angle of the AKO can be adjusted from 0° to the maximum design angle. The maximum tilt angle ranges from 2° to 2.75° depending on tool size (see below). This variable tilt angle is possible because the internal connections of the AKO housing features a tilted pin thread which screws into a tilted box thread. The relative position of the two tilted angles determines the AKO tilt angle and the position of the High Side. The AKO angle is rig floor adjustable.

a. Maximum Adjustment of AKO Motors

On the adjustable sub kick off housing, the angle is infinitely adjustable from 0° up to the maximum:

1) 3-3/4" tool size is 2.2°
2) 4-3/4" tool size is 2.5°
3) 6-3/4" tool size is 2.75°
4) 8" tool size is 2.5°
5) 9-1/2" tool size is 2°
6) 11-1/4" tool size is 2°

The addition of an alignment bent sub, with a 2° tilt angle, above the motor section allows the tool to achieve build rates up to 24°/100 ft. This is the Double Adjustable Motor (DAM). Major components include:

- Standard NaviDrill bearing and drive sub assembly with short gauge, straight rib, integral blade or sleeve type bearing housing stabilization. Rig floor adjustable single tilted U-joint housing.
- Standard Mach 1 or Mach 2 motor section.
- Standard bypass valve.
- String stabilizers with short gauge, straight rib integral blades (optional).

b. Dogleg Capabilities

The dogleg capability for the AKO is variable and is a function of the adjustable U-joint housing angular offset. Lower DLS and AKO settings, the motor can be rotated and used as a steerable motor.

The AKO motor can also be used as a:

- Partially stabilized system with bearing housing stabilizer
- Fully stabilized system with bearing housing and top stabilizer
- Slick system (without stabilization) where a wear protection hard banding ring on the AKO sub is one of the points which supports the tool inside the hole.

Maximum allowable deflection angle on the AKO sub may be limited when contact of the tool with the borehole wall exceeds mechanical limitations. This maximum angle is called "recommended Maximum Angle".

The NaviDrill AKO is available for medium radius applications in 3-3/4", 4-3/4", 6-3/4", 8", 9-1/2",11-1/4" OD sizes for hole sizes from 4-1/2" to 26". Mechanical operating and performance characteristics for the AKO are identical to those for the standard NaviDrill.

c. Tilt Angle

The proper tilt angle and steerable motor deflection technique is usually dependent upon the directional requirements and characteristics of the well plan.

When kicking off or sidetracking, high tilt steerable motors are recommended. The tilt angle selected should produce a greater dogleg severity in the oriented mode than the rate of change specified in the well plan.

By getting higher dogleg severities than specified, the directional driller can "get ahead" of the well plan build requirements and begin utilizing the practice of drilling intervals using oriented and rotary modes. The directional driller can reduce a high build up rate increasing the percentage of footage drilled in the rotary mode.

Typically, the rate of penetration will increase when switching from the oriented mode to the rotary mode. As a rule of thumb, the tilt angle selected should theoretically produce a minimum of 1.25 times the maximum dogleg severity required for the well plan. Directional drillers must keep in mind that the TGDS (Theoretical Geometric Dogleg Severity) assumes that tool face orientation is constant. In practice this is difficult to do, especially in high torque applications. As a result of a constantly changing tool face orientation, the actual rate of change could be less than expected.

When a choice is available, a tool with a higher dogleg capability can increase overall efficiency by reducing oriented drilling requirements.

When tangent section or straight hole drilling, a lower tilted tool may be more desirable to reduce bit wear and increase ROP. However, this depends on the extent to which orientation may be necessary and the anticipated ease of oriented drilling.

d. Placement

The stabilizer is most commonly run directly above the motor. According to the 3-point geometry, increasing "L" (by moving the first string stabilizer higher in the BHA) reduces the Theoretical Geometric Dogleg Severity. This does not always work in practice. It has been found that moving the stabilizer higher can make it harder to get away from vertical in a kick-off. However, once some inclination has been achieved, the rate of build is often greater than the TGDS. For flat turns or for dropping angle, increasing "L" does reduce the dogleg rate as theory predicts.

e. Size and Design

The diameter of the first string stabilizer must not be greater than the diameter of the UBHS and is usually less. It should have preferably the same physical design as the UBHS.

First string stabilizer size - oriented mode

If the first string stabilizer diameter is decreased to less than the UBHS and an upward toolface orientation is present, then the oriented dogleg rate is increased. This is true for both AKO and DTU motors.

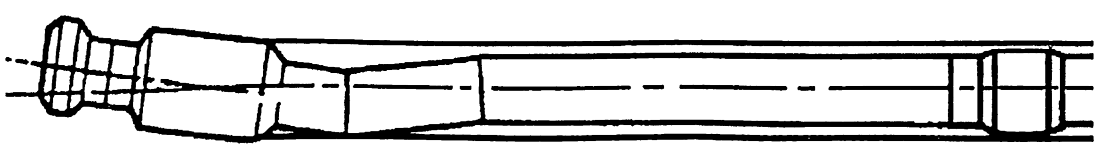


Fig 2.10a Up ward tool face

If the first string stabilizer diameter is decreased to less than the UBHS and a downward toolface orientation is present, then the oriented dogleg rate is reduced.
In either of the above cases, the more undergauge the first string stabilizer, the greater the effect. The same basic effect is seen with both the AKO and the DTU steerable systems.

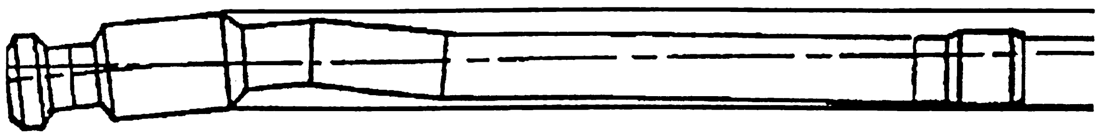


Fig 2.10b Down ward tool face

Field results have shown that an undergauge first string stabilizer is required to produce a holding tendency when NDS is run in the rotary mode. The requirements for the first string stabilizer gauge diameter will be a function of formation trends and hole inclination.
The following table can be used as a general guideline for determining the required diameter for the first string stabilizer so that inclination is maintained. Table 5-10 can be used as a general guideline for determining first string stabilizer changes in diameter to produce a significant change (minimum of 0.25°/100') in rotary inclination reaction.

Hole Size (in)	First String Stabilizer Gauge (in)
8½	8 - 8 1/4
9 7/8	9 1/8 - 9 5/8
12¼	11¾ - 12
14¾	14 1/8 - 14½
17½	16 - 17

Table 2.3 Required Diameters for First String Stabilizer String

Hole Size (in)	Change Required in Gauge of First String Stabilizer (in)
8½	1/8
12¼	¼
17½	3/8

Table 2.4 Fine Tuning Gauge of First Stabilizer

2.8 Kicking-Off

Bottom hole Assemblies

During kick-off operations, two basic factors will determine general NDS assembly design:

- Required build up rate
- Expected length of run

The following example assembly for a 17-1/2" hole is designed to have a rotary hold tendency.

- 17-1/2" Rock Bit
- 11-1/4" Mach 1, AKO or DTU, 17-1/4" UBHS
- 16-1/2" First String Stabilizer
- Float Sub
- 9-1/2" NMDC
- 9-1/2" MWD
- 16-1/2" Non-magnetic Stabilizer
- 2 x 9-1/2" NMDC
- Crossover
- 2 x 8" Steel Drill Collars (increase or decrease if required)
- Jars
- 8" Steel Drill Collar
- Crossover
- HWDP (sufficient amount to provide weight on bit)

The following example assembly for a 17-1/2" hole is designed to have a rotary build tendency.

- 17-1/2" PDC Bit
- 11-1/4" Mach 2, AKO or DTU, 17-1/4" UBHS
- Crossover
- 12-1/4" First String Stabilizer
- Float Sub
- 9-1/2" NMDC
- 9-1/2" MWD
- 16-1/2" Non-magnetic Stabilizer
- 2 x 9-1/2" NMDC
- Crossover
- 2 x 8" Steel Drill Collars (increase or decrease if required)
- Jars
- 8" Steel Drill Collar
- Crossover

• HWDP (sufficient amount to provide weight on bit)

This assembly is designed to have a considerable rotary build tendency. A good estimate would be 2°/100'.

