4.9.5 KICKING OFF

BOTTOM HOLE ASSEMBLIES

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

- Build up rate required.
- Expected length of run.

Four examples of BHAs are presented: two for 17 1/2" holes (rotary hold and considerable rotary build tendency) and two for 12 1/4" (rotary hold and rotary build tendency).
Note that crossovers have not been mentioned but have to be used where necessary.

RECOMMENDED GUIDELINES

- When beginning a kick-off, it is recommended to have the first string stabiliser in new open hole and not up in the casing to prevent hanging up or any other anomalous assembly reactions.
- Be aware of the fact that when using a steerable motor assembly in vertical or near vertical holes, the actual dogleg may be less than the TGDS calculated.
- Initially, in a kick-off, the directional driller should observe the actual oriented dogleg severity of the steerable assembly for a interval of at least 60 feet. Constant monitoring of the actual oriented dogleg severity is necessary to plan subsequent oriented/rotary drilling intervals.
- Minimising rotary speed will slightly increase the fulcrum effect. This practice can reduce oriented drilling intervals and further optimise the system.
- During the initial stage of a kick-off from vertical, stabiliser hang-up can occur. This problem may exist until the wellbore is inclined and/or the first string stabiliser enters the curved, oriented hole.
- Consider beginning the kick-off early; this can reduce oriented drilling requirements and the maximum inclination of the well path.

INTERVAL DRILLING

An estimate of the proportion of the footage which will have to be drilled in oriented mode can be determined by the following formula.

$$\%\ \text{footage oriented} = \frac{(DL - DLR) \times 100}{DLO - DLR}$$

where : DL = required dogleg (°/unit length)

DLO = actual dogleg when oriented (°/unit length)

DLR = actual dogleg when rotary drilling (°/unit length)

Example:
Planned build-up rate = 2.5°/30 m
Build-up rate obtained when oriented = 3.5°/30 m
Build-up rate obtained during rotary drilling = 0.5°/30 m

$$\%\ \text{footage oriented} = \frac{(2\cdot 5 - 0\cdot 5) \times 100}{3\cdot 5 - 0\cdot 5} = 67\%$$

4.9.5 KICKING OFF

BOTTOMHOLE ASSEMBLIES

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

- Build up rate required.
- Expected length of run.

Four examples of BHAs are presented: two for 171/2" holes (rotary hold and considerable rotary build tendency) and two for 121/4" (rotary hold and rotary build tendency).
Note that crossovers have not been mentioned but have to be used where necessary.

RECOMMENDED GUIDELINES

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$$\%\ \text{footage oriented} = \frac{(2 \cdot 5 - 0 \cdot 5) \times 100}{3 \cdot 5 - 0 \cdot 5} = 67\%$$

FOUR EXAMPLES OF BOTTOM HOLE ASSEMBLIES

The following example assembly for
a 171/2" hole is designed to have a rotary hold tendency.

171/2" Bit
111/4" Steerable mud motor,
171/4" UBHS
161/2" First String Stabiliser
Float Sub
91/2" MWD
91/2" Drill Collar
161/2" Stabiliser

The following example assembly for a 171/2" hole is designed to have a considerable rotary build tendency. A good estimate would be 2°/100'.

171/2" Bit
111/4" Steerable mud motor
171/4" UBHS
16" First String Stabiliser
Float Sub
91/2" MWD
91/2" Drill Collar
161/2" Stabiliser

2 x 91/2" Drill Collars
2 x 8" Drill Collars (increase or decrease if required)
Jars
8" Drill Collar
HWDP

2 x 91/2" Drill Collars
2 x 8" Drill Collars (increase or decrease if required)
Jars
8" Drill Collar
HWDP

The following example assembly for a 121/4" hole is designed to have a rotary hold tendency.

121/4" Bit
91/2" Steerable mud motor
121/8" UBHS
12" First String Stabiliser
8" MWD
8" Drill Collar
12" Stabiliser
2 x 8" Drill Collars
Jars
8" Drill Collar
HWDP

The following example assembly for a 121/4" hole is designed to have a rotary build tendency.

121/4" Bit
91/2" Steerable mud motor
121/8" UBHS
11" First String Stabiliser
8" MWD
8" Drill Collar
113/4" Stabiliser
2 x 8" Drill Collars
Jars
8" Drill Collar
HWDP

4.9.6 TANGENT SECTION DRILLING

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

BASIC ASSEMBLY DESIGN PRINCIPLES:

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

STEERABLE DRILLING ASSEMBLY FOR TANGENT SECTION DRILLING

A typical BHA for drilling a 121/4" hole tangent section is:
121/4" bit
91/2" steerable mud motor
121/8" UBHS
113/4" string stabiliser
8" MWD tool
8" drill collar
113/4" stabiliser

3 x 8" drill collars
Jars
8" drill collars as required
HWDP as required

OPERATIONAL GUIDELINES

- After observing the steerable assembly directional tendencies over a rotary drilled interval of at least 200' (30 m) , a plan for drilling long distances between orientations should be established. This plan should minimise the number of orientation tool-sets and maximise penetration rate.
- Oriented drilling intervals should be minimised. Oriented drilling in a tangent or hold section is performed to correct the present well path and to compensate for anticipated trends.
- Never let the drilled well path get too far from the planned trajectory. Temper this with the fact that "drilling on the line" can be significantly more expensive than allowing small deviations. As surveys are obtained, calculate and plot the position on both horizontal and vertical plans. At all times there must be a feasible course to drill from the current location to the intended target.

