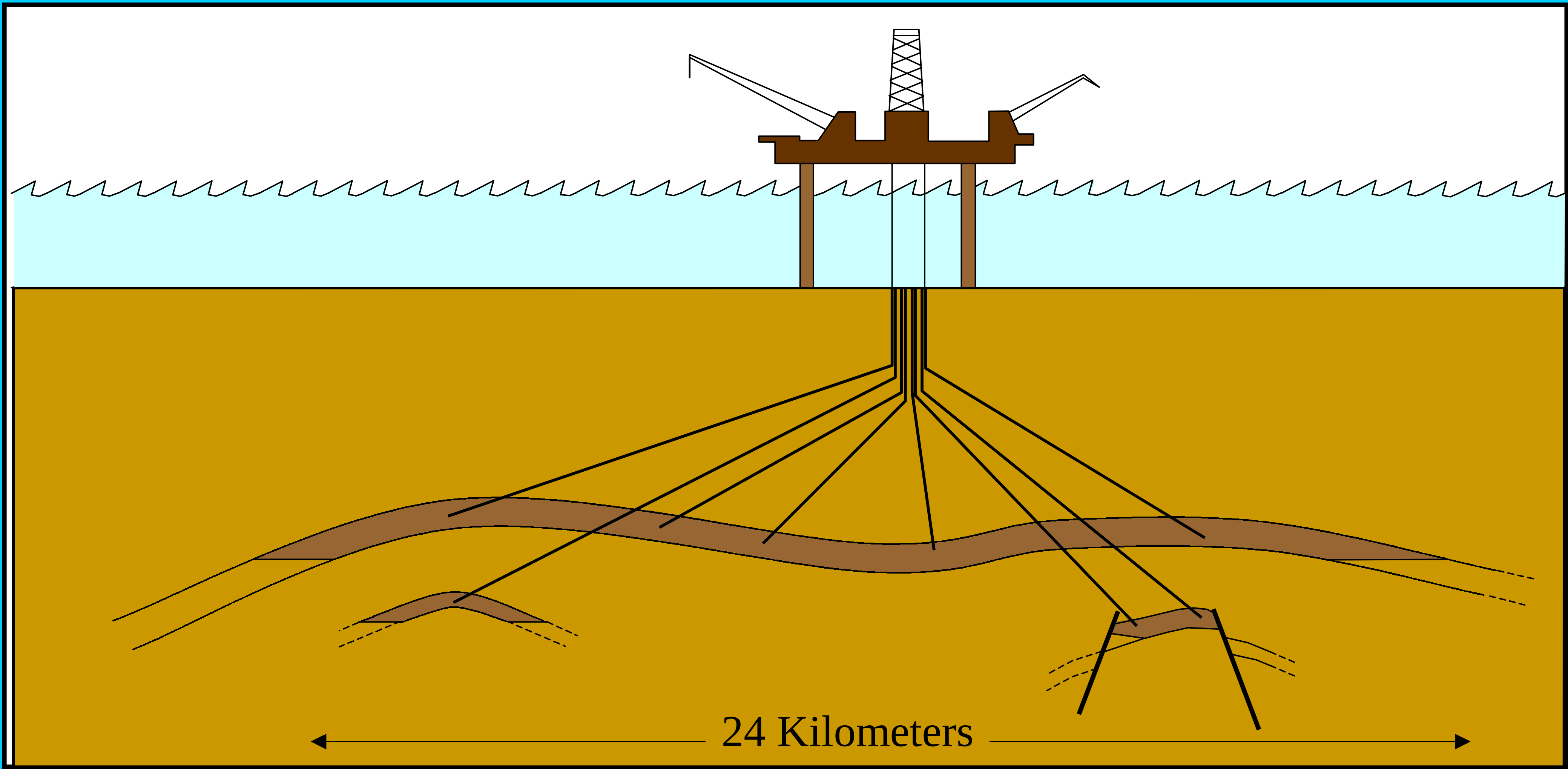
Well Engineering & Construction



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Pore Pressure

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1.0 Introduction

This chapter will present the origins of pore pressure and principles its determination. It should be emphasized here that this subject alone requires more than one book to cover in detail.

Hence the emphasis will be placed on the practical utilisation of pore pressure in the well planning process. It is hoped that the ideas presented here will help the engineer to better understand lithological columns and deduce potential hole problems before producing a final well plan.

Knowledge of formation pressures is vital to the safe planning of a well. Accurate values of formation pressures are used to design safe mud weights to overcome fracturing the formation and prevent well kicks. The process of designing and selection of casing weights/grades is predominately dependent on the utilisation of accurate values of formation pressure. Cementing design, kick control, selection of wellhead and Xmas trees and even the rig rating are dependent on the formation pressures encountered in the well.

2.0 DEFINITIONS

All formations penetrated during the drilling of a well contain pressure which may vary in magnitude depending on depth, location and proximity to other structures. In order to understand the nature, extent and origin of formation pressures, it is necessary to define and explain basic wellbore pressure concepts.

2.1 HYDROSTATIC PRESSURE

Hydrostatic pressure is defined as the pressure exerted by a column of fluid. The pressure is a function of the average fluid density and the vertical height or depth of the fluid column.

Mathematically, hydrostatic pressure is expressed as:

$$HP = g \times \rho_f \times D \qquad (1.1)$$

where:
HP = hydrostatic pressure
g = gravitational acceleration
ρ_f = average fluid density
D = true vertical depth or height of the column

In field operations, the fluid density is usually expressed in pounds per gallon (ppg), psi per foot, pounds per cubic foot (ppf) or as specific gravity (SG).

In the Imperial system of units, when fluid density is expressed in ppg (pounds/gallon) and depth in feet, the hydrostatic pressure is expressed in psi (lb/in^2):

$$HP\ (psi) = 0.052 \times \rho_f\ (ppg) \times D\ (ft) \qquad (1.2)$$

For the purposes of interpretation, all wellbore pressures, such as formation pressure, fracture pressure, fluid density and overburden pressure, are measured in terms of hydrostatic pressure.

When planning or drilling a well it is often more convenient to refer to hydrostatic pressures in terms of a pressure gradient. A pressure gradient is the rate of increase in pressure per unit vertical depth i.e., psi per foot (psi/ft). It should be noted that fluid densities, measured in ppg or SG, are also gradients.

Hydrostatic pressures can easily be converted to equivalent mud weights and pressure gradients.Hydrostatic pressure gradient is given by:

$$HG = HP / D \quad \ldots \text{(psi/ft)} \tag{1.3}$$

It is usual to convert wellbore pressures to gradients relative to a fixed datum, such as seabed, mean sea level or ground level. The resulting figure (pressure gradient) allows direct comparison of pore pressures, fracture pressures, overburden pressures, mud weights and Equivalent Circulating Density (ECD) on the same basis. In addition the use of pressure gradients accentuates variations in pressure regimes in a given area when values are plotted or tabulated.

When pressure gradients are used to express magnitudes of wellbore pressure, it is usual to record these as Equivalent Mud Weight (EMW) in ppg.

Example 1.1: Hydrostatic Pressure

Calculate the hydrostatic pressure for the following wells:

a. mud weight = 9 ppg, hole depth = 10100 ft MD (measured depth), 9900 ft TVD (true vertical depth)

b. mud gradient = 0.468 psi / ft, hole depth = 10100 ft MD (measured depth), 9900 ft TVD (true vertical depth)

Solution

a. From **Equation (1.2)**:

HP (psi) = 0.052 x ρ_f (ppg) x D (ft) = 0.052 x 9 x 9900 = 4632 psi

b. Hydrostatic pressure = fluid gradient (psi / ft) x depth (ft)..........psi

= 0.468 (psi /ft) x 9900(ft) = 4633 psi

2.2 Porosity & Permeability

Porosity is the total pore (void) space in a rock

Permeability is the ease with which fluids can flow through through the rock.

2.3 Overburden Pressure

The overburden pressure is defined as the pressure exerted by the total weight of overlying formations above the point of interest. The total weight is the combined weight of both the formation solids (rock matrix) and formation fluids in the pore space. The density of the combined weight is referred to as the bulk density (ρ_b).

The overburden pressure can therefore be expressed as the hydrostatic pressure exerted by all materials overlying the depth of interest:

$$\sigma_{ov} = 0.052 \text{ x } \rho_b \text{ x } D \tag{1.4}$$

where

σov = overburden pressure (psi)
ρ_b = formation bulk density (ppg)
D = true vertical depth (ft)

And similarly as a gradient (EMW) in ppg:

$$\sigma_{ov} = \frac{0.433 x \rho_b}{0.052} \tag{1.5}$$

σovg = overburden gradient, ppg

ρ_b = formation bulk density (gm/cc)

(the factor 0.433 converts bulk density from gm/cc to psi/ft)

In a given area, the overburden gradient is not constant with depth due to variations in formation density. This results from variations in lithology and pore fluid densities. In addition the degree of compaction and thus formation density, increases with depth due to increasing overburden.

A useful equation for calculating the overburden gradient under field conditions of varying lithological and pore fluid density is given by:

$$\sigma_{ovg} = 0.433[(1-\phi)\rho_{ma} + (\phi x \rho_f)] \tag{1.6}$$

where

σovg= overburden gradient, psi/ft

ϕ = porosity expressed as a fraction

ρ_f= formation fluid density, gm/cc

ρ_{ma}= matrix density, gm/cc

Note the densities in **Equation (1.6)** are expressed in gm /cc, instead of the usual units of ppg. With the exception of the oil industry, all other industries use the Metric system of units where density is usually expressed in gm/cc. The oil industry borrows many of its measurements from other industries.

A list of typical matrix and fluid densities is included in **Table 1.1** below:

Table 1.1

Substance	Density (gm/cc)
Sandstone	2.65
Limestone	2.71
Dolomite	2.87
Anhydrite	2.98
Halite	2.03
Gypsum	2.35
Clay	2.7 - 2.8
Freshwater	1.0
Seawater	1.03 - 1.06
Oil	0.6 - 0.7
Gas	0.15

To convert densities from gm/cc to gradients in psi/ft simply use:

$$\text{Gradient (psi/ft)} = 0.433 \times (\text{gm /cc}) \tag{1.7}$$

To convert from psi/ft to ppg, use:

$$\text{Density (ppg)} = \text{gradient (psi/ft)} / 0.052 \quad (1.8)$$

2.4 Generation of Overburden vs. Depth Graph

The calculation and compilation of the overburden gradient for a given field or area is the building block for a well plan. In addition, the overburden gradient is used in the analysis of pore and fracture pressures.There are many techniques for the quantification of pore pressure and fracture pressure from drilling and petrophysical data which all require input of overburden gradient data. **Figure 1.1** **a** shows a plot of bulk density vs. depth, which is generated from wireline logs. This figure can then be used to generate an overburden gradient vs. depth plot by merely applying **Equation (1.4)** at selected depths, as shown in **Figure 1.1** **b**.

Example 1.2: Overburden Gradient Calculations

Calculate the overburden gradient for the following:

Formation type: sandstone, density = 2.65 gm/cc

Formation water: 1.03 gm/cc

For porosities 5%, 20% and 35%.

Solution

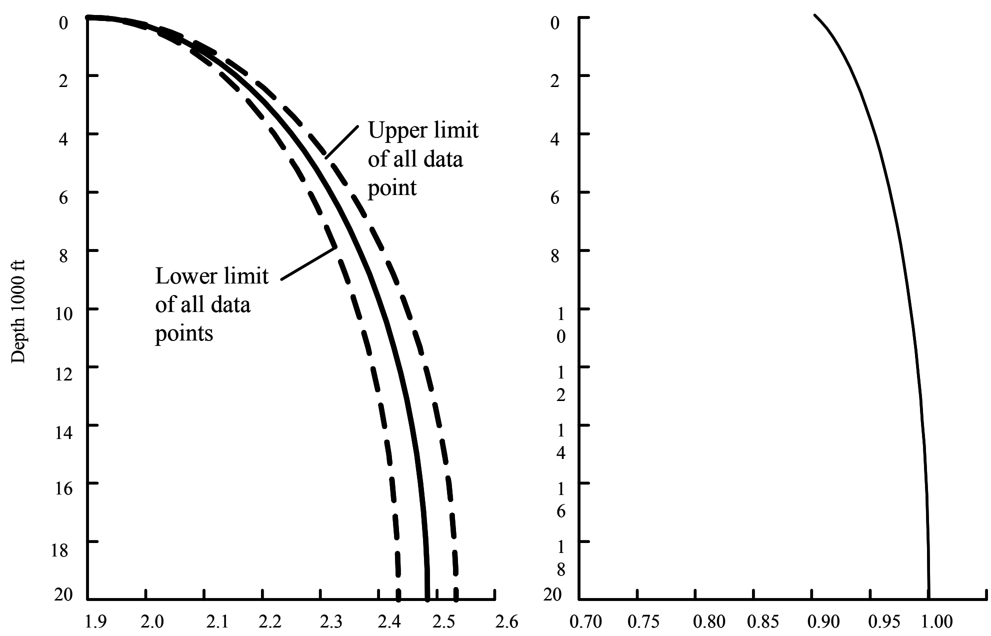
For Sandstone

For $\phi = 5\%$ $\sigma ovg = 0.433 \times [(1 - 0.05) \times 2.65 + (0.05 \times 1.03)] = 1.11$ psi/ft

For $\phi = 20\%$ $\sigma ovg = 1.01$ psi/ft

For $\phi = 35\%$ $\sigma ovg = 0.90$ psi/ft-

Figure 1.1 Construction of Overburden Gradient



a. Bulk density (g/cc) b. Overburden stress gradient (psi/ft)

2.5 Effects of Water Depth On Overburden Gradient

In offshore operations, the depth of the sea (length of the water column) determines how much the overburden gradient is reduced. The reduction in overburden gradient is due to water being less dense than rock and for a given height; the hydrostatic head caused by water is less than that caused by any rock. The resultant effect is that as the water depth increases, the numerical value of the overburden gradient and in turn the fracture gradient reduce. Hence, offshore wells will have lower overburden gradient near the surface due to the influence of seawater and air gap and the uncompacted sediments. In onshore wells, the near surface overburden gradient is influenced mainly by the uncompacted surface sediments.

Example 1.3: Overburden Gradient Calculations For Offshore Wells

Determine the overburden gradient at various depths for the following offshore well:

Water Depth= 500 ft

RKB/MSL= 65 ft

Specific gravity of sea water= 1.03 gm/cc

Rock density= 1.9 gm/cc from seabed to 1000ft, and 2.1gm/cc from 1000-3000 ft

Calculate the overburden gradient of the formations:

At seabed, 200 ft, 500 ft, 1000 ft and at 3000 ft below seabed.

Solution

Remember to convert densities from gm/cc to psi/ft using Equation (1.7).

a. At seabed

Water pressure = 0.433 (psi/ft) x 1.03 (gm/cc) x 500 (ft) = 223 psi

Overburden gradient (OBG) = water pressure / depth

= 223/ (500+65) = 0.395 psi/ft = 7.6 ppg

b. At 200 ft below seabed

Water pressure= 223 psi

Weight of formation= 0.433 x 1.9 x 200 ft = 164.54 psi

Overburden gradient (OBG) = total weight of sea water and rocks /total depth

= (223 + 164.5)/ (500+65+200)

= 0.507 psi/ft = 9.74 ppg

c. At 500 ft below seabed

Water pressure= 223 psi

Weight of formation= 0.433 x 1.9 x 500 ft = 411.4 psi

Overburden gradient (OBG) = total weight of sea water and rocks /total depth

= (223 + 411.4)/ (500+65+500)

= 0.605 psi/ft = 11.5 ppg

d. At 1000 ft below seabed

Water pressure = 223 psi

Weight of formation

= 0.433 x 1.9 x1000 ft = 822.7 psi

Overburden gradient (OBG) = total weight of sea water and rocks /total depth

= (223 + 822.7)/ (500+65+ 1000)

= 0.668 psi/ft = 12.9 ppg

e. At 3000 ft below seabed

Water pressure = 223 psi

Weight of formation (with density of 1.9 gm/cc)= 0.433 x 1.9 x1000 ft = 822.7 psi

Weight of formation (with density of 2.1 gm/cc)= 0.433 x 2.1 x2000 ft = 1818.6 psi

Overburden gradient (OBG) = total weight of sea water and rocks /total depth

= (223 + 822.7+1818.6)/ (500+65+ 3000

=0.8035 psi/ft = 15.5 ppg

Table 1.2 may be completed for water depths ranging from 100 ft to 5000 ft.

Table 1.2 Overburden Gradient For Offshore Operations

Formation Depth	Overburden Gradient, ppg			
	Water Depth, ft			
	100	500	1000	5000
Seabed	5.2	7.6	8.05	8.47
200 ft	11.0	9.74	9.28	8.75
500 ft	13.2	11.5	10.54	9.13
1000 ft	14.32	12.9	11.81	9.68
3000 ft	16.3	15.4	14.61	11.62

2.6 Matrix Stress

Matrix stress is defined as the stress under which the rock material is confined in a particular position in the earth's crust. The matrix stress acts in all directions and is usually represented as a triaxial stress, using the Greek symbol σ, pronounced Sigma (further details are given in **Chapter 2**.

The vertical component of the matrix stress is that portion which acts in the same plane as the overburden load. The overburden load is supported at any depth by the vertical component of the rock matrix stress (σ_{mat}) and the pore pressure. This relationship is expressed as:

$$\sigma_{ov} = P_f + \sigma_{mat} \tag{1.9}$$

The above simple expression is used in many mathematical models to quantify the magnitudes of pore pressure using data from various drilling or petrophysical sources.

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3.0 Pore Pressure

Pore pressure is defined as the pressure acting on the fluids in the pore spaces of the rock. This is the scientific meaning of what is generally referred to as formation (pore) pressure.

Depending on the magnitude of pore pressure, it can be described as being either normal, abnormal or subnormal. A definition of each follows.

3.1 Normal Pore Pressure

Normal pore pressure is equal to the hydrostatic pressure of a column of formation fluid extending from the surface to the subsurface formation being considered In other words, if the formation was opened up and allowed to fill a column whose length is equal to the depth of the formation then the pressure at the bottom of the column will be equal to the formation pressure and the pressure at surface is equal to zero.

Normal pore pressure is not a constant. The magnitude of normal pore pressure varies with the concentration of dissolved salts, type of fluid, gases present and temperature gradient. For example, as the concentration of dissolved salts increases the magnitude of normal pore pressure increases.

3.2 Abnormal Pore Pressure

Abnormal pore pressure is defined as any pore pressure that is greater than the hydrostatic pressure of the formation water occupying the pore space. Abnormal pressure is sometimes called overpressure or geopressure. Abnormal pressure can be thought of as being made up of a normal hydrostatic component plus an extra amount of pressure. This excess pressure is the reason why surface control equipment (e.g. BOPs) are required when drilling oil and gas wells.