Interval drilling

An estimate of the required footage to be drilled in oriented mode can be determined using:

% Footage Oriented = $[(D_L - D_{LR})/(D_{LO} - D_{LR})] \times 100$

where:

D_L = required dogleg (°/100')
D_{LO} = actual dogleg when oriented (°/100')
D_{LR} = actual dogleg when rotary drilling (°/100')

Example:

Planned build-up rate = 2.5°/100'
Build-up rate obtained when oriented = 3.5°/100'
Build-up rate obtained during rotary drilling = 0.5°/100'
% Footage Oriented = [(2.5 - 0.5) / (3.5 - 0.5)] x 100 = 67%

2.9 Tangent Section Drilling

Tangent or hold sections can prove to be very economical using NDS, although NDS performance drilling will not usually match that of straight motor performance drilling. Long sections of hole can be drilled faster than with conventional rotary assemblies, and corrections can be performed, if required, to keep the well on course. Basic design principles include:

- An undergauge first string stabilizer is required to maintain inclination when rotary drilling with NDS.
- The assembly should be capable of producing an acceptable dogleg rate to allow for shorter corrective oriented intervals.
- Decreasing the diameter of the first string stabilizer versus increasing "L" is preferred because TGDS is affected less. This practice also limits the number of variables to one, the OD of the first string stabilizer.

A typical BHA for drilling a 12-1/4" hole tangent section is:

• 12-1/4" PDC bit
• 9-1/2" Mach 1 motor, AKO or DTU, 12-1/8" UBHS
• Crossover
• 11-3/4" string stabilizer

• 8" NMDC
• 8" MWD tool
• 11-3/4" non-magnetic stabilizer
• 2 x 8" NMDC
• 2 x 8" DC
• Jars
• 8" DC and Crossover

HWDP as required

When drilling a tangent or hold section with NDS, the following should be observed:

- After observing NDS directional tendencies over a minimum of 200 ft of rotary drilled interval, a plan for drilling long distances between orientations should be established. This plan should minimize the number of orientation toolsets and maximize penetration rate.
- Oriented drilling intervals should be minimized. Oriented drilling in a tangent or hold section is performed to correct the present wellpath and to compensate for anticipated trends.
- Never let the drilled wellpath get too far from the planned trajectory, because "drilling on the line" can be significantly more expensive. As surveys are obtained, calculate and plot the position on both horizontal and vertical plans. At all times there must be a feasible course to drill from the current location to the intended target.

2.10 Drop Sections

When a drop section is drilled, the gauge of the first string stabilizer can be increased to produce more of a dropping tendency in the rotary mode. The recommended diameter is no larger than the UBHS. Increasing the diameter of this stabilizer can increase hole drag and stabilizer hang up.

Typical rotary drop rates are seldom much higher than 1°/100 ft, with 0.5° to 0.75°/100 ft commonly produced when the angle is less than 20°. If higher drop rates are required, then oriented drilling will be mandatory.
The following is a general design for a drop assembly while rotary drilling.
• 12¼" bit
• AKO or DTU motor
• Crossover
• 12" first string stabilizer
• 8" NMDC
• 12" NM stabilizer

- 8" MWD

The following guidelines should be considered when drilling drop sections.

- Except in stringent circumstances, the drilled well path can be positioned "ahead" of the planned path. This will usually reduce the oriented drilling requirements.
- In hard to drill or problem formations, oriented toolsets should be minimized or avoided.
- Actual dogleg rate when drilling to drop inclination with an oriented system is usually less than the TGDS.
- The NDS assembly should be designed such that the TGDS is at least 125% of the required drop rate.
- Stabilizers should be selected such that rotary drilling either assists in achieving desired dog-leg, or produces a neutral tendency.

Chapter 3

DIRECTIONAL SURVEYING

Directional surveys are required to:

- Determine the exact bottom hole location of the well in order to monitor reservoir performance
- Monitor the actual well path while drilling to ensure the target will be reached
- Orient deflection tools (such as directional drilling assemblies) in the required direction when making corrections to the well path
- Ensure the well being drilled is in no danger of intersecting an existing well
- Calculate the true vertical depths of the various formations encountered to allow accurate geological mapping
- Warn the directional driller of potential problems along the course of the wellbore (severe doglegs in the well)
- Fulfill requirements of regulatory agencies.

3.1 Survey Calculations

One of the uses of directional survey instruments is to record the information needed to calculate a directional survey. This information includes hole azimuth and inclination obtained at a known measured depth. One must have a basic understanding of the terms and concepts used in this process in order to calculate accurate survey results.

3.2 Terminology

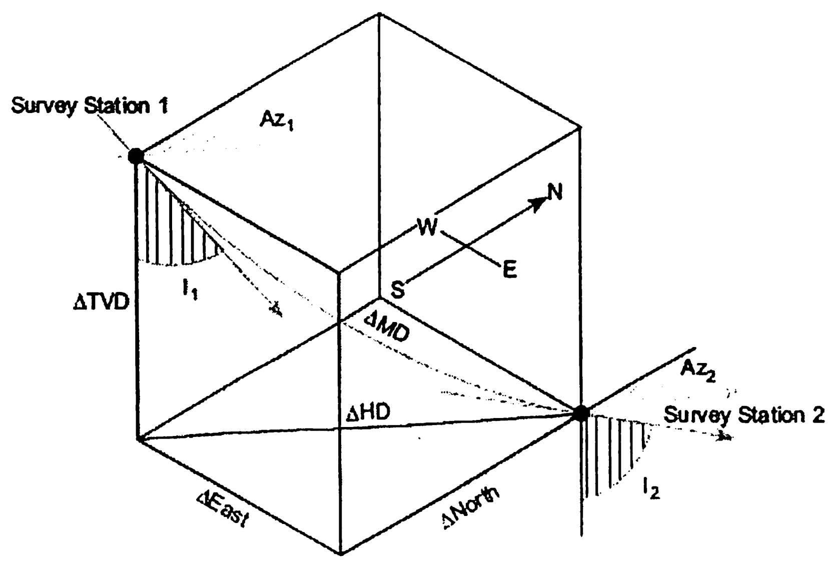


Fig 3.1 A curved section in a well bore to be surveyed

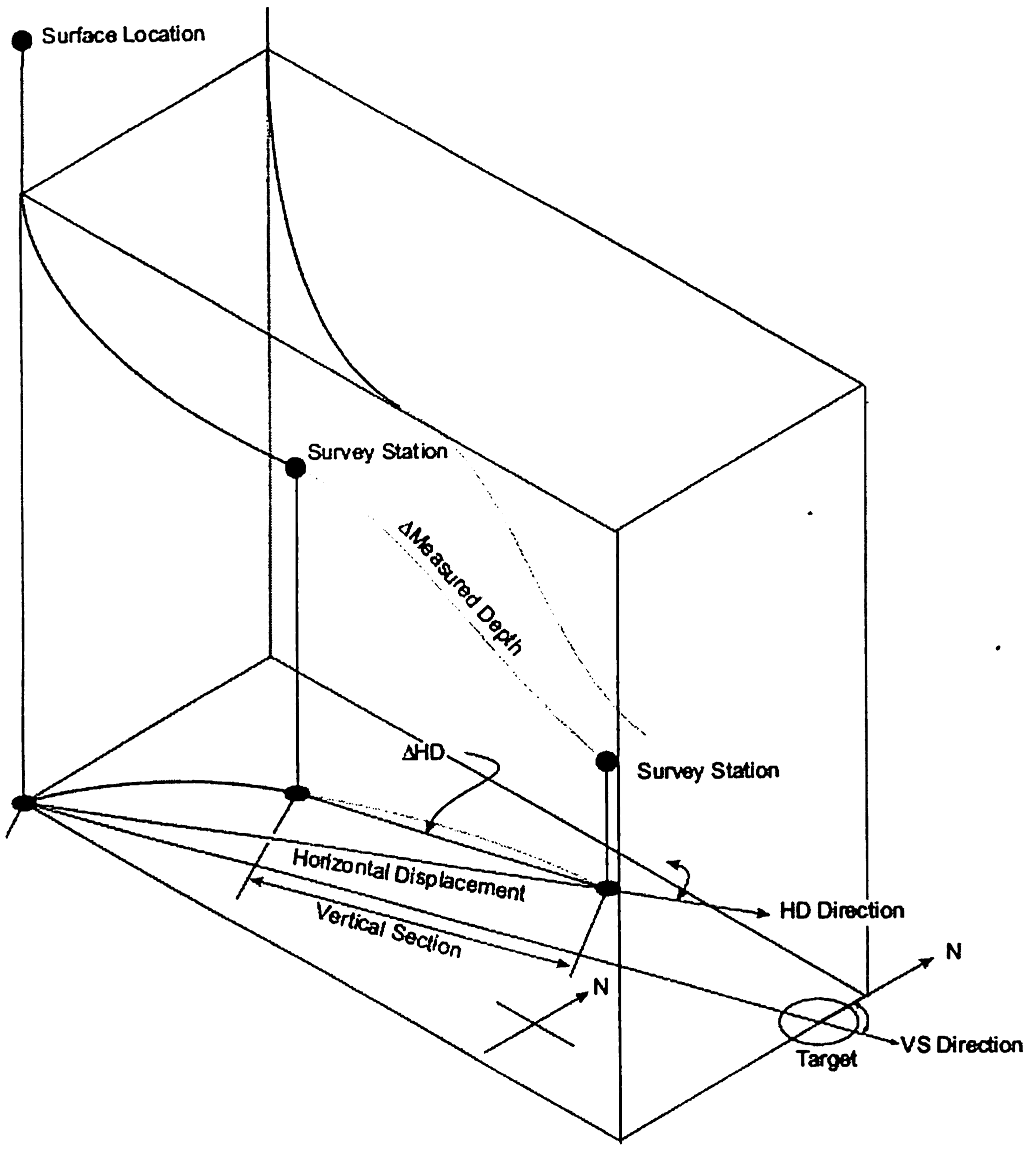


Fig 3.2 projection of well curve along X and Y directions

- Survey Station = any point along the wellbore at which a survey is taken.
- Measured Depth (MD) = the length of hole drilled as measured along the wellbore from the survey origin, to any point along the wellbore.
  Incremental Measured Depth (ΔMD) = Change in measured depth between two survey stations.

