INTRODUCTION

Directional drilling is the science of directing a wellbore along a predetermined trajectory to intersect a designated sub-surface target.

From its early beginnings in the 1920s when it was regarded as a "black art", directional drilling has evolved to the point where it can truly be regarded as a science, although not always an exact science. The offshore drilling industry is founded on directional drilling. Without the use of directional drilling techniques, it would not be economical to produce oil from most offshore fields. Improvements in directional drilling tools and techniques coupled with advances in production techniques have led to a steady increase in the proportion of wells drilled directionally rather than vertically. As the search for oil extends into ever more hostile and demanding environments, this trend will continue.

Topic 2 looks at how a vertical well can be maintained close to the vertical. Causes of deviation from the vertical are considered as are the mechanical behaviour of drilling assemblies. Formation effects are also discussed. Methods of deviation control in vertical wells are then outlined. Much of the material in this first section anticipates topics discussed in later sections with reference to directional wells.

Topic 3 briefly outlines some of the many applications of directional drilling.

Topic 4 covers well planning and includes an explanation of reference systems and coordinates. The discussion focusses mainly on the geometrical planning of the well path and deals briefly with subjects such as "nudging" and collision avoidance.

In Topic 5, downhole drilling motors are described. The operating principles of both turbine and positive displacement motors are explained. The major sub-assemblies of both types are described and their functions explained; typical output characteristics are given.

Topic 6 provides a brief review of the traditional tools and methods of deflecting wellbores in a controlled fashion. Whipstocks, the jet deflection method and the use of bent subs with downhole motors are all described.

Topic 7 deals with the vital subject of toolface orientation, which is relevant not only to the traditional deflection tools but also to steerable motors.

In Topic 8 the principles used to effect directional control of rotary assemblies are discussed in detail. Typical examples of rotary BHA design are given and explained.

Topic 9 provides a detailed discussion of "steerable motors" or "drilling systems", to use the modern terminology. As this is the modern way to drill directional wells, the topic is discussed in depth.

Finally, Topic 10 deals with BHA weight requirements. There is a discussion of buckling analysis which is relevant to the subject of running drill pipe in compression. The section explains how directional BHAs can be shortened by running drill pipe in compression, which is consistent with the Group's anti-stick philosophy.

4.2.2 MECHANICAL BEHAVIOUR OF DRILLING ASSEMBLIES

The principal mechanical forces which cause a bit to deviate are called the "buckling" and "pendulum" effects, and they are shown simply in Figure 2.4.1 ***where the forces illustrated are defined as follows:***

W_1 = the total weight-on-bit, acting along the axis of the drill collar.

W_2 = one component of W_1 which acts along the axis of the hole.

W_3 = a component of W_1, complementary and normal to W_2, acting at right angles to the hole axis. This force acts laterally at the bit.

W_1, W_2 and W_3 are forces which occur when the centre line of the drill collars is displaced from the hole axis due to bending of the assembly.

W_4 = the vertical downward force caused by gravity acting on the length of drill collars below the wall contact point.

W_5 = one component of the drill collar weight W_4 which acts along the axis of the assembly, and contributes to the total weight-on-bit, W_1.

W_6 = a component of W_4, complementary and normal to W_5; it acts at right angles to the drill collar axis and back towards the vertical. Part of this force also has a lateral influence at the bit.
The forces W_4, W_5 and W_6 are due to gravity and the inclination of the hole, and illustrate the pendulum effect.

BENDING OF DRILL COLLARS

When weight is applied to the bit the lower part of the drill collars will bend to some extent under the compressive load. The direction of the force applied at the bit will then no longer coincide exactly with the centre line of the hole; as the bit drills ahead the lateral component of the bit weight, W_3, will tend to deflect it.
The direction of W_3 depends on the direction of bending of the lowest part of the bottom hole assembly, which in turn depends on the geometry of the system - in particular the position of the lowest two stabilisers (which act as fulcrums). In the figure no stabiliser is present, the BHA is sagging towards the lower side of the hole and the inclination at the lower end of the collars is greater than that of the hole. The inclination of the hole is thus likely to increase.
The amount of inclination change, and the length of the assembly involved, will depend on:

- **the stiffness, i.e. the dimensions, of the drill collars.**
- **the hole diameter.**
- **the arrangement of stabilisers in the assembly.**
- **the compressive load applied**

Bending, and the corresponding directional force at the bit, W3, is increased by:

- **greater clearance between the drill collar assembly and the hole.**
- **smaller, more flexible drill collars.**
- **more compressive force, i.e. weight-on-bit.**

As bending increases, the length of the assembly mainly involved (from the bit to the first point of drill collar wall contact), tends to shorten. This is called the "active drill collar length", and in practice the position of the first stabiliser determines this dimension. Usually not more than the bottom 50 m (150 ft.) of the assembly is active in the absence of stabilisers; or at high inclination or with high bit weight, perhaps less than 20 m (60 ft.).

THE PENDULUM EFFECT OF GRAVITY ON THE ASSEMBLY

The effect of gravity on the drill collars below the wall contact point acts vertically downward. Part of this force is transmitted to the bit along the axis of the drill collars, and its complementary component, W_6, acts towards the vertical, perpendicular to the axis of the assembly. This force is supported by the formation at the wall contact point and at the bit (see Figure 2.4.1).
Considered separately the influence of this lateral force at the bit is to reduce the inclination of the hole. Its magnitude increases:

- **when hole inclination is greater.**
- **when heavier drill collars are used below the contact point.**
- **when the active drill string length is increased.**

In Figure 2.4.1 each of the above factors will tend to increase the value of the lateral component (W_6) of the drill collar weight (W_4) below the wall contact point.

CONTROL OF MECHANICAL FACTORS

By changing the make-up of an assembly and altering the drilling parameters it is possible to vary the magnitude of the lateral forces at the bits W_3 and W_6, which directly influence the tendency of the bit to deviate from the existing path of the hole in a vertical plane.
Note that, although W_3 acts normal to the hole axis, and W_6 to that of the drill collars, for practical purposes these forces can be considered to act in directly opposite directions.
Therefore inclination can be expected to increase if the effect of drill collar buckling is greater than the pendulum tendency, but it should decrease when the pendulum force predominates.

4.2.3 FORMATION EFFECTS ON DEVIATION

Formation characteristics add considerably to the complexity of deviation problems, and numerous theories have been suggested to explain observed effects.

FORMATION BIT INTERACTION OR ANISOTROPIC THEORY OF ROCK FAILURE

In uniform rocks, equal chip volumes are formed on each side of a bit tooth, and the bit drills straight ahead.
However, in dipping laminated formations, larger chip volumes are formed on one side of the tooth, causing the bit to be pushed laterally, with resultant deviation.
The magnitude of this effect varies with the degree of dip angle. Normally the direction of deviation generated is up-dip for angles of dip up to 45° - 60° and down-dip for high angles of formation dip (over 60°).
There is no completely satisfactory explanation for naturally occurring deviation. However, theory and practice indicate that uncontrolled deviation will not exceed an angle perpendicular to, or parallel to, the formation dip.

4.2.4 DEVIATION CONTROL IN VERTICAL HOLES

The overall objective in a vertical well is to achieve the most economical cost per unit length, consistent with keeping the inclination (among other important factors) within acceptable limits.
This means it is necessary to select a drilling assembly that will produce an equilibrium of the deviating forces at the bit, while allowing the maximum weight-on-bit and therefore the optimum drilling speed.
The two methods commonly employed to control inclination in vertical holes use:

- **the pendulum technique.**
- **packed-hole drilling assemblies.**

THE PENDULUM TECHNIQUE

Factors which determine the magnitude of the hole straightening force are:

- **the drill collar weight below the wall contact point.**
- **the active drill string length.**
- **weight-on-bit.**

The use of heavier drill collars above the bit increases the lateral corrective force (W_6). Larger collars are also stiffer and more resistant to buckling, and their larger outside diameter allows less displacement of the assembly from the centre line of the hole.
The logic of this approach has been clearly demonstrated by experimental work using extra-heavy drill collars above the bit, which are manufactured from depleted uranium or tungsten. With these collars, higher bit weights could be used without increased inclination.
Raising the wall contact point by including a stabiliser at a specified distance above the bit increases the active drill string length, and also therefore the lateral force (W_6). This will again reduce the displacement of the drill collars from the axis of the hole, and the deviating force (W_3). This approach is limited by the possibility of buckling below the stabiliser if this is placed too high, which would then necessitate a reduction in bit weight.
Reducing bit weight alone will cause less buckling and encourage the correcting force (W_6) to exceed the inclination building effect (W_3), but less weight-on-bit will produce a lower rate of penetration and higher cost per meter.
In 1953/1955 Woods and Lubinski published data which recommended optimum stabiliser positions for the fastest penetration rate within given deviation limits. For quoted hole sizes and inclinations, combined with values for formation dip and an index which represents the severity of the formation effect, the tables specify:

- **drill collar diameter,**
- **position of the first stabiliser above the bit,**
- **allowable weight-on-bit,**

all for a condition of zero deviation, i.e. equilibrium of the forces at the bit, and no increase in inclination.

Modern developments of such research provide computer programs which evaluate a comprehensive range of forces acting at the bit and at other points in the assembly. In particular the magnitude of the transverse forces exerted by the bit on the formation, perpendicular to the hole axis, can be predicted. A positive transverse force tends to increase inclination. The value of this force, and the tendency of the formation influence, together determine whether existing inclination will remain constant or change. Such predictions can be very helpful when selecting a drilling assembly, both to control inclination and obtain the best possible progress.
Further information on this subject is given in Topic 4.8.1.

PACKED-HOLE DRILLING ASSEMBLIES

This technique seeks to prevent further deviation by preventing displacement of the assembly from the centre line of the hole. Progressive application of the principle would involve:

- **the use of drill collars with the largest practicable outside diameter.**
- **using a high concentration of stabilisers.**
- **using square drill collars (the maximum development of the first two points) having a diagonal dimension equal to the bit size.**

Square drill collars are effective in hard rock when natural deviating effects are severe, but they can be difficult to trip, liable to stick, and most difficult to fish.
Packed-hole assemblies minimise deviating (direction) trends, but it will be difficult to bring inclination back. In addition the minimum annular clearance substantially increase swabbing risks, overpulls, and the chances of sticking the tools; also extra handling time is involved on the rig floor.

MINOR EFFECT ON INCLINATION

The factors described above consider the composition of the assembly, formation effects, and weight-on-bit.
Varying the other drilling conditions, particularly rotary speed and bit hydraulics, may also influence the behaviour of the assembly.
Such effects are difficult to predict or quantify, but in general terms, if more hole is made due to increased RPMs or bit hydraulics, then the same magnitude of directional deflection will be achieved by the bit over a longer drilled interval. Therefore the rate of inclination change (dogleg severity) will be reduced. Conversely, reducing the rate of penetration by using less rotary speed or hydraulics will tend to increase the deviation rate.
When it is essential to keep the inclination of a vertical hole within tight limits, and the techniques described are not sufficiently effective, the only alternative remaining is to employ corrective directional drilling methods.

4.3.1 APPLICATIONS OF DIRECTIONAL DRILLING

The following text and sketches illustrate the most common applications of directional drilling.

Multiple wells from offshore structures

A very common application of directional drilling techniques is in offshore drilling. Many oil and gas deposits in the Gulf of Mexico, North Sea and other areas are situated beyond the reach of land based rigs. To drill a large number of vertical wells from individual platforms is obviously impractical and would be uneconomical. The conventional approach for a large oilfield has been to install a fixed platform on the seabed, from which many directional wells may be drilled. The bottomhole locations of these wells can be carefully spaced for optimum recovery.
In a conventional development, the wells cannot be drilled until the platform has been constructed and installed in position. This may mean a delay of 2 - 3 years before production can begin. This delay can be considerably reduced by pre-drilling some of the wells through a subsea template while the platform is being constructed. These wells are directionally drilled from a semi-submersible rig or jack-up and tied back to the platform once it has been installed.

Controlling Vertical Wells

Directional techniques are used to straighten crooked holes. In other words, when deviation occurs in a well which is supposed to be vertical, various techniques are used to bring the well back to vertical. This was one of the earliest applications of directional drilling.

Sidetracking

Sidetracking out of an existing wellbore is another application of directional drilling. This sidetracking may be done to bypass an obstruction (a "fish") in the original wellbore, to explore the extent of the producing zone in a certain sector of a field, or to sidetrack a dry hole to a more promising target. Wells are also sidetracked to access more reservoir by drilling a horizontal hole section from the existing well bore.

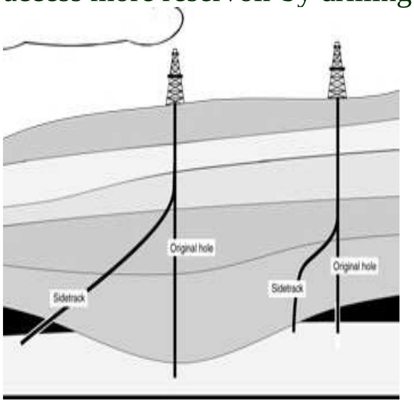

Figure 2.4.4 : Sidetracking

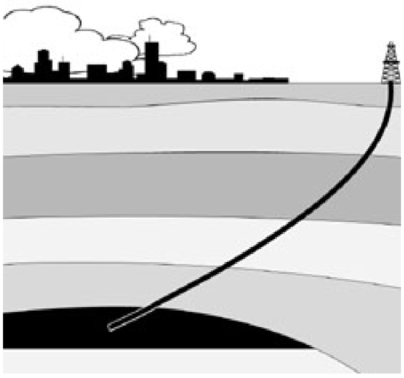

Figure 2.4.5 : Inaccessible locations

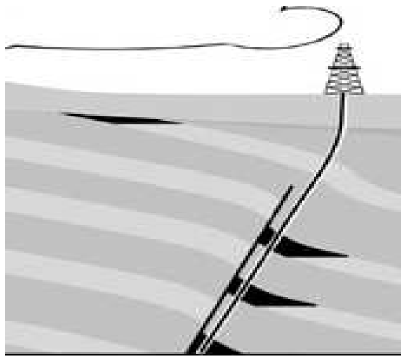

Figure 2.4.6 : Fault drilling

Inaccessible locations

Directional wells are often drilled because the surface location directly above the reservoir is inaccessible, either because of natural or man-made obstacles. Examples include reservoirs under cities, mountains, lakes etc.

Fault Drilling

Directional wells can be used to avoid drilling a vertical well through a steeply inclined fault plane which could slip and shear the casing.
They are also used to drain, in one well, a staggered series of small accumulations trapped below a fault. This technique is known as "fault scooping".

Salt Dome Drilling

Directional drilling programs are sometimes used to overcome the problems of salt dome drilling. Instead of drilling through the salt, the well is drilled at one side of the dome and is then deviated around and underneath the overhanging cap.

Shoreline Drilling.

In the case where a reservoir lies offshore but quite close to land, the most economical way to exploit the reservoir may be to drill directional wells from a land rig on the coast.

Relief Wells

Directional techniques are used to drill relief wells from a safe distance in order to "kill" wells which are flowing out of control (blow-outs).
The relief well(s) is/are designed either to enter the reservoir close to the blow-out well, for a so-called saturation kill with water, or to intersect the blow-out well for a direct kill using high density drilling fluid.

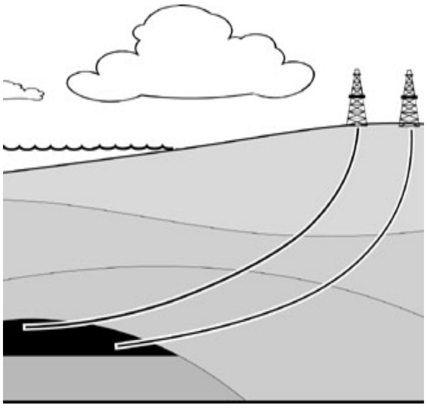
Figure 2.4.8 : Shoreline drilling

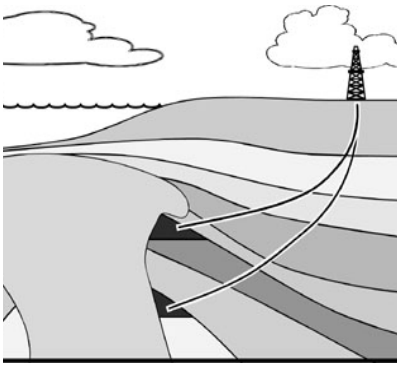
Figure 2.4.7 : Salt dome drilling

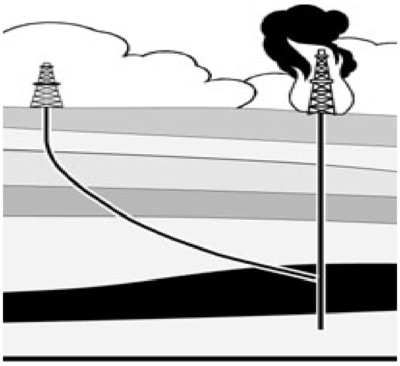
Figure 2.4.9 : Relief wells

The above are only some of the many applications of directional drilling. Although it is not a new concept, horizontal drilling is the fastest growing branch of directional drilling, with major advances occurring in the tools and techniques used. One application which is specific to horizontal (and almost horizontal) wells is to drill through a shallow reservoir parallel to the bedding plane, thus allowing one well to drain an area which would have required several vertical or medium angle wells.
Horizontal wells also make possible the recovery of liquid hydrocarbons from an interval between an oil-water contact and a gas-oil contact that is so thin that it could not be produced at all from a vertical well, because of the coning effect.

WELL PLANNING

4.4.1. INTRODUCTION

There are many aspects involved in planning a well and many individuals from various companies and disciplines are involved in designing various programs for the well (e.g. drilling fluid program, casing program, drill string design for each section, bit program, etc.). The new engineered approach to well planning means that service contractors become equally involved in areas such as drill string design which are vitally important in planning a deviated well, especially horizontal or extended wells.
In this section we shall concentrate on those aspects of well planning which have always been the province of directional drilling companies.

4.4.2. REFERENCE SYSTEMS AND CO-ORDINATES.

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

- Depth references
- Inclination references
- Azimuth references
- Field coordinates

DEPTH REFERENCES

There are two kinds of depths:

- Measured depth or the depth "along hole" (ahd) 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, wireline depth counter, or mud loggers depth counter.
- True vertical depth (tvd) is the vertical distance from the surface reference point to a point on the borehole course. This depth is always calculated from the deviation survey data.

In most drilling operations the Rotary Table or Derrick Floor elevation is used as the working depth reference. The abbreviations "brt" (below rotary table) and "bdf" (below derrick floor) are used to indicate depths measured from the rotary table. The kelly bushing (KB) is sometimes also used as a depth reference. 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 reference must be defined and always referred to. Offshore, mean sea level is sometimes used, in which case the depth is called a sub-sea depth. Variations in actual sea level from MSL can be read from tide tables or can be measured.

As an example, the drilling crew would usually refer to the depth of a casing shoe as being 1,000 m ahbdf, whereas the field development geologist would prefer to relate it to a formation boundary and would say that the casing is at 700 m tvss. (There is no significance in these numbers.)

INCLINATION REFERENCES

The inclination of a well is the angle (usually expressed in degrees) between the vertical and the bore hole axis at a particular point. The vertical reference is the direction of the local gravity vector and would be indicated by, for example, a plumb bob.

AZIMUTH REFERENCE SYSTEMS

For directional surveying there are three azimuth reference systems:

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

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

True (Geographic) North

This is the direction of the geographic North Pole which lies on the axis of rotation of the Earth. The direction is shown on maps by the meridians of longitude.