4.9.7 DROP SECTIONS

When a drop section is to be drilled, the gauge of the first string stabiliser can be increased to produce more of a dropping tendency in the rotary mode. The recommended diameter, however, is no larger than the UBHS. Increasing the diameter of this stabiliser can also increase hole drag and stabiliser hang up.
Typical rotary drop rates are seldom much higher than 1°/100', with 0.5°to 0.75°/100' commonly produced when the angle is less than 20°. If higher drop rates are required. then oriented drilling will be mandatory.
The following is a general design for a drop assembly while rotary drilling.
121/4" bit
91/2" steerable mud motor (slick)
121/8" first string stabiliser
8" MWD tool
8" drill collar
12" stabilizer , etc.
The following guidelines should be considered when drilling drop sections.

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

4.9.8 AZIMUTH CONTROL

Rotary Mode

- Rotary drilling with steerable drilling assemblies usually exhibits an azimuth hold tendency.
- The dip and strike of the formation will affect the tendency of the steerable drilling assembly to walk.
- The conventional directional concept of increasing rotary RPM to stiffen an assembly is applicable with steerable drilling assemblies.

Oriented Mode

- Changes in azimuth are most efficiently performed in oriented mode.
- Due to the stabilisation of the steerable motor, the toolface can be orientated for maximum turn without dropping inclination (a typical problem with motor and bent sub assemblies in soft formations).
- A reduction in TGDS can be expected when oriented for a turn due to the effect of the undergauge first string stabiliser.

BHA WEIGHT AND WEIGHT ON BIT

4.10.1 INTRODUCTION

An important consideration in designing the bottom-hole assembly is the total number of drill collars and heavy weight drill pipe required to provide the desired weight on bit. In drilling vertical wells, it has long been standard practice to avoid running ordinary drill pipe in compression. (This was recommended by Lubinski in 1950). This is achieved by making sure that the buoyed weight of drill collars and heavy weight pipe exceeds the maximum weight on bit. This practice was also adopted on low-angle directional wells.
In directional wells it has to be remembered that, since gravity acts vertically downwards, only the along-hole component of the weight of BHA elements contributes to the weight on bit. The problem this creates is that if high WOB is required when drilling a high-angle well, then a long and expensive BHA would be needed in order to avoid having any drill pipe in compression. It is, however, common practice to use about the same BHA weight as would be used on a low-angle well and run the drill pipe in compression. Analysis of drill pipe buckling in inclined holes by a number of researchers, notably Dawson and Paslay, has shown that drill pipe can tolerate significant levels of compression in small-diameter high-angle holes because of the support provided by the low side of the hole. Drill pipe is commonly run in compression in drilling horizontal wells, without apparently causing damage to the pipe.
Additional information about the design of bottom-hole assemblies in deviated wells is given in Section 2 Part 1 - Drill string design.

4.10.2 ALONG-HOLE COMPONENTS OF FORCE

Consider a short element of a BHA which has a weight W.
The effective weight in drilling fluid= W x BF, where BF = the buoyancy factor of the drilling fluid.
The component of the weight acting along borehole = W x BF x cosθ, where θ is the borehole inclination.
Note: In this chapter, θ is used for inclination and I is used for axial moment of inertia.
If the BHA is not rotated, the friction force, F_{fr}, acting up the borehole on the BHA element is given by $F_{fr} = \mu N$, where μ is the coefficient of friction and N is the normal reaction force between the BHA element and the bore hole wall.
If this normal reaction is due only to the weight of the BHA element itself, then
$N = W \times BF \times \sin\theta$ and hence
$F_{fr} = \mu \times W \times BF \times \sin\theta$
The net contribution to the WOB from this BHA element is therefore
$W_{bit} = W \times BF \times (\cos\theta - \mu \sin\theta)$

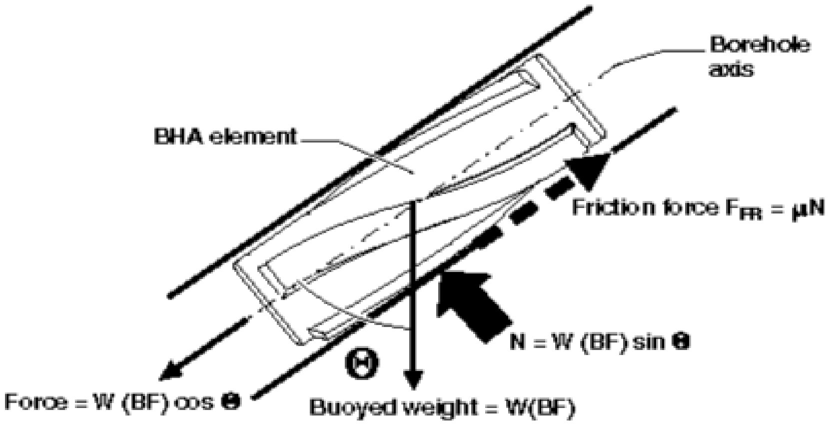

Figure 2.4.77 : Forces on the BHA

4.10.3 REQUIRED BHA WEIGHT FOR ROTARY ASSEMBLIES

When two contacting surfaces are in relative motion, the direction of the force of sliding friction on each surface acts along the line of relative motion and in the opposite direction to its motion. Therefore, when a BHA is rotated, the friction forces mainly act circumferentially to oppose rotation (torque) with only a very small component acting along the borehole (drag).