Abnormal pore pressure can occur at any depth ranging from only a few hundred feet to depths exceeding 25,000 ft. The cause of abnormal pore pressure is attributed to a combination of various geological, geochemical, geothermal and mechanical changes. However for any abnormal pressure to develop there has to be an interruption to or disturbance of the normal compaction and de-watering process as will be outlined later in this chapter.

3.3 Subnormal Pore Pressure

Subnormal pore pressure is defined as any formation pressure that is less than the corresponding fluid hydrostatic pressure at a given depth.

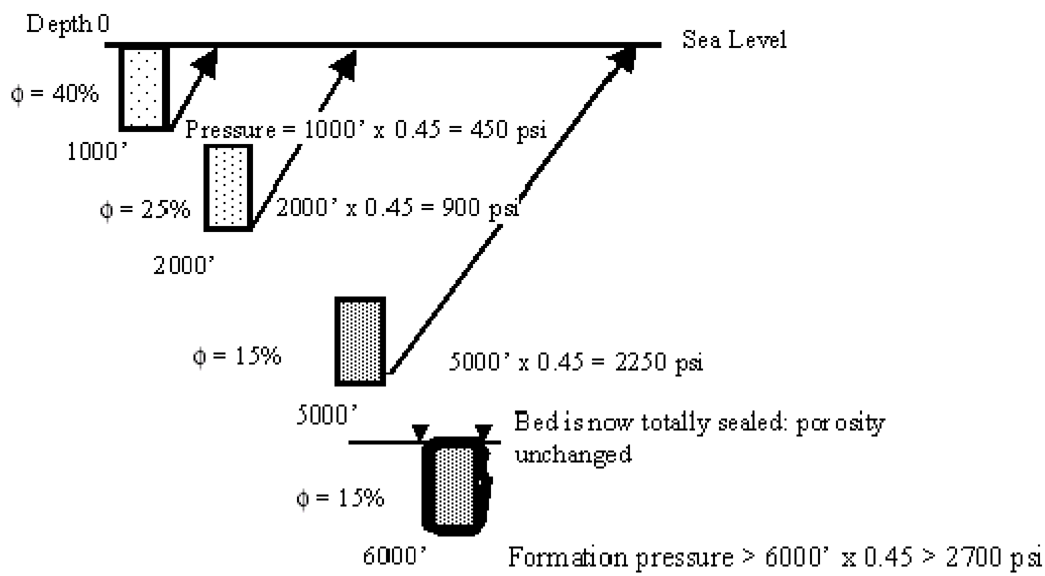
Subnormal pore pressures are encountered less frequently than abnormal pore pressures and are often developed long after the formation is deposited. Subnormal pressures may have natural causes related to the stratigraphic, tectonic and geochemical history of an area, or may have been caused artificially by the production of reservoir fluids. The Rough field in the Southern North Sea is an example of a depleted reservoir with a subnormal pressure.

4.0 Causes Of Abnormal Pore Pressure

Abnormal pore pressure is developed as a result of a combination of geological, geochemical, geophysical and mechanical process as will be discussed in the following paragraphs. These causes may be summarised under:

- Depositional Effects
- Diagenetic Processes
- Tectonic Effects
- Structural Causes; and
- Thermodynamic Effects

Figure 1.2 Pore Pressure Development Due to Undercompaction



4.1 Depositional Effects

4.1.1 Undercompaction of Shales

Normal compaction of sediments occurs as follows:

1. The volume of a sediment is reduced as the grains are squeezed together due to the weight of the overlying sediments.
2. The weight of the overlying sediments causes a reorganization of the grains of the volume of sediments below and the expulsion of intergranular fluid.
3. The porosity of the volume sediment is reduced.
4. The degree of compaction is controlled by original porosity, the amount of pore fluid and shape and degree of sorting of rock grains.
5. Normal compaction usually leaves the pore fluid in the sediment at hydrostatic or normal pressure.

Undercompaction of sediments is the process whereby abnormal pore pressure is developed as a result of a disruption of the balance between rate of sedimentation of clays and the rate of expulsion of the pore fluids as the clays compact with burial.

Water-wet sediments are usually carried by rivers and deposited in seas. A good example of a current deposition situation is the Nile Delta in Egypt formed by sediments carried by the Nile river into the Mediterranean sea. It should be noted that these sediments are mostly clays with adsorbed water sandwiched between the solid clay particles.

When the first deposited layer undergoes compaction as a result of further sedimentation, some of the interstitial water which is continuous with the overlying seawater will be expelled to the sea. As the interstitial or pore fluid is in contact with the sea the pressure in the pores (or pore pressure) is normal, see **Figure 1.2**. The value of this normal pressure at say 1000 ft is approximately 450 psi assuming a sea water gradient of 0.45 psi/ft, as shown in **Figure 1.2**.

As sedimentation continues, the clays are compacted further; the solid layers are squeezed closer together and the pore water is expelled to the sea. The clay sediment has high permeability and porosity (60-90%). In this initial state, as long as the rate of sedimentation remains fairly slow, the pore fluid will continue to escape as compaction increases and therefore the clay will continue to exhibit a normal pore pressure (see **Figure 1.2**)

If the equilibrium between compaction and expulsion of water is disrupted such that the pore fluid cannot escape, abnormal pore pressure will result. This disruption can result from:

- an increase in the rate of sedimentation
- reduction in the rate of fluid expulsion caused by (i) a decrease in permeability due to solids blocking the passages or (ii) the deposition of a permeability barrier such as limestone or evaporite stringers.

When disruption to the normal compaction process occurs, three things happen:

1. the same volume of pore fluid remains in the rock
2. porosity of the rock is maintained at the new depth and fluids can not escape and compaction of the rock is prevented

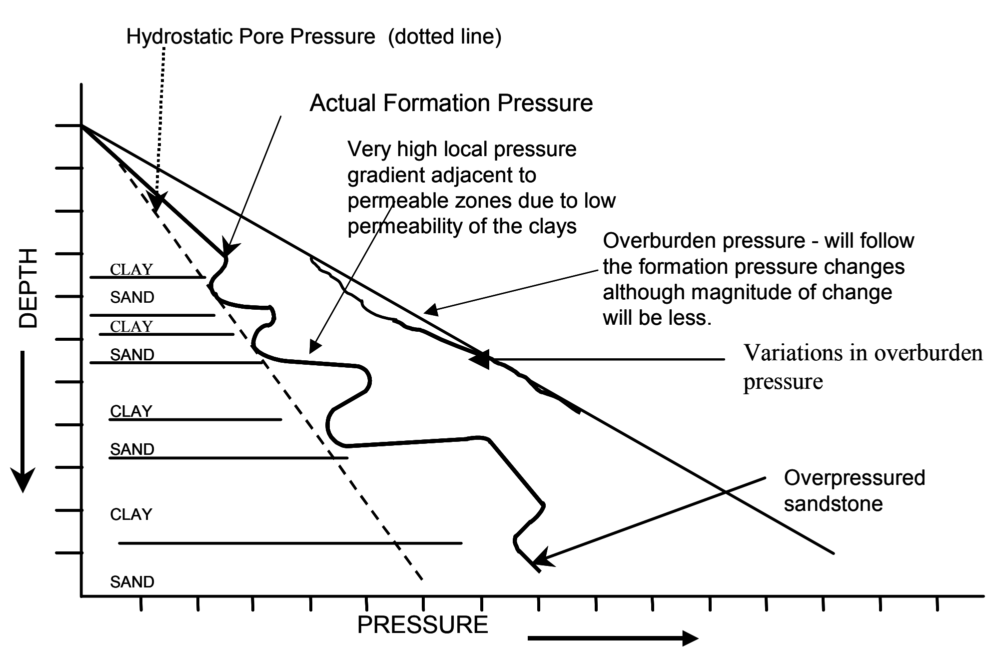
3. the fluid begins to support the increasing weight of the overburden and consequently its pressure increases and further compaction is inhibited.

Abnormal pore pressure resulting from this process will have a gradient no greater than the overburden gradient, as the pressures are being produced by the excess overburden load being supported by the trapped pore fluid. In **Figure 1.2**, at 6000 ft the formation pressure would be greater than the normal pressure of 2700 psi, but would be less than the overburden pressure of 6000 psi, assuming an overburden gradient of 1 psi/ft.

Such mechanisms of clay undercompaction and resulting abnormal pore pressure development are common throughout the world, the Gulf of Mexico and Papua New Guinea are largely attributed to this cause.High rates of sedimentation are proposed by many authors as being the dominant cause of North Sea tertiary clay overpressures.

It should be noted that the majority of pressure detection techniques are based on establishing a normal clay compaction trend and any deviation from this normal trend is an indication of overpressure or less frequently underpressure.

Figure 1.3 OverPressure At Clay/ Sand Boundaries, After Ref 1



If beds of permeable sandstones are present within a clay sequence and these permeable sands possess a hydraulic conduit to a zone of a lower potential [1] then rapid de-watering of the clay can occur at the clay/sand boundary as compaction increases. This rapid dewatering of the clays and the increased overburden causes a decrease in the porosity and permeability preventing further flow of water and eventually results in overpressure development (see **Figure 1.3**). The reduced permeability impedes the flow of fluid from the clay causing the entrapped fluid to carry a greater proportion of the overburden and in turn be overpressured.

These clay/sand sequences can exhibit marked pressure gradient differences between sand and clay units as shown in **Figure 1.3**.

4.1.2 Deposition of Evaporites

The deposition of evaporites can create high abnormal pore pressures in the surrounding zones with the pore pressure approaching the overburden gradient. Halite is an evaporitic rock formed from the evaporation of sea waters; its thickness varies from a few feet to thousands of feet. Halite is totally impermeable to fluids and behaves like a sponge (highly viscous) absorbing the overburden stress from above and then exerting equal stresses in all three directions. This is an extremely important property as it indicates that the horizontal stress is equal to the overburden stress. As we shall see in **Chapter 5**, this stress system requires casing set across salt section to have a very high collapse strength.

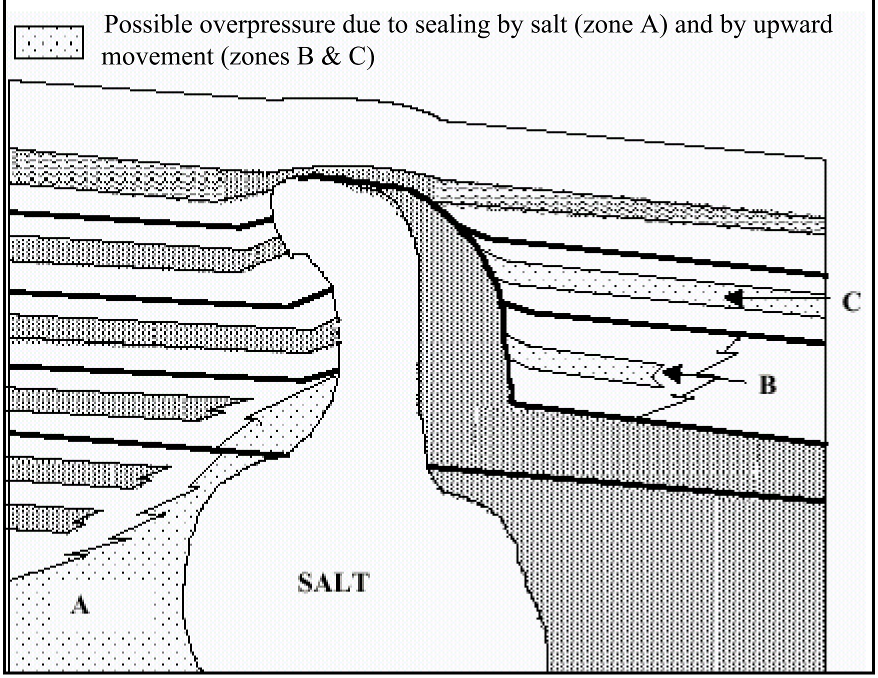
When salt is deposited, the pore fluids in the underlying formations cannot escape and therefore become trapped and abnormally pressured.

Salt Diaparism

Diapirism is the piercement of a formation by a plastic, mobile, less dense underlying formation, typically salt. Salt exhibits plastic behaviour at elevated temperatures and pressures and due to its low density will move upwards to form salt domes in overlying formations.

Salt has no porosity and no permeability and therefore can be a perfect seal.Indeed, the Rotliegendes gas reservoirs in the Southern North Sea owe their existence to the perfect seal provided by the Zechstein salt.

Figure 1.4 Overpressure caused By Salt Diapairism



The creation of the salt dome can lead to abnormal pressure development in surrounding formations in two ways:

- Firstly, the movement of the salt creates additional tectonic stresses within the overlying sediments whilst at the same time providing a lateral seal limiting pore water expulsion. These tectonic stresses usually create folding and faulting in the surrounding zones.
- Secondly the salt may encapsulate rafters of overlying formations (usually limestones and dolomites) as it flows upwards, trapping pressures within the rafters. In this instance the salt prohibits further de-watering of the rafter and abnormal pressure will develop.

Examples of rafting resulting in extreme abnormal pressure can be seen in the Gotnia formation in Kuwait, where abnormal pore pressures of 19.5 ppg are observed in limestone rafters. A typical distribution of abnormal pore pressure regimes around a salt dome is shown in **Figure 1.4.**

Platten Dolomite rafters are usually encountered while drilling zechstein sequences in the Southern North Sea. Saltwater pressures have been encountered with pressure gradients as high as 19 ppg.

4.1.3 Diagenetic Processes

With increasing pressure and temperature, sediments undergo a process of chemical and physical changes collectively known as diagenesis. Diagenesis is the alteration of sediments and their constituent minerals during post depositional compaction. Diagenetic processes include the formation of new minerals, recrystallisation and lithification.

Diagenesis may result in volume changes and water generation which if occurring in a seabed environment may lead to both abnormal or sub-normal pore pressure.

Clay Diagenesis (Conversion of Smectite to Illite) [1]

The diagenetic changes which occur in shales are one of the most important mechanisms by which abnormal pressure may be generated in a marine environment.

On initial burial, marine clays are composed of predominantly smectite clays of which montmorillonite is by far the most common. Montmorillonite has a swelling lattice and contains approximately 70-85% water during initial deposition. The water is held as interlayer water between the clay platelets and also as free pore water. This environment is usually alkaline in nature and is rich in calcium and magnesium ions but poor in potassium ions. Clay structure is discussed in **Chapter 7**, **Figure 7.1**.

Upon further burial, compaction expels most of the free pore water and the water content is thus reduced to approximately 30%. With further burial, there will be increases in both the overburden load and temperature and these two effects cause all but the last layer of structural water to be expelled to the pore space. This causes the clay lattice to collapse and in the presence of potassium ions, montmorillonite diagenesis to illite [1] occurs.

If the water released in this process cannot escape during compaction, then the pore fluid will support an increased portion of the overburden and will thus be abnormally pressured.

The transition from montmorillonite to illite is dependent on depth, temperature and ionic activity. In areas of high geothermal gradient, the alteration occurs at shallow depths than those with low geothermal gradient. In the North Sea, the diagenesis process of clays is thought to occur at temperatures of 90-100 deg C and at depths from 6500 – 9750 ft.

Diagenesis of Sulphate Formations

Anhydrite ($CaSO_4$) is diagenetically formed from the dehydration of gypsum ($CaSO_4 . 2H_2O$). During the process large volumes of water are released and this is accompanied by a 30-40% reduction in formation volume. However, with the liberated water, a net 1% volume increase is observed [1].

The process is most commonly responsible for abnormal pressures in halite/anhydrite sequences. As the diagenetic change takes place and water is produced, the halite acts as a totally impermeable barrier. The water remains held at the halite/ anhydrite boundary and supports very large portions of the overburden gradient. When drilled, high pressure saltwater flows are common.

Diagenesis of Volcanic Ash

The diagenesis of volcanic ash results in three main products; clay minerals, methane and carbon dioxide. Thus formations that contain large amounts of volcanic ash may become overpressured due to the production of these gases. Overpressure encountered in the South China Sea and NW Coastal USA is attributed to this cause.

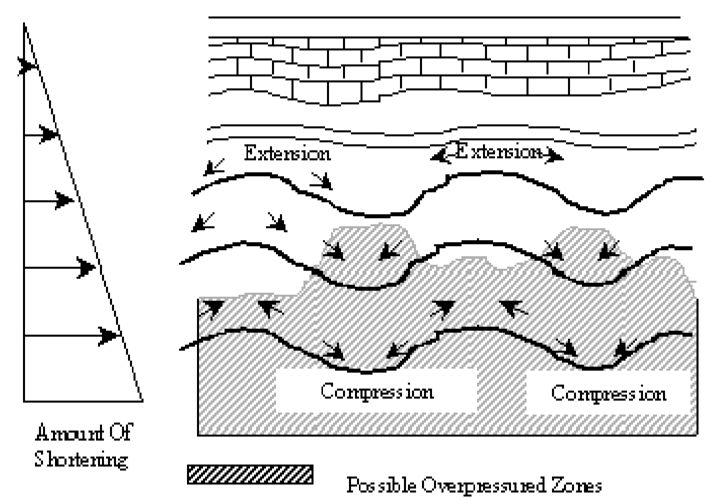
4.1.4 Tectonic Effects

Tectonic activity can result in the development of abnormal pore pressure as a result of a variety of mechanisms including: folding, faulting, uplift and salt diaparism.Salt diaparism was discussed earlier.

Folding

Folding is produced by the tectonic compression of a geological basin.The additional horizontal tectonic stress created by folding compacts the clays laterally. For the formation to remain normally pressured, the increased compaction must be balanced by pore water expulsion. If the formation water cannot escape, abnormal pressure will result,**Figure 1.5**.

Figure 1.5 Overpressure Due To Folding[1]



The magnitude of pressure generated can exceed the overburden gradient due to the additional tectonic stress which may be balanced by the pore pressure.Examples of abnormal pressure development associated with folding are common, most notably Southern Iran (Qum and Aghar Jari fields) where pressure gradients of 19 ppg are observed. The Tapungato field in Argentina is another example.

Faulting

Faulting in sedimentary rocks is caused by tectonic activities. Sedimentary beds are broken up, moved up and down or twisted.There are a variety of reasons why abnormal pressure develop due to faulting:

1. The fault plane act as a seal against a permeable formation thereby preventing further pore fluid expulsion with compaction. The permeable zone will become overpressured.
2. If the fault is non sealing, it may transmit fluids from a deeper permeable formation to a shallower zone, causing abnormal pressures in the shallow zone.

3. A zone may move down the fault plane causing the zone to be subjected to a higher overburden pressure and higher geothermal temperature. If the zone further compacts and the pore fluids can not escape, abnormal pressure will result.

4. Rate of sedimentation usually increases on the downthrown block and this rapid sedimentation can lead to undercompaction and development of overpressure.