Grid North

During drilling operations we are working on a curved surface (i.e., the surface of the Earth) but when we calculate horizontal plane co-ordinates we assume we are working on flat surface. Obviously it is not possible exactly to represent part of the surface of a sphere on a flat well plan. Corrections have to be applied to the measurements. There are many different projection systems which can be used.

UTM System

As an example of a grid system, let us examine the Universal Transverse Mercator (UTM) System. In the 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 circle running around the Earth passing through both geographic North and geographic South Poles.)

The meridians of longitude converge towards the North Pole and therefore do not produce a rectangular grid system. The grid lines on a map form a rectangular grid system, the Northerly direction of which is determined by one specified meridian of longitude. This direction is called Grid North. It is identical to True North only for the specified meridian.

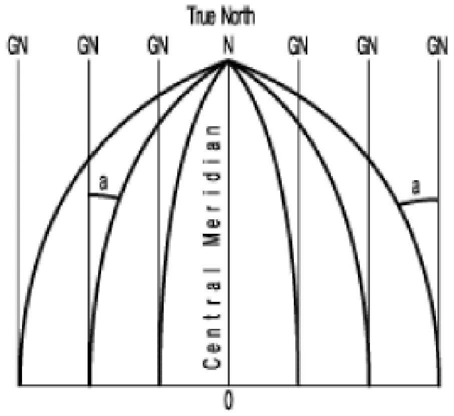

Figure 2.4.10 : Azimuth references

The relationship between True North and Grid North is indicated by the angles 'a' in Figure 2.4.10. Convergence is the difference in angle between grid north and true north for the location being considered.
The reference meridians used are 6° 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° meridian (Greenwich) on the left and 6° East on the right. Each zone is further divided into grid sectors - a grid sector covering 8° latitude starting from the equator and ranging from 80° South to 80° North. The sectors are given letters ranging from C to X (excluding I and O)

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Therefore each sector is uniquely identified by a number from 0 to 60 (zone number) and a letter. For example, sector 31 U, shown in Figure 2.4.11, is the Southern North Sea.

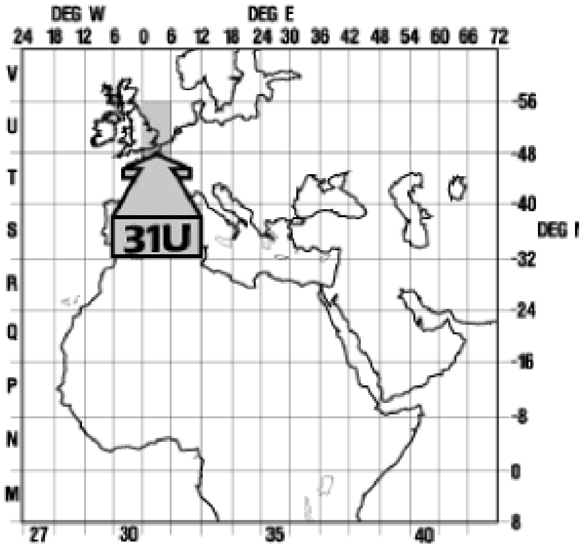


Figure 2.4.11 : UTM sector 31U

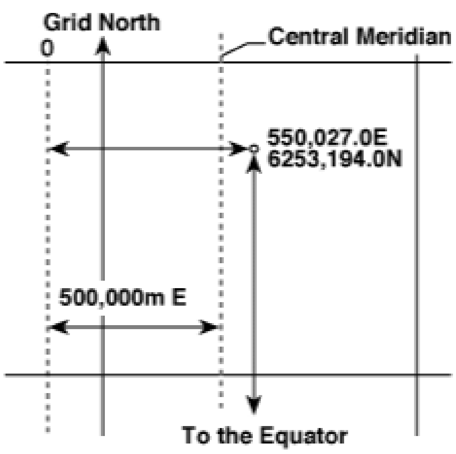


Figure 2.4.12 : UTM co-ordinates

Co-ordinates in the UTM system are measured in meters. North co-ordinates are measured from the equator. For the Northern hemisphere, the equator is taken as 0.00 m North whereas for the Southern hemisphere the equator is 10,000,000 m North (to avoid negative numbers). The East co-ordinates for each sector are measured from a line 500,000 m west of the central meridian for that sector. In other words, the central meridian for each zone is arbitrarily given the co-ordinate 500,000 m East. Again, this avoids negative numbers.
So UTM co-ordinates are always Northings and Eastings, and are always positive numbers. See Figure 2.4.12.

Lambert Projection.

An alternative projection system used in some parts of the world is the conical projection or LAMBERT system, whereby 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.
Further discussion of the co-ordinate systems and map projections is beyond the scope of this text.

FIELD CO-ORDINATES

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

DIRECTION MEASUREMENTS

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

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

Figure 2.4.13

- The quadrant system
  In the quadrant system (Figure 2.4.14), the directions are expressed as angles from 0°- 90° measured from North in the two Northern quadrants and from South in the Southern quadrants.

Figure 2.4.14

Figure 2.4.15 shows how to convert from the quadrant system to azimuth, and vice versa, and also shows how to apply the correction from Magnetic to True North in the two systems. The subjects of Magnetic Declination Corrections and Grid Convergence Corrections will be dealt with in detail later, in the Part on surveying.

Figure 2.4.15

4.4.3. PLANNING THE WELL TRAJECTORY

One area of well planning in which directional companies are often 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. A number of aspects must be carefully considered before calculating the final well path.

THE TARGET.

The target is 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 centre). A target zone should be selected as large as possible to achieve the objective. If multiple zones are to be penetrated, the multiple targets should be selected so that the planned pattern is reasonable and can be achieved without causing excessive drilling problems.

TYPES OF DIRECTIONAL PATTERNS

With the advent of steerable systems, some wells are planned and drilled with complex paths involving 3-dimensional turns. This happens particularly in the case of re-drills, where old wells are sidetracked and drilled to completely new targets.

These complex well paths are, however, harder to drill and the old adage that "the simplest method is usually the best" holds true. Therefore, most directional wells are still planned using the traditional patterns which have been in use for many years. The common patterns used for the vertical projection are shown on this and the following pages

- Build and hold
- S-well
- Deep kick-off and build

A mathematical treatment is given in Appendix 1

Catenary curve well plan

It has been suggested that an efficient well path for many directional wells would be to plan the well as a continuous, smooth curve all the way from KOP to target; the so-called catenary method. A catenary curve is the natural curve that a cable, chain or any other line of uniform mass per unit length assumes when suspended between two points. The similar suspension of a drill string would also form a catenary curve.

Proponents of the catenary method argue that it results in a smoother drilled wellbore, that drag and torque are reduced and that there is less chance of key seating and differential sticking than with traditional well profiles. However, in practice it is hard to pick BHAs which will continuously give the required gradual rate of build, so it is in reality no easier to follow a catenary curve well plan than a traditional well plan. Also, the catenary curve method produces a much higher maximum inclination than would result from the build and hold or S type patterns. Three examples of well plans are shown.

Build and Hold

The features of this trajectory are:

- Shallow kick-off point (KOP)
- Build-up section (which may have more than one build up rate).
- Tangent section to TD

Its applications are:

- Deep wells with large horizontal displacements.
- Moderately deep wells with moderate horizontal displacement, where intermediate casing is not required.

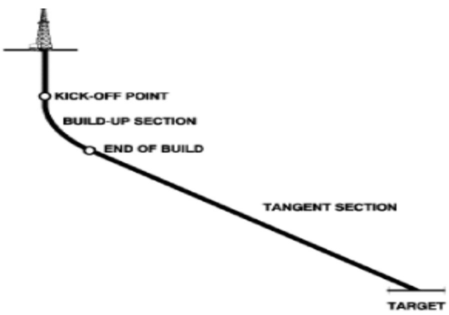


Figure 2.4.16 : Build & hold trajectory

S Type Well

The features of this trajectory are:

- Shallow KOP
- Build-up section
- Tangent section
- Drop-off section

There are several variations:

- Build, hold and drop back to vertical
- Build, hold, drop and hold (illustrated here)
- Build, hold and continuous drop through reservoir

Its applications are:

- Multiple pay zones.
- To reduce final angle in reservoir for easier completions.
- Lease or target limitations.
- For well spacing requirements on multi-well fields.
- Deep wells with a small horizontal displacement.

The disadvantages of the S-Type well are:

- Increased torque and drag.
- Increased risk of key-seating.
- It may give logging problems due to increased maximum inclination.

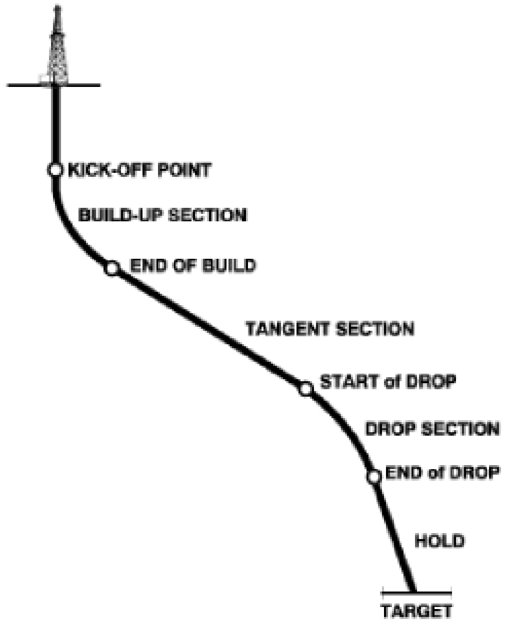


Figure 2.4.17 : S-shape trajectory

ALLOCATION OF SLOTS TO TARGETS

Even this is not always as simple as you would think. Obviously, from a directional driller's viewpoint, slots on the North East of the platform or pad should be used for wells whose targets are in a North Easterly direction. However, there are generally other considerations (e.g. water injection wells may have to be grouped together for manifolding requirements). Also, as more wells are drilled and the reservoir model is upgraded, it has been known for targets to be changed!

The inner slots are used to drill to the innermost targets (i.e., those targets at the smallest horizontal distances from the platform) and these wells will be given slightly deeper kick-off points. The outer slots are used to drill to the targets which are furthest from the platform. These wells will be given shallow kick-off points and higher build-up rates to keep the maximum inclination of the well as low as possible.

KICK-OFF POINT AND BUILD-UP RATE

The selection of both the kick-off point and the build-up rate depend on many factors including the hole pattern selected, the casing program, the drilling fluid program, the required horizontal displacement and the maximum tolerable inclination. Choice of kick-off point may be severely limited by the requirement 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 to reach a given target.

In practice, the well trajectory may be calculated for several choices of KOP and build-up rate and the results compared. The optimum choice is that which gives a safe clearance from all existing wells, keeps the maximum inclination within desired limits and avoids unnecessarily high dogleg severities.

TANGENT SECTION

During the eighties, a number of extended reach drilling projects were successfully completed. 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 if the maximum inclination of the wells is limited to 60°. However, inclination angles over 65° may result in excessive torque and drag on the drill string and present hole cleaning, logging, casing, cementing and production problems. These problems can all be overcome with today's technology, but should be avoided whenever there is an economic alternative.

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

DROP-OFF SECTION

On S-type wells, the rate of drop off is selected mainly with regard to ease of running casing and avoidance of completion and production problems. It is much less critical with regard to drilling because there is less tension in the drill pipe that is run through this deeper dogleg and less time will be spent rotating below the dogleg.

THE HORIZONTAL PROJECTION

On many well plans, the horizontal projection is just a straight line drawn from the slot to the target. On multi-well platforms 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. Of course, this is a 3-dimensional turn, but on the horizontal plan it would typically look like Figure 2.4.19.

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

LEAD ANGLE

In the old days (pre 1985) it was normal practice to allow a "lead angle" when kicking off a well. Since roller cone bits used with rotary assemblies tend to "walk to the right", the wells were generally kicked off in a direction several degrees to the left of the target direction. In extreme cases the lead angles could be as large as 20°.

The greatly increased use of steerable motors and the widespread use of PDC bits for rotary drilling have drastically reduced the need for wells to be given a "lead angle". Many wells today are deliberately kicked off with no lead angle (i.e. in the target direction).

Deep Kick-off and Build

The features of this trajectory are:

- Deep KOP
- Build-up section
- Short tangent section (optional)

Its applications are:

- Appraisal wells to assess the extent of a newly discovered reservoir.
- Repositioning of the bottom part of the hole or re-drilling.
- Salt dome drilling.

The disadvantages of the Deep Kick-off and Build-Type well are:

- Formations are harder so the initial deflection may be more difficult to achieve.
- Harder to achieve desired tool face orientation with downhole motor deflection assemblies - more reactive torque (see Subtopic 4.6.3).
- Longer trip time for any BHA changes required.
- On multi-well platforms, only a very few wells may be given deep kick-off points because of the small separation of the slots and the difficulty of keeping wells vertical in firmer formation. Most wells must be given shallow kick-off points to reduce congestion below the platform and minimise the risk of collisions.

Figure 2.4.18 : Deep kick-off and build trajectory

4.4.4. NUDGING

The technique of "nudging" is used on platforms in order to "spread out" conductors and surface casings and thereby minimise the chance of a collision when wells are drilled. Basically, when the hole for surface casing is drilled, some angle is built at a low rate (e.g. 1°/100') in the chosen direction.
As well as the basic reason of "spreading things out", other reasons for "nudging" are:

- to drill from a slot located on the opposite side of the platform from the target, when there are other wells in between
- to keep wells drilled in the same general direction as far apart as possible
- if the required horizontal displacement of a well is large compared to the total vertical depth, then it is necessary to build angle right below the surface conductor to avoid having to use a high rate of build

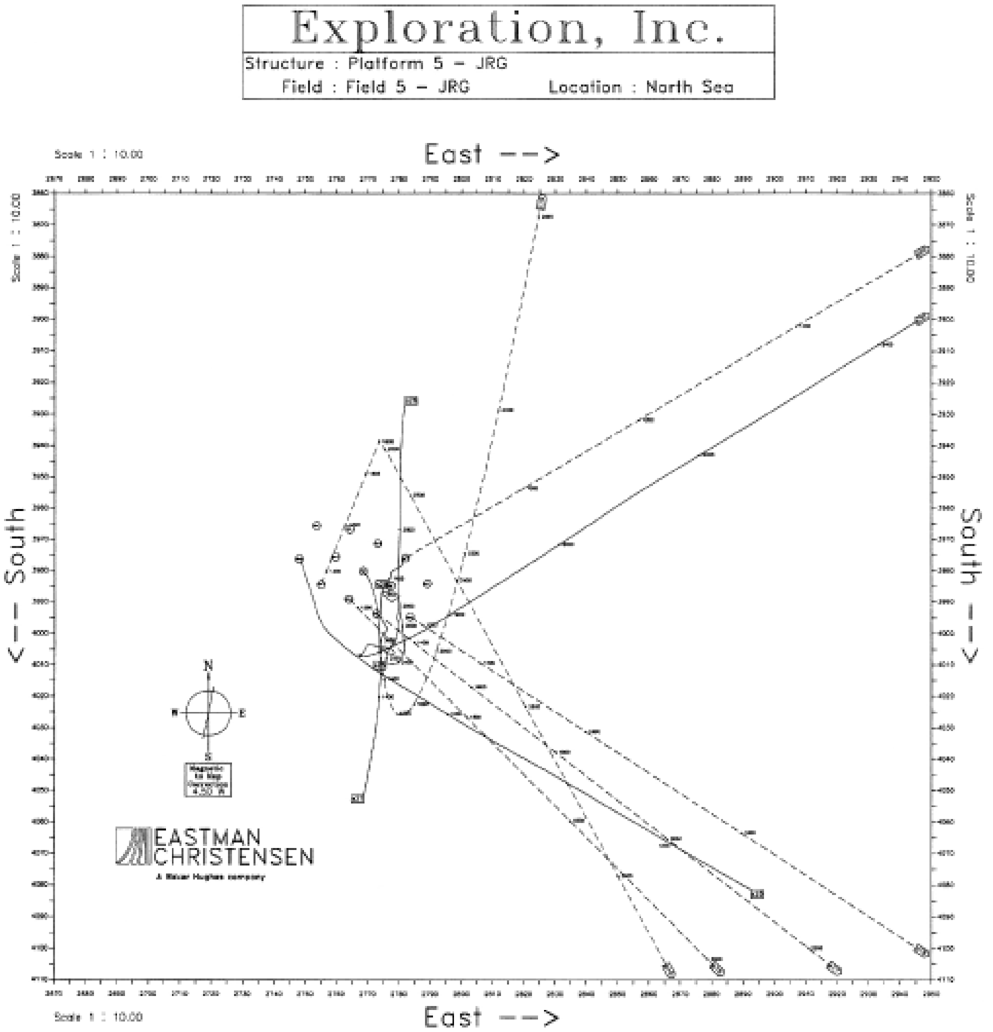


Figure 2.4.19 : A three-dimensional turn on the horizontal plan

TECHNIQUES FOR "NUDGING"

- When the formation is suitable (soft), jetting is the best technique to use.
- The most common method is to use a mud motor of $9^1/2$" OD or greater with a $17^1/2$" bit and a $1^1/2$° bent sub. Using a $1^1/2$° bent sub gives a low build rate and hence a low dogleg severity as required. The hole is opened out to the required gauge after the mud motor run.
- Occasionally the job is performed with a large mud motor and 26" bit from the start. In this case either a $1^1/2$°or 2° bent sub might be used.

PLANNING A NUDGE PROGRAM

The directions in which the wells are "nudged" should be chosen so as to achieve maximum separation. The wells will not necessarily be nudged in their target directions.
The nudges will not only be shown on the individual well plans for each well, but also a structure plot will be drawn which will show the well positions at the surface casing point after the nudge.

4.4.5. PROXIMITY (ANTI-COLLISION) ANALYSIS

On multi-well projects, particularly offshore, there is only a small distance between slots. In order to eliminate the risk of collisions directly beneath the platform, a proposed well path is compared to existing and other proposed wells. The distances between other wells and the proposal are calculated at frequent intervals in the critical section. These calculations can be performed using the applications COMPASS or WELLPLAN
Survey uncertainty must also be computed both for the proposed well and the critical existing wells. All the major operating companies have established criteria for the minimum acceptable separation of wells, which are usually linked to "cone of error" or "ellipse of uncertainty" calculations. Three examples of well plans are shown.

DOWNHOLE MOTORS

4.5.1. INTRODUCTION

The idea of using a downhole motor to directly turn the bit is not a new one. Indeed, the first commercial motor used was turbine driven. The first patent for a turbodrill existed in 1873. The USSR focused efforts in developing downhole motors as far back as the 1920s and has continued to use motors extensively in their drilling activity. After 1945, the West focused efforts more on rotary drilling but the field of application for downhole motors increased spectacularly from about 1980 onwards.
The turbine consists of a multistage vane type rotor and stator section, a bearing section, a drive shaft and a bit rotating sub. Each stage consists of a rotor and stator of identical profile. The stators are stationary, locked to the turbine body, and deflect the flow of drilling fluid onto the rotors which are locked to the drive shaft. The rotors are forced to turn; the drive shaft is thus forced to turn, causing the bit sub and the bit to rotate.
A positive displacement motor is a hydraulically driven downhole motor that uses the Moineau principle to drive the drilling bit, independent of drill string rotation.