Measurements of downhole WOB by MWD tools confirm that when the BHA is rotated there is only a small reduction in weight on bit due to drag. This can be allowed for simplistically by using a safety factor.

Neglecting drag, and extending the discussion above to the whole BHA,

$$W_{bit} = W_{BHA} \times BF \times \cos\theta$$

Where :

W_{BHA} = the total air weight of the BHA

W_{bit} = the weight on bit

Therefore, if no drill pipe is to be run in compression,

$$\text{Required weight of BHA(in air)} = \frac{\text{maximum WOB}}{BF \times \cos\theta} \times \text{safety factor}$$

Example

Drilling 17 1/2" hole with a roller cone bit, we want to use 45,000 lbs WOB in the tangent section at 30° inclination. What air weight of BHA is required to avoid running any drill pipe in compression? The drilling fluid density is 10ppg. Use a 10% safety margin.

$$\text{Required BHA weight} = \frac{45,000 \times 1.1}{0.848 \times \cos 30^\circ}$$
$$= 67,400 \text{ approximately}$$

Suppose we have 180' of 9 1/2" tubulars weighing 220 lbs per foot, a 9 1/2" MWD tool weighing 3,400 lbs and 90' of 8" tubulars weighing 154 lbs per foot.

How many joints of 5" HWDP would be required?

Total weight of DC section	= (180 x 220) + 3,400 + (90 x 154) lbs	=	56,860 lbs
Required air weight of HWDP	= 67,500 lbs - 56,860 lbs	=	10,640 lbs
Weight of 1 joint of HWDP	= 1,480 lbs		
Number of joints of HWDP required	= 10,640/1,480	=	7.2

Therefore a minimum of 8 joints of HWDP are required

It must be emphasised that the Safety Factor in the preceding example is to compensate for loss of weight due to friction while drilling in the deviated section of the well.

4.10.4 RUNNING DRILL PIPE IN COMPRESSION

Consider the following example.
We are drilling a 12 1/4" tangent section in hard formation using an insert bit. We want to use 50,000lbs WOB. The hole inclination is 60û and the drilling fluid density is 11 ppg.
What air weight of BHA is required if we are to avoid running any drill pipe in compression ? Use a 15% safety margin.

Required BHA weight

$$= \frac{50,000 \times 1.15}{0.832 \times \cos 60^\circ} \text{ lbs}$$

$$= 138,200 \text{ lbs}$$

This is roughly the weight of ten strands of 8" drill collars, or alternatively, six strands of 8" collars pluss 44 joints of HWDP ! This is just not practical ! It would be a long, stiff and expensive BHA.

CRITICAL BUCKLING FORCE

Dawson and Paslay developed the following equation for critical buckling force in drill pipe.

$$\boxed{F_{cr} = 2\left(\frac{EIW\sin\theta}{r}\right)^{1/2}}$$

Where:
E is Young's modulus.
I is the axial moment of inertia.
W is the buoyed weight per unit length.
θ is borehole inclination.
r isthe radial clearance between the pipe (tool joint) and the borehole wall.
Note that consideration must be given to the possibility of an oversize hole when calculation 'r'
If the compressive load reaches the value F_{cr}, then sinusoidal buckling occurs.
The sinusoidal buckling equation given above can be used to develop graphs and tables of values such as those in Appendix 2. If the compressive load at a given inclination lies below the graph, then the drill pipe will not buckle.
The reason that pipe in an inclined hole is so resistant to buckling is that the hole is supporting and constraining the pipe throughout its length. The low side of the hole forms a trough that resists even a slight displacement of the pipe from its initial straight configuration. It follows that this equation is not applicable for vertical holes, for which other equations are available.
Note that, intuitively, it may seem that the "radial clearance" in the above equation would be that between the drill-pipe and the hole rather than between the tool-joint and the hole. However in practice it appears that a better correlation with theory is obtained if the radial clearance of the tool-joint is used.

Calculating BHA weight with drill pipe in compression

The conclusion of the previous paragraph is that on high-angle wells in small hole sizes, a fraction of the weight on bit can safely be provided by having drill pipe in compression. It is suggested that 90% of the critical buckling force be used as the maximum contribution to the weight on bit from ordinary drill pipe.
Denoting the total air weight of the BHA by W_{BHA}, the weight on bit by W_{BIT} and the critical bucklingload by F_{cr}, we have:

$$W_{BIT} \times SF = (W_{BHA} \times BF \times \cos\theta) + 0.9F_{cr}$$

$$W_{BHA} = \frac{(W_{BIT} \times SF) - 0.9F_{cr}}{BF \times \cos\theta}$$

Continuing the example at the beginning of this sub-Topic 4.10.4, let us recalculate the weight of the BHA required assuming some drill pipe is to be run in compression.
Suppose we are using 5" drill pipe; referring to the table for 5" drill pipe in 121/4" hole in Appendix 2, we see that the critical buckling load at 60° inclination is 29,300 lbs. Our equation then gives:

$$W_{BHA} = \frac{(50,000 \times 1.15) - (0.9 \times 29,300)}{0.832 \times 0.5} \text{ lbs}$$
$$= 74,800 \text{ lbs approximately}$$