Uplift

If a normally pressured formation is uplifted to a shallower depth then the formation will appear to have an abnormal pressure due to the fact that the formation pressure has more hydrostatic pressure than a corresponding normally pressured zone at the same depth. In some cases, this abnormal pressure is further increased if uplifting was followed by a corresponding erosion of the overburden. However, unless the formation remains totally sealed, the increase in pressure due to uplifting is offset by a decrease in pressure due to cooling effects caused by moving from greater depth to a shallower depth.

4.2 Structural Causes

4.2.1 Reservoir Structure

Abnormal pore pressure can exist in both horizontal and non-horizontal reservoir structures which contain pore fluids of differing densities i.e. water, oil and gas. Examples of structures in which this may occur are lenticular reservoirs, dipping reservoirs and anticlinal reservoirs.

In dipping reservoirs, formation pressures which are normal in the deepest water zone of the reservoir, will be transmitted to the updip part of the structure.

In large structures or gas reservoirs, the overpressure gradient contrast developed can be quite significant. Therefore, careful drilling practices should be adopted in order to minimise the risks associated with high overbalance as the reservoir is drilled down through the water zone.

Figure 1.6 Overpressure Due To Density Differences

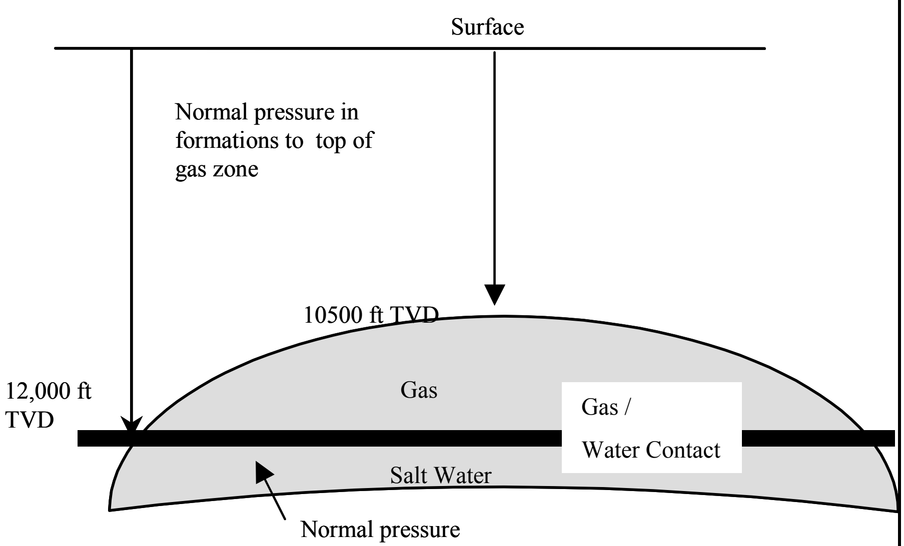


Figure 1.6 illustrates the development of abnormal pressure in an anticlinal reservoir. The normal pressure in the area is assumed to be 9 ppg. The reader can verify that the pressure at the top of the gas is in fact abnormal (= 5466 psi or 10 ppg) compared to adjacent formations at the same depth by carrying out simple hydrostatic pressure calculations as shown in **Figure 1.6**.

4.2.2 Piezometric Fluid Level

A Piezometric fluid level is an imaginary surface which defines the level to which ground water will rise in a well. For example, the water table is a piezometric fluid level. The depth of water table below surface is dependent on the topography in the area and the degree of erosion.

Aquifer systems can exhibit abnormal pore pressure dependent upon the structure of the aquifer and the relative elevation of the wellsite to the water table elevation. Abnormal pore pressure will be experienced if the water table in the aquifer is higher than the wellsite elevation. Conversely subnormal pressures may be experienced if the elevation of the wellsite is greater than the elevation of the water table in the aquifer.

The influence of piezometrics is most noticeable in onshore wells in arid areas and in near shore wells affected by the sea and flowing rivers.

4.3 Thermodynamic Processes

Thermodynamic processes may be considered as additional contributory factors in most of the causes of abnormal pore pressures discussed earlier. The various thermodynamic processes which may cause abnormal pore pressure formation are discussed below.

4.3.1 Organic Matter Transformation (Thermal Cracking)

At high temperatures and pressures associated with deep burial, complex hydrocarbon molecules (kerogen) will break down into simpler compounds. Kerogen alters to hydrocarbon at 90 deg C. This thermal cracking of the compound can result in 2 to 3 fold increases in the volume of the hydrocarbon. If this occurs in a sealed environment, high pore pressures could result. The pressures will be substantially increased if the hydrocarbon system becomes gas generative. This happens when oil is cracked to gas.

This cause has been postulated as a possible cause of the high (17 ppg) pore pressures recorded in the high pressure/high temperature (HP/HT) reservoirs in the deep Jurassic claystones and sandstones of the central North Sea. In some areas of the central North Sea, the pore pressure of the gas is almost equal to the fracture gradient making the drilling and control of these wells extremely difficult. The cost of drilling and completing one such deep, well in the central North Sea was £55 million in the year 2000.

4.3.2 Aquathermal Effects

The earth temperature normally increases linearly with depth. As formations are buried deep into the earth, their temperature will also increase. If the formations are totally sealed preventing escape of fluid then abnormal pressure will develop as described before.

Abnormally pressured formations typically exhibit a higher than normal porosity and therefore a higher than normal pore fluid content. Due to the high fluid content and the clay acting as an insulator of the earth's heat, the increased temperature causes thermal expansion of pore fluids (pressure cooker effect) resulting in increased pore pressure.

Any rock which is lowered in the geothermal gradient could develop abnormal pressure due to the expansion of fluids with increasing temperature. However, the earth movement required to increase the temperature significantly typically occurs at such a slow rate that any fluid expansion should be compensated by fluid expulsion[1]. Therefore it is obvious that for the aquathermal pressuring to have any effect on the pore pressure gradient, the formation would have to be totally sealed without loss of any fluid. If fluid leaked by even the smallest amount, then pressure increase due to thermal effects would be minimal [1].

4.3.3 Osmosis

Osmosis is defined as the spontaneous flow of fluid from a more dilute solution to a more concentrated solution across a semi-permeable membrane.

The osmotic pressure across the membrane is proportional to the concentration differential. For a given concentration, the differential osmatic pressure is also found to increase with temperature.

Relating this process to the wellbore, it can be shown that a relatively clean clay can act as a semi-permeable membrane. Therefore if salinity variations exist between claystone beds, osmotic flow can occur from the formation with less concentrated pore fluid to the more concentrated formation. If the flow is towards an isolated formation then a pressure build up can occur. In addition the osmotic potential existing across a formation may inhibit the normal de-watering process and thus lead to abnormal pore pressure development.

4.3.4 Permafrost

In Alaska and Siberia, drilling and production operations may result in extensive thawing of the permafrost around the wellbore. If the thawed permafrost re-freezes later in winter, then 'freeze-back' pressures will result. In Alaska, 'freeze-back' pressures of the order of 0.66 psi/ft to as high as 1.44 psi/ft have been recorded.Damage to surface casing may result from these pressures.

5.0 Abnormal Pore Pressure Evaluation

The following subsections will briefly discuss and illustrate the numerous techniques to detect and in some cases quantify abnormal pore pressure whilst drilling. Pre-drilling methods from seismic operations will not be discussed here.

There are basically three methods for detecting and measuring pore pressure:

1. Mud logging methods: includes measurements of drilling parameters and evaluation of drill cuttings and gas levels at surface
2. Measurement While Drilling, logging while drilling and wireline logging methods
3. Direct methods: DST, production tests and RFT

All available data should be used in evaluating pore pressure regimes. Any one parameter taken in isolation can lead to misleading and possibly incorrect conclusions.

6.0 Mud Logging Methods

Mud logging is carried out in a specially instrumented unit designed to:

1. Measure Drilling parameters (ROP,WOB, RPM, flow rate)
2. Measure properties of drill cuttings from samples collected at the shale shaker
3. Measure gas levels from well
4. Produce a lithological column as well is drilled
5. Determine where to drill to and when to stop
6. Give warnings of increasing pressures
7. Help determine accurately the depth of casing seats

6.1 RATE OF PENETRATION (ROP)

Drillbits break the rock by a combination of several processes including: compression (weight-on-bit), shearing (rpm) and sometimes jetting action of the drilling fluid. The speed of drilling is described as the rate of penetration (ROP) and is measured in ft/hr.

The rate of penetration is affected by numerous parameters namely: Weight On Bit (WOB); Revolutions Per Minute (RPM); bit type; bit wear; hydraulic efficiency; degree of overbalance; drilling fluid properties, hydrostatic pressure and hole size.

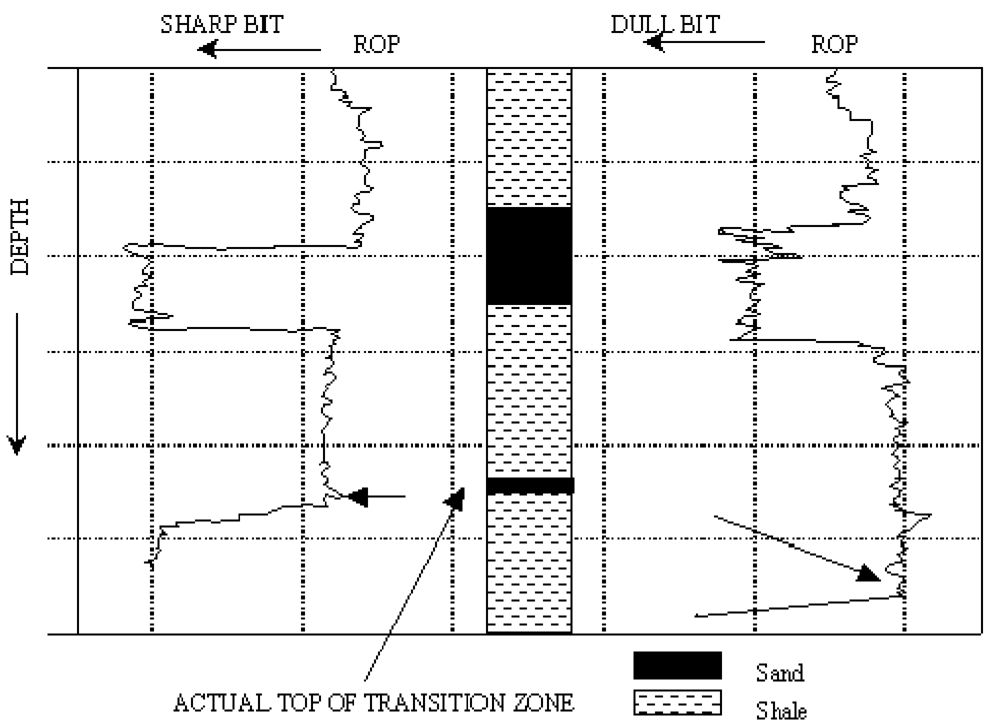
The difference between the mud hydrostatic pressure and pore pressure is called the **overbalance** or "**Chip Hold Down Pressure (CHDP)**". This overbalance prevents formation fluids from entering the wellbore while drilling. However, this overbalance (CHDP) also acts to keep the rock cuttings held to the bottom of the wellbore. The effects of bit rotation and hydraulics offset this force and ensure that cuttings are lifted from the bottom of the hole.The CHDP (differential force) has one of the largest effect on ROP especially in soft to medium strength formations.

If all parameters affecting ROP are held constant whilst drilling a uniform shale sequence then ROP should decrease with depth. This is due to the natural increased compaction with depth reflecting a decrease in porosity and increased shale density and increased shale (compressive) strength.

When entering an abnormally pressured shale, the drillbit sees a shale section which is undercompacted. The increased porosity and decreased density of the undercompacted section results in the formation becoming more ‘drillable’ as there is less rock matrix to remove. Consequently ROP increases, assuming all drilling parameters were kept constant. In addition, the reduced differential pressure (less CHDP) between the mud hydrostatic and pore pressure further increases ROP.

The increase in ROP on entering an abnormally pressured zone is shown in **Figure 1.7**. As can be seen from this figure a sharp drillbit would pick up the onset of the transition zone much faster than a dull bit. Careful monitoring of ROP during drilling is useful in detecting the onset of an abnormal pressure, however, the value of the ROP parameter on its own is limited as outlined below.

Figure 1.7 ROP As An Indicator of Overpressure, Ref 1



Limitations of ROP

ROP is affected by changes in WOB, RPM, bit type, hole size, bit wear, hydraulics, mud parameters and lithology. Hence, a sudden increase in ROP may not be due to penetrating an abnormal pressure zone, but may be caused by changes in any one of the above parameters.

Experimental work has shown that the effect of increasing pore pressure on ROP is limited to a differential pressure of 500 psi. However, when the overbalance is greater than 500 psi, ROP shows little change over large changes in differential pressure.

6.2 Corrected D Exponent

From the previous section it is clear that a method of correcting, or normalising ROP for changes in drilling parameters is desirable to make interpretation of drilling rate easier and improve its effectiveness as an indicator of pore pressure. The D exponent is an example of one such 'normalised' drilling rate. The D exponent is the culmination of the work of Bingham (1965) and Jordan and Shirley (1967) [2]. The authors provided the following mathematical expression for calculating the D exponent:

$$d_c = \frac{\log \frac{(ROP)}{(60xRPM)}}{\log \frac{(12xWOB)}{(10^6xB)}} \qquad (1.10)$$

where

d= D Exponent, in d-units

ROP= penetration rate (ft/hr)

RPM= rotary speed (rpm)

WOB= weight on bit (lbs.)

B= diameter of the bit, inch

As can be seen from **Equation (1.10)**, the D Exponent basically attempts to correct the ROP for changes in RPM, weight on bit and hole size. The D exponent is proportional to rock strength and for normally pressured formations, the D exponent increases linearly with depth, reflecting increased rock strength with depth. For abnormally pressured shales, the D exponent deviates from the normal trend and actually decreases with depth.

A further modification of the D exponent was proposed by Rehm et al (1971) [3] who attempted to correct the D Exponent for the effect of changes in mud weight. The resultant equation for the corrected D Exponent (dc) is as follows:

$$d_c = d\left(\frac{NPP}{ECD}\right) \qquad (1.11)$$

where

dc= corrected D Exponent (dimensionless)

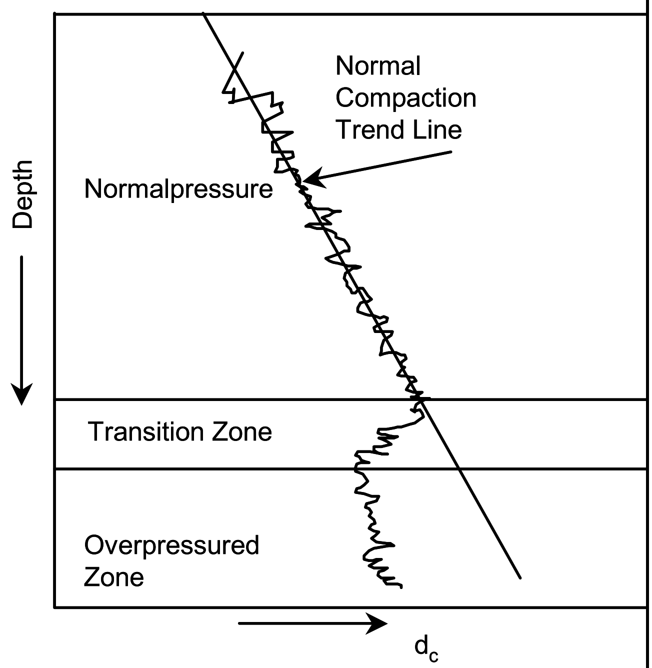
NPP= normal pore pressure gradient (ppg)

ECD= equivalent circulating density (ppg)

The correction has no sound theoretical basis, however it makes the dc exponent more sensitive to changes in mud weight (therefore overbalance) and increasing pore pressure and is therefore universally used.

An idealised response of the dc exponent or abnormal pore pressure with depth is shown in **Figure 1.8**. As the overpressured zone is encountered the formation becomes less dense and will have a higher porosity than a normally pressured rock at the same depth. The decrease in rock strength results in a greater rate of penetration and hence a reduction in dc exponent.

Figure 1.8 Response Of Corrected dc In Transition And Overpressured Zones



Example 1.4: D Exponent

Calculate the d exponent for the following well

B = 12.25"
WOB= 50,000 lb
RPM = 80
ROP=30 ft/hr

Solution

Using **Equation (1.10)**

$$d_c = \frac{\log \frac{(ROP)}{(60xRPM)}}{\log \frac{(12xWOB)}{(10^6xB)}}$$

$$d_c = \frac{\log\frac{(30)}{(60x80)}}{\log\frac{(12x(50,000))}{(10^6x12.25)}}$$

dc = 1.68

6.2.1 Pore Pressure Calculation From dc Exponent Data

(a) Plot dc values on a semi-log paper against depth.

(b) Establish a normal pressure trendline through dc values corresponding to known clean, normally pressured shales.

The plotted trendline predicts the dc value at any depth in shale sections which exhibit normal compaction and normal pore pressure.

The trend line should slope to the right indicating an increased value of dc for normally pressured shale with depth. This slope reflects the increasing density and decreasing porosity and drillability in a normally pressured shale with increasing burial.

To aid in establishing a normal pressure trendline it is often convenient to plot shale point dc values only. This eliminates the confusion brought about by erratic dc values resulting from the drilling of other lithologies.

(c) Plot the actual dc values alongside the trendline, **Figure 1.8**

(d) Calculate the Pore Pressure, using **Equation (1.12)** or **Equation (1.13)**.

There are two methods of calculating pore pressure from dc data, the Eaton Method and the Ratio Method. The Eaton Method [10,11] is used in most sedimentary basins for calculating pore pressure from shale point dc values. The Ratio Method has been used successfully in clastic limestone sequences in the Middle East.

(

i) Eaton Method

1. Record the value of the normal trendline dc (dcn) and observe dc (dco) at the depth of interest. NOTE: use only dco values from shales. Do not use any other lithology dc value.
2. Record the overburden gradient from the overburden plot at the depth of interest.
3. Use the following formula to calculate pore pressure:

$$PP = \sigma_{ov} - (\sigma_{ov} - P_n) \times \left(\frac{d_{co}}{d_{cn}}\right)^{1.2} \qquad (1.12)$$

where

PP= Pore pressure (ppg)

σov= Overburden (ppg)

Pn= Normal pore pressure gradient (ppg)

dco= Observed value of dc at depth of interest

dcn= Normal trendline value of dc at depth of interest

As can be seen from **Equation (1.12)** the Eaton Method is basically simple if we remember the basic pressure relationship $\sigma_{ov} = P_f + \sigma_{mat}$. Rearranging the latter equation as matrix stress equal to $\sigma_{ov} - P_n$, where P_n is normal formation pressure, shows that the Eaton formula uses the

factor $(\sigma_{ov} - P_n)\left[\frac{d_{co}}{d_{cn}}\right]^{1.2}$ to calculate the actual matrix stress. This value of this factor is largely

dependent on the degree of undercompaction reflected in the equation by the ratio between the observed dc and the dc value for normally pressured shales at the depth of interest.