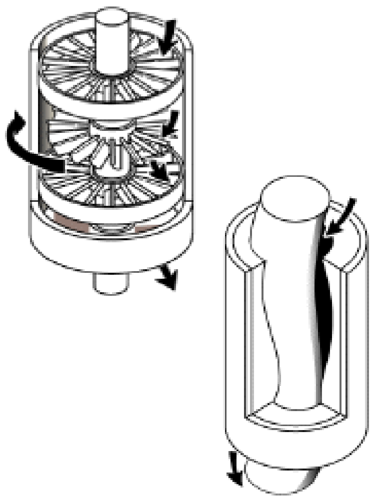


Figure 2.4.23 : Differences between the turbine motor (left) and positive displacement motor (right) designs

4.5.2. POSITIVE DISPLACEMENT MOTORS

The PDM is made up of several sections:

- The by-pass valve or dump sub.
- The motor section.
- The universal joint or connecting rod section.
- The bearing section with drive sub.

BY-PASS VALVE

A by-pass valve allows fluid to fill the drill string while tripping in the hole and drain while tripping out. While drilling fluid is being pumped, the valve closes to cause fluid to move through the tool. Most valves are of a spring piston type which closes under pressure to seal off ports to the annulus. When there is no downward pressure, the spring forces the piston up so fluid can channel through the ports to the annulus. (Figure 2.4.24)

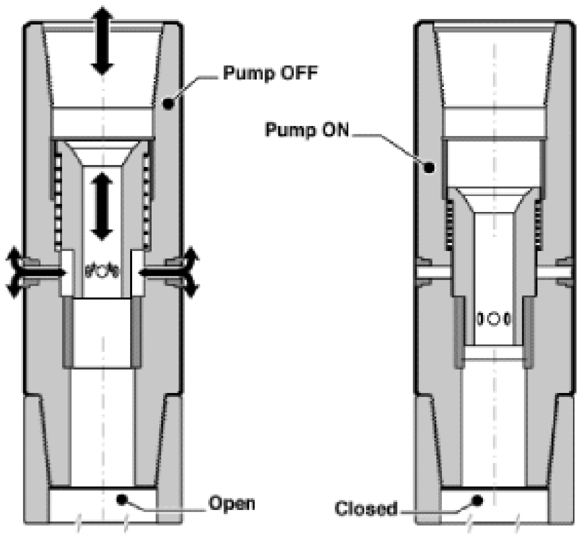
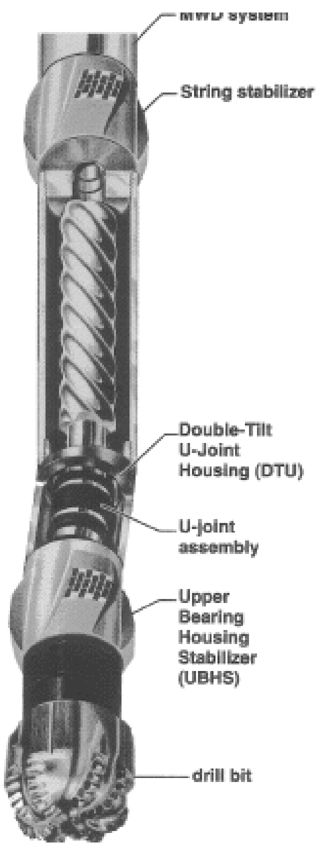


Figure 2.4.24 : Bypass Valve



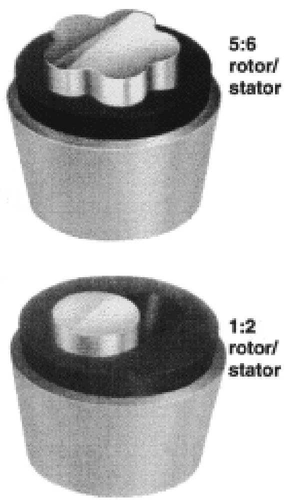


Figure 2.4.25 : Motor details

MOTOR SECTION

This is a reverse application of Rene Moineau's pump principle. The motor section consists of a rubber stator and steel rotor. The simple type is a helical rotor which is continuous and round. This is said to be a single lobe type. The stator is moulded inside the outer steel housing and is of an elastomer compound. The stator will always have one more lobe than the rotor. Hence motors will be described as 1/2, 3/4, 5/6 or 9/10 motors. Both the rotor and stator have a certain pitch length and the ratio of the pitch lengths is equal to the ratio of the number of lobes on the rotor to the number of lobes on the stator.

As drilling fluid is pumped through the motor, it fills the cavities between the dissimilar shapes of the rotor and stator. The rotor is forced to give way by turning or, in other words, is displaced; hence the name positive displacement motor. It is the rotation of the rotor shaft which is eventually transmitted to the bit.

CONNECTING ROD ASSEMBLIES

Since the rotor is spiral shaped, it does not rotate concentrically, rather it traces a back and forth motion. This motion must be converted back to concentric motion and is transmitted to the bit via the drive sub. This is achieved by a connecting rod assembly. There are several possible types.

Universal-joint

U-joint assemblies (Figure 2.4.26a) have been conventionally utilised by the industry and are still used in most positive displacement motors presently in the field. The assembly consists of two universal joints, each grease filled and sealed with oil-resistant reinforced rubber sleeves which protect them from drilling fluid contamination. A drawback of the U-joint assembly is the lack of sufficient strength for higher torque applications such as that encountered with recent generations of high torque PDMs, particularly when used with PDC bits. This inherent weakness results from the manufacturing process whereby the U-joint is "flame-cut" rather than machined.

Flex rod

Another development in connecting rod assembly technology has been the utilisation of flexible steel or titanium flex rods (Figure 2.4.26b). While, in general, flex rods are limited by the degree of allowable lateral bending, they have the advantage of low maintenance as they do not require the use of lubricants or rubber sleeves as with U-joints. Their utilisation has generally been limited to low offset steerable motors or straight motor applications. One unique approach has been to mount the flex rod inside the hollow rotor of a short, high torque steerable PDM rather than connecting it to the bottom of the rotor. By connecting a long flex rod to the inside of the top end of the rotor and extending the flex rod through the rotor to connect to the top of the drive sub assembly, the overall rate of bend of the flex rod is decreased due to its increased length.

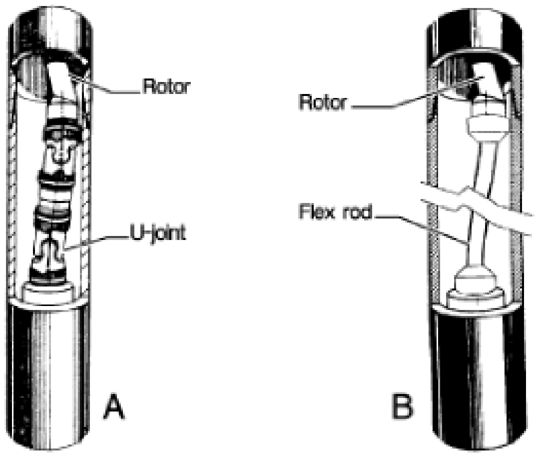


Figure 2.4.26 : Connecting rods

BEARING SECTION

A typical positive displacement motor utilises three sets of bearings attached to a drive shaft. These are two sets of radial bearings ("upper" and "lower") with one set of axial thrust bearings.

The axial thrust bearing section supports the on and off bottom loading and hydraulic thrust. It consists of a series of ball bearings stacked one on top of the other, each set being contained in its own race (or groove). The number of axial thrust bearings will vary, depending on the size of the tool.
The upper and lower radial bearings are lined with tungsten carbide inserts.
The function of these bearings is to support the concentrically rotating drive shaft against lateral loads. The inherent design of the upper radial bearing limits the amount of fluid flow diverted to the annulus to cool and lubricate the bearing package. This diversion of flow is typically 2 - 10%, depending on motor and bit pressure drop. The major portion of the drilling fluid is collected by ports in the drive shaft and exits through the bit. In some motors, diamond bearings are being used and may need up to 20% of the flow to be diverted, depending upon conditions. Figure 2.4.27 illustrates typical bearing sections found in PDMs.

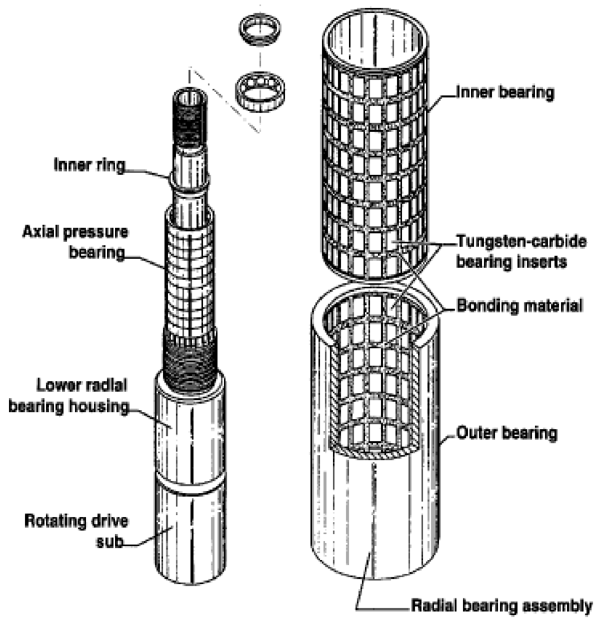


Figure 2.4.27 : Bearing sections

TYPES OF POSITIVE DISPLACEMENT MOTORS

PDMs come in various configurations. As has been mentioned previously, the stator will have one more lobe than the rotor. The first types of PDMs, and the simplest, are 1/2 motors. These generally give medium to low torque output and medium to high speed. Torque output is directly proportional to pressure drop across the motor. The 1/2 motors have good applications in performance drilling with a PDC, diamond, or TSP-type bits. Some shorter models are used for directional purposes.
The multi-lobe motors have high torque output and relatively slow speed. Therefore, they have good applications with roller cone bits and for coring. These motors are also suitable for use with PDC bits, especially the large cutter types which require a good torque output to be efficient. These tools, being fairly short, also have good directional applications with bent subs as a deflection device. These multi-lobe motors may be constructed with a hollow rotor and a nozzle or blank will be placed in a holding device at the top. The nozzle allows for high flow rates to be accommodated by by-passing the excess flow from the motor section and the fluid will exit through the bit.
Figure 2.4.28 is an illustration of a multi-lobe (5/6) positive displacement motor

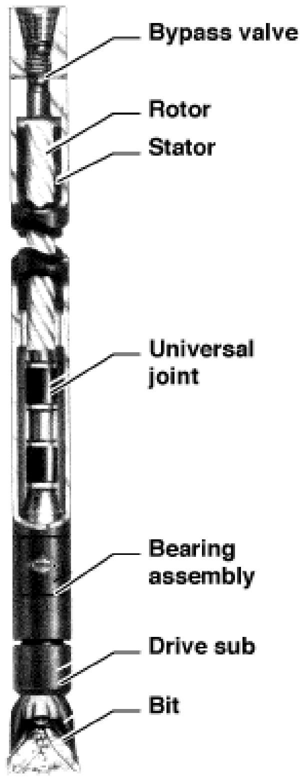


Figure 2.4.28 : Navi-Drill Mach 1C

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CHARACTERISTICS

Torque is directly proportional to the motor differential pressure. This makes the tool very simple to operate. RPM is directly proportional to flow rate,though somewhat affected by torque output.

$$\text{Hydraulic power input} = \frac{P \times Q}{60}\ \text{kW}$$

$$\text{Hydraulic power input} = \frac{P \times Q}{1,714}\ \text{HP}$$

Where :

P = the pressure drop across the motor (kPa / psi)

Q = the flow rate (m3/min / gals/min)

$$\text{Mechanical power output} = \frac{P \times Q}{5,252}\ \text{HP}$$

Where :

T = the torque (Nm / lbs-ft)

N = the bit speed (rpm)

$$\text{Efficiency} = \frac{\text{Mechanical power outpu}}{\text{Hydraulic power input}}$$

OBSERVATIONS

- Motor stall will be obvious due to an increase of surface pressure. Motor stalling is best avoided as it erodes the service life of the motor.
- LCM can be pumped safely, though care should be taken that the material is added slowly and evenly dispersed, and the system is not slugged.
- Sand content in the drilling fluid should be kept to a minimum.
- Temperature limits are around 270°F, 130°C, but higher temperature stators have been developed.
- Pressure drop through the tool while working is typically in the range of 50 - 800 psi.
- Allowable wear on bearings is of the order of 1- 8mm , depending upon tool size.
- The tool should be flushed out with water prior to laying down.
- In general, drilling fluids of a low aniline point may damage the rubber stator. As a rule, the oil in oil based muds should have an aniline point of at least 150°F (60°C). Usually, this is related to the aromatic content which should be equal to or less than 10%. Contact the local supplier if there is any doubt.
- If a by-pass nozzle is fitted to a multi-lobe rotor, then it must be sized very carefully to allow the motor section to develop the necessary power, and any variation of the flow for which the nozzle was inserted will compromise the motor's performance.

MOTOR ORIENTATION/CONTROL

All directional wells require steering during initial kick-offs, correction runs, sidetracks, and re-drills. This is discussed in Subtopics 4.6 and 4.9.

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4.5.3. TURBINES

The turbine is made up of several sections:

- The drive stages or motor section.
- The axial thrust bearing assembly and radial bearings.
- The bit drive sub.

The drive stages, or motor section, consists of a series of stators and rotors of a bladed design. One stator and one rotor together form a stage. Turbines will be referred to as 90 stage, 250 stage, etc. The number of stages will determine the torque generated. Each stage, theoretically, applies an equal amount of torque to the control shaft and it is the sum of those torques which will be output to the bit.

The drive sub is simply the bit connection and bearing shaft. The radial bearings protect the shaft from lateral loading. The thrust bearings support the downwards hydraulic thrust from drilling fluid being pumped through the tool and the upward thrust of weight being applied to the bit. Theoretically, weight on bit should be applied to equalise the hydraulic thrust and therefore unload the bearings and prolong their life.

DRIVE SECTION

This consists of a series of bladed stators, fixed to the outer tool housing and bladed rotors fixed to the central rotating shaft. Drilling fluid flow is deflected at a pre-determined angle off the stator blades to hit the rotor blades and cause the shaft to rotate. The angle of the blades will affect the torque and speed output of the turbine. (Figure 2.4.29)

BEARING SECTION

Usually, thrust bearings are made up of rubber discs (Figure 2.4.29) which are non-rotating, being fixed to the outer housing of the tool, and rotating steel discs attached to the central rotating shaft. Long bearing sections known as cartridges are used for long life in tangent or straight hole drilling sections. These are changeable on the rig. If the bearings wear past the maximum point, considerable damage can be inflicted as the steel rotors will crash into the stators below.

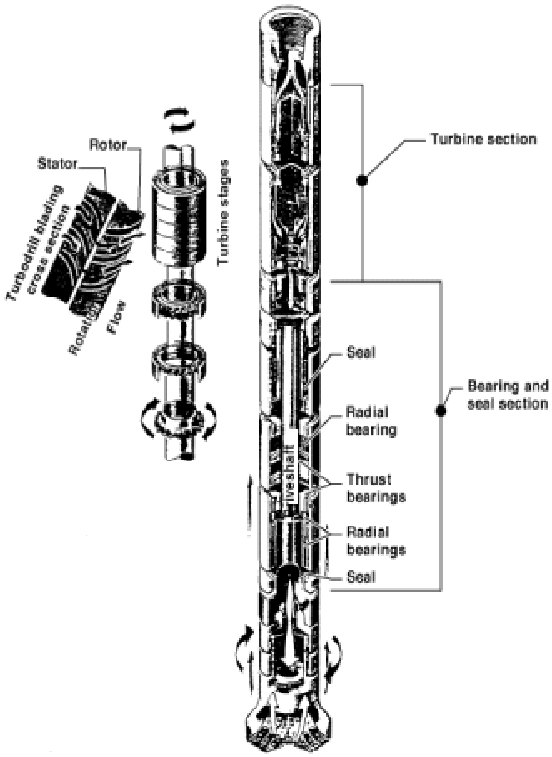


Figure 2.4.29 : Turbine details

DIRECTIONAL TURBINE

This is a short tool which has a set number of stages and its bearing section entirely within one housing. That is, it is not a sectional tool and will be typically less than 30 ft (9 m) long. It is designed for short runs to kick off or correct a directional well, using a bent sub as the deflection device. Steerable turbodrills do exist and will be discussed later.

CHARACTERISTICS

- Torque and RPM are inversely proportional (i.e., as RPM increases, torque decreases and vice versa).
- RPM is directly proportional to flow rate (at a constant torque).
- Torque is a function of flow rate, drilling fluid density, blade angle and the number of stages, and is affected by varying weight on bit.
- Optimum power output takes place when thrust bearings are balanced.
- Changing the flow rate causes the characteristic curve to shift.
- Off bottom, the turbine RPM will reach "runaway speed" and torque is zero.
- Optimum performance is at half the stall torque and at half the runaway speed, the turbine then achieves maximum horsepower.
- A stabilised turbine used in tangent sections will normally cause the hole to "walk" to the left.

OBSERVATIONS

- There is minimal surface indication of a turbine stalling.
- Turbines do not readily allow the pumping of LCM.
- Sand content of the drilling fluid should be kept to a minimum.
- Due to minimal rubber components, the turbine is able to operate in high temperature wells.
- Pressure drop through the tool is typically high and can be anything from 500 psi to over 2,000 psi.
- Turbines do not require a by-pass valve.
- Usually, the maximum allowable bearing wear is of the order of 4 mm

DEFLECTION TOOLS AND TECHNIQUES

4.6.1. WHIPSTOCKS

The whipstock was the main deflection tool from 1930-1950. The standard whipstock is seldom used nowadays, but it has not disappeared completely. Whipstocks are also used in coiled tubing drilling for re-entry work. There are three types of whipstock used in conventional directional drilling:

STANDARD REMOVABLE WHIPSTOCK

The standard removable whipstock is used mainly to kick off wells, but is also used for sidetracking. It consists of a long inverted steel wedge which is concave on one side to hold and guide a whipstock drilling assembly. It is also provided with a chisel point at the bottom to prevent the tool from turning, and a heavy collar at the top to withdraw the tool from the hole. This whipstock is used with a drilling assembly consisting of a bit, a spiral stabiliser, and an orientation sub, rigidly attached to the whipstock by means of a shear pin. The whipstock assembly is lowered to the bottom of the hole and orientated. Weight is applied to set the whipstock and shear the pin. The bit is then drilled down and forced to deflect to one side by the whipstock. A 12 to 16 foot (4-5 m) "rat hole" is drilled below the toe of the whipstock. The assembly is then pulled out of hole, taking the whipstock with it. A hole opener run is made to open the rat hole out to full gauge. The hole opener assembly is then tripped out and a rapid angle build assembly run in hole to "follow up" the initial deflection. This whole procedure may have to be repeated several times in the kick-off.

It is obvious that the major disadvantage of the standard whipstock is the number of "trips" involved which uses a lot of rig time. The other important disadvantage is that the whipstock produces a sudden, sharp deflection - in other words, a severe dogleg - which may give rise to subsequent problems with the hole. The advantages are that it is a fairly simple piece of equipment which requires relatively little maintenance and has no temperature limitations.

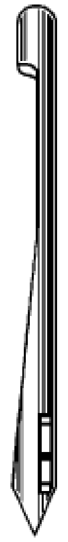


Figure 2.4.30 : The standard removable whipstock

CIRCULATING WHIPSTOCK

The "circulating whipstock" is run, set and drilled like the standard whipstock. However, in this case the drilling fluid initially flows through a passage to the bottom of the whipstock which permits more efficient cleaning of the bottom of the hole and ensures a clean seat for the tool. It is most efficient for washing out bottom hole fills.