- True Vertical Depth (TVD) = the vertical distance between the survey origin and any point along the wellbore. This distance represents the amount of hole drilled in a vertical plane.

Incremental True Vertical Depth (ΔTVD) = Change in true vertical depth between any two points or survey stations.

- Inclination (I) = The angle, measured in degrees, by which the wellbore or survey instrument axis varies from the vertical axis. An inclination of 0° is true vertical, and an inclination of 90° is horizontal.
  Incremental Inclination (ΔI) Change in inclination between any two points or survey stations.

- Azimuth Hole Direction (Az) = The angle, measured in degrees, of the horizontal component of the borehole or survey instrument axis from a known north reference. This reference can be true north, magnetic north, or grid north, and is measured clockwise by convention. Azimuth is measured in degrees and expressed in either azimuth form (0° to 360°) or quadrant form (NE, SE, NW, SW).
  Incremental Azimuth. ΔAz) = Change in azimuth between any two points or survey stations.

- Latitude - North/South Displacement *Northing* (Lat) = The horizontal distance the wellbore moves from the survey origin in a due north or south direction. A positive value indicates a northerly displacement, while a negative value indicates a southerly displacement. It is used to plot the trajectory of the wellbore on a horizontal projection.
  Incremental Latitude. ΔLat) = Change in latitude between any two points or survey stations.

- Departure - East/West, Displacement *Easting* (Dep) = the horizontal distance the wellbore moves from the survey origin in a due east or west direction. A positive value indicates a easterly displacement, while a negative value indicates a westerly displacement. It is used to plot the trajectory of the wellbore on a horizontal projection.
  Incremental Departure (ΔDep) = Change in departure between any two points or survey stations.

- Horizontal Displacement i.e. Closure (HDisp) = the distance from the survey origin to the point or survey station in question.
  Incremental Horizontal Displacement, *Course* Deviation (ΔHDisp) = Change in horizontal displacement is the length of the line made by connecting any two points or survey stations projected onto a horizontal plane. It represents the distance the wellbore moves horizontally between two points or survey stations. Its length depends on the inclination and the incremental measured depth.

- Dogleg (DL) = Dogleg is a measure of the total angular change in the wellbore. It is the three-dimensional angular change calculated using both inclination and azimuth between two survey stations. Inclination and azimuth measurements at stations are used, not their average. In general, all of the inclination change will show up as dogleg, and azimuth changes at higher inclinations will have a greater effect on dogleg than the same azimuth change at low inclination angles. Dogleg is independent of the survey calculation method used.

  Dogleg Severity (degree/100 ft) (degree/30 m) (DLS) = Dogleg severity is dogleg calculated over some standard length. The standard length is usually 100 feet in the imperial system and 30 meters in the metric system.

- Vertical Section Direction (VSDir) = Vertical section direction is the direction of a horizontal line from the surface location to the target.

- Vertical Section (VS) = Vertical section is the horizontal distance the wellbore moves in the direction of the target per station or in total. The two factors that affect vertical section are the Incremental horizontal displacement and its direction, as compared to the direction of the target.
  Incremental Vertical Section (ΔVS) = Change in vertical section between any two points or survey stations.

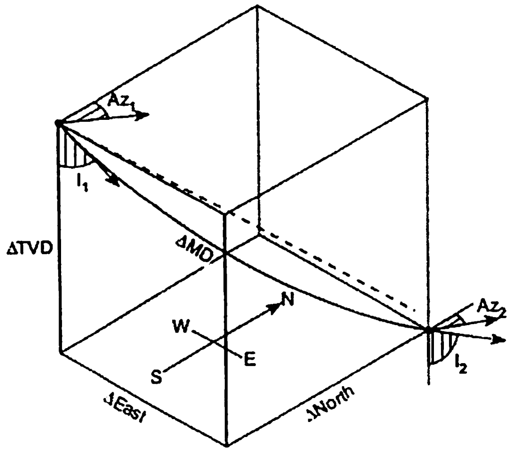
3.3 Different Calculation Methods

There are several methods of computing directional surveys. However, of these methods, only four are commonly used today. These methods are:

3.3.1 Average Angle Method

This method uses the average of the inclinations and azimuths measured at the upper and lower survey stations. The average of the two sets of angles is assumed to be the inclination and the azimuth over the incremental measured depth. The wellbore path is then calculated using simple trigonometric functions.

This method lends itself quite well to field operations, as it requires only simple calculations that can be performed on a hand-held calculator. This method is much more accurate than the tangential method, and only slightly less accurate than the radius of curvature or minimum curvature methods.



Average Angle Calculations

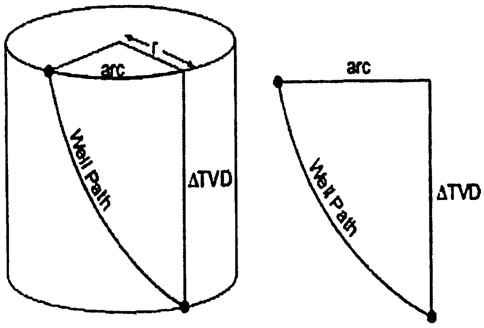
$$\Delta North = \Delta MD \times \sin\left(\frac{I_1 + I_2}{2}\right) \times \cos\left(\frac{Az_1 + Az_2}{2}\right)$$

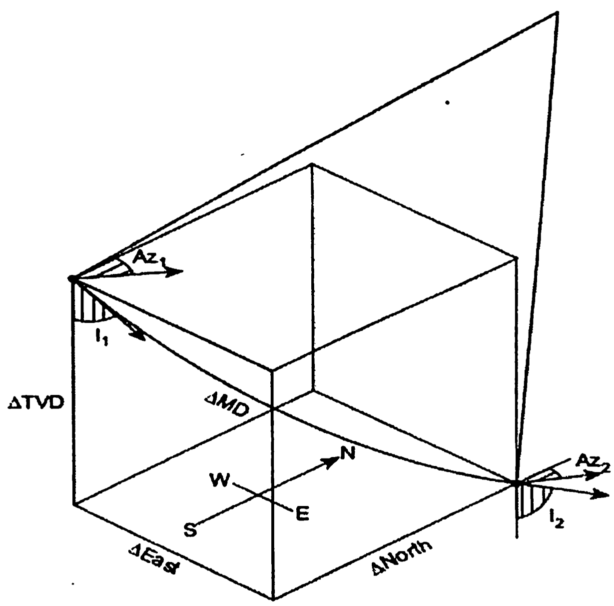
$$\Delta East = \Delta MD \times \sin\left(\frac{I_1 + I_2}{2}\right) \times \sin\left(\frac{Az_1 + Az_2}{2}\right)$$

$$\Delta TVD = \Delta MD \times \cos\left(\frac{I_1 + I_2}{2}\right)$$

Actual well bore = ____________ Calculated well bore = - - - - - - - - -

3.3.2 Radius of Curvature Method





This method uses the inclination and azimuth measured at the upper and lower ends of the course length to generate a circular arc when viewed in both the vertical and horizontal planes.

This method assumes that the well path lies on a cylinder whose axis is vertical, and has a radius equal to the radius of curvature in the horizontal plane. It determines the length of the arc between the upper and lower ends of the course length in the horizontal plane. The cylinder can then be "unwrapped" to calculate the length of the circular arc along the cylinder surface.

Consequently the incremental TVD is unaffected by changes in azimuth. This curve has the shape of a circular arc in a vertical plane wrapped around a cylinder. It is tangential to the inclination and azimuth passing through the upper and lower ends of the course length.