(ii) Ratio Method

The ratio method is much simpler and does not require values of overburden. To calculate pore pressure, use the following formula:

$$PP = P_n \times \left(\frac{d_{cn}}{d_{co}}\right) \tag{1.13}$$

where
PP= Pore pressure (ppg)
Pn= Normal pore pressure (ppg)
dco= Observed d exponent
dcn= Normal trendline value of d exponent

The ratio method is considered unsuitable for use in most shale sequences. However, it has been found to give accurate results in interpreting pore pressures from clastic limestone data in the Middle East.

Example 1.5: Pore pressure from D Exponent

Using the Eaton Method, calculate the pore pressure at depth 12000 ft given: (refer to **Figure 1.8** for trend)

dcn (from normal trend) = 1.5 d-units

dco (from new trend) = 1.1 d-units

Overburden gradient = 19 ppg

Normal pore pressure in area = 9 ppg

Solution

a. Eaton Method

$$PP = \sigma_{ov} - (\sigma_{ov} - P_n) \times \left(\frac{d_{co}}{d_{cn}}\right)^{1.2}$$

$$PP = 19 - (19 - 9) \times \left(\frac{1.1}{1.5}\right)^{1.2}$$

Pore pressure = 12.1 ppg

b. Ratio Method

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$$PP = P_n \times \left(\frac{d_{cn}}{d_{co}}\right)$$

$$PP = 9 \times \left(\frac{1.5}{1.1}\right) = 12.3 \text{ ppg}$$

6.2.2 LIMITATIONS OF THE D EXPONENT

(i) It can only be used to calculate pore pressures in clean shales or clean argillaceous limestones.

(ii) Large increases in mud weight cause lower values of dc.

(iii) dc exponent values are affected by lithology, poor hydraulics, type of bit, bit wear, motor or turbine runs and unconformities in the formation.

6.3 DRAG, TORQUE AND FILL

Drag, rotating torque and fill can be used as indirect, qualitative indicators of abnormal pore pressure. They are also indicators of hole instability and other mechanical problems which have nothing to do with abnormal pressure.

Drag is the excess force which is necessary to pull the drill string up, whether this happens on a connection or a trip. As an abnormally pressured shale is drilled, the shale tends to cave into the wellbore due to the inability of the mud density to prevent encroachment of the formation into the open hole. However, drag may also be noted as a result of (a) clay hydration; (b) the drill string being in contact with the low side of the hole on a deviated well and (c) due to ineffective hole cleaning.

Rotating torque often increases in an abnormally pressured zone due to the physical encroachment of the formation (most notably shale) into the borehole. In addition, as pore pressure increases and differential pressure decreases, the increased porosity and fluid content of the formation, combined with a decrease in chip hold-down pressure, allow greater penetration of the rock by the drillbit. This leads to an increase in ROP and a greater friction (increased torque) between the bit and the rock. However, increasing torque is also caused by drilling deviated holes, out of gauge holes and bearing wear.

Fill is the settling of cuttings and/or cavings at the bottom of the hole. Fill is often observed when an over pressured shale is drilled into. The shale tends to cave into the wellbore due to the inability of the mud density to hold back the wellbore. Fill may also be due to a mechanically unstable formation; knocking off the formation by the drill string on trips; ineffective hole cleaning and poor suspension properties of the drilling fluid.

Variations in drag, torque and fill are usually encountered in both normally pressured and abnormally pressured zones. Hence these indicators should be used in conjunction with other indicators to give a definitive indication of drilling into an abnormally pressured zone. The same apply to any of the indicators that are discussed in this book. The author recommends the use of at least four indicators, preferably plotted on the same plot.

6.4 Gas Levels

Hydrocarbon gases enter the mud system from various sources during drilling operations. The gases are extracted from the mud for analysis in the mud logging unit. At present, there is no quantitative correlation between gas levels and pore pressure. However, changes in gas levels can be related to levels of differential pressure in the wellbore indicating over-, near or under-balanced operations.

The main sources of gas in the drilling fluid are:

- Gas liberated from the physical action of cutting the rock and circulating the cuttings to surface.
- Gas flowing into the wellbore due to underbalanced conditions.

The gas levels resulting from these sources are dependent on the mud weight, cuttings concentration, differential pressure, formation porosity and permeability and gas saturations.

There are three types of gas levels: Background Gas, Connection Gas and Trip Gas.

Background Gas

All drilled wells will have a background gas level which is usually measurable. Background gas originates from the rock being cut by the bit. The background gas level is a function of the porosity of the formation, the hole size (column cut), ROP and mud circulation rate. In

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addition the degree of overbalance in permeable formations will affect background gas levels. In wells with a high overbalance, the gas will be flushed away from the wellbore resulting in low levels of gas seen at surface.

Background gas may increase on drilling into an abnormally pressured environment as a result of the following:

(i) Porosity increases in abnormally pressured shales.

ii) Reduced overbalance reduces the flushing action into the formation.

(iii) Rate of penetration often increases due to reduced differential pressure and higher porosity of the formation.

Connection Gas

When circulation is stopped to make a connection, the effective mud weight is reduced from the ECD (equivalent circulating density) to the static mud weight. In addition picking up the pipe induces a further reduction of mud weight due to the induced 'swabbing' effect. This reduction in bottom hole hydrostatic pressure may be sufficient to allow a small amount of gas to flow into the wellbore. When the gas is circulated to surface, it appears as a long narrow peak above the background gas level.

Trip Gas

Trip gas is produced by the same mechanism as connection gas, but the effect of swabbing is increased due to the higher pulling speeds when tripping. Trip gas can only be used to asses trends in increasing overpressure over several trips.

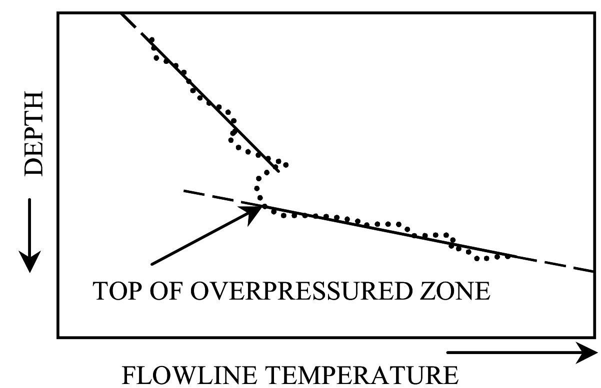
6.5 Temperature Data

6.5.1 Flowline Temperature

The radial flow of heat from the earth's core causes the subsurface temperature to increase with depth. The geothermal gradient is the rate of change in temperature per unit depth and is usually assumed constant for any given area. Upon encountering abnormal pore pressure, it has been noted that the temperature gradient is increased when compared to normally pressured formations in the same area.

This is caused by the increased pore water content of the abnormally pressured strata. Pore water has approximately 1/6th of the thermal conductivity of the formation matrix which in practical terms means the heat flow through a zone containing more water than normal would be greatly retarded. An abnormally pressured zone would therefore contain more heat (high temperature) than a comparable normal zone due to the high water content.

Figure 1.9 Flowline Temperature As An Indicator Of Overpressure



The top of an abnormally pressured zone should therefore be marked by a sharp increase in temperature and geothermal gradient as shown in **Figure 1.9**. The increase in geothermal gradient may well be indicated by an increase in mud temperature at the flowline. In addition, the pressure seal above the abnormally pressured zone may show a decrease in geothermal gradient due to the increased compaction and hence lower porosity of this zone. Again this may be reflected by a reduced mud temperature at the flowline. An idealised flowline temperature plot on encountering abnormal pore pressure is shown in **Figure 1.9**.

In practice, the flowline temperature in not a definitive indicator of abnormal pressure as it is influenced by several factors including: circulation rate, ROP, length of static time in well, mud conditions, additions of new mud to the mud system and cooling effect of the sea around marine risers

Due to the difficulty in interpreting temperatures, the flowline temperature is regarded as a qualitative indicator which is used to support and validate other pressure data.

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6.5.2 Bottomhole Formation Temperature

The actual Bottom Hole formation Temperature (BHT) cannot be determined from flowline temperature measurements. Only a few years ago, the closest approach to measuring BHT is to record downhole temperature during wireline logging runs. Mud temperatures recorded from successive logging runs are used to predict the actual BHT, assuming that the maximum temperature is at the bottom of the hole.

However, today's advanced MWD technology allows much more accurate monitoring of BHT and consequently accurate evaluation of geothermal gradient.Increased bottom hole temperature usually sometimes coincides with high pressure zones. Once again this parameter should not be used alone but in conjunction with other parameters.

6.6 Drill Cuttings Parameters

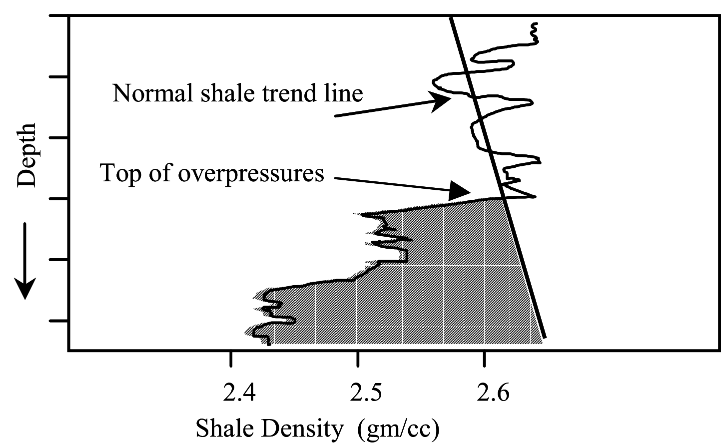
The drilling process produces a large amount of cuttings which are transported to the surface and separated from drilling mud at surface at the shale shakers. When the drill cuttings reach the surface, they are highly intermixed and are usually broken further during their trip from the bottom of the hole. Intermixing from cavings falling off the sides of the hole can make analysis of drillcuttings highly unreliable. However, despite these problems, drill cuttings can provide important information about the formation being drilled and the magnitude of pore pressures contained with the rocks.

6.6.1 Shale Bulk Density

Shale density increases with depth in a normally compacted and normally pressured sequence. Abnormally pressured shales often display a degree of undercompaction resulting in higher porosity and hence lower density.If shale density measurements are plotted against depth a normal compaction (normal pore pressure) trendline may be established. Any decrease in the shale density away from the normal compaction trendline may indicate the presence of abnormal pore pressure. **Figure 1.10** shows a typical bulk density plot and shows the response to abnormal pressure.

The magnitude of abnormal pore pressure can be determined by calculation using a equivalent depth method, or from empirical curves.

Figure 1.10 Shale Density Trend For Picking Up Overpressured Zones, After Ref 1



The inaccuracy of the shale density measurements limits the usefulness of this parameter for pore pressure calculation.Other limitations include: effects of drilling mud on cuttings, contamination with other open zones and consistency of mud logging personnel in measuring density. Tectonically pressured shales usually appear as normal shales using the density method alone. The response of shale density values in abnormally pressurised zones will vary with the type of mechanism that caused the overpressure.

However, shale density plots are an excellent means of qualitatively determining the top of an abnormal pore pressure zone.They should be constructed during the drilling of all exploration wells in which long shale sections are prognosed.

6.6.2 Shale Factor

Shale factor is a measure of the Cation Exchange Capacity (CEC) of the shale. The CEC of a shale sample increases with the montmorillonite content; a highly reactive clay mineral. The montmorillonite content is dependent on the level to which montmorillonite conversion to illite has taken place. As discussed in the causes of abnormal pore pressure, with increasing depth and pressure montmorillonite diagenesis to illite occurs, resulting in expulsion of water.

In normal compaction trendline, the montmorrillonite content should decrease with depth. Abnormally pressured zones often have a higher montmorrillonite content than normally pressured-shales of the same depth. Hence a plot of the shale factor against depth may show an increase away from the normal compaction trendline on entering the abnormal pore pressure zone. The shale factor would then decrease on leaving the abnormal pressure zone and entering a lower pressure zone.

In general variation in the shale factor are usually smaller than other indicators and for this reason the shale factor should be used with caution as an approximate qualitative method.

6.6.3 Cuttings Size and Shape

Cuttings size and shape can give qualitative evidence of the onset of abnormal pore pressure and also the development of wellbore instability.

Cavings are much larger than normal drilled cuttings and are easily identifiable at the shakers. However, large cavings can also be produced due to hole instability problems unrelated to insufficient mud weight, see **Chapter 12**.

7.0 Measurement While Drilling (MWD) & Logging while drilling (LWD) Data

MWD/LWD tools provide a variety of downhole drilling and electric log parameters which are applicable to the detection of abnormal pore pressure while drilling.

with the exception of WOB and torque, all the following parameters can be measured either by wireline methods after the well is drilled (as was done in the past) or while drilling using Logging-while drilling methods.

Depending on the type of MWD/LWD tool selected for the well any or all of the following parameters may be available.

7.1 Downhole Weight-On-Bit (DWOB)

Field evidence indicates that actual DWOB values are usually less than surface WOB values due to the frictional drag of the drillsting on the borehole wall. This is specifically true of directional wells. DWOB values can be used for the calculation of dc exponents which increase their accuracy and reduce the scatter of dc values often seen on deviated wells.

7.2 Downhole Torque

Measurement of downhole torque may be used to indicate bit wear or as an overpressured indicator as discussed earlier. On deviated wells, surface torque readings are usually useless due to the drillstring contact with the well, however, measurement of downhole torque to a great degree, eradicates the drillstring effect.

7.3 Downhole Temperature

The difference between downhole annulus temperature and temperature of the fluid entering the well will give an indication of the amount of heat imparted to the fluid. Hence, the use of downhole temperature for overpressure detection is the same as flowline temperature.

7.4 Gamma Ray

The gamma ray log is used to identify lithology. Shales show a higher level of radioactivity than sands, evaporites and limestones. Hence, the gamma ray tool is used to detect clean shales for evaluation by the dc exponent method whilst drilling.

7.5 Sonic Logs

In general, the acoustic logs are considered to provide the most reliable quantitative estimations of pore pressure. The main benefits of acoustic logs are that they are relatively unaffected by borehole size, formation temperature and pore water salinity. The parameters that do affect the acoustic log are formation type and compaction related effects such as porosity/density and are therefore directly applicable to pore pressure evaluation.

Theory Of Sonic Logging

The sonic log measures the transit time (Δt) for a compressional sonic wave to travel through the formation from transmitter to receiver. The time to travel through one foot (or one metre) is termed the Interval Transit Time (ITT). In a shale sequence showing a normal compaction profile (and therefore normal pressure); the transit time should decrease with depth due to the decreased porosity and increasing density, **Figure 1.11**.

Abnormally pressured shales tend to have higher porosity and lower density than normally pressured shales at the same depth. Hence the ITT values will be higher.

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By constructing a logarithmic plot of ITT vs linear depth a normal pressure trendline can be established through clean shales. Abnormally pressured shales will therefore show an increased ITT above the normal trendline value at the depth of interest. Pore pressure can then be calculated at the point of interest using the following Eaton equation:

$$PP = \sigma_{ov} - (\sigma_{ov} - P_n) \times \left(\frac{\Delta t_n}{\Delta t_o}\right)^3 \qquad (1.14)$$

where

PP =Pore pressure (ppg)

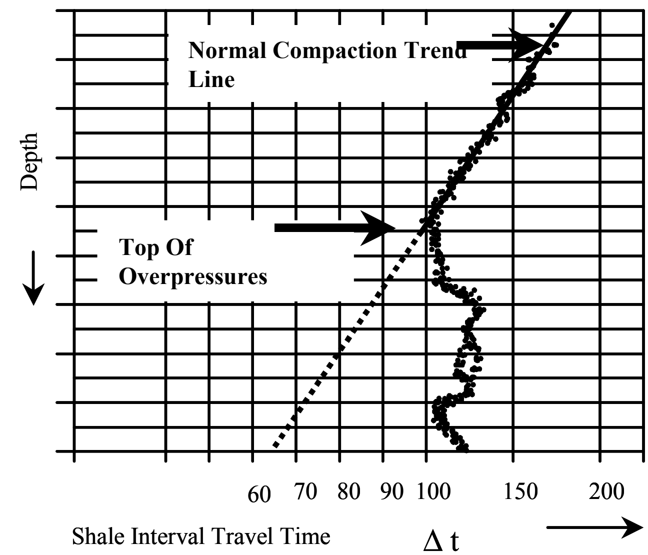
σov =Overburden (ppg)

Pn =Normal pore pressure (ppg)

Δt_n =Normal pore pressure trendline Δ t value at depth of interest

Δt_o =Observed Δ t value at the depth of interest.

Figure 1.11 Response Of Shale Point Acoustic Transit Time To Abnormal Pressure



The Eaton method has proved to be the most applicable calculation for most sedimentary sequence compared with use of a trend curve developed from one or several specific areas.

Example 1.6: Pore Pressure From Sonic Logs

A sonic log was run in a well at 8000 ft. The normal transit time (Δt_n) for this depth is 110ms and from logs (Δt_0) is 130 ms. Calculate the pore pressure at 8000 ft if the overburden pressure is 7,500 psi. Normal pore pressure gradient is 0.465psi/ft.

Solution

Convert pore pressure gradient to psi: 8000x 0.465 = 3720 psi

This is the Pn value in the following equation:

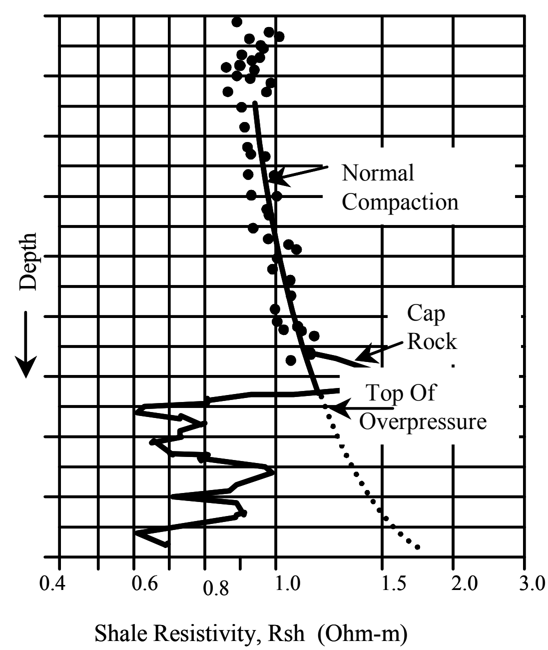
$$PP = \sigma_{ov} - (\sigma_{ov} - P_n) \times \left(\frac{\Delta t_n}{\Delta t_o}\right)^3$$

$$PP = 7500 - (7500 - 3720) \times \left(\frac{110}{130}\right)^3 = 5210 \text{ psi}$$

7.6 Resistivity Logs

Shale resistivity values were obtained originally from the amplified short normal log. However, in recent years the use of deep induction logs is preferred as these enable the use of data in all types of drilling fluid and affording a greater depth of investigation.