PERMANENT CASING WHIPSTOCK

The "permanent casing whipstock" (Figure 2.4.31) is designed to remain permanently in the well. It is used where a "window" is to be cut in casing for a sidetrack. The casing whipstock is set using a permanent packer. The special stinger at the base of the whipstock slips into the packer assembly. A stainless steel key within the packer locks the whipstock's anchor-seal and prohibits any circular movement of the whipstock during drilling.
The normal procedure is to orientate the packer system and then set the packer. After this, the starting mill is pinned to the casing whipstock and the whole assembly run slowly in hole and seated in the packer.
Although the packer has already been orientated, it is good practice to orientate the casing whipstock in the same manner as the packer. This should ensure that a faster "latch up" will take place without endangering the shear pin.
After the whipstock has been "seated" in the packer, the pin is sheared and circulation and rotation begun. The starting mill is used to make an initial cut through the casing and mill approximately 2 ft (50-60 cm) of casing. The lug that held the starting mill to the whipstock must also be milled off.
This assembly is tripped out and the mill changed. A tungsten carbide or diamond speed mill is used to cut the rest of the window. Once the window has been cut, approximately 5 ft (150-160 cm) of formation is cut before pulling out of hole. Next, a taper mill is run with a watermelon mill immediately above it. This is done to "clean" the top and the bottom of the window. Finally, another trip is made to change over to the drilling assembly which is used to drill ahead.
The advantage of using a casing whipstock, instead of the normal method of milling a section and side tracking, is that the operation usually takes less time. The main disadvantage is that it gives a sharp dogleg, and so the casing whipstock is not recommended if there is a considerable distance to drill below the sidetrack, so that several trips in and out through the window may be required. This is because problems can occur when trying to pull stabilisers, etc. back into the casing through the window. On the other hand, if there is only a short distance to be drilled below the sidetrack point, then the casing whipstock is well worth considering.
In recent years, improvements in the design of casing whipstock systems have eliminated the need for so many trips in and out of hole.

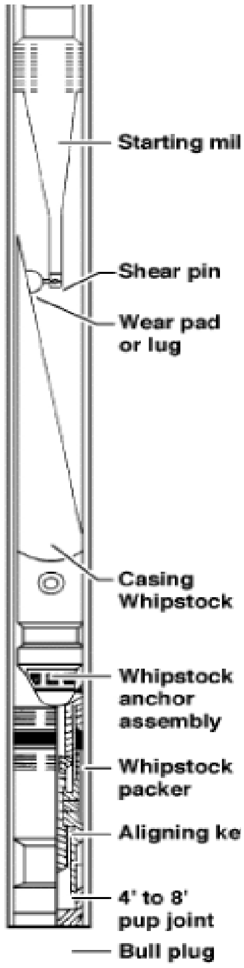


Figure 2.4.31 : The permanent casing whipstock

4.6.2. JETTING

Jetting (or badgering) is a technique used to deviate wellbores in soft formation. The technique was developed in the mid 1950s and superseded the use of whipstocks as the primary deflection technique.
Although jetting has subsequently been supplanted by downhole motor deflection assemblies (as the primary deflection method) it is still used frequently and offers several advantages which make it the preferred method in some situations.
A special jet bit (like the one shown above) may be used, but it is also common practice to use a standard soft formation tricone bit, with one very large nozzle and two small nozzles.

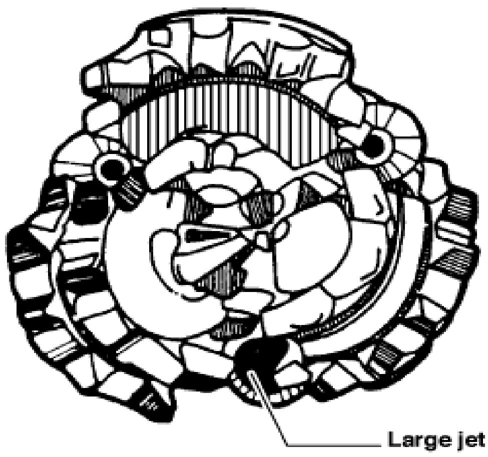


Figure 2.4.32 : A jetting bit

REQUIREMENTS FOR JETTING

- The formations must be soft enough to be eroded by the drilling fluid emerging from the large jet nozzle. As a rough rule of thumb, if formations cannot be drilled at penetration rates of greater than 80 ft/hr using normal drilling parameters, they are not suitable for jetting. Jetting is most effective in soft, sandy formations, and of course effectiveness is reduced as depth increases, since the formations become more compacted. In the Gulf of Mexico, the maximum depth for effective jetting is approximately 2500 feet.
- Adequate rig hydraulic horsepower must be available. For jetting to be successful there must be adequate hydraulic energy available at the bit to erode the formation. A rule of thumb for jetting is that drilling fluid velocity through the large jet should be 500 ft/sec or greater.

JETTING ASSEMBLIES

A typical jetting assembly used to drill a 121/4" pilot hole is:
121/4" jet bit
extension sub
121/4" stab
UBHO sub
3 x 8" DC
121/4" stab
DC
HWDP as required.
This is essentially a strong angle build rotary assembly (see Topic 4.8) with a suitable bit for jetting. The upper stabiliser is optional and is often omitted.

NOZZLING THE BIT

There are three alternatives:
a) Use a specialised jet bit with a large extended nozzle in place of one of the cones.
b) Fit one large and two small nozzles in a conventional tri-cone bit.
c) Blank off one nozzle of a conventional bit to divert the flow through the other two.
Flow through two jets may be desirable in large hole sizes (e.g. 171/2") because of the large washout required to deflect the bit and near bit stabiliser. Both (a) and (b) work well in most hole sizes which are commonly jet drilled. (b) is the most common option because it uses standard bits and nozzles and results in a bit dressed in such a way as to be suitable for both jetting and drilling.
A 121/4" bit dressed for jetting would typically have the main nozzle size 26/32" or 28/32" and the other two nozzles 10/32" or 8/32".

. PROCEDURE FOR JETTING

1. The assembly is run to bottom, a survey is taken and the large jet nozzle (the "toolface") is orientated in the required direction.
2. Maximum circulation is established (e.g. 800 gpm [3,000 l/min] in 121/4" hole) and a controlled washing away of the formation opposite the large jet is effected, with the kelly in the rotary table and the table locked.
3. The drill string may be spudded up and down periodically, but not rotated, until several feet of hole have been made and the bit and near bit stabiliser have been forced into the washed out pocket. The technique is to lift the string 5 to 10 feet (2-3 m) off bottom and then let it fall, catching it with the brake so that the stretch of the string causes it to spud on bottom rather than using the full weight of the string. Another technique which may improve the effectiveness of jetting involves turning the rotary table a few degrees (15°) right and left while jetting.
4. Having jetted 3 to 8 feet (1-3 m) of hole, the exact distance depending on required build rate and previous results, drilling is begun. The circulation rate is now reduced to about 50% of that used for jetting. Hole

cleaning considerations are ignored while drilling the next 10 feet (3 m) or so. High weight on bit (40-45 Klb / 18-22 tons) and low rotary speed (60-70 RPM) should be used to bend the assembly and force it to follow through the trend established while jetting. Progress may be difficult at first because of interference between the stabiliser and the irregularly shaped jetted hole.

5. After approximately 10 feet (3 m) of hole has been drilled, the pump rate can be increased to perhaps 60% - 70% of the rate originally used while jetting. High WOB and low RPM should be maintained. The hole is drilled down to the next survey point.

6. A survey is taken to evaluate progress. If the dogleg is too severe the section should be reamed and another survey taken.

7. At the start of a kick-off, jetting is repeated every single until about 3° of angle has been built. After that, it is normal to jet every "double". After drilling each section, the jet nozzle has to be re-orientated to the desired tool face setting before jetting again. The operation is repeated until sufficient angle has been built and the well is heading in the desired direction.

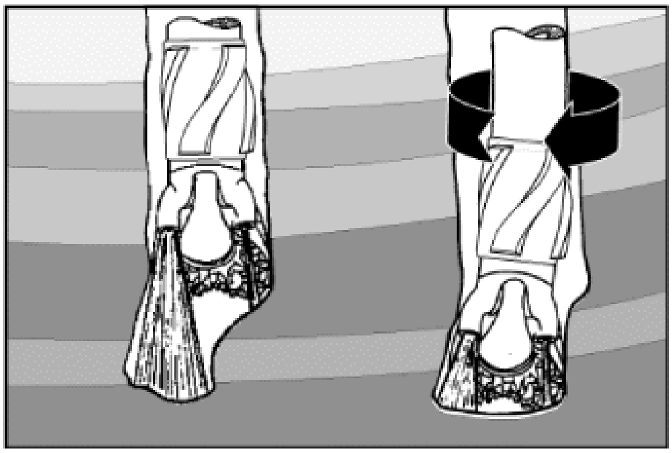


Figure 2.4.33 : Jetting

The principle is that, during the initial spudding and washing process, a pocket is produced in the formation opposite the jet nozzle. When high WOB is then applied and the drill string rotated, the bit and near bit stabiliser work their way into the pocket (the path of least resistance). The collars above the near-bit stabiliser bend and contact the low side of the hole. This causes a bending moment about the near-bit stabiliser which acts as a pivot or fulcrum, and the bit is pushed harder into the pocket (i.e. the direction in which the large jet nozzle was originally orientated)

ADVANTAGES OF THE JETTING TECHNIQUE

- It is a simple and cheap method of deflecting well bores in soft formations. No special equipment is needed except, perhaps, a jet bit.
- The dogleg severity can be partly controlled from surface by varying the number of feet "jetted" each time.
- The survey tool is not far behind the bit, so survey depths are not much less than the corresponding bit depths.
- Orientation of tool face is fairly easy.
- The same assembly can be used for normal rotary drilling as an angle build assembly.

DISADVANTAGES OF THE JETTING TECHNIQUE

- The technique only works in soft formation and so usually only at shallow depths. For this reason, jetting is mainly used to kick wells off at shallow depths.
- In jetting, high dogleg severities are often produced. Deviation is produced in a series of sudden changes, rather than a smooth continuous change. For this reason, it is normal practice to jet drill an undergauge hole and then open it out to full gauge, which smooths off the worst of the doglegs.

4.6.3. DOWNHOLE MOTOR AND BENT SUB

A common method of deflecting wellbores is to use a downhole motor and a bent sub. As illustrated in Figure 2.4.34, the bent sub is placed directly above the motor and it is the bent sub which makes this a deflection assembly. Its lower thread (on the pin) is inclined 1°- 3° from the axis of the sub body.
The bent sub acts as the pivot of a lever and the bit is pushed sideways as well as downwards. This sideways component of force at the bit gives the motor a tendency to drill a curved path, provided there is no rotation of the drill string. The degree of curvature (dogleg severity) depends on the bent sub angle and the OD of the motor, bent sub and drill collars in relation to the diameter of the hole. It also depends on the length of the motor.
A downhole motor and bent sub assembly may be used for kicking off wells, for correction runs or for sidetracking.
Notice the absence of any stabilisers in the lower part of this assembly.
Usually there would be no stabilisers for at least 90 feet (30 m) above the bent sub. In fact, it is not uncommon for the entire BHA to be "slick" when a motor and bent sub is used for kicking off at shallow depths.

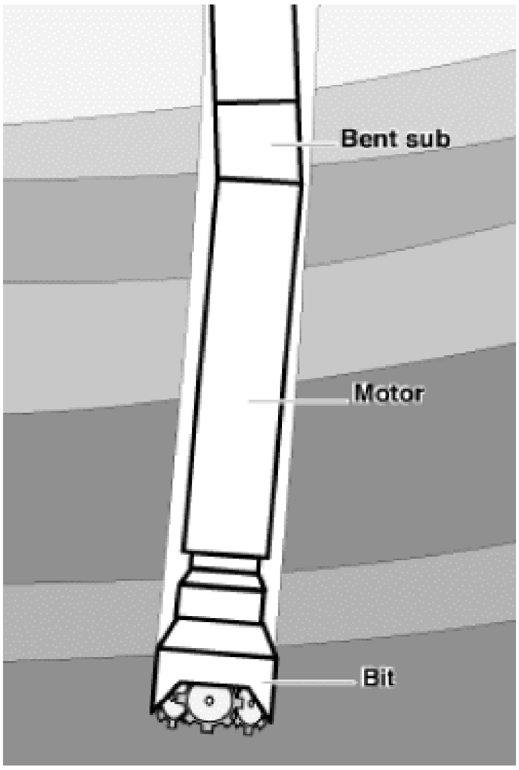


Figure 2.4.34 : Downhole motor and bent subassembly

RUNNING PROCEDURES

The motor is first inspected and then tested using standard procedures.
Before drilling can begin with a motor and bent sub assembly, the bent sub (toolface) must be orientated in the desired direction.

- The pipe is worked until string torque is eliminated. Best results are obtained by using a moderately fast up and down pipe movement. It is recommended that the bit be kept a minimum of 5 feet from the bottom of the hole.
- Make a reference mark on the kelly bushings, lock the rotary table and take a survey to determine tool face orientation.
- Turn the pipe to achieve the desired tool face orientation. This orientation should include an allowance for the anticipated left-hand reactive torque.
- When orienting, turn the pipe to the right unless the turn is less than 90° left of the present setting. Work the string up and down so that the turn reaches the bottomhole assembly.
- Lock the rotary table before beginning to drill.

REACTIVE TORQUE

Reactive torque is created by the drilling fluid pushing against the stator. The stator is locked to the body of the motor, so the effect of this force is to twist the motor and, hence, the whole BHA anti-clockwise. As the weight-on-bit is increased, the drilling torque created by the motor increases. The reactive torque increases in direct proportion. Thus a reasonable, although simplistic, way to view this is that the clockwise drilling torque generated at the bit is the "action" and the counter-clockwise torque on the motor housing is the "reaction". The reactive torque at the motor is equal to the drilling torque.

Reactive torque causes a problem for directional drillers when they are using a motor and bent sub to deflect the well-bore. The twisting of the BHA caused by reactive torque changes the facing of the bent sub (i.e. the tool face orientation). If they are obtaining tool face orientation from single shot surveys, the directional driller has to estimate how much turn to the left they will get due to reactive torque. He initially sets the tool face that number of degrees round to the right of the desired tool face, so that the reactive torque will bring it back to the setting required while drilling.

Drill string design will affect the extent of "drill string twist." This concept is important to understand because it can directly affect the tool face orientation of the downhole motor. This twisting of the drill string becomes more critical at greater depths, especially when using smaller OD drillpipe in a high torque environment.

When drilling is in progress, every endeavour must be made to keep the drilling parameters constant and, hence, obtain constant reactive torque and a steady tool face setting. Reactive torque occurs with both types of downhole motors. Obviously, high torque motors produce higher reactive torque.

Factors affecting reactive torque

The reactive torque which the motor generates will be in direct proportion to the differential pressure across the motor. This in turn is influenced by:

- Motor characteristics
- Bit characteristics
- Formation drillability
- Weight on bit

The estimation of reactive torque has always been a problem for the directional driller. Several charts and rules of thumb have evolved to give a first estimate in the absence of data . One such rule is that the reactive torque will produce a rotation of the order of 10-20° / 1000 feet measured depth (30-60°/1,000 m). The lower end of the range may be used for low torque motors and the higher end for high torque motors.

The use of MWD

The problem of reactive torque disappears if MWD tools are used because the orientation of the BHA can be measured, with a surface read-out, under drilling conditions (see Topic 4.6).

POSITIVE DISPLACEMENT MOTORS VERSUS TURBINES FOR USE WITH A BENT SUB

For directional work with a bent sub, Positive Displacement Motors offer several advantages over turbines. When drilling with a PDM, the directional driller can use the pump pressure gauge as a weight indicator. If the pump pressure is constant, the differential pressure across the PDM is constant, so the torque and WOB are constant. It is also much easier to tell if a PDM has stalled because there will be an immediate large increase in surface pressure. PDMs give a longer bit life than turbines because of the slower rotational speed. They can tolerate LCM whereas turbines cannot (or only a very limited amount). Finally, instead of using a bent sub, a PDM with a small bend at the U-joint housing can be used. As this bend is nearer to the bit, a smaller angle of bend will have the same effect as a larger bent sub angle. This reduces the problem of the bit riding the side of the hole while tripping in and out.

A major advantage of turbines is that they can operate at higher temperatures than PDMs.

ADVANTAGES OF A DOWNHOLE MOTOR AND BENT SUB AS A DEFLECTION TOOL

- It drills a smooth, continuous curve.
- Dogleg severity is more predictable than with other deflection tools.
- It can be used in most formations.
- As there is no rotation from surface, it is possible to use a wireline "steering tool" for surveying and orientation while drilling. Alternatively, a Measurement While Drilling system can be utilised, which would be the normal choice nowadays.

DISADVANTAGES OF DOWNHOLE MOTOR AND BENT SUB AS A DEFLECTION TOOL

- Reactive torque changes the tool face when drilling commences. It may also be difficult to keep a steady tool face because the assemblies used are often "slick" (no stabilisers) - stabilisers have an "anchoring" tendency..
- The motors themselves are expensive and require maintenance. Of course, this is more than offset by the savings due to good hole condition and the greater degree of control which motors give.

POSITIVE DISPLACEMENT MOTORS WITH KICK-OFF SUBS (BENT HOUSING)

An alternative to using a bent sub is to use a PDM with a single bend in the universal joint housing, described either as a kick-off sub or a bent housing by different manufacturers. Historically, these "single tilt" motors were used for difficult deviation jobs such as sidetracking over a short section of hole into hard formation. Since the bend is closer to the bit than when a bent sub is used, a smaller tilt angle can be used while still giving a strong deviation tendency.

A further development of the single tilt motor was the double tilt motor in which there are two bends in the housing (in the same plane). The effect of this is to tilt the axis of rotation of the lower section with the bit, but keep the bit closer to the axis of the hole.

Both single and double tilt motors have been used as steerable motors. If the drill string is rotated so that the body of the motor rotates, then a fairly straight path is drilled, whereas if the tilt (tool face) is orientated in a desired direction and there is no drill string rotation, then the motor will drill a controlled curve. This subject is more fully discussed in Topic 4.9.

After having been tried, double tilt motors are being phased out again in favour of the single tilt versions as they slide better and give better control of the desired inclination change.

TURBINESS WITH A BENT HOUSING

Currently some operators are using a steerable turbine design which incorporates a bent housing close to the bit. It has been demonstrated that they can sustain a dog-leg capability of up to 8°/100 ft. Incorporation of a stalling pressure has also been achieved with these new designs.

TOOL FACE ORIENTATIONS

4.7.1 INTRODUCTION

The "Toolface" of a deflection tool or steerable motor system, is the part which is oriented in a particular direction to make a desired deflection of the wellbore. There are two basic ways of expressing toolface orientation:

- Magnetic or Gyro Toolface: this is the toolface orientation measured as a direction on the horizontal plane. If measured by a "magnetic" type survey tool, this is called a magnetic toolface; whereas if it is measured by a gyroscopic survey device, it is called a gyro toolface. Toolface orientation is only measured and expressed in this way at low inclinations, say less than 5° typically.
- High Side Toolface: this is the toolface orientation measured from the high side of the hole in a plane perpendicular to the axis of the hole.

It must also be pointed out that the term toolface is commonly used by directional drillers and surveyors as a shortened version of "toolface orientation".

A magnetic or gyro toolface reading can be converted to a high side toolface reading using the formula:

High side toolface = mag/gyro toolface - hole azimuth

(A negative answer means the angle is measured anti-clockwise or left of high side). The above formula is based on the fact that the high side direction is the azimuth of the borehole.