This method is one of the most accurate methods available and is still simple enough to be computed with the use of a hand calculator.

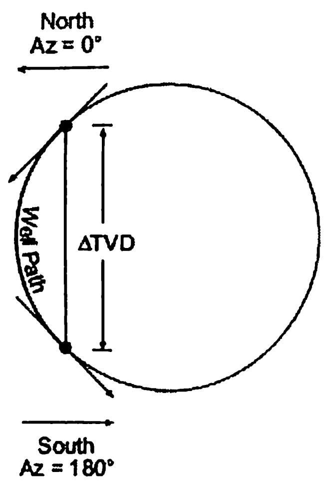
$$\Delta North = \frac{\Delta MD \times ((\cos I_1 - \cos I_2) \times (\sin Az_2 - \sin Az_1))}{(I_2 - I_1) \times (Az_2 - Az_1)}$$

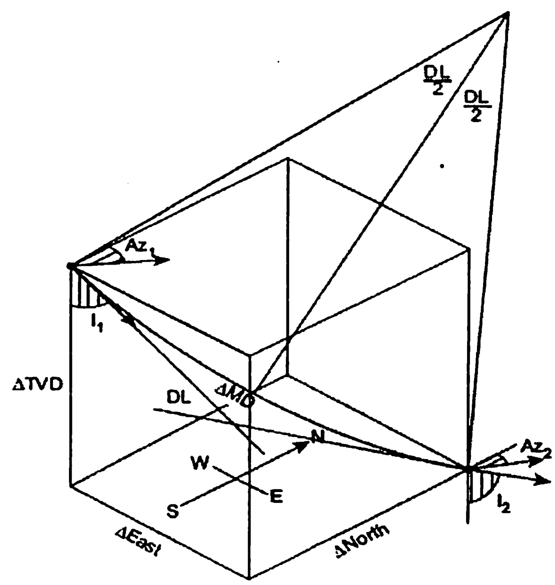
$$\Delta East = \frac{\Delta MD \times ((\cos I_1 - \cos I_2) \times (\cos Az_1 - \cos Az_2))}{(I_2 - I_1) \times (Az_2 - Az_1)}$$

$$\Delta TVD = \frac{\Delta MD \times ((\sin I_2 - \sin I_1))}{(I_2 - I_1)}$$

3.3.3 Minimum Curvature Method

Like the radius of curvature method, this method uses the inclination and azimuth measured at the upper and lower ends of the course length to generate a smooth arc representing the wellbore path. This method is really a modification of the balanced tangential method. Instead of approximating the wellbore path with two straight lines, the minimum curvature replaces these lines with a circular arc. This arc is calculated by using a dogleg scale factor based on the amount of angular change over the course length. The plane of the arc is at an oblique angle.





This method assumes that the well path lies on a sphere. As a result the delta TVD will be a function of both the inclinations and azimuths of the upper and lower ends of the course length. The difference between the radius of curvature and minimum curvature methods is that the radius of curvature uses the inclination change over the course length to calculate displacements in the vertical plane and the azimuth change to calculate displacement in the horizontal plane, whereas the minimum curvature method uses the dogleg to calculate displacements in both planes.

$$\Delta North = \frac{\Delta MD}{2}((\sin I_1 \times \cos Az_1) + (\sin I_2 \times \cos Az_2)) \times RF$$

$$\Delta East = \frac{\Delta MD}{2}((\sin I_1 \times \sin Az_1) - (\sin I_2 \times \sin Az_2)) \times RF$$

$$\Delta TVD = \frac{\Delta MD}{2}(\cos I_1 + \cos I_2) \times RF$$

$$\text{Where } RF = \frac{2}{DL} \times \tan\frac{DL}{2}$$

$$\text{and } \cos DL = \cos(I_2 - I_1) - \sin I_1 \times \sin I_2 \times (1 - \cos(Az_2 - Az_1))$$

3.4 Directional Toolface

There are two types of toolface obtained from magnetic directional survey instruments: magnetic and gravity. Gravity toolface also referred to as highside. The toolface reference is used for orientation purposes and can also be referred to as the reference orientation. This reference can be used to orient downhole directional drilling tools, such as mud motors, jetting assemblies, or whip stocks. They can also be used to position subsea structures or reference downhole packers and core orientations. An orientation lug, t-slot, or keyway attached to the survey instrument is used to transfer and monitor the reference orientation.

3.4.1 Magnetic Toolface

Magnetic toolface is the direction, in the horizontal plane, the bent sub scribe line is pointing with regard to the north reference (Grid, Mag, or True).

Magnetic Toolface = Direction Probe Magnetic Toolface + Toolface Offset

Magnetic orientation is used when the inclination of the wellbore is less than 5° to 8°. When the inclination is below this amount, the survey instrument cannot accurately determine the highside of the instrument for orientation purposes. The toolface will be presented in azimuth or quadrant form, referenced

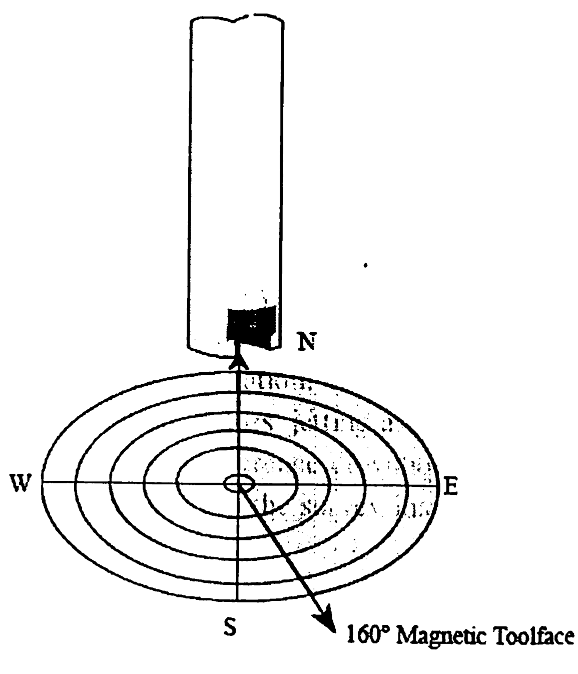


Fig 3.3 magnetic tool face

to magnetic north. The magnetic tool face reading is whatever magnetic direction the toolface is pointed. For example, if the orientation lug on the survey instrument is pointed towards due east, the magnetic tool face would be 90°. If the orientation lug on the survey instrument is pointed towards S 20 E, then the magnetic tool face would be 160°.

3.4.1.1 "No-No" Zone

One specific condition where magnetic toolface orientation cannot be used accurately is referred to as the "No-No" zone. This zone exists when hole inclination + area dip angle = 85° to 90°, and hole direction is between N 10 E and N 10 W. When the survey instrument is in this position, the lines of magnetism are parallel to the survey instrument; therefore, the survey instrument's ability to measure the lug's orientation is reduced. Gravity orientation should be used when this occurs. This condition is normally restricted to the extreme northern sections of the Earth's surface where dip angle is usually high.

3.4.2 Gravity Toolface (Highside)

Gravity toolface is the angular distance the bent sub scribe line is turned, about the tool axis, relative to the high side of the hole.

Gravity toolface = Dir Probe Grav Toolface + Toolface Offset

If the inclination of the wellbore is above 5° to 8°, then the gravity toolface can be used. The toolface will be referenced to the highside of the survey instrument, no matter what the hole direction of the survey instrument is at the time. The toolface will be presented in a number of degrees either right or left of the highside. For example, a toolface pointed to the highside of the survey instrument would have a gravity toolface of 0°. A toolface pointed to the low side of the survey instrument would have a gravity toolface of 180°. If the orientation lug was rotated to the right of highside, the gravity toolface would be 70° to the right.

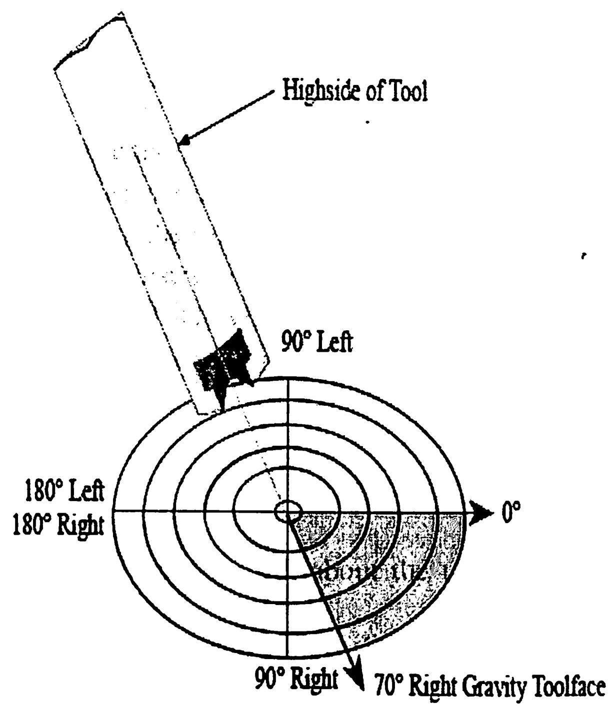


Fig 3.4 gravitational tool face

Chapter 4

DRILLSTRING DESIGN

Good drilling techniques and proven drillstring design can prevent excessive casing, wellhead and limit drill pipe wear and fatigue. The following guidelines can help extend drillstring life and avoid problems

5.1 Correct BHA Design

To minimize deviated well bores, especially at shallow depths, the correct bottomhole assembly (BHA) should be used.