Figure 1.12 Use of shale resistivity for abnormal pressure determination



Shale resistivity increases with depth. The resistivity (the reciprocal of conductivity) of shales depends upon the following factors:

- porosity
- salinity of the pore water
- temperature.

The salinity of the pore water does not normally vary greatly with depth and hence its effect is often discounted. In addition, temperature normally increases uniformly with depth and Hence resistivity values can be corrected for the temperature increase. Porosity is thus the major factor affecting resistivity values.

Theory of Resistivity Logging

The basic theory relies upon shale resistivity increasing with depth in normally pressured shale as the porosity decreases. An increasing porosity, and thus higher pore water content, is indicative of abnormally pressured shales and will result in lower resistivity.

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A logarithmic plot of shale resistivity vs linear depth is constructed. A normal pore pressure trendline is established through known normally pressured shales and thus any decrease in shale resistivity value away from the trendline indicates abnormal pore pressure (See **Figure 1.12**).

The magnitude of the abnormal pore pressure can be calculated using an Eaton type equation as given in **Equation (1.14)**.

7.6.1 Formation Density Logs

A typical formation density logging tool consists of a radioactive source which bombards the formation with medium energy gamma rays. The gamma rays collide with electrons in the formation resulting in scattering of the gamma rays. The degree of scattering is directly related to the electron density and therefore the bulk density of the formation.

The Compensated Density Tool (FDC) has a gamma ray source and two detectors mounted on a skid which is forced against the formation by an eccentering arm. The skid has a plough shaped leading edge to cut through any filter cake which is present. The dual detectors are used to compensate for any filter cake effects.

A plot of shale bulk density versus depth will show a straight line normal compaction trendline, see **Figure 1.10**. The shale bulk density will increase with depth due to the increased compaction. This results in reduced porosity and pore water expulsion. In an abnormally pressured shale, compaction is often retarded, resulting in increased porosity and thus lower density than a normally pressured shale at an equivalent depth. As such a decrease in shale bulk density values from the normal compaction trendline is observed when entering a zone of abnormal pore pressure.

8.0 Direct Measurements of Pore Pressure

8.1 Repeat Formation Tester (RFT) Data

The RFT is a wireline run tool designed to measure formation pressures and to obtain fluid samples from permeable formations. When run into the hole the tool can be re-set any number of times. This enables a series of pressure readings to be taken and permits the logging engineer to pre-test the formation for permeable zones before attempting to take a fluid sample or a pressure recording.

The RFT tool provides 3 distinct pieces of pressure data:

1. The drilling fluid hydrostatic pressure (two readings).
2. The formation pore pressure.
3. The pressure transient induced by the withdrawal of 2 small samples. The tool has 2 pre-test chambers of 10cc volume which can be used to sample the formation at 2 differing rates.

The two mud hydrostatic readings are used for quality control of the data. The two values are compared to verify stability of the tool, and should be within a few psi's of each other.

The RFT is only useful after the hole section is drilled and can only work across porous and permeable zones. The formation pore pressure measured by RFT is used to verify the estimates made while drilling the well and to construct a reservoir pressure profile. This will yield information on the pressure gradients and nature of the reservoir fluids.

The pressure, flow rate and time data from the pre-test sample can be used to calculate reservoir characteristics, such as permeability.

Limitations Of RFT

(a) The RFT tool provides accurate, definitive data on formation pore pressure. However, the formation pressure data can only be obtained from permeable formations, such as reservoir sandstones or limestones. These formations may contain pressures which bear no resemblance to the pore pressure in the overlying and underlying formations, and as such their application is restricted to the formation sampled.

(b) In HPHT wells the RFT tool should be considered for use prior to performing potentially problematic drilling operations, such as coring, in order to fine tune the required mud density and minimise the risk of swab or surge problems.

8.2 Drill Stem Test (DST) Data

DST is a method of testing formations for pressure and fluid. A Drill stem with a packer is run and set just above the zone to be tested. The packer is set and a DST valve is opened to allow the reservoir to communicate with the inside of the drillstem which is run either empty or with a small calculated cushion.

The drillstem is run with several pressure gauges. The purpose of the pressure gauges is to record the downhole pressure during the sequence of flow and shut in periods that comprise the DST. The pressures recorded during the test are used to calculate reservoir characteristics such as formation pressure, permeability, skin damage and productivity index.

Analysis of the pressure build up from shut in periods leads to accurate determination of the formation pore pressure. The second shut-in period is used for determining the final shut-in reservoir pressure. The actual static reservoir pressure is determined from Horner analysis of DST pressure data.

Limitations Of DST

Data from drill stem tests enables accurate determination of reservoir pressure. However, the pressure data can only be obtained from permeable formations that exhibit sufficient hydrocarbon reservoir potential to warrant the expense of DST. As with RFT pressure data, the reservoir pressure calculated from the DST may, or may not be the same as the pore pressure in the adjacent formations.

9.0 Summary Of Pressure Determination

When collecting pore pressure data for a new well, it imperative to label the data points according to the source used to measure or calculate them. Hence the data may come from mud logging, LWD or RFT and DST sources. Obviously, the RFT and DST pressure data are the most definitive and have the least uncertainty associated with them. Mud programme and casing seat selection can therefore be based on RFT and DST pore pressure values.

While the RFT(Repeat Formation Tester) and DST (Drillstem Test) data provide definitive values of pore pressure for the well, these direct measurements are only possible in permeable formations and are obtained after the well is drilled. They are also not applicable to the surrounding, largely impermeable, shale sections where the majority of overpressure is developed.

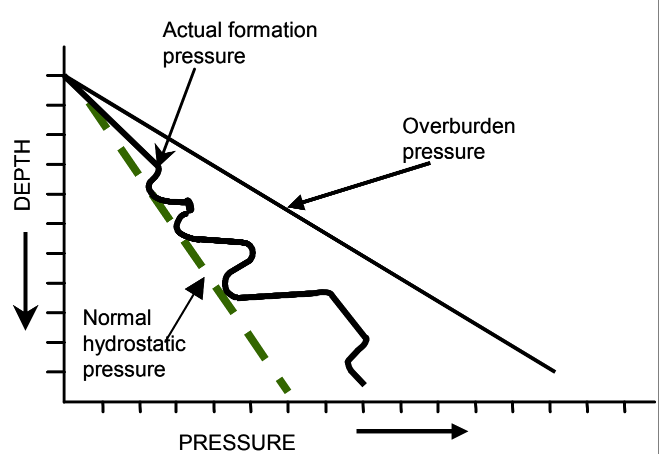
Estimates and calculations of pore pressure from mud logging, wireline and drilling log data are restricted solely to shale sections. Establishing a normal compaction trendline (normal pore pressure trendline) is of great importance when calculating pore pressure from log-derived shale properties. Of the various logs available, sonic log data is considered to be the most accurate, as it is largely unaffected by borehole size, formation temperature and pore water salinity.

10.0 Learning Milestones

In this chapter, you should have learnt to:

1. Distinguish between normal and abnormal pressure.
2. Calculate pressures and pressure gradients
3. Calculate overburden and matrix stress for both onshore and offshore wells.
4. List sources of abnormal pressure
5. List applications of mud logging
6. Calculate pore pressure using D Exponent
7. Calculate pore pressure using sonic method
8. List sources of gas in a well

Figure 1.13 Basic wellbore pressures



9. Determine the difference between pore pressure values as determined from direct methods (DST, RFT) and indirect methods (sonic, resistivity and mud logging)

10. Be able to plot hydrostatic pressure (limit of pore pressure on left), pore pressure and overburden pressure (limit of pore pressure on right) on same graph paper as shown in **Figure 1.13**. The pore pressure line in this figure would probably contain mixed data from mud logs, DST, PWD (pressure while drilling) and production tests. This graph together with Fracture Gradient forms the basis of well design.The reader should therefore familiarise himself with the differences between the three lines shown in **Figure 1.13**.The reader should also note that the normal hydrostatic line varies from one area to another as discussed in **"Hydrostatic Pressure" on page 2**.**Figure 1.13** is considered the corner stone of well design.

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12.0 EXERCISES

1. Write down the equation for calculating the hydrostatic pressure of mud when

   a. mud density is in ppg.

   b. mud gradient in psi/ft

2. Define: normal pressure and abnormal pressure

3. Calculate the overburden gradient for a well having a bulk density of 15 ppg at 5000 ft TVD if:

   a. the well is a land well

   b. the well is an offshore well with a water depth of 1000 ft (actual penetration is 4000 ft) and RKB (rotary table) to MSL (mean sea level) is 60 ft.

   (Answers a = 0.78 psi/ft, b= 0.71 psi/ft)

4. List four drilling parameters that are measured on the rig which can be used to estimate /indicate abnormal pressures.

2

Formation Integrity Tests

Content

Introduction

It is my aim that the methods presented in this chapter can be used directly in well designs and field operations with little modifications. Although, there is a great deal of maths required to explain some of the ideas presented here, the chapter gives the minimum amount of mathematical derivations to keep the book practical.

1.0 Formation Integrity Tests

The term Formation Integrity is one of the most widely misused term in the oil industry. It is usually used to indicate a test to determine the fracture gradient. In reality, the term Formation Integrity Test has a more encompassing meaning which includes:

Limit Test: A test carried out to a specified value, always below the fracture gradient of the formation.

Leak off Test: A test carried out to the point where the formation leaks off.

Fracture Gradient Test: A test carried out to the leak off point and beyond until the formation around the wellbore fails.The fracture gradient is equal to the earth minimum horizontal stress.

Another widely used term is the Shoe Bond Test which is carried out to test the strength of the cement at the casing shoe. There is no theoretical basis to this test other than deciding on a cement strength value and carrying out a test to this value. The reader should note that the cement strength increases with time until a certain peak value is attained, which under downhole conditions is difficult to ascertain.

This Chapter will be mainly concerned with Fracture Gradient determination as the other tests become merely derivatives if this test is carried out completely. For example, if a leak off tests is carried out to full formation fracture then this test gives three values: leak off value, formation breakdown strength and fracture gradient value, **Figure 2.3**.

We will use the term Formation Integrity Test (FIT) to describe the test irrespective of what value is eventually determined.

1.1 FORMATION INTEGRITY TESTS: PURPOSE

Formation strength tests can be carried out to the leak-off pressure or to a pre-determined limit as specified in the drilling programme.

The main reasons for performing a formation integrity test (FIT) are:

(a) To investigate the strength of the cement bond around the casing shoe and to ensure that no communication is established with higher formations.

(b) To determine the fracture gradient around the casing shoe and therefore establish the upper limit of primary well control for the open hole section below the current casing.

(c) To investigate well bore capability to withstand pressure below the casing shoe in order to validate or invalidate the well engineering plan regarding the next casing shoe setting depth.

(d) To collect regional information on the formation strength for optimisation of well design for future wells.

2.0 Fracture Gradient Determination

In oil well drilling, the fracture gradient may be defined as the minimum horizontal in- situ stress divided by the depth.

The accurate prediction of fracture gradient is essential to optimising well design.

At the well planning stage, the fracture gradient can be estimated from the offset well data. If no offset well data is available then the fracture gradient can be predicted using any of several published models [2-5]. The most widely used predictive method is the Hubbert and Willis method as outlined in **"Predicting Fracture Gradient" on page 59**.

As the well is drilled, Formation Integrity Tests (FIT) are carried out to determine the approximate value of fracture gradient beneath each casing shoe. The FIT pressure is converted to an EMW to determine the upper limit of primary well control for the next hole section.

FIT limit tests are not designed to break the formation but merely to reach a value below the minimum horizontal stress. The value of the minimum horizontal stress is the Fracture Gradient at the point the test is carried out.

FITs are typically carried out once in each open hole section after drilling out the casing shoe. The test should be repeated when weaker zones are drilled into as this lower fracture gradient may have a vital impact on well design and primary well control. However, it is not always possible, practical or desirable to repeat FITs at every formation change. In this case predictive methods should be used to asses formation strength, see **"Predicting Fracture Gradient" on page 59**

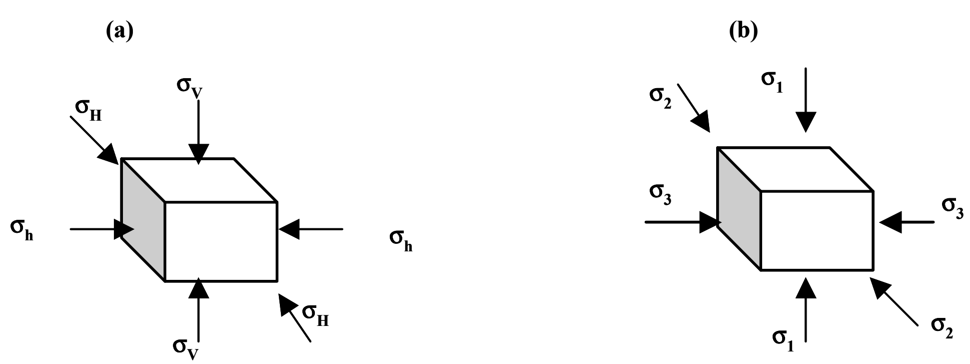
2.1 FACTORS INFLUENCING FRACTURE GRADIENT

At any particular point below the earth's surface, there are three independently acting stresses which are perpendicular to each other. As shown in **Figure 2.1**a, there are three normal stresses: vertical stress (σ_V) and two horizontal stresses (σ_H and σ_h). This notation is widely used in Rock Mechanics as it is usual to have shear stresses associated with planes containing normal stresses.

In most oilwell applications, the rock under consideration is subjected to in-situ stresses with have no shear stresses. Normal stresses which have no associated shear stresses are described as Principal Stresses and are mutually perpendicular to each other, **Figure 2.1**b:

- The maximum principal stress (designated σ_1)
- The intermediate principal stress (designated σ_2)
- The minimum principal stress (designated σ_3)

Figure 2.1 In-Situ Earth Stresses



In most cases the maximum principal stress will be vertical due to the pressure of the overlying rock. This is defined as the overburden pressure.

In a tectonically stable basin, the maximum principal stress will be vertical and the horizontal stresses will be equal. In any area undergoing tectonic activity the horizontal stresses are distorted creating an intermediate and a minimum principal stress. In areas of high tectonic activities such as mountain belts, the maximum principal stress may be horizontal and the minimum principal stress is vertical. **Figure 2.2** shows the typical states of stress underground characterised by differing tectonic stresses.

In N-W Europe [6], the state of stress is influenced by the movement of North Africa towards the N-W resulting in high stresses in the N-W direction and in the upward growth of the Alps. The three stresses are: vertical stress (overburden, σ_V) is the maximum stress and the intermediate horizontal stress is in the N-W direction and the minimum horizontal stress (σ_h) is normal to σ_H

In tectonically active areas such as Columbia the state of stress at depth is as follows:

$\sigma_V \approx \sigma_2$

$\sigma_H \approx \sigma_1$

$\sigma_h \approx \sigma_3$

Fracture of the formation results when the pressure in the wellbore is equal to, or greater, than the minimum principal stress (assuming the tensile strength of rock is negligible). The fracture will propagate along the path of least resistance which is perpendicular to the direction of the minimum principal stress. Thus fractures will be vertical in areas where the minimum principal stress is horizontal, and horizontal where the minimum principal stress is vertical, see **Figure 2.2**.

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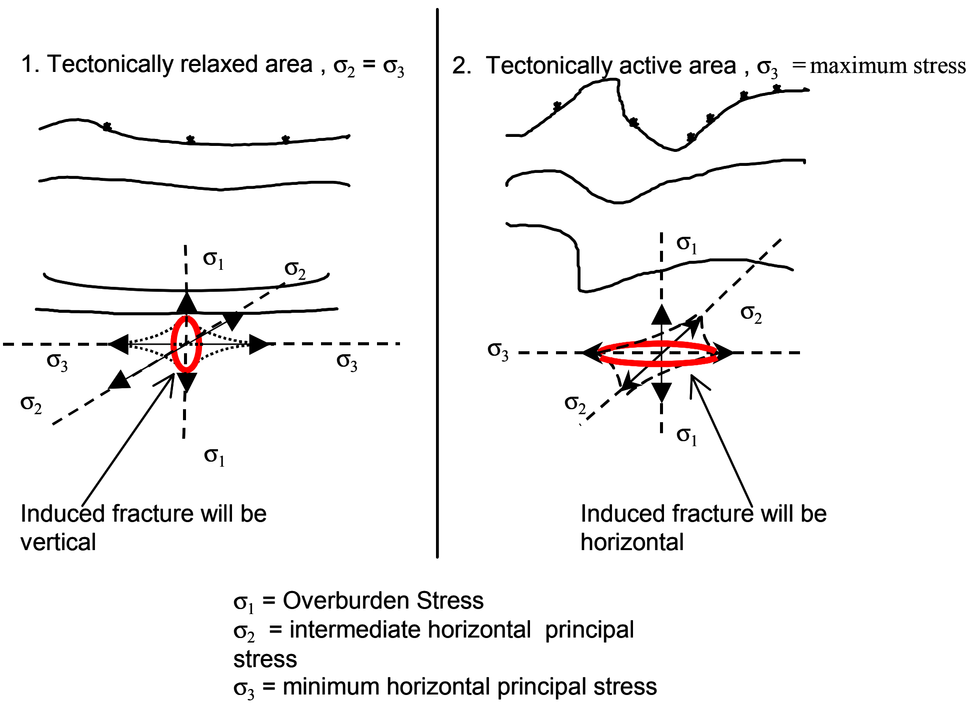
Figure 2.2 Tectonic Stresses In Idealised Regions, After Ref 15



Hence the major factor determining the pressure required to fracture the formation will be the magnitude of the minimum stress underground. All subsurface stresses are interrelated and as such the following common relationships are seen:

(a) Increasing overburden increases the fracture gradient.

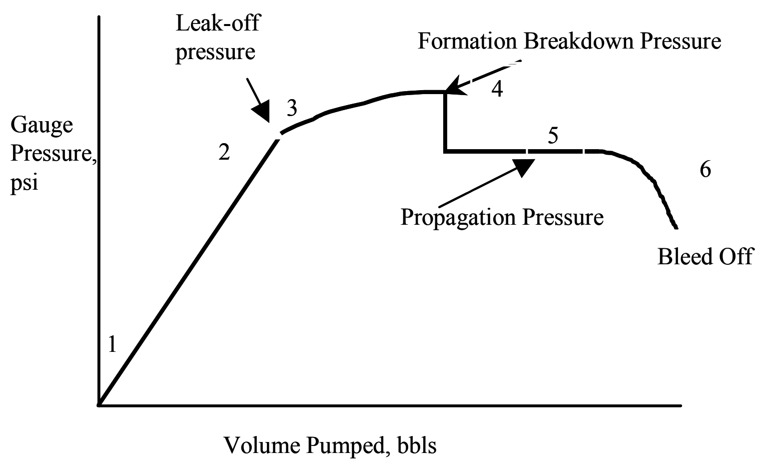
(b) Increasing pore pressure increases the fracture gradient. Large pore pressure decreases reduce the fracture gradient.