In the remainder of this Topic, methods for selecting the required toolface orientation are discussed. These methods are also used to predict the changes in inclination and azimuth which result from drilling ahead with that toolface setting.

4.7.2 DEVIATED-WELL GEOMETRY

Before discussing the orientation of deviation tools further it is important that you can visualise the significance of the values of azimuth and inclination in deviated wells. This is shown in Figure 2.4.35.
The inclination at any survey point, S, is the angle I between the tangent to the well bore and the vertical.

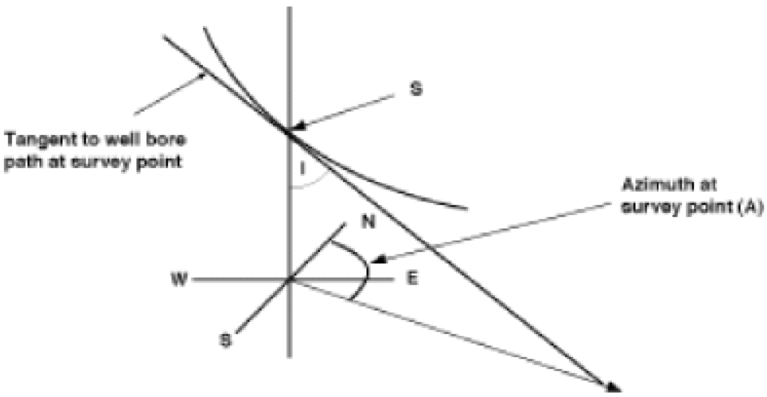


Figure 2.4.35 : Deviated well geometry

By projecting this tangent on to a horizontal plane (as shown in the figure), the azimuth (A) can be measured relative to north (true, magnetic or grid).
In practice, changes in inclination and azimuth usually occur simultaneously and it is necessary to consider the situation in three dimensions in order to define the change in course of the well between two survey points S_1 and S_2.
If the inclination and azimuth at each survey point are known, vector diagrams can be constructed enabling:

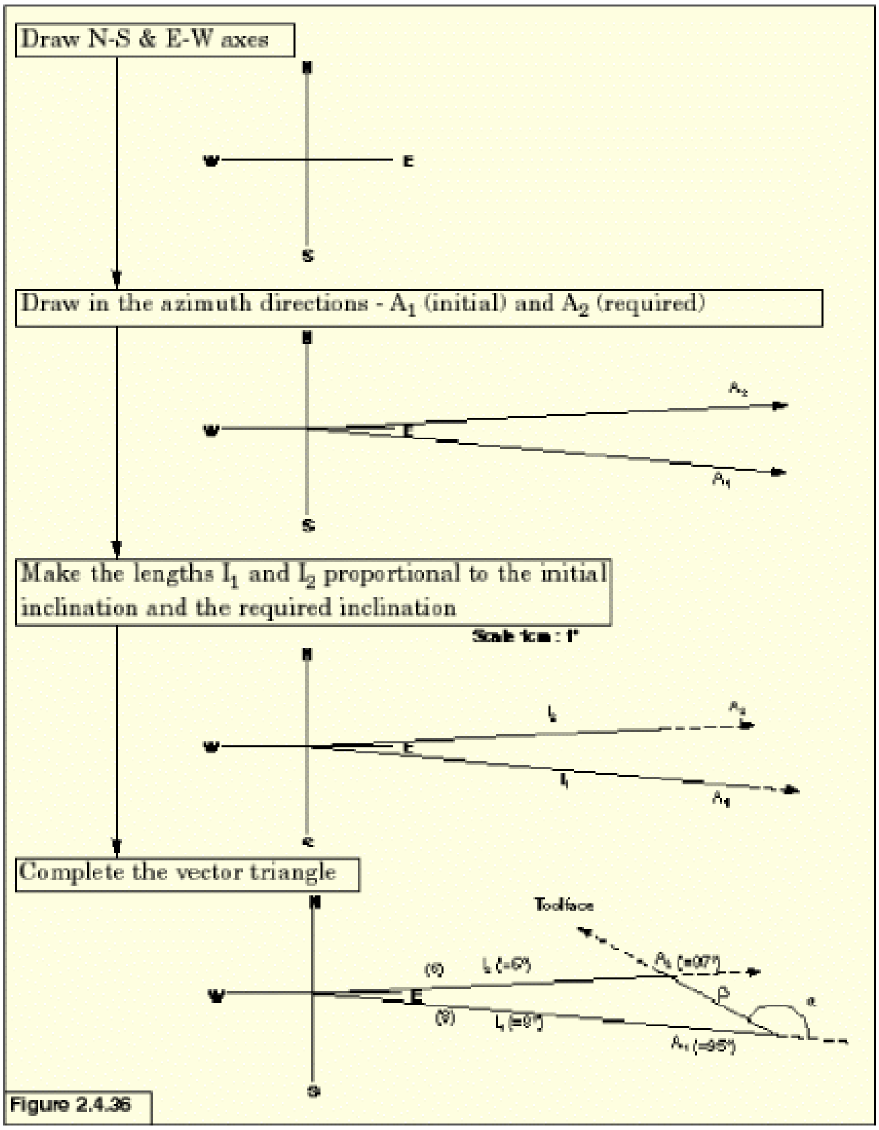
- the position of S_2 to be calculated relative to S_1.
- the actual angular change in the path of the well to be calculated, i.e. the value of the dogleg.

In practice this may be done using a computer program based on sine and cosine rules or by constructing vector triangles.

4.7.3. CONSTRUCTING VECTOR TRIANGLES

Vector triangles may be constructed as shown below.
A change in downhole orientation is achieved between survey point S_1 and survey point S_2 according to the following data:

Survey point S_1 = 1026 m (3365 ft.) AH
Inclination I_1 = 8°
Azimuth A_1 = 95° Mag.
Survey point S_2 = 1056 m (3466 ft.) AH
Inclination I_2 = 6°
Azimuth A_2 = 87°Mag.
Find the dogleg between the survey points, and the tool-setting angle employed.
Construct the vector triangles as follows:



Measure these angles with a protractor and ruler. You may then confirm them using a computer. You should have found that the tool-setting angle was 158° (α) and the dogleg was 2.1° (ß).
We will now move on to look at the ways in which these vector triangles may be practically applied.

4.7.4 SETTING THE TOOL

Tool Setting for Inclination Change only

To change inclination while maintaining a constant azimuth, the tool must be set at 0° or 180°. Setting the tool at 0° increases the inclination; setting it at 180° decreases the inclination. This is shown in the following example.
Given the following data:

Existing inclination I_1 = 12°
Existing azimuth A_1 = 93°
Tool dogleg potential = 3°/100 ft

What will be the effect over an interval of 100 ft of:

1. Setting the tool at 0°
2. Setting the tool at 180°

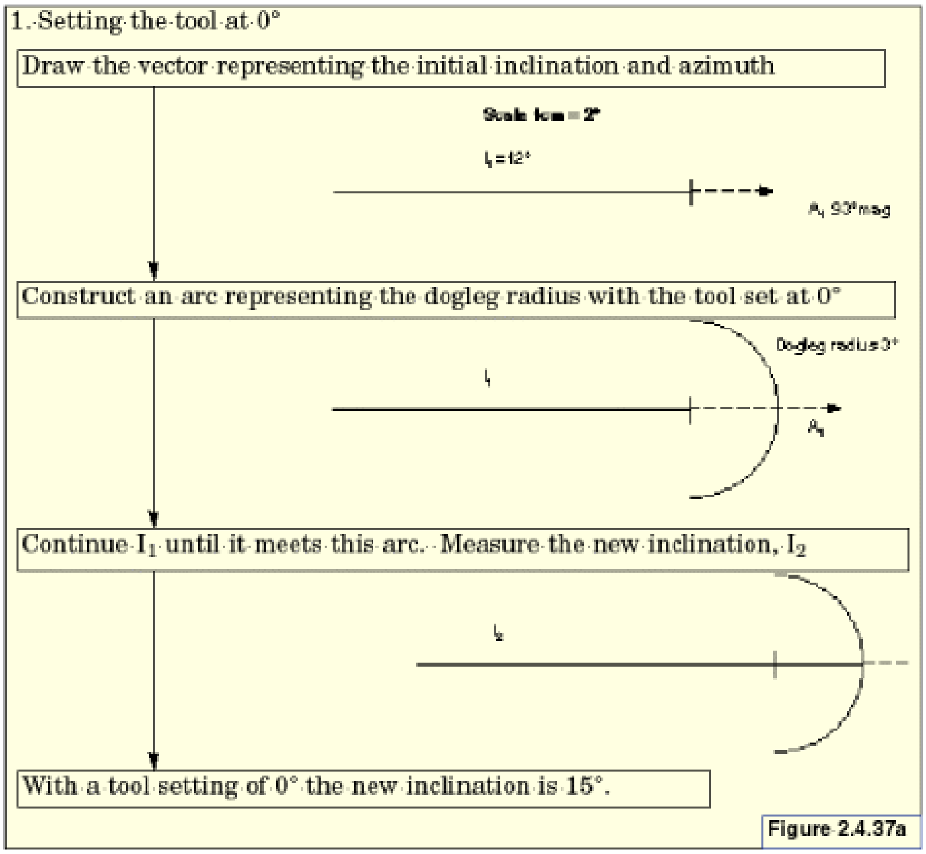


Figure 2.4.37a

Tool Setting for Azimuth Change only

If the inclination of the well is to be kept constant, the vector diagram is an isosceles triangle.

To maintain a constant inclination with a tool of given dogleg potential the resultant azimuth change can be determined as shown in the example overleaf. You should note that there is only one tool-setting angle possible when a change in azimuth is required.

You are given the following data:

Existing inclination I_1 = 8°

Required inclination I_2 = 8°

Existing azimuth A_1 = 117° Mag

Tool dogleg potential = 3.5°/100 ft

Assuming that a left-hand change in azimuth is required over a 100 ft interval, what will be the new azimuth of the bore-hole (A_2) ? Estimate the tool setting required.

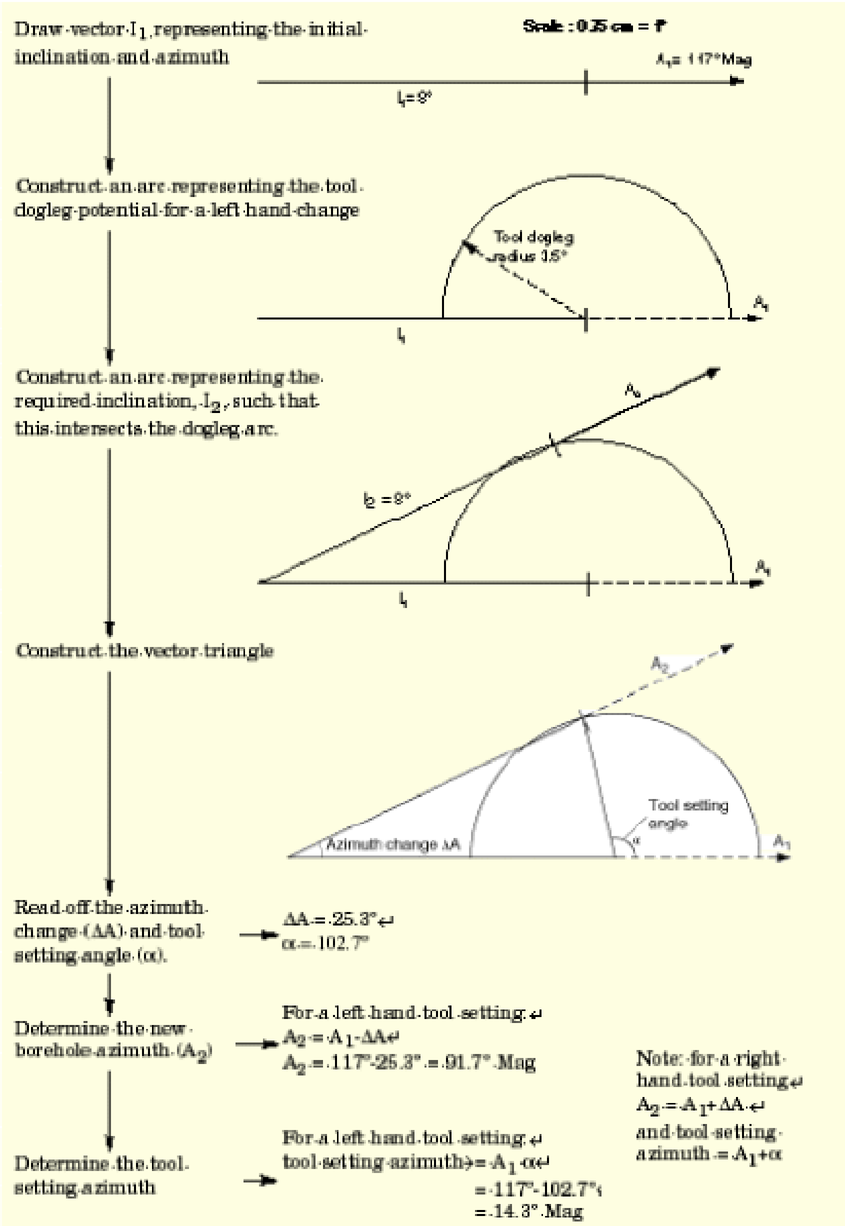


Figure 2.4.38

The new bore-hole azimuth is thus 91.7° Mag. This is achieved with a tool setting angle of 102.7° left hand side (azimuth = 14.3° Mag).

You require an azimuth change of 20.16° (left) over an interval of 100 ft). What tool-setting angle would be required to achieve this change given the following data?

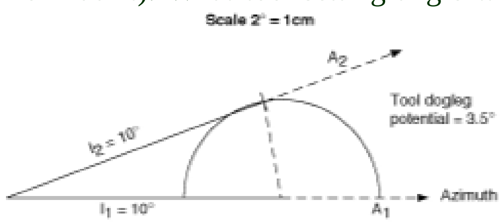


Figure 2.4.39

Required inclination = 10°

Existing inclination = 10°

Existing azimuth = 198° Mag

Tool dogleg potential = 3.5°/100 ft

Your vector diagram should have looked like Figure 2.4.39.

From your computer program or the vector diagram you should have the following results:

Tool-setting angle = 100.1°

Tool-setting azimuth = 198° - 100.1°

= 97.9° Mag

Note that 20.16° is the maximum azimuth change possible without changing the inclination.

Tool Setting for Combined Inclination and Azimuth Change

Tools may be set for combined inclination and azimuth change. A variety of combinations of azimuth and inclination change is possible depending on the tool-setting angle.

When setting tools for combined inclination and azimuth change there are always two possible tool settings. The setting you choose depends on the required inclination. However, as you increase the azimuthal change, the capacity to change the inclination is reduced (See below).

Consider the following worked example which is illustrated in Figure 2.4.40 below.

You want to change the azimuth of the well over an interval of 100 ft in accordance with the data below:

Existing inclination = 17°

Existing azimuth = 93° Mag

Tool dogleg potential = 3.5°/100 ft

Azimuth change (ΛA) = 10.5° right

What tool setting is required and what will be the new inclination

The new bore-hole azimuth is thus 91.7° Mag. This is achieved with a tool setting angle of 102.7° left hand side (azimuth = 14.3° Mag).

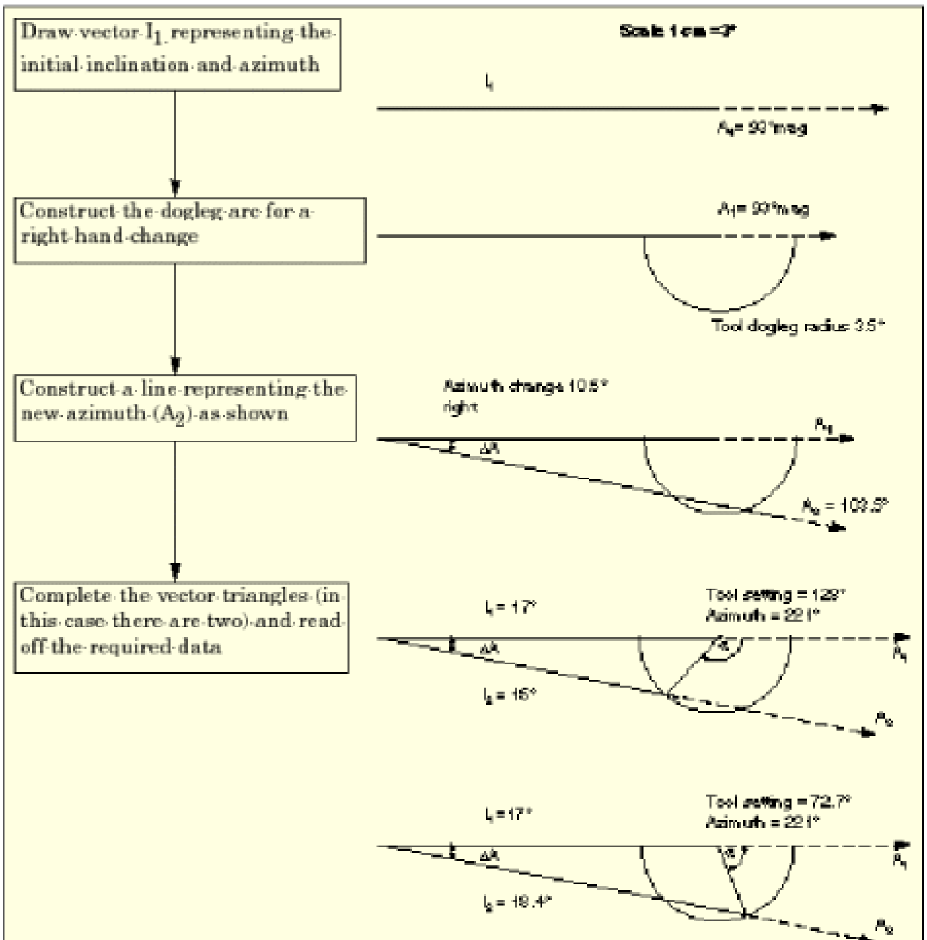


Figure 2.4.40

Tool Setting for Maximum Azimuth Change

To find the tool setting for maximum azimuth change the line representing the new inclination and azimuth is constructed tangentially to the dogleg arc as illustrated in Figure 2.4.41.

A deviation tool is commonly run in order to achieve the maximum possible azimuth correction. In these circumstances a small decrease in inclination may be expected. However, this effect is only significant at low angles of inclination.

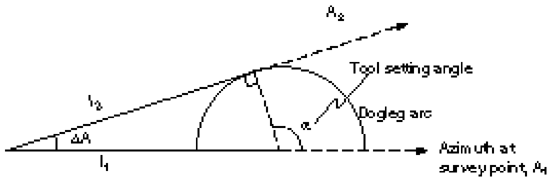


Figure 2.4.41

Effect of Inclination on Potential Azimuth Change

For a given dogleg potential the maximum azimuth change rapidly decreases as inclination increases. The effect of inclination on azimuth change for a dogleg angle of 3° is illustrated in the table below and in Figure 2.4.42.