The smoother the wellbore profile the lower the side loading forces will be.

Obviously, not all wellbores can have the ideal near-vertical profile, but longer, straighter tangents in planned directional holes will greatly decrease tubular side loading. Designing a BHA that incorporates the minimum weight required, thereby minimizing tension loads on the drillstring, will further minimize side loading.

A short drill collar "lock-in" assembly with heavy wall drill pipe for the required bit weight limits the tension in the drillstring.

In high angle well bores, a certain amount of drill pipe can be run in compression.for bit weight to further limit the weight of the BHA and subsequent tension in the drillstring. Where feasible, drilling to deeper depths prior to departure will help minimize drillstring side loading.

With the advancements available in steerable navigational systems, wellbore path trajectories can frequently be changed at greater depths while still insuring arrival at the desired target.

Historically, solutions for drillstring and casing wear problems have been addressed through the application of hardbanding.

Tungsten carbide hard banding has generally been accepted as the most effective and least costly approach to limiting drill string wear.

The tradeoff for prolonged drill string life through the use of tungsten carbide hard banding is accelerated casing wear. The development of casing "friendly" hard banding significantly improves casing wear problems but at the expense of the drill string components.

5.2 Drill String Design

In addition to planning a wellbore trajectory that will limit drill string wear and damages, the selection of a drill string design that is resistant to wear and damages is equally important.

Larger, stronger drill strings prevent the accumulation of fatigue, increase hydraulic parameters and control hole deviation problems.

A typical problem begins in BHA design based on the use of 8-in. OD drill collars with 65/8-in. regular connections.

Sufficient 9½-in OD or larger drill collars for bit weight plus a 15% margin has proven to virtually eliminate connection failures and provide far superior deviation control and weight concentration directly above the bit.
One stand of 8-in. OD or preferably API 8¼-in OD drill collars should be run in tension in the destructive transition one with long (5-ft) bottleneck crossover subs between the drill collars (9½-in OD to 8¼-in OD) and between the drill collars and heavy wall drill pipe (8¼-in. OD drill collars to 5-in. heavy wall pipe).

The use of larger stronger drillstring components in smaller hole sizes has also prevented the accumulation of fatigue, improved hydraulics and controlled deviation.
These stronger drill strings have been successfully run in 4¾ in. and largerhole sizes, including 5¾-5 7/8 in., 6-6½ in., 7 5/8-7 7/8 in., 8 3/8-8¾ in., 9 7/8 in. and 10 5/8 in.
In all cases, significant increases in rates of penetration (ROP), were achieved, deviation was controlled and repairs due to damage were reduced. Specific examples include:

- The use of 4 1/8-in. OD drill collars and 3½-in. Slim Hole drill pipe in 4¾-in. and 4 7/8-in. hole sections. Tubulars with 4 1/8- in. OD box by 313/16-in. OD pin up connections have prolonged tool joint life and improved hydraulics by using a larger bore 3½-in. tube.
- The use of 5-in. OD drill collars, 3½- in. heavy wall drill pipe and 3½-in. drill pipe with 4¾-in. OD box by 4½-in. OD pin up connections in 57/8-in. hole sections.
- The use of 5¼-in. OD drill collars, 4- in. heavy wall drill pipe and 4-in. drill pipe with 5¼-in. OD box by 47/8-in. OD pin up connections in 6-6½-in. hole sections. Fishability is retained, hydraulics are improved, ROPs are increased, deviation control is achieved and tool joint wear life is appreciably increased
- The use of 7-in. OD drill collars, with fishable pin dimensions have been repeatedly used in 77/8-in. hole sections for added weight on bit and deviation control. Ideally, 5-in heavy wall drill pipe and 5-in. drill pipe with 63/8-6½-in. OD box by fishable dimensioned pin up connections would significantly lower costs through improved performance.
- The use of 7¾-in. OD drill collars with fishable pin areas in 83/8-8½-in. hole sizes and ideally 5½-in. heavy wall drill pipe and 5½-in. drill pipe, both with fishable pin dimensions. In addition to substantial deviation control, hydraulic parameters and drillstring service life are increased. In addition to these benefits, particularly with the 5½-in. tubulars, tool joint service life and full make up torque (MUT) life may be appreciably increased.

Box OD and pin ID are the primary dimensions controlling joint strength. Large box ODs maintain maximum tool joint strength and provide a longer service life.

Conventional			Pinup		
TJ OD	MUT	Status	TJ OD	MUT	Status
7 1/8 in.	55,800	Full	7 1/2 in.	55,800	Full
7 in.	53,800	Reduced	7 3/8 in.	55,800	Full
6 7/8 in.	48,500	Reduced	7 2/8 in.	55,800	Full
6 3/4 in.	44,000	Reduced	7 1/8 in.	55,800	Full
			7 in	53,000	Reduced
			6 7/8 in.	48,500	Reduced
			6 3/4 in.	44,000	Reduced
*5 1/2-in. HT operational life 7 1/8-in. OD x 3 3/4-in. ID			Longer life 100%, longer full MUT, no rig changeout.		

Fig 5.1 Comparison between conventional and pin-up tool joints

In the case of 5½-in. drill pipe with 7-in. OD box connections, the drill pipe have a min 6 15/16". OD for Premium Class rating or just 1/16 in. of OD wear. Starting with a 7½-in. OD box would increase wear life to 9/16 in. for multiple life cycle extensions and multiple full make up torque cycles. At 6¾-in. OD, standard 5½-in. drill pipe must be replaced (or re-built if permitted). But if one started with a 7½-in. OD box connection, a full 7-in. OD would remain, or essentially a whole wear life.

In addition, as the 7½-in. OD connection wore down, complete full make up torque remained in force, whereas the standard connection was continually downgraded in make up torque values. 5½-in. drill pipe with a 3½-in. bore and 7-in. OD box would be box weak, thus experiencing a reduction in strength and make up torque. The 7½-in. OD box would not have any reduction in torsional strength until worn to 71/8-in. OD. Box strong connections provide a longer service life. Large box connections and fishable pin tool joints insure a long service life for standard API connections as well as for premium double shouldered and wedge thread connections.

Large drill collars provide weight and stiffness in the packed bottom hole assembly (BHA) and pendulum BHA designs provide for maximum control of hole deviation.
Strong box connections also insure against developing fatigue cracks and premature failures. An industry wide report on drillstring failures would surely be shocking as to the total of preventable failures. Unscheduled events including washouts, unnecessary tripping for premature repairs and inspections, crooked hole problems, slow penetration rates and shortened service life could all be minimized if not virtually eliminated by simply using larger, stronger more efficient drillstring

designs based on proven technology. Optimization of the drillstring for a given wellbore path is a relatively easy approach that consistently results in improved performance and reduced wear on all drilling components.

Hole size	Conventional drill pipe	Pin up drill pipe	Increase
	3 1/2-in., 13.3#, NC-38 tool joints 4 3/4-in., OD x 2 11/16-in. ID Torsional: 14,361/10,367 ft lb Tensile: 271,569/589,308 lb	4-in., 14.0#, NC-40 tool joints 5 3/8-in. OD x 2 11/16-in. ID, 4 7/8-in. pin Torsional: 18,196/15,283 ft lb Tensile: 285,359/776,406 lb	 +25/+43% +5/+32%
6 in. through 6 3/4 in.	Tube ID: 2.764 in.	Tube ID: 3.340 in.	+0.576 in.
	4-in., 14.0#, slim hole, 3 1/2 in. XH tool jts 4 5/8-in. OD x 2 9/16-in. ID Torsional: 18,196/13,273 ft lb Tensile: 285,359/525,637 lb	4-in., 14.0#, NC-40 tool joints 5 3/8-in. ODx 2 11/16-in. ID, 4 7/8-in. OD pin Torsional: 18,196/15,283 ft lb Tensile: 285,359/776,406 lb	4-in. slim hole vs 4-in. Pin-up +0/+15% +0/+47%
	Tube ID: 3.340 in.	Tube ID: 3.340 in.	