3.0 THEORY OF WELLBORE BREAKAGE

The creation of a well in the ground will disturb the in-situ earth stresses and will actually induce stresses around the wellbore. The induced stresses exist across a thin shell around the wellbore and will increase the strength of the wellbore. This increased strength (or stress raisers) due to drilling a hole in a medium is a well established idea in Mechanical Engineering and was borrowed by Drilling Engineers about fifty years ago.

Essentially then if one attempts to pressurise a wellbore and if a graph of pressure vs. volume pumped is established then a linear trend will initially be seen, **Figure 2.3**. If the test were to continue at higher pressures, then theoretically the wellbore will fracture when the pressure reaches the minimum horizontal stress.

Figure 2.3 FIT Graph



However, as the wellbore strength has been artificially increased by the presence of the wellbore it will take pressure in excess of the minimum horizontal strength to fracture the wellbore.

The pressure required to rupture the walls of the wellbore is called the Formation Breakdown Pressure. Once this pressure is exceeded and a fracture is generated in the virgin rock, then the pressure required to maintain the fracture will be less the Formation Breakdown Pressure. On the graph, this is seen as a drop in pressure, see **Figure 2.3**.

The constant pressure (point 5) required to propagate a fracture is called the Fracture Propagation Pressure. This is equal to the minimum horizontal earth stress.

In drilling, we are rarely interested in propagating a fracture. The engineer is merely interested in establishing the actual value of the minimum horizontal stress. Hence in practice once the rock is fractured, the shut-in pressure value is taken as equal to the minimum horizontal stress. The latter value is commonly known as the Fracture Gradient and is given by point 5 in **Figure 2.3**.

It should be noted that the above discussion only applies to vertical wells. In directional wells, the formation breakdown pressure can occur at values higher or lower than the fracture propagation pressure (minimum horizontal stress) depending on the hole inclination and azimuth.

3.1 Lithology Effects

The rock type and the existing stress system play a major role in the shape, size and length of fractures created. Under the action of stress, rock can be behave elastically and then rupture; this is called brittle failure and most rocks fail under this type. Rocks can also deform elastically, plastically and then rupture, just like steel. Some rocks exhibit creep effects where the rock deforms almost indefinitely under the action of a constant stress.

The fracture gradient is actually dependent on several factors including: formation type, rock strength, mineralogy, permeability and orientation of planes of weakness such as bedding planes.

4.0 FIT Procedural Guidelines

The following guidelines outline the typical equipment, preparation and procedures required to perform a successful FIT, see **Figure 2.4**.

(a) Equipment

(i) Mud pressure gauges are not sufficiently accurate for these tests. Large scale gauges of various ratings to cover the expected pressure range of the proposed test should be mounted on a small bore manifold on the cement unit.

(ii) The cement pumps should always be used in preference to the mud pumps when conducting an FIT.

(b) Preparation

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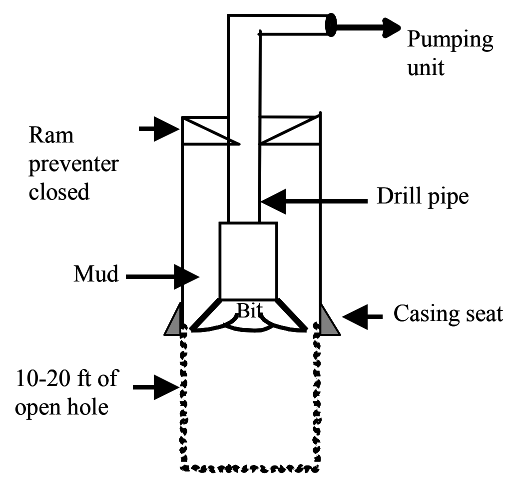
The casing is usually tested when the cement plug is bumped to a value dependent on the maximum surface pressure expected when a kick is taken during the drilling of the next hole section or the wellhead flowing pressure for a production casing, see **Chapter 5**.

The casing pressure test should be carried out at the same pump rate as the proposed FIT and a graph plotted of pressure vs. volume. The maximum surface pressure for a limit test should be now calculated if the intention is not to fracture the formation during the proposed full FIT. This pressure becomes the maximum surface gauge pressure during a limit FIT.

Figure 2.4 FIT Set-Up



(c) FIT Limit Test - Procedure

Drill 10-20 ft of new formation and perform the FIT test. Pump equal increments of mud (usually 1/2 bbl) recording gauge pressure at each increment. Continue the test to the pre-calculated surface pressure value. A graph of gauge pressure vs. volume pumped should be plotted whilst the FIT test is being carried out, **Figure 2.3**.

Care should be taken to halt the test as soon as divergence from the pressure/volume slope is seen or if the pre-determined pressure limit has been reached. If this is done the formation will not fracture.

If a true fracture gradient value is required then the test should be continued until the rock fractures and a stabilised pressure is obtained. This pressure is known as the fracture propagation pressure and is equal to the minimum horizontal stress. The fracture gradient is equal to the fracture propagation pressure.

(iii) Calculate the Fracture Gradient (FG) using the following formula:

$$FG = \rho_m + \frac{FIT(pressure)}{0.052xD} \qquad (2.1)$$

where

FG = Fracture Gradient (ppg)
ρm = Mud Density (ppg)
FIT = Maximum Test Pressure (psi) after rock fracture
D = TVD (feet)

In the event a limit test is performed (i.e. to a pressure value below point 5 in **Figure 2.3**), FG is obviously not the "true" fracture gradient, however, it shall be used as such for Kick Tolerance and Maximum Allowable Annular Shut-in Pressure (MAASP) calculations to provide added safety.

It should be observed that if a limit test is carried out to a pre-determined safe pressure, then all the FIT result will indicate that the rock is strong enough to that pressure value. Limit tests should ideally be carried out in area after the true fracture gradient has been determined. This is especially true as the formation breakdown pressure in a directional well may well be less than the fracture gradient in the same well.

4.1 FIT INTERPRETATION

Figure 2.3 shows a typical fracture test carried out in a claystone formation. From points 1-2 the rock is deforming elastically in response to the applied stress (pressure). At point 3 the rock starts to deform plastically and there is no longer a straight line relationship between pressure and volume.

A limit FIT test would be terminated at point below point 3, preferably at or near point 2. Point 3 marks the first noted deviation from the linear relationship of pressure vs. volume and is known as the leak-off point

If the test were continued beyond the leak-off point the formation would continue to deform plastically until it fractures (point 4). Point 4 is known as the formation breakdown pressure. If the pump is stopped at this point the pressure would usually stabilise at point 5 and no further fracture propagation would occur. When the well is opened and bled down, the volume of fluid returned should be approximately equal to the volume pumped.

If pumping was continued beyond point 4 (ie after formation breakdown) the fracture created would propagate at a pressure lower than that at point 4. This pressure is termed the fracture propagation pressure, point 5. The fracture propagation pressure gives the definitive measurement of fracture gradient.

Various types of FIT pressure vs. volume profiles may be encountered, depending on the type of formation (mineralogy, compressive strength, permeability etc.), mud properties and on local geological stress conditions. Brittle formations, (limestone, cemented sandstones etc.) show little or no plastic deformation prior to fracture. The first deviation from the pressure/volume relationship will be at formation fracture. In addition fractures induced in brittle formations tend not to heal. Hence it is strongly recommended that only limit tests are performed on these formations; the application of a full FIT to leak-off is not recommended.

In non-consolidated and loose formations, very low pressures result in leakage of mud to the formation. In this case the final pumping pressure will always be higher than the stabilised pressure. This makes interpretation of fracture gradient in these formation very difficult.

5.0 Predicting Fracture Gradient

When planning exploration or wildcat wells, where there is little or no reliable offset well data, the fracture gradient can be estimated using various predictive techniques. In addition, when drilling a well, fracture gradient should be calculated for each new lithology drilled. It is usually assumed that the fracture gradient at the casing shoe is the lowest within the open hole section.

The assumption that the fracture gradient is lowest at the previous casing shoe is not necessarily true. As previously discussed, fracture gradients vary with the in-situ stresses (overburden, pore pressure etc.), superimposed tectonic stresses and formation type. Hence the lowest fracture gradient in an open hole section is not always found at the previous casing shoe. This can have severe implications for the well control practice and casing setting depths.

Fracture gradient estimates made whilst drilling are normally the responsibility of the mud logging contractor. The estimates made should be used to establish a predicted leak-off pressure prior to conducting an FIT. When the predicted fracture gradient is dangerously close to the maximum anticipated mud weight, consideration should be given to performing a repeat FIT test. In some critical wells, several open hole FITs are carried out as the hole section is being drilled.

The kick tolerance and MAASP are always based on the calculated or direct measurement of fracture gradient.

5.1 Hubbert and Willis Method

The Hubbert and Willis method is based on the premise that fracturing occurs when the applied fluid pressure exceeds the sum of the minimum effective stress and formation pressure. The fracture plane is assumed to be always perpendicular to the minimum principal stress.

According to the Hubbert and Willis method, the total injection (or fracturing) pressure required to keep open and extend a fracture is given by:

$$FG = \sigma'_3 + Pf \qquad (2.2)$$

where σ'_3 is the effective minimum principal stress (= minimum principal stress minus pore pressure)

In terms of overburden gradient, Poisson' ratio (ν) and formation pressure, the above equation becomes:

$$FG = \left(\frac{\nu}{1-\nu}\right)\left(\frac{(\sigma_v - P_f)}{D}\right) + \frac{P_f}{D} \qquad (2.3)$$

Example 2.1: Fracture Gradient Calculations

Given that the formations pressure at 5000 ft is 2400 psi and the overburden stress is 1 psi/ft (determined from bulk density logs), estimate the formation fracture gradient at 5000 ft.

Solution

$$FG = \left(\frac{\nu}{1-\nu}\right)\left(\frac{(\sigma_v - P_f)}{D}\right) + \frac{P_f}{D}$$

$$FG = \left(\frac{0.4}{1-0.4}\right)\left(\frac{(1x5000-2400)}{5000}\right) + \frac{2400}{5000} = 0.83 \text{ psi/ft}$$

5.2 FORMATION BREAKDOWN GRADIENT

Knowledge of the formation breakdown gradient (FBG) is of paramount importance during kick situations when the casing shut-in pressure, CSIP, is being monitored. The sum of the hydrostatic pressure of fluids in the annulus and CSIP is always kept below the FBG at the casing shoe. It may be argued that, for added safety, control should be based on the fracture propagation pressure (= σ_3) rather than the FBG. However, in deviated wells and in areas where σ_3 is considerably different from σ_2, the calculated FBG can be lower than σ_3. The FBG (point 4 in **Figure 2.3**) is given by:

$$FBG = 3\sigma_3 - \sigma_2 + T - P_f \tag{2.4}$$

where T = rock tensile strength

Equation (2.4) is only valid when no fluid invades or penetrates the formation. In porous and permeable rocks the drilling mud normally penetrates the formation, thereby changing the magnitude of the stress concentrations around the borehole. The effect of fluid penetration is to create a force radially outward which reduces the stress concentration at the walls of the hole, thereby making it easier to fracture the wellbore. Haimson and Fairhurst[10] modified **Equation (2.4)** to take into account the effects of fluid penetration, to obtain formation breakdown pressure as given below:

$$\mathrm{FBG} = \frac{3\sigma_3 - \sigma_2 + \mathrm{T}}{2 - \alpha\left(\frac{1 - 2\nu}{1 - \nu}\right)} - \mathrm{Pf} \tag{2.5}$$

where $\alpha = 1 - (C_r / C_b)$; C_r = the rock matrix compressibility;

C_b = the rock bulk compressibility,

$0.5 \leq \alpha \leq 1$ when $0 \leq \nu \leq 0.5$

and, finally, $0 \leq \alpha\left(\frac{1-2\nu}{1-\nu}\right) \leq 1$

Haimson and Fairhurst[10] refer to the formation breakdown pressure as fracture initiation pressure. In this book we will stick with the name FBG, formation breakdown pressure.

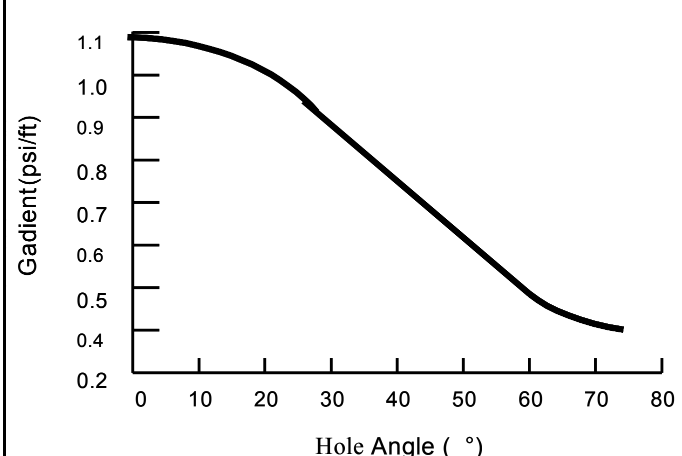
Hence, when $\alpha\left(\frac{1-2\nu}{1-\nu}\right)=1$, **Equation (2.5)** reduces to **Equation (2.4)** for the case of no fluid penetration.

The derivation of **Equation (2.4)** and its use to calculate safe mud weight for a horizontal well will be given in **Chapter 12.**

5.3 Effects of Hole Deviation On Formation Breakdown Gradient

All previous equations were given for the case of vertical holes in which the vertical principal stress had no influence on the magnitude of fracture pressure. However, as the hole starts deviating from vertical, the overburden stress starts contributing to the fracture pressure, thereby reducing the magnitude of the formation breakdown pressure:

Figure 2.5 Effects of Hole Deviation on FBG



$$FBP=\sigma_3\left(3-\cos^2\alpha\right)-\sigma_1\sin^2\alpha+T-P_f \tag{2.6}$$

Figure 2.5 shows the reduction in the FBG as the hole deviation increases. This figure is based on data from a North Sea well.

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6.0 CASING SEAT SELECTION

Accurate knowledge of pore pressure and fracture gradient plays a major role in the selection of proper casing seats that allow the drilling of each successive hole section without fracturing. Pore pressure, mud weight and fracture gradient are used collectively to select casing seats.

In **Chapter 1** and in this chapter, we have learnt how to calculate and interpret pore pressure, fracture gradient, FBG and overburden pressure.These values would normally be plotted on a graph paper to represent the well design basis (blue print).

The following example illustrates a method for the selection of casing seats.

Example 2.2: Casing Seat Selection

Using the data in columns 1 and 2 of **Table 2.1**, calculate the fracture gradient at the various depths for the following land well using **Equation (2.3)**. Assume $\nu = 0.4$.

Table 2.1 : Example 2.2

(1)	*(2)*
True Vertical Depth (ft)	***Pore pressure (psi)***
3000	1320
5000	2450
8300	4067
8500	4504
9000	5984
9500	6810
10000	7800
11000	10171

Solution

The following steps may be used to complete columns 3-6 of **Table 2.2**:

(1) The required hydrostatic pressure of mud is taken as equal to pore pressure + 200 psi, where 200 psi is the magnitude of overbalance. Any reasonable value of overbalance may be used depending on company policy.

(2) Calculate the pore pressure and mud pressure gradients by simply dividing pore pressure and mud pressure by depth to obtain the gradient in psi/ft.

Table 2.2 : Example 2.2

(1) True Vertical Depth (ft)	(2) Pore pressure (psi)	(3) Mud pressure = pore pressure + 200 psi (psi)	(4) Pore pressure gradient (psi/ft)	(5) Mud pressure gradient (psi/ft)	(6) Fracture gradient (psi/ft)
3000	1320	1520	0.44	0.51	0.81
5000	2450	2650	0.49	0.53	0.83
8300	4067	4267	0.49	0.51	0.83
8500	4504	4704	0.53	0.55	0.84
9000	5984	6184	0.66	0.69	0.89
9500	6810	7010	0.72	0.74	0.91
10000	7800	8000	0.78	0.80	0.93
11000	10171	10371	0.92	0.94	0.97

(3) Calculate the fracture gradient by use of **Equation (2.3)**:

$$FG = \left(\frac{\nu}{1-\nu}\right)\left(\frac{(\sigma_v - P_f)}{D}\right) + \frac{P_f}{D}$$

By use of $\nu = 0.4$, this equation becomes

$$FG = \frac{2}{3}\left(\frac{\sigma_v}{D} - \frac{P_f}{D}\right) + \frac{P_f}{D}$$

where $\frac{Pf}{D}$ is the pore pressure gradient.

Taking $\frac{\sigma_v}{D} = 1$psi/ft, and using **Table 2.2**, the fracture gradient at 5000 ft, for example, is calculated as follows:

$$FG = \frac{2}{3}(1 - 0.49) + 0.49 = 0.83 \text{ psi/ft}$$

The same equation can be used to calculate FG at other depths (see **Table 2.2**).

6.1 Casing Seat Selection Method

Steps

1. On the same graph paper, plot the pore pressure gradient, the mud pressure gradient and the fracture gradient against depth as shown in **Figure 2.6**. Some engineers, also plot the overburden gradient (extreme right of graph) and hydrostatic pressure (extreme left) to represent the limits of the wellbore pressures.The author recommends using only pore pressure, mud pressure and FG for casing seat selection.