Inclination	Azimuth change
5°	$\arcsin\left\{\frac{3}{5}\right\} = 36.9°$
10°	$\arcsin\left\{\frac{3}{10}\right\} = 17.5°$
15°	$\arcsin\left\{\frac{3}{15}\right\} = 11.5°$

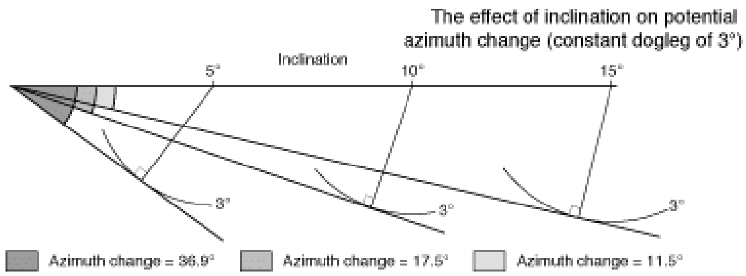


Figure 2.4.42

Over a wide range of inclination its effect on potential azimuth change is more conveniently shown on a graph - see Figure 2.4.43, also for a dogleg angle of 3°.

You can see that there is a big advantage in maintaining a low angle of inclination. It allows greater azimuthal changes in course direction to be made for a given tool dogleg potential. However you should remember that inclination angles below 15° also allow the bore hole to "wander" more easily.

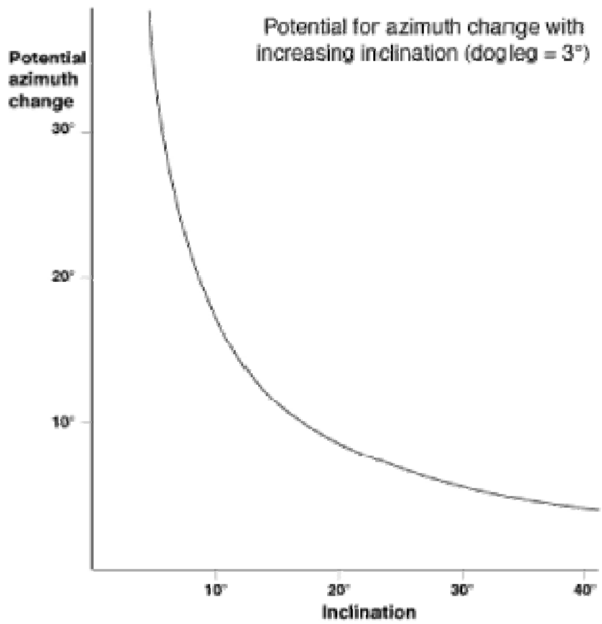


Figure 2.4.43

DIRECTIONAL CONTROL WITH ROTARY SYSTEMS

4.8.1. INTRODUCTION

Another important aspect of a directional driller's job is to design rotary BHAs which will drill the planned trajectory. In this section we shall concentrate on the basic principles used in directional control when drilling with rotary assemblies, and the typical assemblies used for each section. The effect of drilling parameters such as weight-on-bit will be considered as will the effect of formation anisotropy.

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-stabilised assemblies to reduce this tendency. Until the eighties it was standard practice to give wells a lead angle to the left of the required azimuth to compensate for this right hand walk.

4.8.2. SIDE FORCE AND TILT ANGLE

Directional trends are accepted to be related to the direction of the resultant force at the bit. It has also been shown that the bit tilt angle (i.e. 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 stabiliser, the bit tilt angle is small and the magnitude of the side force at the bit is the key factor.

Factors which affect the directional behaviour of rotary assemblies are:

- Gauge and placement of stabilisers.
- Diameter and length of drill collars.
- Weight-on-bit.
- Rotary speed.
- Bit type.
- Formation anisotropy and dip angle of the bedding planes.
- Formation hardness.
- Flow rate
- Rate of penetration.

Of course, some of the above factors are interrelated.

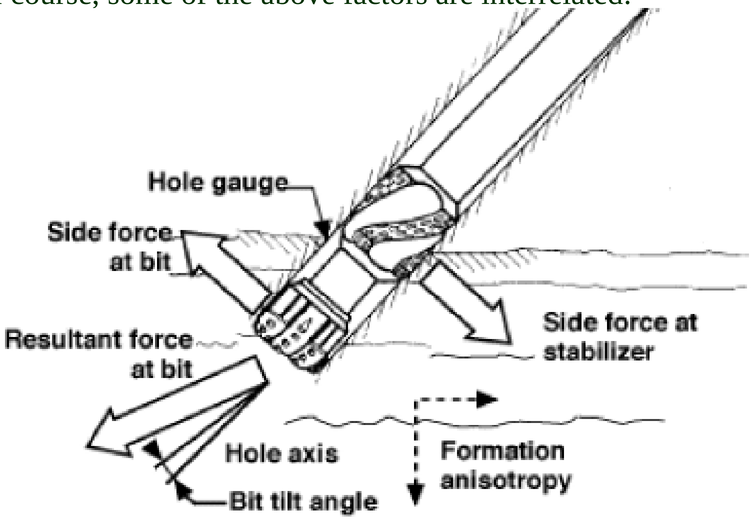


Figure 2.4.44 : Bit forces and tilt angle

4.8.3. BASIC DIRECTIONAL CONTROL PRINCIPLES

- The Fulcrum Principle is used to build angle (i.e. increase borehole inclination)
- The Stabilisation Principle is used to hold (maintain) angle and direction.
- The Pendulum Principle is used to reduce the inclination (or to prevent a vertical well from deviating).

We shall now consider each of these principles in turn and look at typical assemblies which are used.

FOUR TYPICAL BUILD ASSEMBLIES

(For clarity only one set of units is shown - in this case oilfield units) :
Figure 2.4.46 shows a 90' Build Assembly:
17 1/2" bit / 17 1/2" NB stab / 3 x 9 1/2" x 30' DCs / 17 1/2" stab / 9 1/2" x 30' DCs as needed/ etc. This assembly will build angle rapidly, typically at 2.0° - 3.5°/100', depending on the inclination and the drilling parameters.
Figure 2.4.47. shows a 60' Build Assembly
17 1/2" bit / 17 1/2" NB stab / 2 x 9 1/2" x 30'DCs / 17 1/2" stab / 9 1/2" x 30' DCs as needed / etc. This assembly will build angle at the rate of 1.5° - 2.5°/100', depending on the inclination and the drilling parameters.

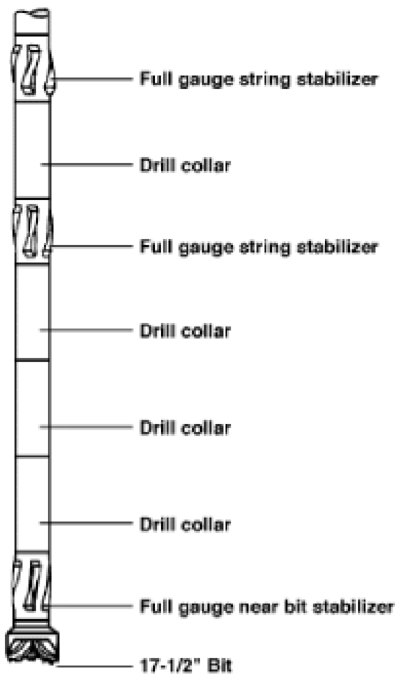


Figure2.4.46
Rapid angle build assembly - 17 1/2"

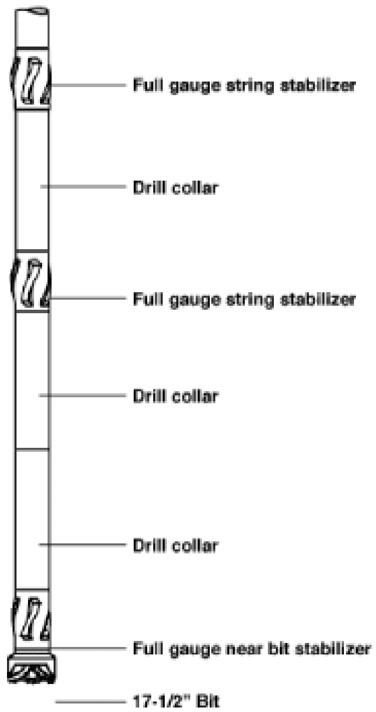


Figure2.4.47
Medium angle build assembly - 17 1/2"

Figure 2.4.48 shows a Gradual Angle Build Assembly
17 1/2" bit / 17 1/2" NB stab / 9 1/2" x 12' DC / 9 1/2" x 30' DC / 17 1/2" stab / 9 1/2" x 30'DCs as needed / etc. This assembly will build typically at 0.5° - 1.5°/100', depending on the inclination and the drilling parameters.
Figure 2.4.49 shows a Gradual Angle Build Assembly
12 1/4" bit / 12 1/4" NB stab / 8" x 30' DC / 12 1/4" stab / 8" x 30' DCs as needed / etc. This assembly would be used in the tangent section when it is necessary to build angle gradually. It would build typically at 0.5° - 1.0°/100'.

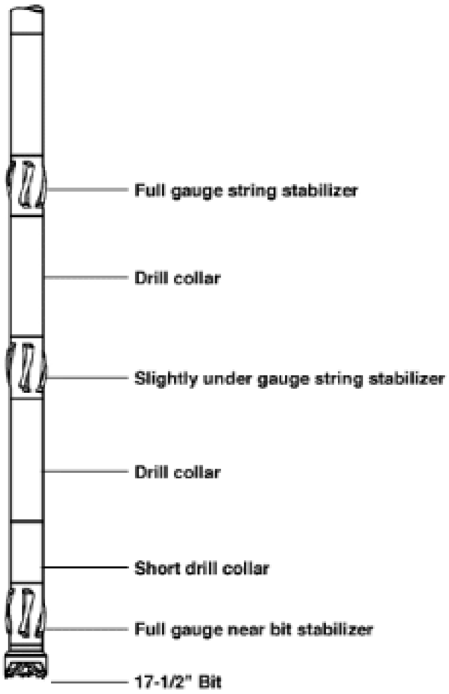


Figure2.4.48
Gradual angle build assembly - 171/2"

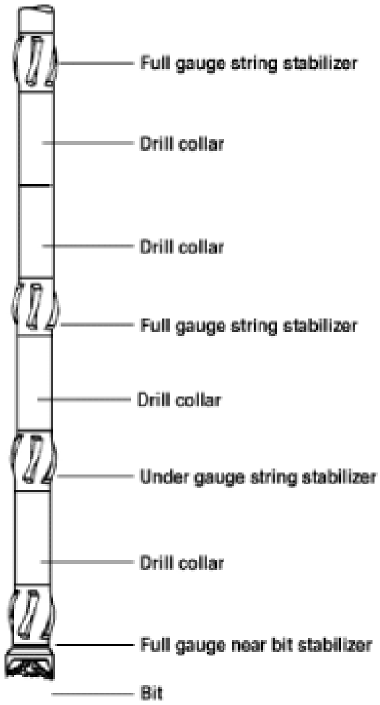


Figure2.4.49
Gradual angle build assembly - 121/4"

THE STABILISATION PRINCIPLE (PACKED HOLE PRINCIPLE)

This principle is that if there are three stabilisers in quick succession behind the bit separated by short, stiff drill collar sections, then the three stabilisers will resist going round a curve and force the bit to drill a reasonably straight path. The first of the three stabilisers should be immediately behind the bit (a near-bit stabiliser) and should be full gauge.

Assemblies which utilise 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 to 160+ RPM) will assist the tendency to drill straight.

Four different packed hole assemblies are illustrated on the opposite page:

Figure 2.4.51: This assembly will give a very slight build or drop rate of 0.1° - 0.5°/100' depending on various factors such as formation characteristics, WOB, RPM, bit type, etc.

Figure 2.4.52: This assembly should hold angle or drop very slightly depending on the exact gauge of the first string stabiliser and hole inclination.

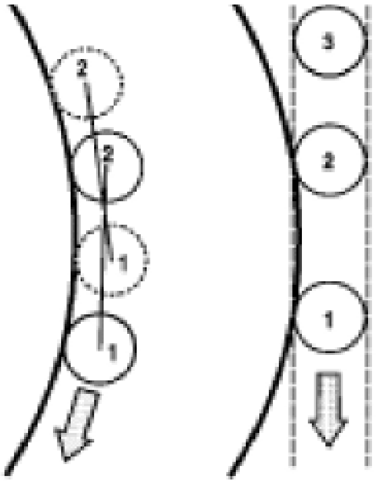


Figure 2.4.50 : The packed hole principle

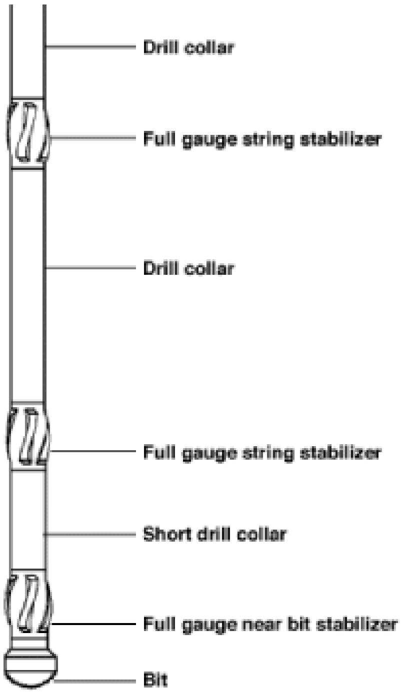


Figure 2.4.51

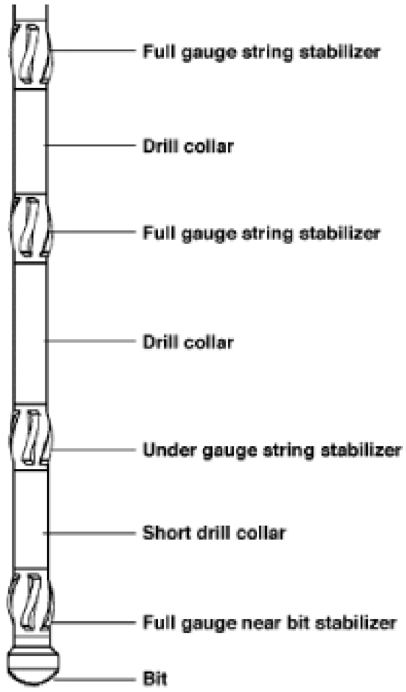


Figure 2.4.52

Figure 2.4.53: The use of two short collars increases the distance between the near-bit and the first string stabiliser. This assembly should hold angle in most applications.
Figure 2.4.54: The tandem stabilisers make this assembly very rigid. In the past it was more common to use tandem stabilisers 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 stabilisers in the BHA increases, so does the possibility of hole sticking.

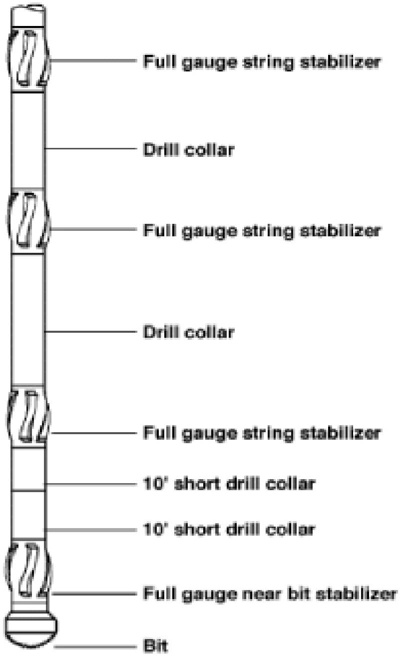


Figure 2.4.53

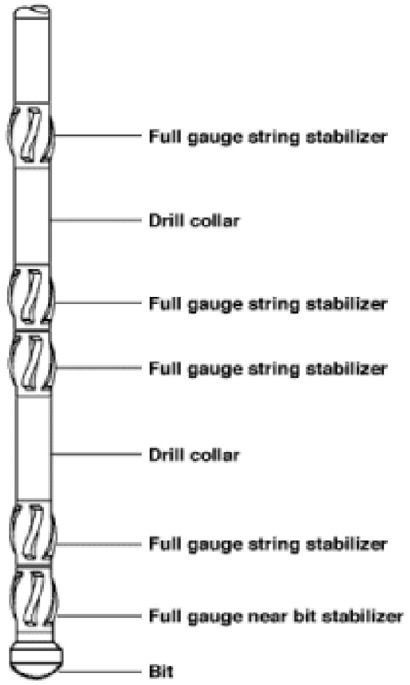


Figure 2.4.54

THE PENDULUM PRINCIPLE

This was the first directional control principle to be formulated and was originally analysed for slick assemblies drilling straight holes. We shall concentrate on pendulum assemblies used in deviated wells.

The portion of the assembly from the bit to the first string stabiliser hangs like a pendulum and, because of its own weight, presses the bit to the low side of the hole. The major design feature of a pendulum assembly is that there is either no near-bit stabiliser or an undergauge near- bit stabiliser. In most cases where a pendulum assembly is used, the main factor causing deviation is the component of force at the bit acting on the low side of the hole. The length of collars from the bit to the first string stabiliser (the "pendulum") must not be allowed to bend too much towards the low side of the hole.

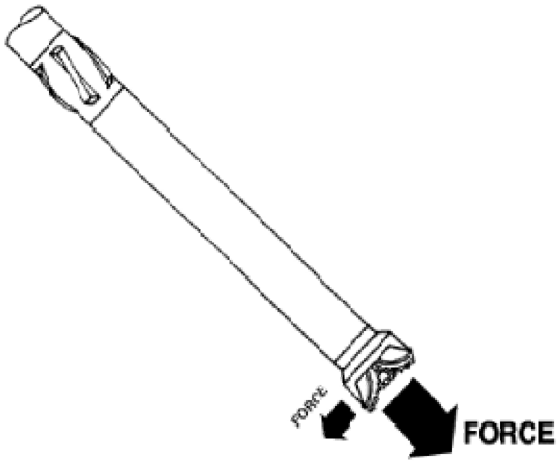


Figure 2.4.55 : The pendulum principle

If the collars make contact with low side as shown in Figure 2.4.56, then the effective length of the pendulum and the side force on low side are both reduced. The situation depicted in this figure is also undesirable because the bit axis has been tilted upwards in relation to the hole axis which will reduce the dropping tendency. (In itself, this would produce a build tendency).

Careful selection of drilling parameters is required to prevent this. High rotary speed (120 to 160+) helps keep the pendulum straight to avoid the above situation. Initially, low weight-on-bit should be used also, 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.

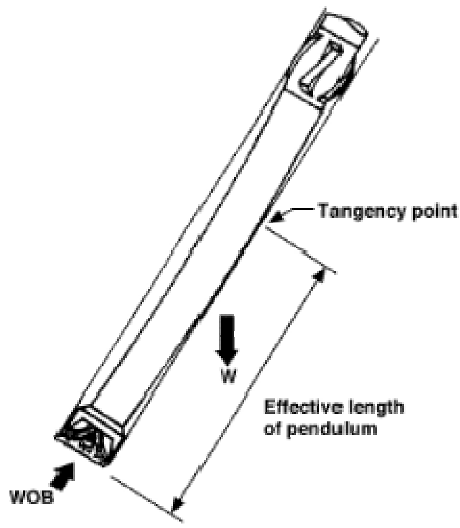


Figure 2.4.56 : Reduction of pendulum force

Some elementary texts on directional drilling depict the pendulum effect as shown in Figure 2.4.57. The implication is that part of the dropping tendency is produced by a downward tilting of the bit axis. It is interesting to note that if this picture were true then the dropping tendency would be increased by increasing WOB and reducing rotary speed, the precise opposite of what was recommended in the previous paragraph.

The example in Figure 2.4.57 is possible for certain lengths of pendulum when there is no near-bit stabiliser and only one string stabiliser. The collars above the upper stabiliser are sagging towards the low side of the hole causing a fulcrum effect about the string stabiliser and tilting the upper portion of the pendulum towards the high side of the hole as shown. Some experienced directional drillers recount instances of pendulum assemblies dropping faster with high WOB and low rotary speed.