Thus a total air weight of 74,800 lbs is required.This is much more feasible than the value of 138,000 lbs previously calculated.
The graphs and tables in Appendix 2 are for the particlular drilling fluid density of 10.68 ppg. However, variations in drilling fluid density have only a minor effect on the value of critical buckling load and so the graphs could be used for drilling fluid densities of up to 14 ppg without introducing a significant error. For drilling fluid densities above 14 ppg, the value of critical buckling load should be re-calculated.

SUMMARY OF RUNNING DRILL PIPE IN COMPRESSION

- When drilling vertical wells, ordinary drill pipes must NEVER be run in compression in any hole size. Therefore sufficient BHA weight must be used to provide all the desired weight on bit with an appropriate safety margin.
- Given that the clearance is in the denominator of the Dawson & Paslay equation, the critical buckling force will decrease as the hole size increases, even in high angle holes. In hole sizes of say 16" or more the drill-pipe should only be run in compression in exceptional cases.
- In smaller hole sizes on high-angle wells (over 45°), drill pipe may be run in compression to contribute to the weight on bit provided the maximum compressive load is less than the critical buckling force. This critical buckling force is the minimum compressive force which will cause sinusoidal buckling of the drill pipe.
- A safety margin of at least 10% should be used in the calculation to allow for some drag (friction) in the hole. However, axial drag is not a major factor when assemblies are rotated.

The preceding discussion concerned rotary assemblies. However, it would also apply to steerable motor systems used in the rotary mode. Provided the steerable system was to be used mainly in the rotary mode, with only minimal oriented drilling anticipated, then the required BHA weight could be calculated on the same basis. If a significant amount of oriented drilling was likely, then the following Sub-Topic is applicable.

Calculating critical buckling force

A set of graphs and tables is presented in Appendix 2 . These are for specific sets of conditions. The following example illustrates how to calculate the critical buckling load for other conditions.
Suppose we have 41/2" drill pipe with a nominal weight of 16.6 lbs/ft in 81/2" hole at 50° inclination with a drilling fluid density of 14 ppg.
Young's modulus, E, for steel is 29 x 10^6 psi

$$\therefore I = \frac{\pi}{64}\left(4.5^4 - 3.826^4\right) = 9.61 \text{ ins}^4$$

The ID of the drill pipe is 3.826". This information can be found in API RP7G.

$$\therefore W = 1.498 \times 0.786 = 1.178 \text{ lbs / in}$$

The approximate weights for different sizes of drill pipe can also be found in API RP7G . In this case it is 17.98 lbs/ft.
In the equation, W is the buoyed weight in lbs/inch.
The air weight = 17.98 lbs/ft = 1.498 lbs/in and the buoyancy factor for 14ppg drilling fluid = 0.786.

sin 50° = 0.766

Radial clearance:

= 1/2 (Hole OD - Tool joint OD)

= 1/2 (8.5" - 6.375")

= 1.06"

$$\text{Radial clearance} = \tfrac{1}{2}(\text{Hole OD} - \text{Tool joint OD}) = \tfrac{1}{2}(8.5'' - 6.375'') = 1.06''$$

The values obtained above may now be substituted in our equation of the critical buckling force.

$$F_{cr} = 2\sqrt{\frac{29\times10^{6}\times9.61\times1.178\times0.766}{1.06}}\ \text{lbs} = 30{,}800\ \text{lbs}$$

4.10.5 BHA REQUIREMENTS WHEN THE DRILL STRING IS NOT ROTATED

As stated earlier, when the drill string is rotated the along-hole component of sliding friction (drag) is small and may be allowed for simply by using a safety factor in BHA weight calculations. Drill string friction for rotary assemblies will mainly affect torque values. When the drill string is not rotated, as when a steerable motor system is used in the oriented mode, axial drag can become very significant and drill string friction may be evaluated taking in more factors by using computer simulation (WellPlan) .

In practice, BHA weight for steerable assemblies on typical directional wells is not a problem for two reasons.

- The WOB is usually fairly low, especially when a PDC bit is used.
- When the drill string is not rotated the drill pipe is not subjected to the cyclical stresses which occur during rotary drilling. Therefore, sinusoidal buckling can be tolerated when there is no rotation of the drill string. Helical buckling must, however, be avoided.

Helical buckling occurs at 1.41 F_{cr}, where F_{cr} is the compressive force at which sinusoidal buckling occurs. Therefore, if BHA weight requirements are evaluated as for rotary drilling, the results will be valid for steerable systems in the oriented mode except for unusual well paths which create exceptionally high values of axial drag. The standard practice of minimising BHA length and weight for steerable assemblies has not created any noticeable increase in the incidence of drill string failure, even when long sections are drilled in the oriented mode.