Fig 5.2 Pinup drill pipes compared

Stress-Strained State Calculations of Drill String

While Drilling Standard Horizontal Well of Total Depth 6 370 m,

G.1 Input data for calculation of drill string

G.1.1 Design profile of the well

Input data (ID):

- Well profile – five-interval J-shaped;
- Length of drillstring – 6370.24 m;
- Vertical projection – 3858.40 m;
- Horizontal projection – 3485.70 m;
- Length of the 1-st straight interval – 1900.00 m;
- Length of the 2-nd straight interval – 1425.84 m;
- Length of the 3-d straight interval – 2131.60 m;
- Zenith angle on the 2-nd straight interval – 35.33°;
- Zenith angle on the 3-d straight interval – 85.64°;
- Radius of the 1-st curved interval – 695.77 m;
- Radius of the 2-nd curved interval – 550.94 m;

Table 5.1 – Borehole parameters

ID mm	Part length m	Stem type
243.90	250.0	Cased
220.30	3279.0	Cased
153.90	710.7	Cased
152.40	2130.5	Uncased

Table 5.2 – Friction factor of contacting couples

Friction factor	Materials
0.33	Steel-Steel
0.44	Rock-Steel
0.3	Steel-Aluminium
0.4	Rock-Aluminium

Table 5.3 – Distribution of temperature along the borehole length

Depth m	Temperature degrees
0	20
4000	80
6400	100

G.1.2 Operation parameters:

-Drilling method – combined, using downhole motor and rotation of the string.

-ROP, m/min = 0.10;

-RPM = 40;

-WOB, kN = 40;

-drag torque on bit, kN·m = 0.9;

-length of drill string, m = 6370.2

G.1.3 Hydraulic parameters of drilling mud:

- Flow-in rate (l/sec) = 15;

- Mud density (kg/m^3) = 1050(1.1 kg/l);

- Mud type = viscous-plastic fluid

- Shear stress (Pa) = 12;
- Elastic viscosity (Pa·c) = 0.015;
- Total area of drilling bit flushing holes (m^2) = 0.00038 (3 nozzles ·12,7 мм);
- Flushing holes flow-in rate factor = 0.80;
- Standpipe D = 140 mm drag coefficient (m^{-4}) = 40000;
- Drilling sleeve D = 76 mm drag coefficient ($м^{-4}$) = 120000;
- Swivel D = 100 mm drag coefficient ($м^{-4}$) = 28000;
- Kelly D = 100 mm drag coefficient ($м^{-4}$) = 40000;
- Downhole motor drag coefficient ($м^{-4}$) = 50000;
- BHA D = 140 mm drag coefficient ($м^{-4}$) = 250000;
- Losses in Downhole motor (MPa) = 5. ("Dyna-Drill-5")

The first step in design includes proper selection of drill pipes which are recommended below

Table 5.4 - Recommended combinations of bit, drill collar and pipe sizes {mm (in)}

Bit size	Drill collar OD	Pipe outside diameter	Bit size	Drill collar OD	Pipe outside diameter
120 (4¾)	79.4	73	190.5 (7 ½)	146.0 - 165.1	114, 129, 133
132(5 3/16)	88.9 - 95.2		215.9 (8 ½)	165.1 - 177.8	
139.7(5 ½)	114.3	90	228.6 (9)	177.8 - 190.5	
158.0(6 ¼)	120.6		215.9 (8 ½)	165.1 - 177.8	129, 133, 140, 147
165.1(6 ½)	127.0	103, 114	228.6 (9)	177.8	
187.3(7 3/8)	139.7		Over 228.6 (9)	177.8 – 266.7	147, 151, 155, 164, 168, 170

The standard design of the drill string for drilling horizontal wells includes:

- BHA, whose composition and length are defined by the drilling conditions and the necessity of using downhole MWD telemetric systems with 200 m to 250 m of HWDP;
- Drill collar – 200 m to 250 m for smooth rigidity transition, from BHA to DP (it is possible to replace plain HWDP by pipes with outside spiral riffling, which would improve the cleaning of the bottom-hole zone);
- DP, whose design parameters, dimension-type, material group and section length are defined by the length, profile and the design of the well;
- HWDP– 300 m to 400 m for producing and applying axial load to the drill string;
- Drill Collars – utilized to provide a load on bit for the purpose of drilling.

Next comes the necessity to calculate the critical buckling loadwhich can be calculated by the following graphs

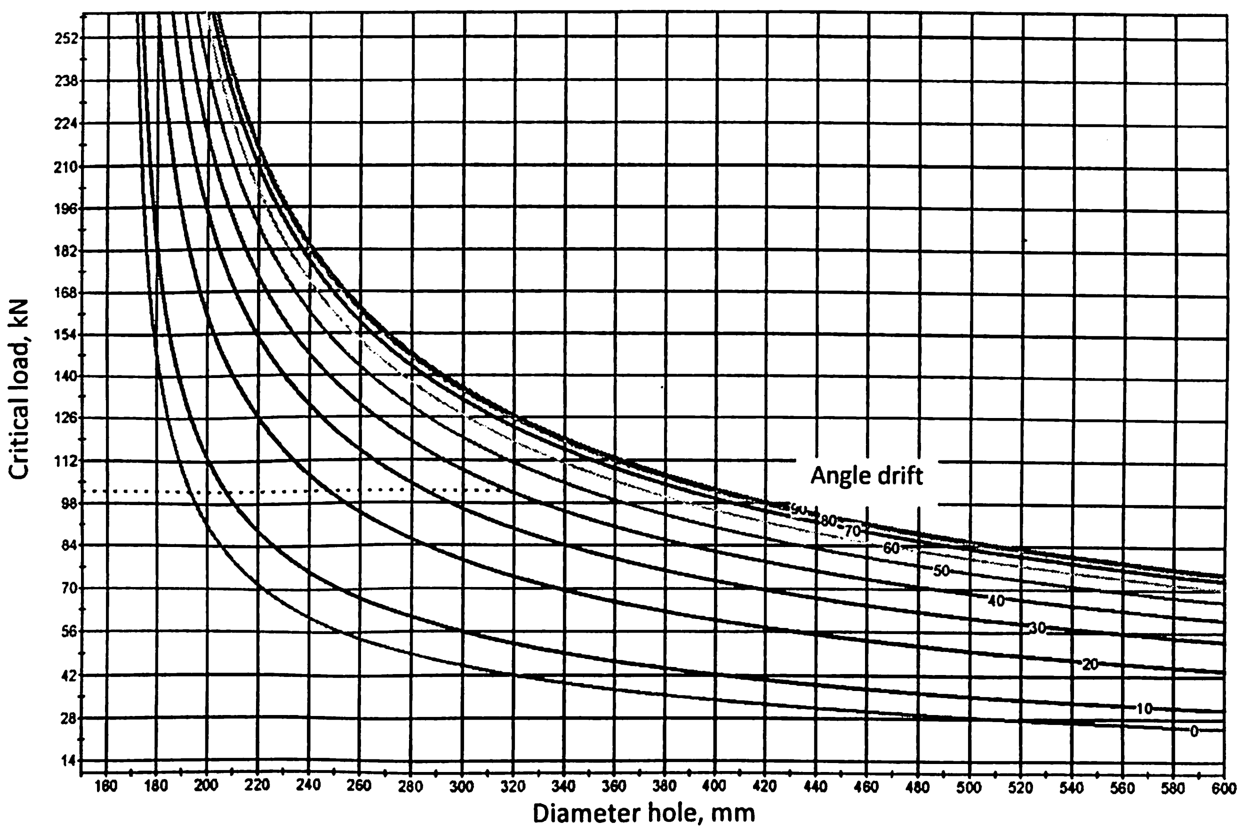


Figure 5.3 - The function of F_{cr} for a particular material group, to the borehole size and inclination angle at the slant borehole portions