It must be emphasised, however, that this is not what would normally occur. The gauge of the bit is effectively a point of support, so that for most pendulum assemblies, especially longer pendulums, the pendulum section is most likely to bend towards the low side of the hole as described previously.

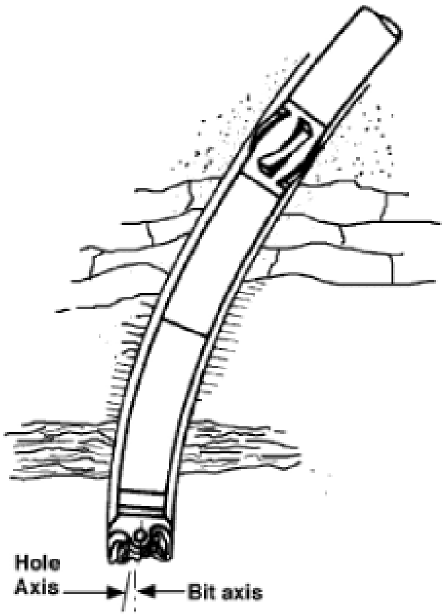


Figure 2.4.57 : One possible interpretation of the pendulum effect

SUMMARY AND RECOMMENDED PRACTICES.

The safest approach to designing and using a pendulum assembly is to concentrate on producing a side force at the bit on the low side of the hole. This is best 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 stabiliser is also stiff and straight and so a second string stabiliser within 30 ft (9 m) of the first is recommended.

- Omit the near-bit stabiliser 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 stabiliser if azimuth control is a consideration. Typically, the near-bit stabiliser need only be 1/4" to 1/2" undergauge in order to produce a dropping tendency.
- The assembly should have two string stabilisers with the second stabiliser not more than 30 ft (9 m) above the first.
- Initially use a low WOB until the dropping tendency is established, then gradually increase bit weight until an acceptable penetration rate is achieved.
- Use a high rotary speed, depending on bit type.
- If possible, do not plan drop sections in hard formation.

Four different pendulum assemblies are illustratedbelow:

Figure 2.4.58 shows a 30 ft (9 m) 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° per 100' /30 m.

Figure 2.4.59 shows a 30 ft (9 m) pendulum assembly with under-gauge near bit stabiliser. This will give a slightly lower rate of drop than the previous BHA, but should reduce bit walk and thereby give better azimuth control.

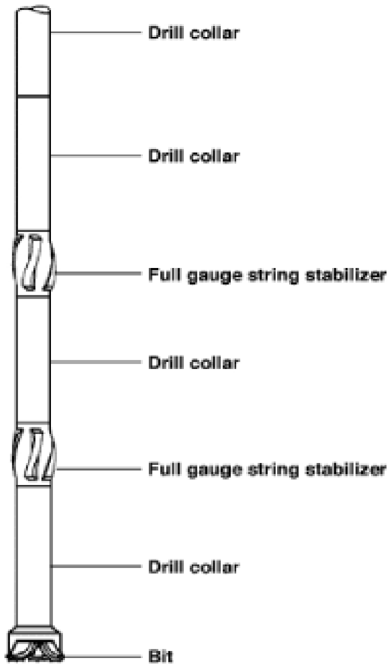


Figure 2.4.58

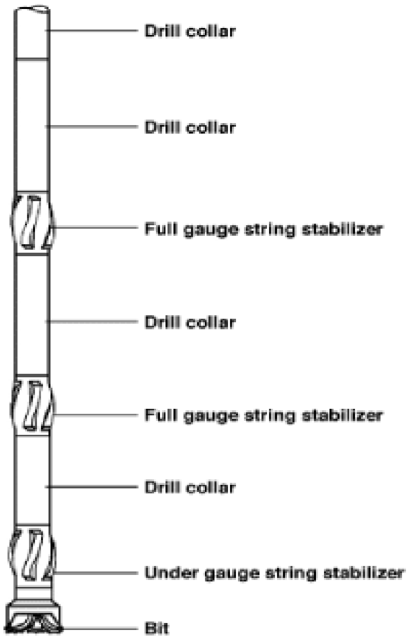


Figure 2.4.59

Figure 2.4.60 shows a gradual angle drop assembly. This short pendulum hook-up would give a more gradual drop rate approximately 1° per 100' /30 m depending on inclination, etc.
Figure 2.4.61 shows a 60 ft (18 m) pendulum assembly used to drill vertical wells. This is too strong a dropping assembly to use on directional wells, except perhaps low angle wells. It is commonly used to drill vertical wells through soft to medium hard formations.

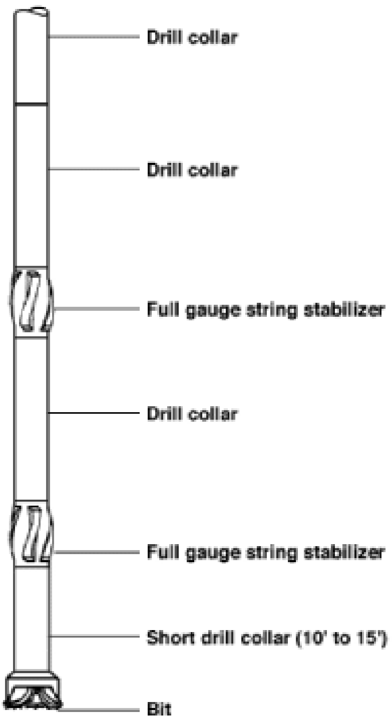


Figure 2.4.60

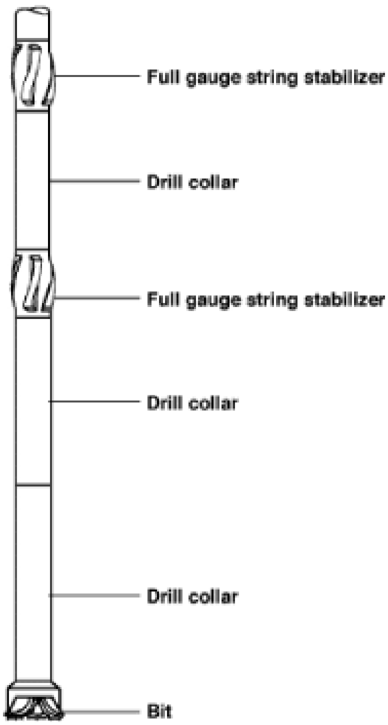


Figure 2.4.61

THE FULCRUM PRINCIPLE

An assembly with a full gauge near-bit stabiliser, followed by 40'-120' (12-36 m) of drill collars before the first string stabiliser, or no string stabiliser at all, will build angle when WOB is applied.

As illustrated in Figure 2.4.45, the collars above the near-bit stabiliser bend, partly due to their own weight and partly because of applied weight-on-bit. The near-bit stabiliser 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 (i.e. the assembly builds angle).

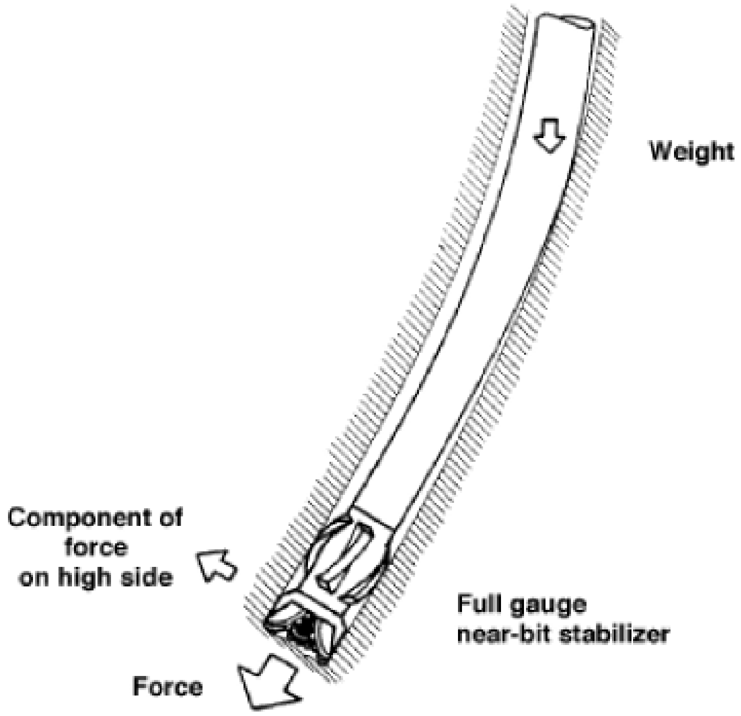


Figure 2.4.45 : The fulcrum principle

The rate of build will be INCREASED by the following:

- An increase in the distance from the near-bit stabiliser to the first string stabiliser.
- 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).

Distance from the near-bit stabiliser to the first string stabiliser

The distance from the near-bit stabiliser to the first string stabiliser is the main design feature of a fulcrum assembly affecting 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 stabiliser is more than 120 ft (36 m) from the near-bit stabiliser (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.

Increase in hole inclination

The rate of build of a fulcrum assembly increases as the inclination increases because there is a larger component of the collars own weight causing them to bend. A simplified picture of 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 are more complicated. To take an example, a strong build assembly which built at a rate of 1.5° per 100ft/30 m when the inclination was only 15° might build at 4° per 100ft/30 m when the inclination was 60°.

Drill collar diameter

As will be discussed later in this Topic (sub-Topic 4.8.5), the stiffness of a drill collar is proportional to the fourth power of the diameter. So a small reduction in the OD of the drill collars used in the fulcrum section considerably increases their flexibility 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 stabiliser 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.

Typical Build Asseblies

Typical build assemblies are shown in Figures 2.4.46 - 2.4.47.

4.8.4. EFFECT OF BIT TYPE ON THE DIRECTIONAL BEHAVIOUR OF ROTARY ASSEMBLIES

ROLLER CONE BITS

When rotary drilling with roller cone bits, the type of bit used makes very little difference to whether an assembly builds, holds or drops angle; as already discussed, this is determined by the configuration of stabilisers and collars and by varying the drilling parameters.

However, the type of bit used has a significant influence on walk rates. Conventional tri-cone rock bits cause right-hand walk in normal rotary drilling. Generally speaking, long tooth bits drilling soft to medium hardness formation give a greater right walk tendency than short tooth bits drilling a hard formation. This is mainly because soft formation bits have a larger cone offset and hence cut rock by a gouging/scraping action.

PDC BITS

During the eighties it became common practice to use PDC bits for rotary drilling, with low WOB and fast rotary speed. 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 the control of the inclination angle is affected by PDC bits, particularly when an angle drop assembly is used.

The gauge length of a PDC bit may significantly affect the rate of build in a rotary assembly. A PDC with a short gauge length may result in a build rate greater than that would be expected with a tri-cone bit. On the other hand, a longer gauge stabilises the bit, thereby tending to reduce the rate of build. The low WOB typically used with PDC bits may also reduce the build rate, as collar flexure decreases with decreasing WOB. When used with packed assemblies in tangent section drilling, longer gauged PDC bits seem to aid in maintaining inclination and direction due to the increased stabilisation at the bit.

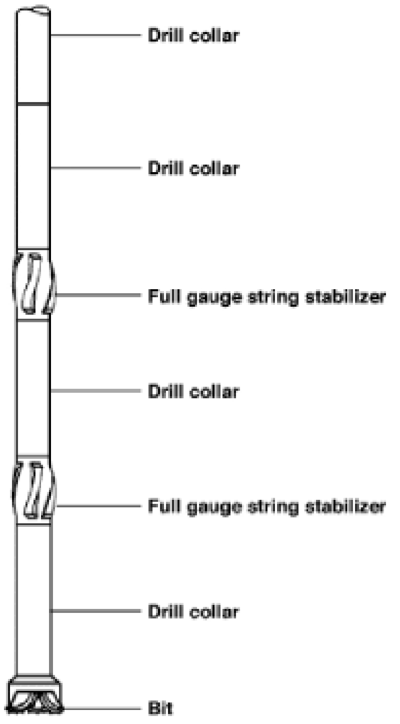


Figure 2.4.58

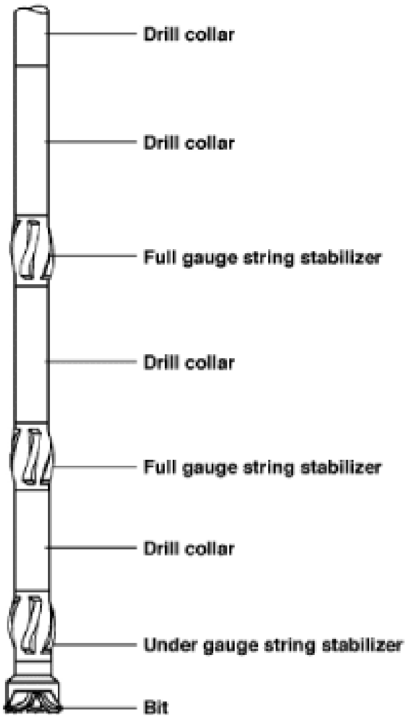


Figure 2.4.59

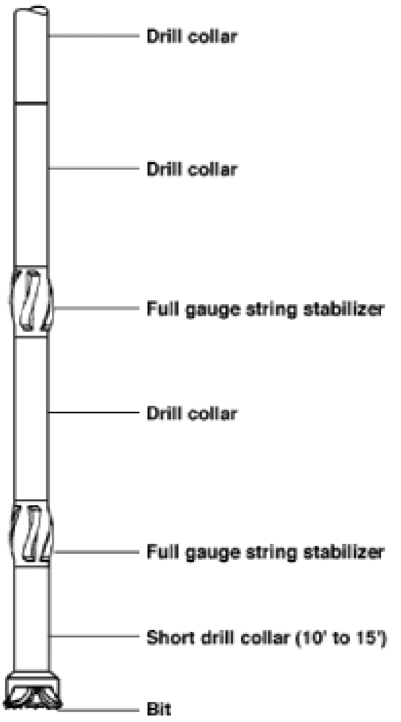


Figure 2.4.60

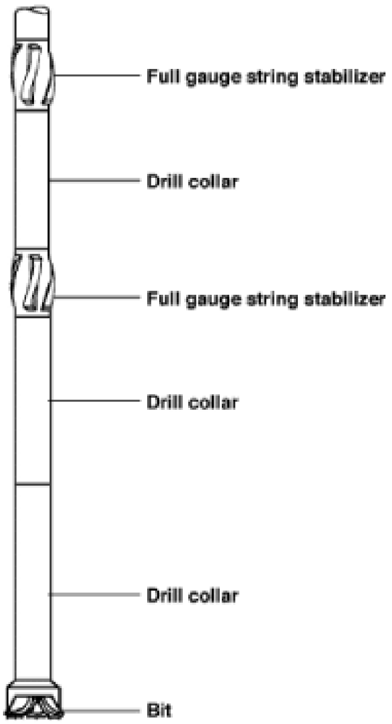


Figure 2.4.61

When used with angle drop assemblies, PDC bits may reduce the drop rate previously obtained with a tricone bit. Generally, the longer the gauge length of the PDC bit, the lower the rate of drop obtained because the bit gauge acts similar to a full gauge near-bit stabiliser. 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.

4.8.5. STIFFNESS OF DRILL COLLARS

As stated earlier, the behaviour 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 may be considered as thick walled cylinders. Their stiffness depends on the axial moment of inertia and the modulus of elasticity of the steel. (See Figure 2.4.62)

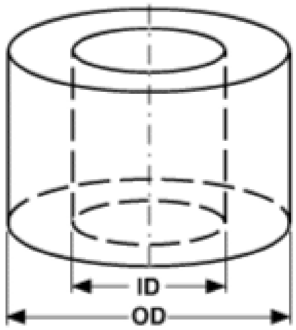


Figure 2.4.62

The axial moment of inertia, I, is given by

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

The weight per unit length, W, is calculated from

$$W = \frac{\pi}{4}\rho\left(OD^2 - ID^2\right)$$

where * is the density of the steel.

Notice that the stiffness is proportional to the difference between the fourth powers of the diameters whereas collar weight is proportional to the difference between their squares. This means that the inside diameter has a much more significant effect on collar weight than on the stiffness.

The relative weights and inertia of some common drill collar sizes are listed in the table below.

Table 2.4.2 : Properties of steel drill collars

Collar				Moment of Inertia		Mass/unit length	
Ins		mm		in^4	cm^4	lbs/ft	kg/m
OD	ID	OD	ID				
4.75	2.25	121	57.2	24	1,000	47	70
6.5	2.81	165	71.4	85	3,500	93	135
8.0	2.81	203	71.4	200	8,200	151	234
9.5	3	241	76.2	400	16,400	217	321

It is interesting to notice that the moment of inertia of a 9 1/2" collar is double 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 stabilisers is W_x

$W_x = W \times BF \times \sin\theta$

where: W = weight/unit length of the drill collar in air,

BF = buoyancy factor of the drilling fluid (Well Engineers Notebook, Section A)

ϑ = inclination of the wellbore

all in consistent units

The accompanying table gives the modulus of elasticity and density of various metals which can be used to manufacture drill collars.

Table 2.4.3 : Properties of different metals used for DCs

Metal	Modulus of Elasticity		Density	
	(10^6 psi)	(10^6 kg/cm2)	(lbs/ft^3)	kg/l
Steel (low carbon)	29.0	2.04	491	7.87
Stainless steel	28.0	1.97	501	8.03
K Monel	26.0	1.83	529	8.47
Aluminium	10.6	0.75	170	2.72
Tungsten	51.5	3.62	1205	19.30

The main 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, aluminium 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. However, it is important that directional drillers understand the effect of changing the drill collar OD.

Effects of changing drill collar OD.

With a fulcrum (build) assembly, reducing collar OD will dramatically increase the build tendency because the collars will be more limber and will bend more. Another factor here 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.

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

With a pendulum assembly, it is best that the pendulum portion be as stiff as possible so it is preferable to use large diameter collars if possible. 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 obtained. Also, of course, reducing the collar OD reduces the weight of the bottom collars which reduces the pendulum force and the rate of drop.

4.8.6. THE EFFECTS OF FORMATION ON BIT TRAJECTORY

In some cases, the nature and hardness of the rock being drilled can have a pronounced influence on directional tendencies, although in many cases the importance of formation effects is exaggerated. Of fundamental importance is whether the rock is isotropic or anisotropic. An isotropic rock is one which has the same properties, or behaves in the same way, no matter which direction you approach it from. Most sandstones are isotropic. Conversely, anisotropic rocks such as shales do not have the same properties in all directions.

Most oilfield drilling (although not all) is done in sedimentary formations. Due to the nature of their deposition, sedimentary rocks have layers or bedding planes and most sedimentary rocks show some degree of anisotropy. Experience from 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, notably 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 variable drillability model which related an index of the rock strength when attacked perpendicular to the bedding planes to the rock strength when attacked parallel to the formation beds. 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 occur more readily along the bedding planes in a sedimentary rock. When the bit is drilling an anisotropic rock, large chips will be cut rapidly on one side of the bit and small chips will be cut out more slowly on the other side. Unequal chip volumes will therefore be generated on each side of a bit tooth as shown below.