Appendix 1
Mathematical solutions

BUILD AND HOLD CONFIGURATION

The following information is required:

- Surface (slot) coordinates
- TVD of the kick-off point (VD1)
- Build-up rate
- Target coordinates
- TVD of target

In the solution which follows for the vertical projection, the well is assumed to be vertical to the kick-off point (KOP). The following values will be calculated:

- Measured depth at end of build section.
- Horizontal displacement at end of build section (H1).
- Vertical depth at end of build section (VD2).
- Inclination of tangent section (a).
- Total measured depth of the target.
- Horizontal displacement of target (H2).

First the horizontal displacement of the target is calculated from the two sets of horizontal plane coordinates:

$$H_2 = \sqrt{(N_T - N_S)^2 + (E_T - E_S)^2}$$

where: N_s = Northing of slot
E_s = Easting of slot
N_T =Northing of target
E_T =Easting of target

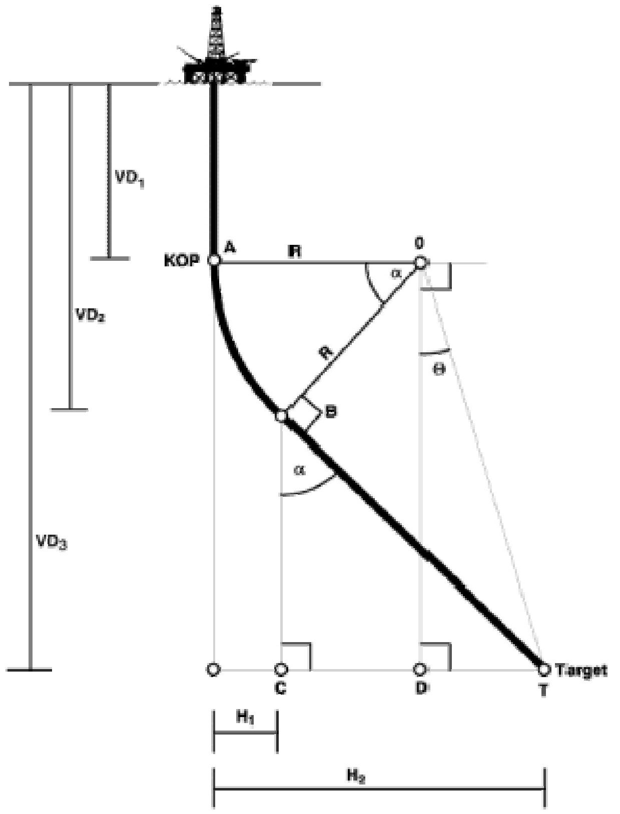

Figure 2.4.78 : Cross section through a "build and hold" type well

These Northings and Eastings must all be measured from the platform or rig reference point.

Referring to Figure 2.4.78, the build-up section is assumed to be on an arc of a circle of radius R. Let the build-up rate be BUR degrees per 100 ft.

Then

$$\frac{BUR}{100}=\frac{360}{2\pi R}$$

$$\therefore R=\frac{36,000}{2\pi(BUR)}=\frac{18,000}{\pi(BUR)}$$

$$DT=H_1-R$$

$$OD=VD_3-VD_1$$

VD_1 and VD_3 are known values

$$\text{Angle } \theta=\arctan\left[\frac{DT}{OD}\right]$$

$$OT=\sqrt{OD^2+DT^2}$$

$$B\hat{O}T=\arccos\left[\frac{R}{OT}\right]$$

$$B\hat{O}D=B\hat{O}T-\theta$$

$$\alpha=90°-B\hat{O}D$$

$$BT=\sqrt{OT^2-R^2}$$

$$BC=BT\cos\alpha$$

$$CT=BT\sin\alpha$$

We can now calculate all the required values:

$$\text{Measured depth at end of build}=VD_1+\frac{100\alpha}{BUR}$$

$$\text{Vertical depth at end of build}=VD_1+R\sin\alpha$$

$$\text{Horizontal displacement at end of build, } H_1=R(1-\cos\alpha)$$

$$\text{Alternatively, } H_1=H_2-CT$$

$$\text{Total measured depth to target}=VD_1+\frac{100\alpha}{BUR}+BT$$

Note :
The above solution assumes that the radius of curvature of the build-up section is less than the horizontal displacement of the target; that, however, need not be the case. The trainee is invited to sketch a new trajectory and work through the logic of the solution on the assumption that the R corresponding to the chosen build-up rate is greater than the horizontal displacement of the target.

S-TYPE WELL

The following information is required:

- Surface (slot) coordinates.
- Target coordinates.
- TVD of target.
- TVD of kick-off point.
- Build-up rate.
- Drop-off rate.
- TVD at the end of the drop-off section.
- Final inclination through the target.

The well is assumed to be vertical to KOP. The following values are calculated:

- Measured depth at end of build.
- TVD at end of build (VD2).
- Horizontal displacement at end of build (H1).
- Inclination of tangent section (a).
- Measured depth at start of drop.
- TVD at start of drop (VD3).
- Horizontal displacement at start of drop (H2).
- Measured depth at end of drop.
- Horizontal displacement at end of drop (H3).
- Total measured depth to target.
- Horizontal displacement of target (H4).