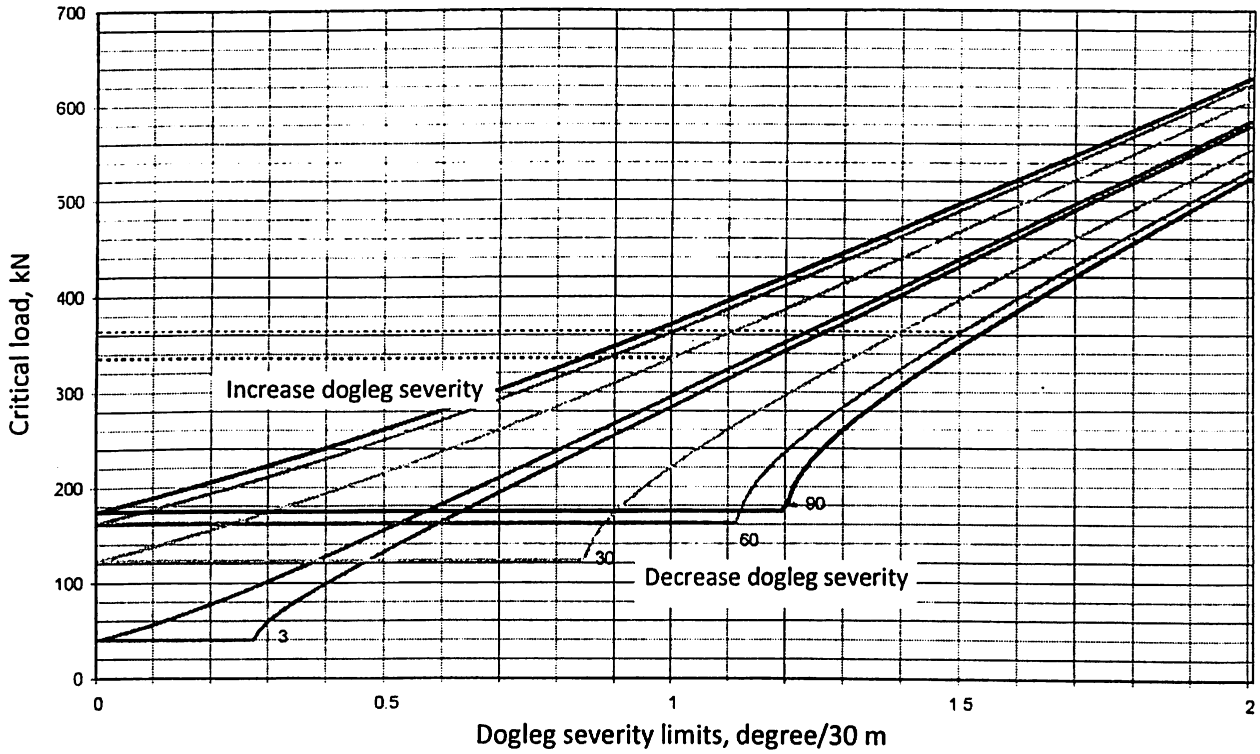


Figure 5.4 - The function of F_{cr} for a particular material group, to the angle build rate (degree/30m) and mean borehole inclination angle at the borehole angle build or drop section

B.2 Formula for calculating polar sectional modulus of torsion of pipe body, cm^3:

$$W_p = \frac{3.14 \times (D^4 - d^4)}{16 \times D}$$

Where

D nominal outside diameter of pipe body, cm;

d nominal inside diameter of pipe body, cm.

For this well the

B.3 Formula for calculating the mass per one linear meter of the pipe including the upset, protector and tool joint, kg/m

$$q = \frac{p_1 + p_2 + p_3 + p_4}{L_{pj}}$$

where

p_1 plain end body mass, kg;

p_2 mass gain due to upsets, kg;

p_3 mass gain due to protector thickening, kg;

p_4 tool joint mass, kg;
L_{pj} pipe and tool joint length, m.

B.4 Formula for calculating tensile load on pipes, kN:

$$P = 0.1 \times F \times Y_m$$

where

F pipe body cross section area, cm^2;
Ym minimum yield strength, MPa.

B.5 Formula for calculating tensile load of tool joint, kN:

$$P = y_m A$$

where

P Minimum tensile strength, kN;
y_m Material minimum yield strength, MPa;
A The thread root cross section area in the reference plane, cm^2

B.6 Formula for calculating maximum permissible torque for pipe body, kNm:

$$M\kappa p = \tau\ W_p / 1000 \times A^{0.5}$$

where

τ shear stress, reaching minimum yield strength, $\tau = 0.4578Y_m$, MPa;
Wp polar sectional modulus of torsion, cm^3.
A = 4.77

B.7 Formula for calculating maximum permissible torque for tool joint

$$T_y = \frac{0.0975\ Y_m A}{10^5}\left(\frac{p}{2\pi} + \frac{R_t f}{Cos\theta} + R_s f\right)$$

where

T_y Torsional yield limit in connection, kNm;
Y_m Minimum yield strength of the tool joint material, MPa;
p lead of thread, mm
f thread friction factor assumed 0.08
θ Half angle of thread, degrees;

$$R_t = \frac{C + [C - (L_{pc} - 15{,}875) \times tpr]}{4}$$

where

C Pitch diameter of thread at gauge point, mm

L_{pc} Pin length, mm;

t_{pr} taper, 1/6

$$R_s = \frac{D_{tj} + Q_c}{4}$$

Where

D_{tj} = tool joint outside diameter, mm;

Q_c = box counterbore, mm;

A = pin cross section area at 15.875 mm from the bearing face.

$$A_p = \frac{\pi}{4}\left[(C - B)^2 - d_{tp}\right]$$

where

d_{tp} Inside diameter pin, mm

$$B = 2\left(\frac{H}{2} - S_{rs}\right) + \frac{tpr}{8}$$

where

H thread height not truncated mm

Srs root truncation mm

B.8. The collapse pressure at which the pipe body stress reaches the yield limit shall be derived from the formula:

The collapse pressure for round pipe P0 is given by:

$P_0 = P_e P_y \left(P_e^2 + P_y^2\right)^{-1/2}$, MPa

The minimum collapse pressure for imperfect pipe Pc is given by:

$P_c = P_0\ (g\text{-}s/s_0)$, MPa

where:

D, t pipe outside diameter and wall thickness less any corrosion allowance, mm

Dmax maximum outside diameter of pipe, mm

Dmin minimum outside diameter, mm

E,υ modulus of elasticity and Poisson' ratio

Y specified minimum yield stress, MPa
A cross sectional area of pipe = π (D2)/4, mm2
a cross sectional area of wall = $\pi\left[D^2-(D-2t)^2\right]/4$ = π(t)[D-t], mm2
T_e effective tension on tubular, kN
G unit weight of water,kg
H water depth, m
P_i internal pressure, MPa
P net external pressure = GH - P_i, MPa
S_a mean axial stress = (T_e – PA)/a
Y_r reduced yield stress = Y {[1-3(S_a/2Y)^2]1/2 –(S_a/2Y)}, MPa
P_y yield pressure with simultaneous tension = 2Y_{rt}/D, MPa
P_e elastic buckling pressure = [2E/(1-υ^2)](t/D)^3, MPa
p plastic to elastic collapse ratio = P_y/P_e
O_i initial ovality = (D_{max} – D_{min})/ (D_{max} + D_{min})
f out-of-roundness function = [1+(O_iD/t)^2]1/2 –O_iD/t
g imperfection function = (1+p^2)1/2/(p^2 + f-2)1/2
b strain reduction factor = 1,5 for API pipe
so critical bending strain = t/2bD
s bending strain experience by tubular

B.9 The internal pressure at which the pipe body stress reaches the yield limit shall be derived from the formula:

$$P_i = \frac{2\ Y_m t}{D}$$

where

P_i internal pressure, MPa;
t wall thickness, mm;
Y_m pipe material yield strength, MPa;
D nominal outside diameter of tube, mm.

B.10 The buoyancy factor (aluminium alloy drill pipes weight loss in drilling mud) shall be derived from the formula:

$$Q = \frac{(L_p + p_2 + p_3) \times \left(1 - \frac{\gamma_m}{\gamma_1}\right) + p_4\left(1 - \frac{\gamma_m}{\gamma_2}\right)}{L}$$

where

Q	mass per 1 linear meter of ADP in drilling mud, kg;
q	plain end pipe mass per 1 linear meter, kg;
	pipe length without a tool joint, m;
p_2	pipe mass gains due to upsets, kg;
p_3	mass gain due to protector thickening, kg;
p_4	tool joint mass, kg;
γ_m	drill mud density, g/cm3;
γ_1	aluminium alloy density 2,78 g/cm3;
γ_2	steel density 7,85 g/cm3;
L	pipe and tool joint length, m.

B.11 Formula for calculating recommended make up torque for aluminum drill pipes tool-joint thread

$$Tj = 0{,}6\ K\ Ty$$

where:

Tj -recommended make up torque for the aluminum drill pipes tool joints, kNm

Ty = the make up torque limit value, which, when applied, shall cause the tool joint body (pin or box) to be under the tensile (for the pin) and compression (for the box) load equal to the minimum yield strength of the tool joint material.