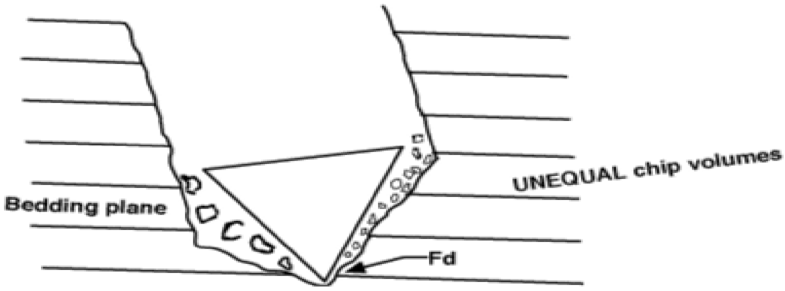


Figure 2.4.63

The forces between the bit tooth and the rock will be greater on the right side of the tooth in the diagram. Therefore there will be a resultant force on the bit acting to the left. This is Fd, the deviation force. It follows that the deviation force depends on the angle of dip.

THE RELATIONSHIP BETWEEN THE ANGLE OF DIP AND DEVIATION FORCE.

Based on the preferential chip formation theory explained above, the graph shown below in Figure 2.4.64 has been derived from experimental work.

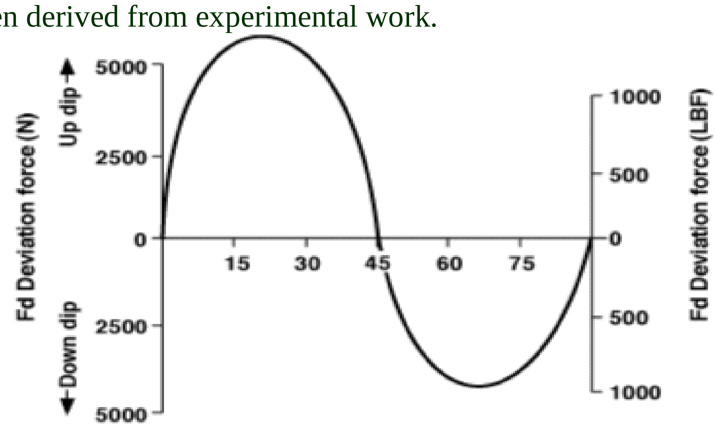


Figure 2.4.64 : Maximum deviation force as a function of formation dip

The effective angle of dip is the angle at which the bit strikes the bedding planes. The graph predicts that when the effective angle of dip is less than 45° the direction of the deviation force is up-dip, but 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 2.4.65. In practice, it has sometimes been observed that an up-dip tendency is observed at dip angles as high as 60°.
Experience of unwanted deviation in vertical wells over many years has borne out the predictions of the graph shown in Figure 2.4.64. Drilling through alternately hard and soft formations with low dip angles, using a well stabilised bit and weights high enough to cause collar flexure, usually results in a course perpendicular to the bedding planes.

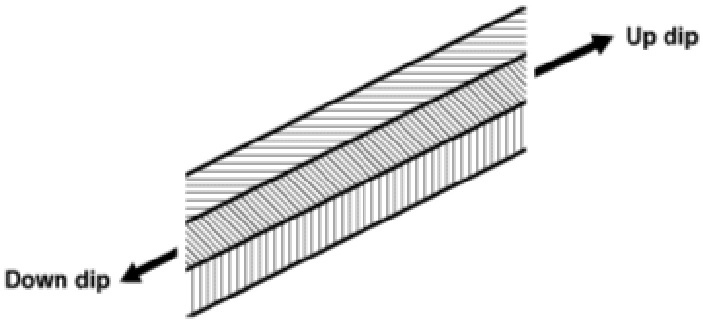


Figure 2.4.65 : Meaning of up-dip and down-dip

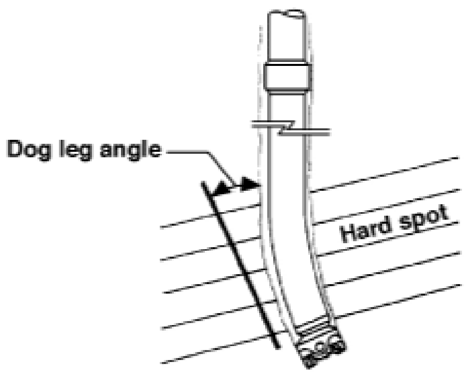


Figure 2.4.66 : Up-dip deviation

Figure 2.4.66 illustrates the tendency of the bit to deviate in the up-dip direction when the formation dip angle is low.
The formation attitudes will have a similar effect on directional tendencies. For dip angles less than 45°, if the direction is due up-dip then the bit will tend to maintain direction but build angle. But if the borehole direction is left of up-dip, the bit tends to walk to the right; whereas if the direction is right of up-dip the bit tends to walk to the left. Both these phenomena are in reality 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, i.e. down-dip as shown in Figure 2.4.67.

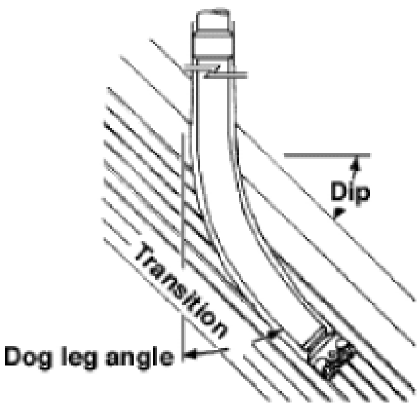


Figure 2.4.67 : Down-dip deviation

For cases where the dip angle is greater than 60°, if the hole direction (Figure 2.4.67) is right of down-dip direction then the bit tends to walk to the left. If the hole direction is left of down-dip direction, then 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.

EFFECTIVE ANGLE OF DIP IN A DEVIATED HOLE

In a directional well, the effective angle of dip is the angle at which the bit strikes the bedding planes.

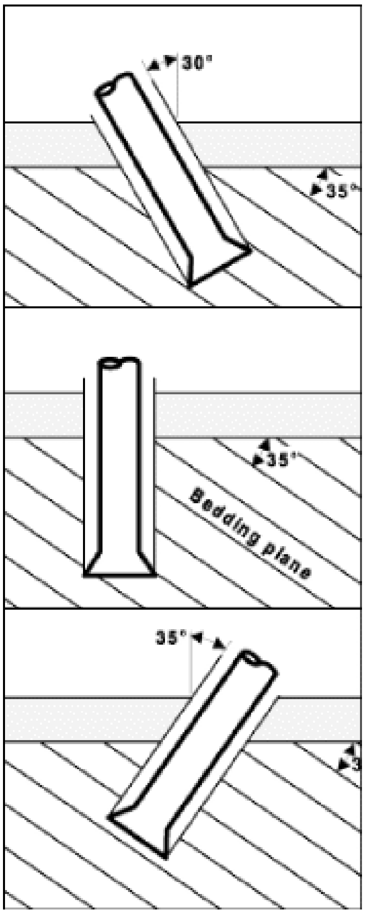


Figure 2.4.68
Hole inclination = 30°
Real dip angle = 35°
Effective dip angle = 30° + 35° = 65°;
There will be a down-dip deviation force.

Figure 2.4.69
Hole inclination = 0°
Effective angle of dip equals real dip angle (35°).
There will be an up-dip deviation force.

Figure 2.4.70
Hole inclination = 35°
Real dip angle = 35°
Effective dip angle = 0°

There will be no deviation force.

FORMATION HARDNESS

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

In very soft formations, the formation may be eroded by the drilling mud exiting from the bit nozzles and an overgauge hole created. 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 in the bit. If it occurs while drilling, then 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 may 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 behaviour in harder formations. This is mainly because the hole is more likely to be the correct 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 weight on bit to get the dropping trend established and the need for high weight on bit 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, either large diameter, heavy collars should be used or a steerable PD motor.

SUMMARY OF FORMATION EFFECTS

It should be emphasised that in many formations, the properties of the rocks have only a minor effect on the directional response of the BHA.

In soft to medium soft formations and in isotropic formations, the rock has little influence on directional response and the BHA should follow its theoretical behaviour.

In medium to hard sedimentary rocks which have an appreciable degree of anisotropy, directional tendencies can be significantly affected by formation attitudes and in particular by the effective dip angle of the bedding planes. If the effective dip angle is less than 45° - 60°, then the bit tends to drill up-dip. If the effective dip angle is greater than 60°, then the bit tends to drill down dip. When the effective dip angle is approximately 0°, the bit has no tendency to deviate from a straight path.

Unwanted deviation tendencies caused by formation effects can best be reduced by packed assemblies. The use of a full gauge near-bit stabiliser definitely reduces bit walk. In cases where strong formation effects have been observed on previous wells in the same area, the design of the assembly should be suitably modified to compensate for the anticipated effect.

STEERABLE DRILLING SYSTEMS

4.9.1 INTRODUCTION

In conventional directional drilling, extra round trips are sometimes necessary to change the BHA for directional control. Also, bit performance may be reduced by conventional deflection techniques.

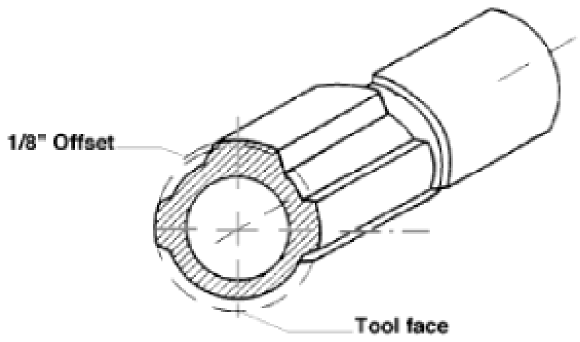
Several methods exist for continuously controlled directional drilling using "steerable downhole motors". These methods are based on tilting the axis of the bit with respect to the axis of the hole and/or creating a side force at the bit. If the drill string, and hence the body of the motor, is rotated from surface, then 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.

A steerable turbine exists which has been used successfully in the North Sea and elsewhere, however most steerable systems presently being used are based on a positive displacement motor and use the principle of tilting the axis of the bit with respect to the axis of the hole. The advantages of steerable drilling systems are that:

- They virtually eliminate trips made for directional assembly changes, thereby saving rig time.
- They permit more complex well paths to be drilled.
- They allow the drilled well to be kept close to the plan at all times.
- Smaller directional targets can be hit.

4.9.2 STEERABLE TURBINES

Early steerable turbines used the side force method by having an eccentric stabiliser at the lower end of the bearing section, i.e. at the bottom end of the turbine body, quite close to the bit. One blade is larger in surface area and is offset by 1/8" as shown in Figure 2.4.71,. When the drill string is rotated, the offset stabiliser has no effect on the well path. When it is desired to deflect the well path, the toolface (the point opposite the centre of the offset blade) is orientated using an MWD tool.



Drilling continues with no rotation from surface and the turbine drills a curved path. These are now obsolete. Modern steerable turbines incorporate a bent housing close to the bit.
Steerable turbines have been used to perform various types of deflection including kick-offs. Their most successful application has been tangent section drilling, performing correction runs as required to keep the well on course

Figure 2.4.71 : Excentric stabiliser

4.9.3 STEERABLE POSITIVE DISPLACEMENT MOTORS

The tilt in a steerable PDM is created by incorporating a bent U-joint housing in the assembly. The system can include either a single tilt or a double tilt.
The advantage of single tilt motors is that they are usually rig-floor adjustable, enabling the tilt angle to be set at any value between zero and some maximum.
The advantage of double tilt motors is that they have a small bit offset that facilitates rotating the string when oriented drilling is not required.

DOUBLE TILT ASSEMBLIES

A double-tilted steerable drilling system consists of the following components, upwards from the bit:

- **a suitable drilling bit**
- **an upper bearing housing with stabiliser**
- **a double tilted U-joint housing**
- **A motor section**
- **a by-pass valve**
- **An undergauge string stabiliser**
- **A survey system, usually MWD.**

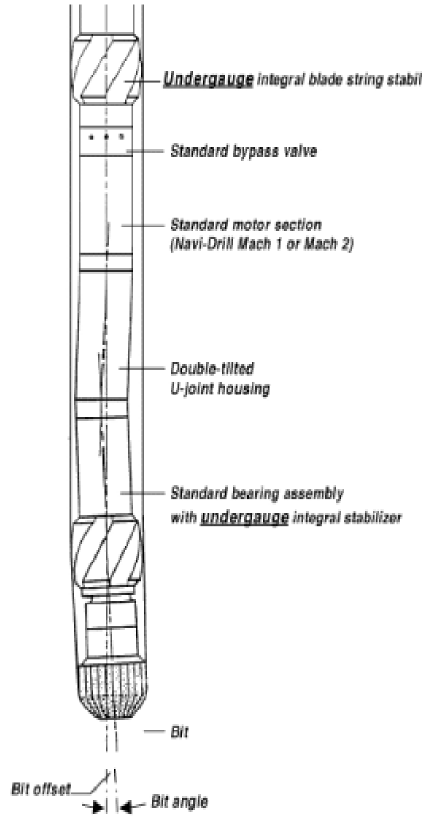


Figure 2.4.72 Steerable double tilt mud motor

The double tilt steerable motor assembly is shown in Figure 2.4.72, and the geometry of the system, compared with a single tilt system is shown in Figure 2.4.73.
The concept of 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 minimised. This bit offset is the distance (in millimetres or inches) from the centre of the bit to the axis of the motor section (extrapolated down to the bit). A small bit offset facilitates rotating the string when oriented drilling is not required.
The double tilted universal joint housing:

- **is slightly longer than a straight housing and universal joint.**
- **is available in various tilt angles and is identified by the tilt angle, which is the mathematical resultant angle computed from the two opposing tilt angles.**
- **is available in various diameters ranging from 43/4" to 111/4". Each diameter has three standard tilt angles designed to provide approximately 2°, 3° and 4° per 100 ft/30 m theoretical dogleg rates.**

As mentioned in Topic 4.6.3 the double tilted universal joint housing was developed from the single tilt housing. However after a period when it was used it has now been phased out again as most operators prefer the single tilt housing.

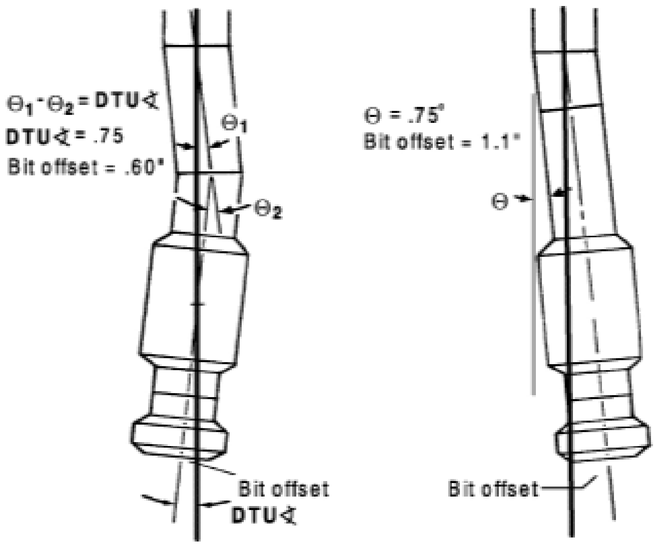


Figure 2.4.73 : The double-tilted universal joint housing

ADJUSTABLE SINGLE TILT ASSEMBLIES

(Sometimes called adjustable kick-off housings)

The advantages of single-tilt adjustable motors are that they:

- incorporate a rig site-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 stabiliser configuration,
- allow a single motor to be used for a variety of build rates on the same well
- require fewer tools to be transported to and from the rig, a particular advantage for remote locations.

The variable tilt angle is possible because the internal connections of the housing feature a tilted pin thread which screws into a tilted box thread. The relative position of the two tilted angles determines the tilt angle of the tool and the position of the High Side. This is rig floor adjustable between 0° and up to 2-3/4° - the maximum angle varies between tools.

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.

4.9.4 TILT ANGLE AND STABILISER

THEORETICAL GEOMETRIC DOGLEG SEVERITY

An essential concept when designing and operating directional drilling assemblies is that of the Theoretical Geometric Dogleg Severity (TGDS). It is defined by three points on a drilled arc:

- The bit
- The motor stabiliser or Upper Bearing Housing Stabiliser (UBHS).
- The first string stabiliser above the motor.

$TGDS = \frac{200 \times \alpha}{L}$ degrees/100 ft, or $TGDS = \frac{60.96 \times \alpha}{L}$ degrees/30 m

Where : a = the tilt angle in degrees

L = the length between the bit and the string stabiliser

(= $L_1 + L_2$) in ft(m)

Note: This equation for calculating TGDS is based on a system which contains full gauge stabilisers.

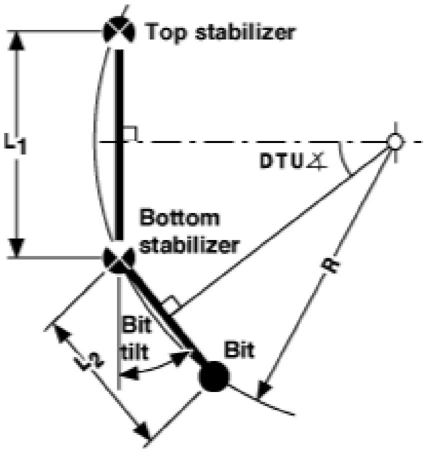


Figure 2.4.74 : TGDS

TILT ANGLE

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

For kicking off or sidetracking, a high tilt steerable motor is 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 utilising the practice of drilling intervals of 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 greatly 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.

FIRST STRING STABILISER.

It is normal practice to run a string stabiliser either directly above the motor or with a pony drill collar between the motor and the stabiliser. Reasons for using this include:

- It defines the third point of contact in the steerable drilling assembly.
- It produces a predictable directional response.
- It centralises the drill string.

Placement

Most commonly it is run directly above the motor. According to the 3-point geometry, increasing "L" by moving the first string stabiliser higher in the BHA reduces the Theoretical Geometric Dogleg Severity. This does not always work in practice. It has been found that moving the stabiliser 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.

Size and design

The diameter of the first string stabiliser 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 stabiliser size - oriented mode

If the first string stabiliser 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 single and double tilted systems.

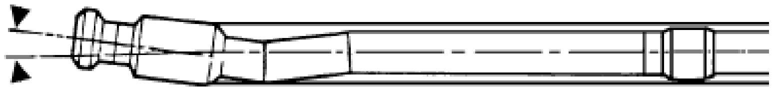


Figure 2.4.75 : Assembly for increased dogleg rate

If the first string stabiliser 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 stabiliser, the greater the effect. Again, the same basic effect is seen with both the single and double tilted systems.

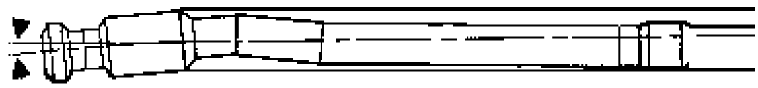


Figure 2.4.76 : Assembly for decreased dogleg rate

Table 2.4.4 : String stabiliser size for maintaining angle

Hole size	First string stabiliser gauge diameter
8½"	8" - 8⅜"
9⅞"	9⅛" - 9⅝"
12¼"	11¾" - 12"
14¾"	14⅛" - 14½"
17½"	16" - 17"

Table 2.4.5 : String stabiliser size for changing angle

Hole Size	First string stabiliser gauge diameter reduction
8½"	⅛"
12¼"	¼"
17½"	⅜"

First string stabiliser size - rotary mode

Field results have shown that an undergauge first string stabiliser is required to produce a holding tendency when a steerable drilling assembly is run in the rotary mode.
The required first string stabiliser gauge diameter is a function of formation trends and hole inclination.
Table 2.4.4 can be used as a general guideline for determining the required diameter of the first string stabiliser such that inclination is maintained.
The second table can be used as a general guideline for determining first string stabiliser changes in diameter to produce a significant change (minimum of 0.25deg per 100ft/30 m) in rotary inclination reaction.