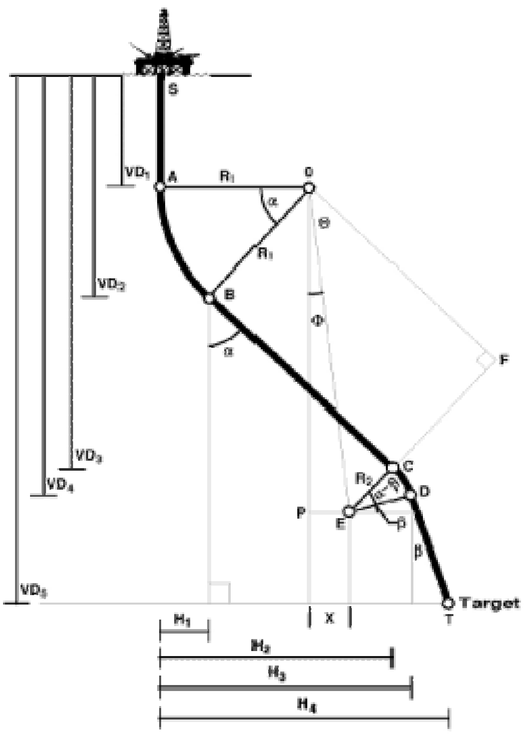

Figure 2.4.79 : Cross section through an S-type well

Let BUR be the build-up rate in degrees per 100 ft. and DOR be the drop-off rate in degrees per 100 ft. As before, the horizontal displacement of the target, H_4, is determined from slot and target coordinates. The radius of the build-up curve is calculated, as before, by:

$$R_1 = \frac{18{,}000}{\pi(BUR)}$$

Similarly , the radius of curvature of the drop section is calculated by

$$R_2 = \frac{18{,}000}{\pi(DOR)}$$

Now referring to Figure 2.4.79, OF is constructed parallel to BC, therefore:

$$\alpha = \theta + \phi$$

Angles β, H_4, VD_4 and VD_5 are known quantities

$$x = H_4 - R_1 - R_2\cos\beta - (VD_5 - VD_4)\tan\beta$$

$$OP = VD_4 + R_2\sin\beta - VD_1$$

$$EF = R_1 + R_2$$

$$OE = \sqrt{OP^2 + X^2} \text{ (in triangle OPE)}$$

$$OF = \sqrt{OE^2 - EF^2}$$

Then we have:

$$\theta = \arctan\left[\frac{R_1 + R_2}{OF}\right]$$

$$\phi = \arctan\left[\frac{x}{OP}\right]$$

Hence the inclination of the tangent section can be calculated since $\alpha = \theta + \phi$

We can now calculate all the required values:

MD at end of build $= VD_1 + \frac{100\alpha}{BUR}$

VD at end of build (VD_2) $= VD_1 + R_1\sin\alpha$

Horizontal displacement at end of build $= R_1(1 - \cos\alpha)$

MD at start of drop $= VD_1 + \frac{100\alpha}{BUR} + OF$ (BC = OF)

VD at start of drop (VD_3) $= VD_2 + OF\cos\alpha$ (BC = OF)

Horizontal displacement at start of drop (H_2) $= H_1 + BC\sin\alpha$

MD at end of drop $= VD_1 + \frac{100\alpha}{BUR} + BC + \frac{100(\alpha - \beta)}{DOR}$

VD at end of drop, V_4, was given

Horizontal displacement at end of drop, H_3 $= H_2 + R_2(\cos\beta - \cos\alpha)$

Total measured depth $= VD_1 + \frac{100\alpha}{BUR} + BC + \frac{100(\alpha - \beta)}{DOR} + \frac{VD_5 - VD_4}{\cos\beta}$

Final note: An S well which drops back to vertical is simply a special case of the above.

Appendix 2
Critical buckling forces

The tables and graphs on the following four pages give the critical buckling forces for specific values of hole inclination when using 5" S135 drillpipe and 5" Hevi-wate drill-pipe in 12 1/4" and 8 1/2" holes, with a drilling fluid density of 10.68 lbs/gal (1.28 kg/l). These are common combinations of hole size and drillpipe, and the drilling fluid density is of the order of magnitude of what will commonly be required. They provide therefore a quick approximation to the critical buckling forces which will be applicable when drilling many conventional wells in normally pressured formations.
For critical cases, or for different conditions, an exact value should be calculated as explained in Topic 10.4.
These tables and graphs have been made by applying the equations given in Topic 10.4, and using the dimensions of new drill-pipe.
The lines plotted on the graphs do not start from 0° (where the equation would indicate a zero critical buckling force) because the equation is not valid for vertical wells. In that case, where a different equation applies. F_{cr} will have a small but non-zero value. The graphs have (arbitrarily) been plotted from 2° to illustrate how sensitive the critical buckling force is to the inclination in this range.
In practice it is irrelevant whether F_{cr} is zero or small in vertical wells, because both emphasize the point that drill-pipe should only be run in compression in significantly deviated wells.