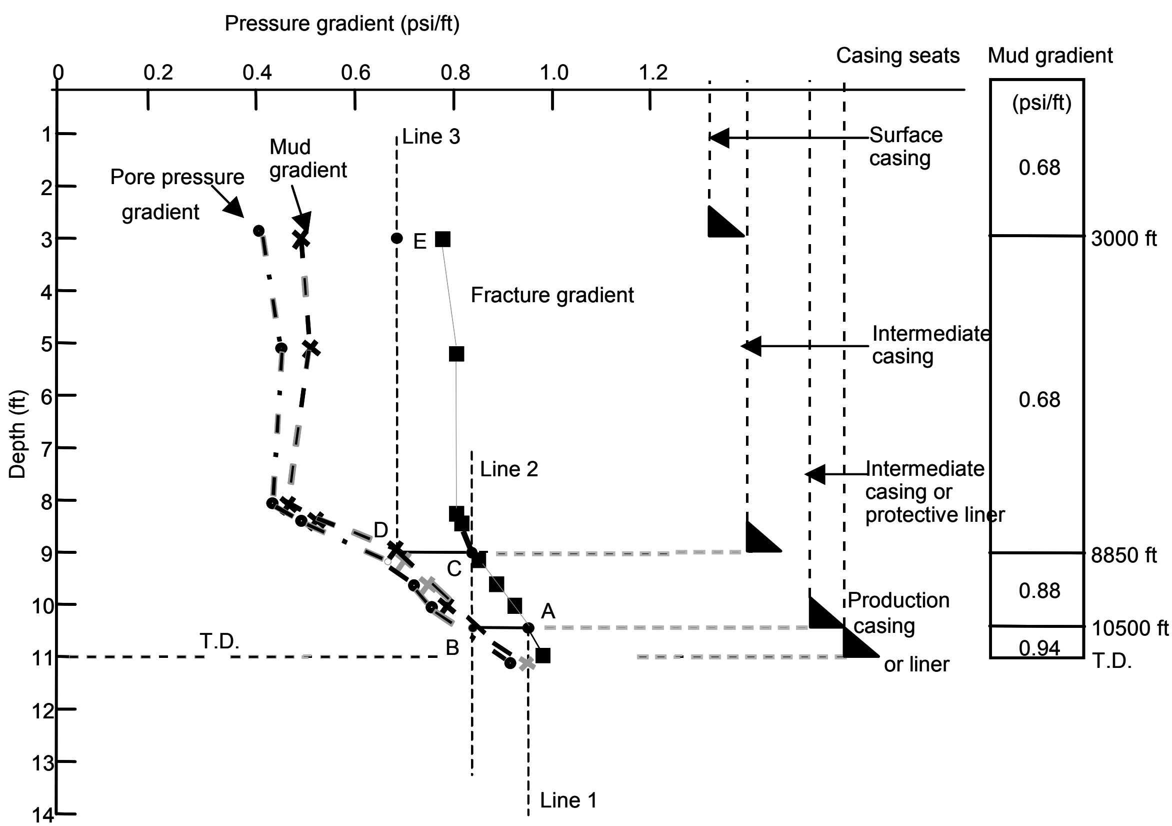
2. Always start at the highest mud weight; in this example the highest mud weight is used at TD.

3. Starting at hole TD (11 000 ft), draw a vertical line (line 1) through the mud gradient until it intersects the fracture gradient line. In our example the mud gradient at TD is 0.94 psi/ft and a vertical line through it (line 1 in **Figure 2.6**) intersects the fracture gradient line at 10 500 ft (point A in **Figure 2.6**). Above 10,500 ft, the mud gradient, 0.94 psi/ft, will exceed the fracture gradient of the open hole section and this section must therefore be cased off before raising the mud weight to 0.94 psi/ft to drill the bottom section. Between 10 500 ft and 11 000 ft the open hole should be cased with either a production liner or a production casing.

4. Above 10 500 ft the hole must be drilled with a mud weight less than 0.94 psi/ft. The new mud gradient is obtained by drawing a horizontal line from point A to the mud gradient line. Point B in **Figure 2.6** gives the new mud gradient as 0.88 psi/ft.

Move vertically from point B (line 2) until the fracture gradient line is intersected at 8850 ft at point C. Point C establishes the maximum depth that can be drilled before changing to the new mud gradient of 0.88 psi/ft. Hence, between points B and C, an intermediate casing can be set at point B.Another protective casing should also be set at point D, 8850 ft.

Figure 2.6 Casing Seat Selection



5. From point C move horizontally to the mud gradient line to point D, where the mud gradient is 0.68 psi/ft. A vertical line from point D (line 3) shows that a hole can be drilled with a mud gradient of 0.68 psi/ft to surface without fracturing the formation.

Suggested casing types at the various setting depths are given in **Figure 2.6**.

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7.0 Learning Milestones

In this chapter, you should have learnt:

1. There are four rock strength values which can be determined from a full Formation Integrity Test: limit strength, leak off gradient, formation breakdown gradient and fracture propagation gradient.
2. Fracture propagation pressure is the Fracture Gradient.
3. Fracture gradient is equal to the earth horizontal minimum strength.
4. How to conduct and interpret an FIT.
5. How to calculate FG.
6. How to calculate FBG or FBP.
7. To plot all wellbore pressures on a single graph (**Figure 2.6**).
8. To select casing seats.

8.0 References

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9.0 EXERCISES

1. Name three values which can be measured during a complete Formation Integrity Test (FIT)

a.

b.

c.

2. List four reasons for carrying out an FIT test

3. How often should an FIT be repeated?

4. List the earth stresses around the wellbore?

5. How many values of wellbore strengths can be measured during a full FIT test?

6. Using the following data taken during an FIT test, calculate the fracture gradient at the casing shoe:

Casing setting depth = 5000 ft

Mud weight = 10.5 ppg

Surface pressure at fracture = 1230 psi

(Ans: 0.79 psi/ft, 15.2 ppg)

7. Given that the formations pressure at 6000 ft is 2800 psi and the overburden stress is 1 psi/ft (determined from bulk density logs), estimate the formation fracture gradient at 6000 ft if Poisson's ratio is 0.4. (Ans: 0.82 psi/ft

8. Determine the formation breakdown gradient for the following well at

Angles: 0, 30, 70 and 90

Depth = 9452 ft

σ_1 = 1 psi/ft

σ_3 = 6143 psi at 9452 ft

Pore pressure = 3500 psi

Tensile strength (T) = 0

9. Using the data in **Example 2.2**, select appropriate casing seats by plotting pressures in psi against depth (not psi/ft as done in **Example 2.2**).

(NB:Lines 1 to 3 should be sloping lines connecting the highest mud weight with the origin.)

3

Kick Tolerance

Contents

1.0 Casing Seat Selection

It is essential to choose a casing seat that can withstand the maximum pressures to which the wellbore will be subjected during the drilling of the next hole section.

Information on formation strength is usually available from offset well data. If fracture gradient data is not available, then the Hubbert and Willis method (discussed in **Chapter 2**) should be used.

The pressure which the formation at the casing seat must be able to withstand is the greater of:

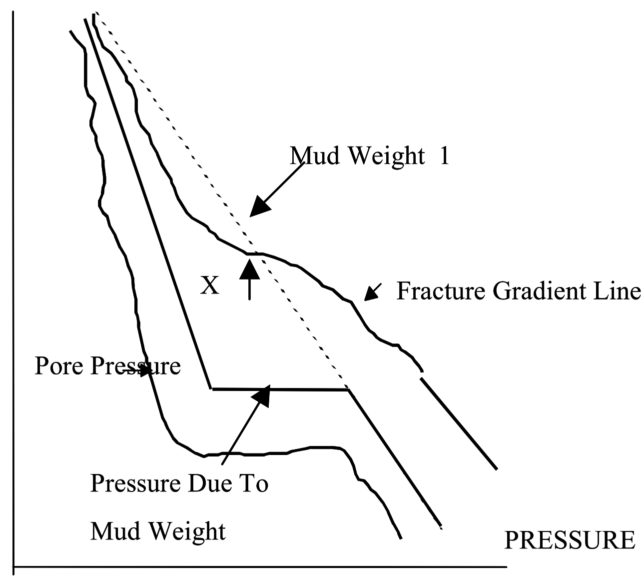
(i) the hydrostatic pressure of the mud used to drill the next section

(ii) the maximum pressure exerted at the casing seat when circulating out gas influx from TD of the next hole section

For exploration wells, it is preferable to use offset well data to select casing seats for the well under consideration. If this data is not available, then the casing seat depth may be determined using the following methods:

(a) The FBP or fracture gradient data together with pore pressure and mud weight should be plotted against depth as shown in **Figure 3.1**. The shallowest casing setting depth is point X. This method was explained in detail in **"Casing Seat Selection" on page 63**

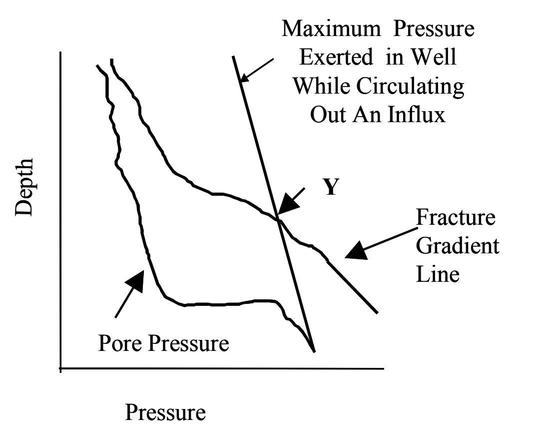
Figure 3.1 Casing Seat Selection Based On Mud Weights



(b) The FBP or fracture gradient data together with pore pressure and kick circulation pressure should be plotted against depth as shown in **Figure 3.2**. The shallowest casing setting depth is point Y. In this chapter, we will show how to calculate the well bore pressures as a kick is circulated out of the well.

The selected casing setting depth is then the deeper of the two depths arrived at under items (a) and (b) above.

Figure 3.2 Casing Seat selection based On Gas Influx Pressures



2.0 Gas Behaviour in a Well

Gas is a highly compressible fluid. Its volume depends on both pressure and temperature. To understand the behaviour of gas as it is circulated out of the hole during a well kill operation, we need to use the ideal gas law:

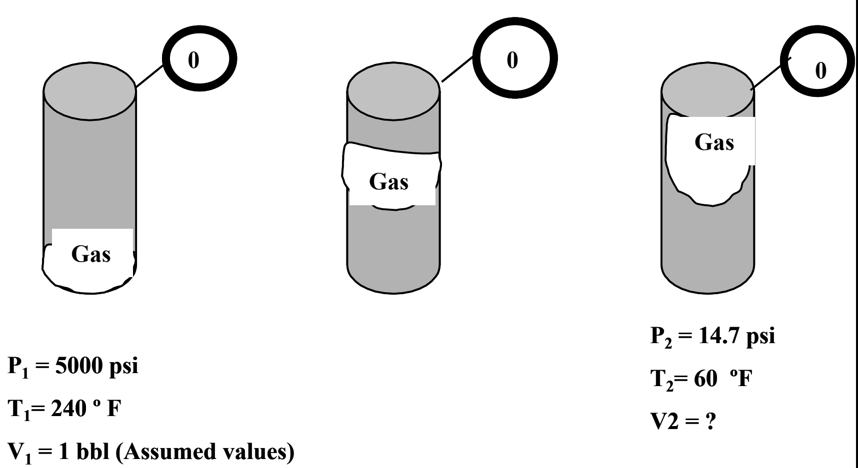
$$PV/T = \text{constant} \tag{3.1}$$

$$\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2} \tag{3.2}$$

Imagine two tubes full of mud. One tube is open to the atmosphere and the other is closed. Imagine two equal quantities of gas injected into the two tubes. The situation is shown in **Figure 3.3** for the open tube and **Figure 3.4** for the closed tube.

In the case of the open tube, when the gas reaches the surface its volume can be calculated using the ideal gas law:

Figure 3.3 Gas Behaviour In An Open Tube



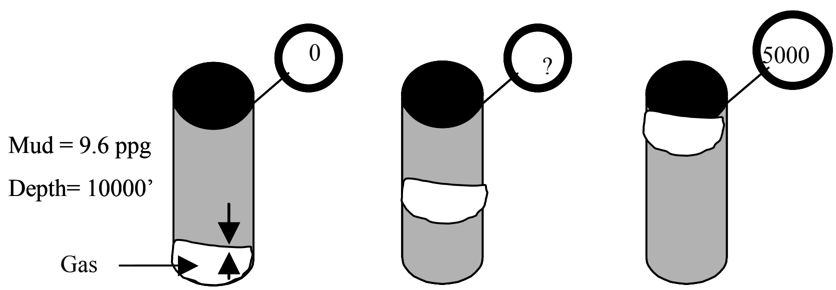
$$\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2}$$

$$\frac{5000 \times 1}{240 + 460} = \frac{14.7 x V_2}{60 + 240}$$

V_2= 253 bbl

When gas is injected into the closed tube it will travel up the tube with its pressure unchanged, although a slight decrease in its volume will be observed. When it reaches the surface its pressure will be superimposed on the hydrostatic pressure of mud. In this case the bottomhole pressure (**BHP**) will be the original hydrostatic pressure of mud plus the gas pressure. This situation is illustrated in **Figure 3.3**.

Figure 3.4 Gas Behaviour In A Closed Tube



BHP= surface pressure + mud hydrostatic head
= 0 +5000 = 5000 psi

BHP= surface pressure + mud hydrostatic head
=5000 +5000 = 10,000 psi

In a real well if gas expansion is prevented as was seen in the closed tube example then the hole will fracture when gas reaches the surface.

Hence when a kick is taken in a well, gas expansion must be allowed to take place to reduce wellbore pressures. This is the basis of well kill methods. On the rig, gas expansion is carried out in a controlled manner by manipulating the choke at surface.Kick tolerance is based on the fact that during a gas kick, gas is circulated out of the well at a controlled rate to reduce its pressure and to keep its expanded volume at surface to a manageable amount.

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3.0 Kick Tolerance

3.1 Definition

For practical purposes, kick tolerance may be defined as the maximum kick size which can be tolerated without fracturing the previous casing shoe. Kick tolerance may also be defined in the terms of the maximum allowable pore pressure at next TD or maximum allowable mud weight which can be tolerated without fracturing the previous casing shoe. **Table 3.1** gives typical kick tolerance values from various operators. The highest values in the range apply to exploration wells; the lowest values to development wells.

Kick tolerance therefore depends on the maximum kick size, maximum formation pressure at next TD and the maximum mud weight which can be tolerated without fracturing the weakest point in the open hole, usually the previous casing shoe. Other factors which affect kick tolerance include density of the invading fluid and the circulating temperatures.

Table 3.1 Typical Values Of Kick Tolerances From various Operators

HOLE SIZE (inch)	KICK VOLUME (bbl)
6"and smaller	10-25
8.5"	25-50
12¼"	50-100
17.5"	100-150
23"	250

4.0 Kick Tolerance Elements

The following elements determine the magnitude of kick tolerance:

1. Pore pressure from next TD
2. Maximum mud weight to be used
3. Fracture Gradient at current casing shoe
4. Design influx volume that can be safely circulated out

5. Type of well: exploration or development

5.0 When to Calculate Kick Tolerance

After a leak-off test and prior to drilling ahead, the kick tolerance should be calculated at intervals through the hole section to be drilled at the expected mud weight. If a factor such as mud weight or drillstring geometry is changed, then the kick tolerance must be recalculated. When drilling into areas of overpressure with rapid pore pressure increase, and increasing mud weight to compensate, the kick tolerance (limited by formation strength at the previous casing shoe) will be rapidly reduced. This will be shown in **Example 3.3**.

6.0 How To Calculate Kick Tolerance

For the purpose of well design and monitoring of wells with potential kick capability, kick tolerance should be calculated in terms of:

1. kick volume which can be circulated out without fracturing the previous casing shoe.
2. Additional mud weight over current mud weight.
3. Drilling Kick Tolerance: This is the maximum pore pressure which can be tolerated without the need to exceed the maximum allowable mud weight.

6.1 Circulation Kick Tolerance

Reference to **Figure 3.5** shows that when the top of the gas bubble reaches the shoe while being circulated using the Driller's method, the pressure at the casing shoe is given by:

$$Px = Pf - Pg - (TD - H - CSD) \times p_m \tag{3.3}$$

where

Pf = formation pressure at next TD, psi

Pg = pressure in gas bubble = H x G

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H = height of gas bubble at casing shoe, ft

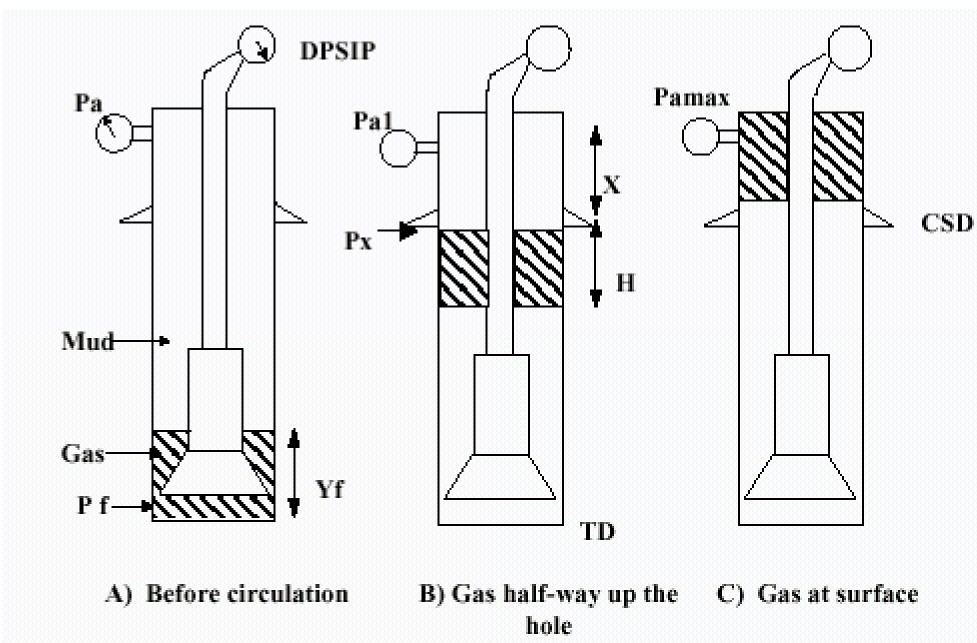
G = gradient of gas = 0.05 to 0.15 psi/ft

TD = next hole total depth, ft

CSD = casing setting depth, ft

p_m = maximum mud weight for next hole section, ppg

Figure 3.5 Circulation Of The Gas Influx Using The Drillers Method



Re-arranging the above equation in terms of H and replacing Px by the fracture gradient at the shoe (FG) gives:

$$H = \frac{0.052 \times pm\ (TD - CSD) + (FG \times CSD \times 0.052 - Pf)}{0.052 \times p_m - G} \tag{3.4}$$

where

FG = fracture gradient at the casing shoe in ppg

Pf = pore pressure in psi

Note: Refer to **Chapter 2** for a detailed discussion of fracture gradient (FG) and formation break down gradient (FBG) determination.

In vertical and near-vertical holes the FBG is invariably greater than the FG. In highly inclined holes the FBG is usually smaller than the FG. For kick tolerance calculations, it is recommended to reduce the value recorded during leak-off tests in vertical wells by 100 psi and to use the resulting value as an approximate value of FG.

The volume of influx at the casing shoe is

$$V_1 = H \text{ x } Ca \quad \text{bbl} \tag{3.5}$$

where Ca = capacity between pipe and hole, bbl/ft

At bottom hole conditions the volume of influx (V_2) is given by:

$$P_2 V_2 = P_1 V_1$$

(The effects of T and Z are ignored for the moment)

$$V_2 = \frac{P_1 V_1}{P_2} \tag{3.6}$$

where

P_1 =fracture pressure at shoe, psi

P_2 =Pf, psi

The value of V_2 is the circulation **kick tolerance** in bbls.