K = constant derived from inspection

B.12 Axis load when the stress in the body of the pipe chucked in the slips link comes up to yield strength is calculated as:

$$Q_{TK}^{C} = Q_{TK}^{l}\,\hat{E} = \frac{Y_m F\ K}{1 + \frac{d_{\text{ñô}}}{4\,l_{\hat{E}}} Ctg(\alpha + \varphi)}$$

where

$Q_{\text{òê}}^{l}$ = ultimate axis load on the pipe in the slips link when surface efficiency equals to one, H;

Ym	pipe material yield strength, MPa;
F	cross section area in the body of the pipe, mm2;
K	surface efficiency (0,7 for = 300 mm and 0,9 for = 400 mm)
dcp	average diameter of the pipe, mm;
lk	work length of a slip (300 or 400), mm;
α	slip inclination angle, grad= 9° 27′ 45″;
φ	friction angle on the surface of slips' conjunction with the body of the slips link, grad.

Ctg (α+φ) =2.5

B.13 The head h shall be derived from the formula:

$$h = H - \frac{n P_p}{\gamma_{mud}}$$

where

H drilling string setting depth, m;
n bearing stress safety margin;
P_p maximum external pressure, Pa;
γ_{mud} mud density, kg/m3.

B.14 Formula to calculate the severity of the dogleg for drill pipe range 2.

$$\alpha = \frac{432000}{\pi} \times \frac{\delta_b}{ED} \times \frac{\tanh KL}{KL}$$

$$K = \sqrt{\frac{T}{EI}}$$

where

α maximum permissible dogleg severity (hole curvature), degrees per 30 m;
E young's modulus, MPa;
D drill pipe OD, mm;
L half the distance between tool joints, mm;
T buoyant weight (including tool joints) suspended below the dogleg, kN;
δ_b maximum permissible bending stress, MPa;
I drill pipe moment of inertia with respect to its diameter, mm^4;

$$I = \frac{\pi}{64}\left(D^4 - d^4\right)$$

where

D nominal outside diameter of pipe body, mm;
d nominal inside diameter of pipe body, mm.

$$\delta_b = 19500 - \frac{10}{67}\delta_t - \frac{0{,}6}{670^2}(\delta_t - 33500)^2$$

$$\delta_t = \frac{T}{F}$$

F cross sectional area of drill pipe body, mm^2.

B.15 The upper sticking limit of the drill pipe is determined on base of measuring the drill string elastic elongation when the axial loads P_1 and P_2 are subsequently applied.

$$H = kEF\frac{\lambda}{\Delta P}$$

where

k	the coefficient that takes into account the drill pipes end thickening and tool joints, approximately – 1,05;
E	pipe material modulus of elasticity;
F	pipe body cross section area;
$\Delta P = P2 - P1$	hookload gain when measuring the drill string elastic elongation;
$\Delta l_1, \Delta l_2$	drill string elastic elongation under P1 and P2 load as appropriate.
P1	load shall be slightly higher than the drill string own weight adjusted by the weight loss in the drilling mud and the pulling-and-running operation resistance;
P2	load shall not exceed the tensile strength limit for this pipe size.

Elastic elongation calculation for the aluminium alloy pipe drill string

In order to determine the true position of the rock cutting tool (drill bit) in a well, the corrections related to the drilling string elastic and thermal elongation shall be introduced.

$$\Delta L = \sum_{k=1}^{m} \left(\Delta l_{\hat{e}c} + \Delta l_{\hat{e}m} + \Delta l_{\hat{e}i} \right)$$

where

ΔL Overall elongation of combined drill string, m;

$\Delta l_{\hat{e}\tilde{n}}$ Elongation of the relevant drill string section «к» under its own weight load, m;

$\Delta l_{\hat{e}\hat{o}}$ Thermal elongation, m;

$\Delta l_{\hat{e}i}$ Elongation from the downhole sections and BHA, m;

m number of the drill string sections.

$$\Delta l_{\hat{e}\tilde{n}} = \frac{l_k^2 q_k \left(1 - \frac{\rho_q}{\rho_k} \right)}{2 E_k F_k}$$

where

l_k Length of one section, m;

q_k Reduced mass of this section drill pipes per 1 m, kg·f/m;

ρ_q Drill mud density, g/cm^3;

$\rho_{\ddot{e}}$ Reduced density of drill pipes material adjusted for the tool joint density, g/cm^3

E_K Young modulus of drill pipes material, g/cm^2;

F_K pipe body cross section area, cm^2;

$$\Delta l_{\ddot{e}\ddot{o}} = \frac{a_k n}{2}(L_k^2 - L_{k-1}^2)$$

where

a_k Coefficient of linear expansion of this section pipes material, °C/m;

n Temperature gradient, °C/m;

L_k and L_{k-1} Well depth at the upper and lower limits of this section accordingly;

$$\Delta l_{\ddot{e}i} = \frac{P_k l_k}{E_k F_k}$$

where

P_k Tensile stress applied to the bottom cross section of this section, kN.

B.16 Formula to calculate the correlation between the tensile strength and torque under emergency conditions.

Static strength condition for any design section of drill string is as follows:

$$|\sigma_i| = \sqrt{\sigma^2 + \grave{A}\tau^2} \leq \sigma_0$$

where

$|\sigma_i|$ Allowable intensity calculated as adjusted to the normative safety factors;

σ and τ The level of normal and tangential stresses applied to the design sections of drill string;

A factor depending on the failure theory selected for calculations and adjusted for anisotropy of drill pipes material. A value diminishes as the operating temperature grows

σ_0 strength parameter, that characterizes the material operating performance. The safety margin is assumed as 1.25 based on processing a great magnitude of data.

B.17 Formulas for calculating the polar section modulus at the pipe body eccentric wear:

$$W_p = \left[\frac{\pi}{2} \left(R_1^4 - r^4 \right) - \frac{\pi a^2 R_1^2 r^2}{R_1^2 - r^2} \right] \times \frac{R_1^2 - r^2}{a r^2 + R_1^3 - a^2 R_1}$$

where

R1 wear radius, cm;

r pipe inside radius, cm;

a wear radius displacement;

$$a = \frac{D}{2} - R_1$$

where

D nominal outside diameter of pipe body, cm.

Table 5.5 - Drill string assembly

№ section	OD mm	Wall Thickness mm	Tool joint Diameter mm	Protector Diameter mm	Weight of one meter in air N/m	Section length m	Drill pipe type
1	127.0	30.0	149.2	127.0	994.0	10.2	BHA
2	88.9	9.3	121.0	88.9	206.0	27.0	SDP-3 1/2"
3	103.0	9.0	127.0	103.0	99.8	2554.0	ADP-103x9
4	88.9	9.3	121.0	88.9	206.0	350.0	SDP-3 1/2"
5	147.0	13.0	178.0	172.0	231.0	3159.0	ADP-147x13P
6	147.0	25.0	178.0	147.0	326.0	135.0	ADP147x25
7	127.0	25.4	165.1	127.0	733.6	135.0	HWDP-5"

Table 5.6 - Distribution of design parameters along drill string sections

Section no	Length by the instrument m		Weight in mud kN		Longitudinal force kN			Drag torque kN·m	
	Section length	Progressive length	Sections	Progressive weight	Friction	Design value	Allowable value	Design value	Allowable value
1	10.20	10.20	8.8	8.8	1.7822	-41.3	8106.7	1.2	152.4
2	18.00	28.20	3.2	12.0	1.0921	-41.8	1451.3	1.2	30.2
3	2553.8	2582.04	172.8	184.8	65.341	-62.2	845.0	5.9	16.7
4	348.08	2930.13	62.1	246.9	7.0874	-18.7	1455.9	6.5	30.3
6	135.00	6105.00	27.8	743.5	0.1849	426.4	2098.6	10.4	50.7
7	265.20	6370.20	168.5	912.0	5.7501	593.6	3999.6	10.6	99.7

Table 5.6 (continued)

Length measured by the instrument m		Active tension MPA					Safety factor		
Section length	Progressive length	Stretching	Max. bending	Torsion	Equivalent	Allowable	Stretching	Bending	Von Mises strength theory
10.20	10.20	-	-	-	-	-	-	-	
18.00	28.20	-17.89	0.00	14.41	30.71	621.10	52.063	-	30.335
2553.84	2582.04	-23.41	6.54	51.25	115.88	317.95	20.370	72.888	4.116
348.08	2930.13	-8.00	16.94	77.01	133.63	623.06	116.784	55.161	6.994
3039.87	5970.00	72.86	7.39	30.74	99.08	325.99	6.711	66.127	4.935
135.00	6105.00	44.50	0.00	20.59	63.26	219.05	7.384	-	5.194
265.20	6370.20	73.21	0.00	30.26	90.04	493.33	10.108	-	8.219

Table 5.7 - Parameters of drill string

Parameters	Value
Total length of drill string, m	6370.00
Extension of drill string, m	9.12
Hook load, kN	593.60
Hydraulical pressure losses, MPa	20.50
Min mud velocity in hole anulus, m/sec	0.47

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