Critical buckling forces (F_{cr})
for new 5" 19.5 lbs/ft S135 drill-pipe in 12 1/4" hole

Drill pipe O.D.	5 inch	127 mm
Drill pipe I.D.	4.21 inch	106.9 mm
Drill pipe weight*	22.60 lbs/ft	33.6 Kg/m
Tool joint O.D. (NC50)	6.625 inch	168.3 mm
Hole diameter	12.25 inch	311.15 mm
Drilling fluid density	10.68 ppg	1.28 Kg/l

* Taken from API RP7G (August 1991)

Inclination	2	5	10	15	20	25	30
F_{cr} (KN)	26.20	41.4	58.4	71.3	81.9	91.1	99.1
F_{cr} (Klbs)	5.90	9.3	13.1	16.0	18.4	20.5	22.3
Inclination		35	40	45	50	55	60
F_{cr} (KN))		106.1	112.3	117.8	122.6	126.8	130.4
F_{cr} (Klbs)		23.9	25.3	26.5	27.6	28.5	29.3
Inclination		65	70	75	80	85	90
F_{cr} (KN))		133.4	135.8	137.7	139.0	139.8	140.1
F_{cr} (Klbs)		30.0	30.5	31.0	31.3	31.4	31.5

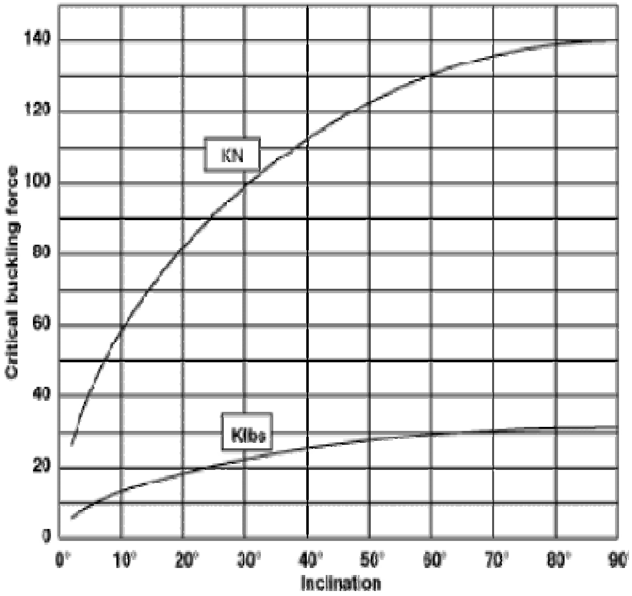

Figure 2.4.80

Critical buckling forces (F_{cr})
for new 5" Hevi-wate drill-pipe in 121/4" hole

Drill pipe O.D.	5 inch	127 mm
Drill pipe I.D.	3.00 inch	76.2 mm
Drill pipe weight*	49.30 lbs/ft	73.4 Kg/m
Tool joint O.D. (NC50)	6.50 inch	165.1 mm
Hole diameter	12.25 inch	311.15 mm
Drilling fluid density	10.68 ppg	1.28 Kg/l
* Taken from API RP7G (August 1991)		

Inclination	2	5	10	15	20	25	30
F_{cr} (KN)	50.60	79.9	112.8	137.7	158.3	176.0	191.4
F_{cr} (Klbs)	11.40	18.0	25.4	31.0	35.6	39.6	43.0
Inclination		35	40	45	50	55	60
F_{cr} (KN))		205.0	217.1	227.7	237.0	245.0	251.9
F_{cr} (Klbs)		46.1	48.8	51.2	53.3	55.1	56.6
Inclination		65	70	75	80	85	90
F_{cr} (KN))		257.7	262.4	266.1	268.7	270.2	270.7
F_{cr} (Klbs)		57.9	59.0	59.8	60.4	60.8	60.9

Critical buckling forces (Fcr)
for new 5" 19.5 lbs/ft S135 drill-pipe in 81/2" hole

Drill pipe O.D.	5 inch	127 mm
Drill pipe I.D.	4.21 inch	106.9 mm
Drill pipe weight*	22.6 lbs/ft	33.6 Kg/m
Tool joint O.D. (NC50)	6.625 inch	168.3 mm
Hole diameter	8.5 inch	215.9 mm
Drilling fluid density	10.68 ppg	1.28 Kg/l

* Taken from API RP7G (August 1991)

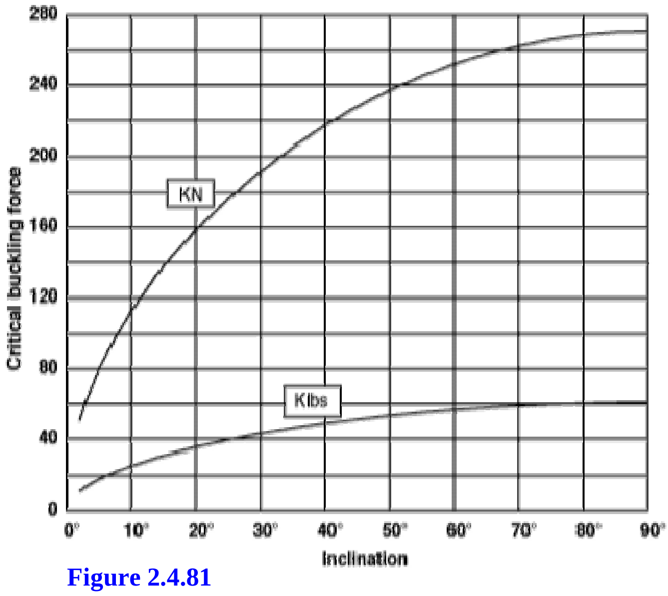

Figure 2.4.81

Inclination	0	5	10	15	20	25	30
F_{cr} (KN)	0	71.6	101.1	123.4	141.9	157.7	171.6
F_{cr} (Klbs)	0	16.1	22.7	27.8	31.9	35.5	38.6
Inclination		35	40	45	50	55	60
F_{cr} (KN))		183.8	194.5	204.0	212.4	219.6	225.8
F_{cr} (Klbs)		41.3	43.7	45.9	47.7	49.4	50.8
Inclination		65	70	75	80	85	90
F_{cr} (KN))		231.0	235.2	238.5	240.8	242.2	242.7
F_{cr} (Klbs)		51.9	52.9	53.6	54.1	54.4	54.6

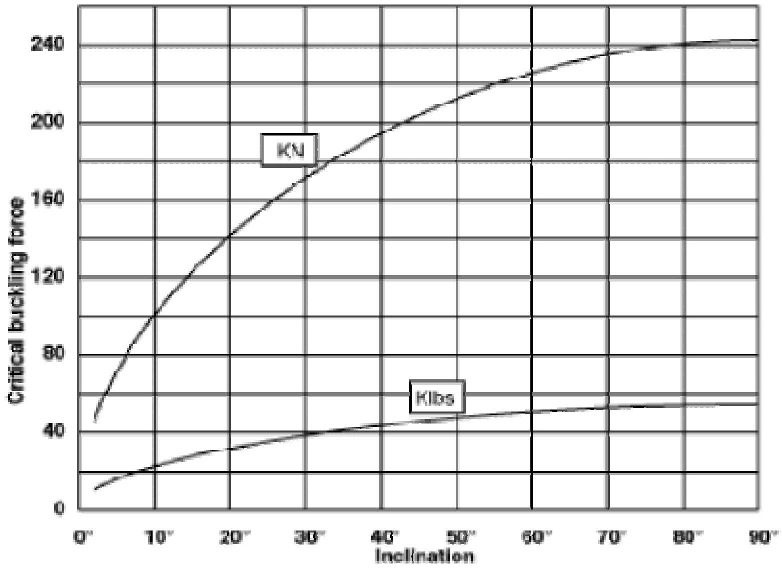

Figure 2.4.82

Critical buckling forces (Fcr)
for new 5" Hevi-wate drill-pipe in 81/2" hole

Drill pipe O.D.	5 inch	127 mm
Drill pipe I.D.	3.00 inch	76.2 mm
Drill pipe weight*	49.30 lbs/ft	73.4 Kg/m
Tool joint O.D. (NC50)	6.50 inch	165.1 mm
Hole diameter	8.25 inch	215.9 mm
Drilling fluid density	10.68 ppg	1.28 Kg/l
* Taken from API RP7G (August 1991)		

Inclination	0	5	10	15	20	25	30
F_{cr} (KN)	0	135.5	191.3	233.5	268.5	298.4	324.6
F_{cr} (Klbs)	0	30.5	43.0	52.5	60.4	67.1	73.0
Inclination		35	40	45	50	55	60
F_{cr} (KN))		347.7	368.0	386.0	401.8	415.5	427.2
F_{cr} (Klbs)		78.2	82.7	86.8	90.3	93.4	96.0
Inclination		65	70	75	80	85	90
F_{cr} (KN))		437.0	445.0	451.2	455.5	458.2	459.0
F_{cr} (Klbs)		98.2	100.0	101.4	102.4	103.0	103.2

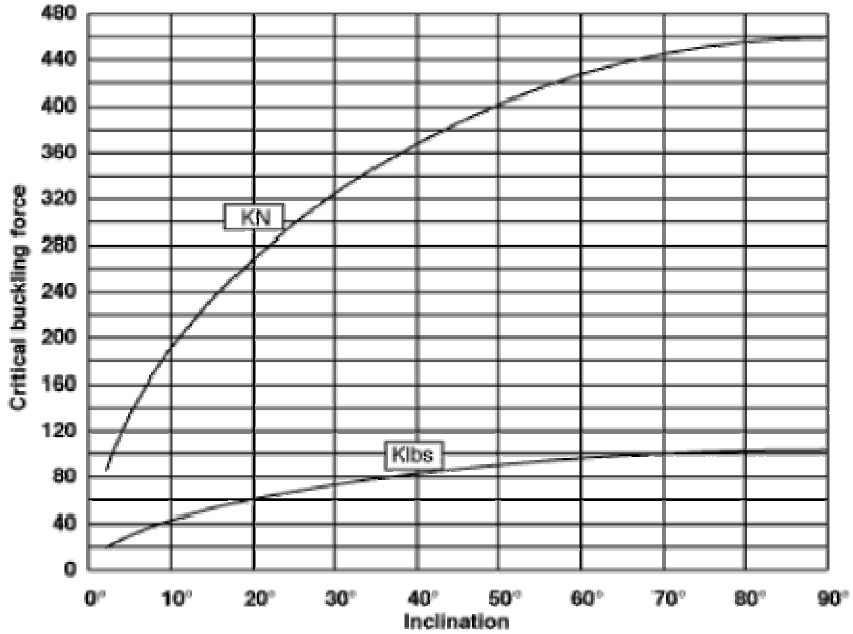

Figure 2.4.83