6.2 Additional Mud Weight

The maximum allowable drillpipe shut-in pressure (DPSIP) is given by:

$$DPSIP = (FG - \rho m) \text{ x } CSD \text{ x } 0.052 \tag{3.7}$$

And in terms of additional mud weight,

$$\text{Kick Tolerance} = (FG - \rho m) \tag{3.8}$$

Example 3.1: Kick Tolerance Calculations

Calculate the kick tolerance for the following well:

9 5/8" casing =14,500 ft

Next TD =17000 ft

FG at 9 5/8" shoe = 16 ppg

Temperature gradient = 0.02 F°/ft

Max. mud weight for next hole =14.5 ppg

Max formation pressure at next hole= 14 ppg

Assume next hole 8 ½" and there is 5" drillpipe from surface to TD

Answer

$$H = \frac{0.052 \times \rho m\ (TD - CSD) + (FG \times CSD \times 0.052 - Pf)}{0.052 \times \rho_m - G}$$

$$H = \frac{0.052 \times 14.5\ (17000 - 14500) + (16 \times 14500 \times 0.052 - 14 \times 17000 \times 0.052)}{0.052 \times 14.5 - 0.1}$$

H = 2405 ft

Volume at shoe = H x capacity between hole/drillpipe

$$\text{capacity} = \frac{\pi(8.5^2 - 5^2)}{4 \times 144}$$

$$= 0.2577\ ft^3/ft = \frac{0.2577}{5.62} = 0.0459\ bbl/ft$$

V_1 = 0.0459 (bbl/ft) x 2405 (ft)

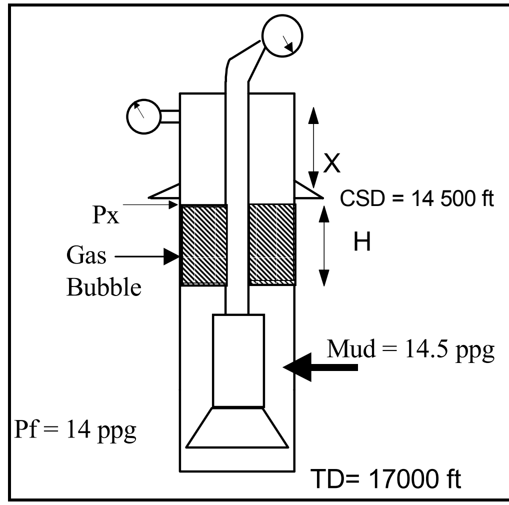
V_1 = 110.4 bbl (volume of bubble at shoe)

Using Boyle's law only:

$$P_1 V_1 = P_2 V_2$$

16 x 14500x 0.052 x 110.4 =14x17000x 0.052 x $\mathbf{V_2}$

$\mathbf{V_2}$ = 107.8 bbls



Temperature Effects

T = surface temperature + temperature gradient + 460

Note the constant 460 is required to convert to degrees Rankin which must be done before the ideal gas law can be used.

T1 (at shoe) = 60 + 0.02(F° /ft) x 14500 (ft) + 460 = 810 R

T_2 (at TD) = 60 + 0.02 x 17000 + 460 = 860 R

$$\frac{P_1 V_1}{T_1} = \frac{P_2 V_2}{T_2}$$

$$\frac{110 \text{x} 16 \text{x} 14500 \text{x} 0.52}{810} = \frac{V2 \text{ x} 14 \text{x} 17000 \text{x} 0.052}{860}$$

V_2 =115 bbl (compared to 107.8 bbl without temperature effects)

If FG= 15.2 ppg, then

H = 1482.87 ft

V_1 = 68 bbl

V_2 = 63 bbl (without temperature effects)

With temperature effects

V_2 = 67 bbls

7.0 Influence of FG on Kick Tolerance

The previous examples clearly show the influence of fracture gradient on kick tolerance. If a well is planned for a given kick tolerance say 50 bbls based on an estimated fracture gradient of say 15 ppg, and if while drilling the well the actual fracture gradient was found to be different from the design value, then two scenarios may be considered:

1. If the actual FG is greater than the design value, then the open hole section below the casing shoe can be drilled further than planned if desired. In other words, the well is actually stronger than planned.
2. If the actual FG is less than the planned, then the reverse of the above is true. The open hole section can not be drilled to it planned depth. The section may then be drilled to a shallower depth with less pore pressure or a cement plug is placed at the shoe to artificially strengthen the shoe. The last practice was actually performed by the author and was found successful in areas with FG less than 15 ppg.

Example 3.2: Kick Tolerance For HPHT Well

This data refers to a high pressure/ high temperature well. The 13 3/8" casing is not expected to see the HP/HT reservoir, but the formation pressure at next TD (12.25") is expected to be high.

13 3/8" shoe	= 10,008 ft RKB
Next TD (12¼")	= 14,190 ft RKB
Fracture gradient at 133/8" shoe	= 16 ppg

(Note: FG is determined from an offset well where the well actually leaked off)

Temperature gradient	= 0.02 ^{o} F/ft
Planned mud weight at TD of next hole	= 15.5 ppg
Max. Formation pressure at next TD	= 14 ppg (= 10268 psi)
Gas Gradient	= 0.15 psi/ft
RKB to MSL	= 85 ft

Calculate the kick tolerance at hole TD in terms of:

1)Maximum kick volume
2)Additional increase in mud weight
3)Maximum pore pressure if a maximum design kick of of 100 bbl

Solution

(1) Firstly, express the fracture pressure at the shoe in terms of psi:

FP =16 x 0.052 x 10008 = 8326 psi
where FP is the fracture pressure in psi

Since this is a high pressure / high temperature well, apply a safety factor of 100 psi to reduce the FP from 8326 psi to 8226 psi, or 15.8 ppg fracture gradient. This is because an actual leak off test was used to determine the fracture pressure value which is greater than the fracture gradient, see **Chapter 2**.

Using **Equation (3.4)** to calculate H gives

$$H = \frac{0.052 \times 15.5\ (14190 - 10008) + (8226 - 10268)}{(0.052 \times 15.5 - 0.15)}$$

$$= 2025 \text{ ft}$$

Hole capacity between 5"DP and 12¼" hole = 0.1215 bbl/ft

$$V_1 = 0.1215 \times 2025$$
$$= 246 \text{ bbl}$$

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At bottom hole conditions

$$V_2 = \frac{246 \text{ x}(8226)}{(10268)} = 197 \text{ bbl}$$

Therefore kick tolerance in terms of maximum kick size at hole TD is 197 bbl.

The calculations with temperature correction are left as an exercise for the reader.

(2) Additional mud weight

$$\text{DPSIP} = (\text{FG} - p_m) \text{ x CSD x } 0.052$$
$$= (15.8 - 15.5) \text{ x } 10008 \text{ x } 0.052$$
$$= 156 \text{ psi}$$

OR 15.8-15.5 = 0.3 ppg of additional mud weight

NOTE: These calculations do not allow for the effects of ECD.

(3) Drilling Kick Tolerance

Hence for the above example if a maximum kick size of 100 bbls is to be maintained then the maximum allowable pore pressure at next TD is calculated as follows:

$$H = \frac{100}{0.1215}$$

$$= 823 \text{ ft}$$

Solving equation **Equation (3.4)** for Pf and using a mud weight of 15.5 ppg gives:

$$823 = \frac{0.052 \text{ x } 15.5\ (14190 - 10008) + (8226 - \text{Pf})}{0.052 \text{ x } 15.5 - 0.15}$$

$$\text{Pf} = 11056 \text{ psi}$$

$$= \frac{11056}{(14190 - 85) \text{ x } 0.052}$$

= 15.1 ppg

Drilling Kick Tolerance = Max. Pf - current estimate of Pf
= 15.1 - 14 = 1.1 ppg

8.0 Kick Tolerance While Drilling

In exploration wells where the values of pore pressure and mud weight are revised constantly, it is advisable to recalculate kick tolerance as the hole is drilled.

Using data from the previous example, a table of revised pore pressure and mud weight values together with calculated kick tolerances are given below:

	Estimated		Kick Tolerance	
TVD (ft)	Mud Weight (ppg)	Pore Pressure (ppg)	Kick Size (bbl)	Add. Mud Weight (ppg)
12000	12.4	11	799	3.4
13000	12.4	12	525	3.4
13500	15.1	13	330	0.7
14190	15.5	14	197	0.3

9.0 Kick Tolerance Graph

For planning purposes, it is useful to construct a Kick Tolerance Graph as shown in **Figure 3.6**. In this figure, the kick volume is plotted on the X-axis (point 2), and the SIDP is plotted on the Y-axis. Point 1 is the maximum SIDP as calculated by **Equation (3.7)**. Point 2 is the maximum kick volume as obtained from **Equation (3.3)** for zero initial drill pipe shut-in pressure. The straight line joining points 1 and 2 is called the: Kick Tolerance graph. If the effects of temperature and gas compressibility are included then a curve is obtained.

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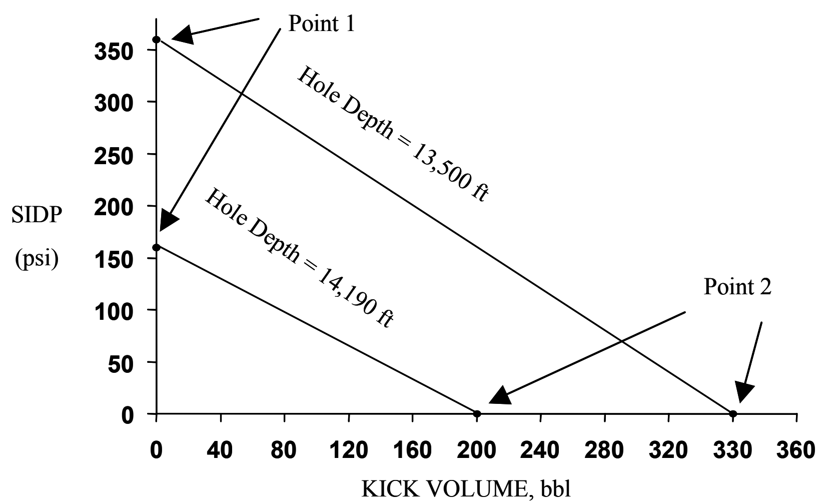
All points to the top and right of the line represent internal blowout and lost circulation conditions. Points below the line represent safe conditions and give kick tolerance for any combination of kick size and drillpipe shut-in pressure.

Note that Kick Tolerance is dependent on values of mud weight and pore pressure and the curve must therefore be updated each time these values change.

Figure 3.6 Kick Tolerance Graph



Example 3.3: Kick Tolerance Graph

Construct a kick tolerance graph for the well given in **Example 3.2** at depths 13500 ft and 14190 ft.

Solution (see Figure 3.6)

1.Maximum kick volume = 330 bbl at 13500 ft and 197 bbl at 14190 ft (point 2).

2. Maximum SIDP = 364 psi at 13500 ft and 156 psi at 14190 ft (point 1)

3. The line joining points 1 and 2 gives the kick tolerance graph

4. From **Figure 3.6** the following tables may be constructed to give the kick size which can be tolerated without shoe fracture.

Hole Depth = 13500 ft

Kick Volume (bbl)	Max. SIDP (psi)
50	310
100	255
150	197
200	143

Hole Depth 14190 ft

50	118
100	74

10.0 Modifying The Calculated Kick Tolerance

The kick tolerance values may be increased when:

1. drilling extremely high porous and permeable zones (1-3 darcies)
2. using low technology kick detection equipment or using old rigs
3. several transition zones with increasing pore pressure are expected in the same open hole section are encountered
4. drilling from a semi-submersible rig

11.0 Use Of Kick Tolerance To Calculate Internal Wellbore Pressures

The internal wellbore pressure exerted by the gas bubble as it is being circulated out of the hole may be easily calculated by solving **Equation (3.3)** for the gas pressure at the top of the bubble. An equation may be obtained by combining **Equation (3.3)** and an equation relating the gas height at any depth (using Ideal gas law) to obtain an equation for the gas pressure at the top of the bubble. Details of this derivation is given in reference [1].

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Gas pressure at any depth within the wellbore is given by:

$$P \textit{ at any depth} = \tfrac{1}{2} \left[A + \left(A^2 + 4.Pf.M.N.y_f.\rho_m\right)^{0.5} \right] \qquad (3.9)$$

Equation (3.9) can be used to determine the internal pressures at casing shoe and at surface. These two values can be used to calculate the expected burst pressures and then used to select appropriate casing grades/weights. The maximum expected surface pressure may also be used as the surface casing test pressure.

The procedure for solving **Equation (3.9)** is as follows:

(1) The appropriate kick volume should be selected based on values given in **Table 3.1**. (i.e. 50 bbl for 8½" hole, 100 bbl for 12¼"hole, etc.).

This is volume V_2 is used to calculate the height of the gas bubble at TD, ie when the kick was first taken.

$$y_f = \frac{V_2}{\text{hole/DP capacity}}$$

(2) Calculate M and N

M = Ratio of hole/DP capacity to casing/DP capacity

$$N = \frac{Zx\ Tx}{Zb\ Tb}$$

Zb, Zx = Compressibility factor at bottom hole and depth X

Tb, Tx = Temperature (Rankin) at bottom hole and depth X

For most wells, the value of N is approximately one.

(3) Calculate Pg = Hydrostatic Pressure in the gas bubble

$$= G\ y_f$$

$$\rho_m = \rho_m \text{ (ppg) } \times 0.052 \text{ psi/ft}$$

(4) Calculate A = $Pf - pm\,(TD - X) - Pg$

where ρ_m is in psi/ft

X =depth to top of gas bubble

At surface X = 0

At CSD X = CSD

(5) The pressure at the top of the gas bubble as it is being circulated out of the hole is then given by:

$$P\ \textit{at any depth} = \tfrac{1}{2}\left[A + \left(A^2 + 4.Pf.M.N.y_f.\rho_m\right)^{0.5}\right]$$

(6) This pressure should be calculated at various points and compared with the formation fracture pressure to determine if the selected casing setting depth is suitable.

(7) The surface casing pressure when the gas bubble reaches the surface is used in:

- casing burst design calculations
- casing test pressure
- wellhead selection

Example 3.4: Internal Pressures Due To A Kick

Calculate internal pressures at surface and shoe for the following well assuming a kick is taken at next TD with a maximum formation pressure of 12376 psi.

Also calculate minimum FG required at shoe

9 5/8" casing	= 14,500 ft
Casing N80, 47lb/ft, ID	= 8.681 inch
Next TD	= 17000 ft
Temperature gradient	= 0.02 F° /ft

Max. mud weight for next hole =14.5 ppg

Max formation pressure at next hole = 12376 psi (14 ppg)

Assume next hole 8 ½", 5" drillpipe from surface to TD

Solution

There are two approaches to solving this problem:

(1) The maximum kick tolerance for this well is used to calculate the internal pressures. From **Example 3.1** the maximum kick tolerance for this well is 108 bbls. This can be considered as the worst case scenario as it indicates that a kick of 108 bbl is taken before the drilling crew notices a pit gain. Today, this is a rare event as kick detection equipment can detect kicks of 10 bbls or less.

(2) A design kick tolerance of say 50 bbls **(see Table 3.1)** is used to calculate the wellbore internal pressures. This is a more realistic scenario and is widely used in the industry.

(i) Using Kick tolerance = 108 bbls

Gas Pressure at Surface

(1) Kick Volume = 108 bbls

$$y_f = \frac{V_2}{\text{hole/DP capacity}}$$

$$y_f = \frac{108 \text{ bbls}}{0.0459 \text{ bbl/ft}} = 2353 \text{ ft}$$

(2) Calculate M

M = Ratio of hole/DP capacity to casing/DP capacity....dimensionless

$$M = \frac{0.0459 \times \frac{bbl}{ft}}{\frac{\pi(8.681^2 - 5^2)}{4} \times \frac{1}{144} \times \frac{1}{5.62} \times \frac{bbl}{ft}} = 0.9392 \text{ dimensionless}$$

Assume N = 1

3) Calculate

Pg = Pressure in the gas bubble = G y_f = 0.1 x 2353

= 235.3 psi

ρ_m = ρ_m (ppg) x 0.052 = 14.5 x0.052 = 0.754 psi/ft

(4) At surface X= 0

A = Pf - ρ_m (TD - X) - Pg= 12,376 – 14.5x 0.052 (17000 – 0) – 235.3

= - 677.3 psi

(5) Px at surface

$$Px = ½ [A + (A^2 + 4.Pf.M.N.y_f.\rho_m)^{0.5}]$$

$$= ½ [-677.3 + ([-677.3]^2 + 4x\ 12376 \times 0.754 \times 2353 \times 0.9392 \times 1)^{0.5}] = 4215 \text{ psi}$$

Gas Pressure at Casing Seat

(1) Kick Volume = 108 bbls

$$y_f = \frac{108 \text{ bbls}}{0.0459 \text{ bbl/ft}} = 2353 \text{ ft}$$

(2) Calculate M

M = Ratio of hole/DP capacity at TD to hole/DP capacity at casing shoe

As the bubble is still inside the hole (just below the shoe), the value of M = 1

Assume N =1

(3) Calculate P_g = Pressure in the gas bubble = $G\ y_f$ = 0.1 x 2353 = 235.3 psi

$\rho_m = \rho_m$ (ppg) x 0.052 =14.5 x0.052 = 0.754 psi/ft

(4) At casing seat X = 14,500 ft

A = $P_f - \rho_m\ (TD - X) - P_g$
= 12,376 – 14.5x 0.052 (17000 – 145000) – 235.3 = 10256 psi

(5) Px at casing seat

$$Px = \frac{1}{2}\left[A + (A^2 + 4.P_f.M.N.y_f.\rho_m)^{0.5}\right]$$

$$= \frac{1}{2}\left[10256 + ([10256]^2 + 4 \times 12376 \times 0.754 \times 2353 \times 0.9392 \times 1)^{0.5}\right]$$

= 11,979 psi

(ii) Using Kick Tolerance = 50 bbls

Following the same procedure as above, we obtain:

At surface

1. y_f = 1089 ft

2. M = 0.9392, N=1

(3) Calculate P_g = Pressure in the gas bubble = $G\ y_f$ = 0.1 x 1089 = 109 psi

$\rho_m = \rho_m$ (ppg) x 0.052 =14.5 x0.052 = 0.754 psi/ft

(4) X = 0

A = -551 psi

(5) $P_{surface}$ = 2826 psi

At Casing shoe = 14500 ft

(1) y_f = 1089.3 ft

(2) M = 1, N=1

(3) Calculate Pg = Pressure in the gas bubble = G yf = 0.1 x 1089.3 = 109 psi

$\rho_m = \rho_m$ (ppg) x 0.052 =14.5 x0.052 =0.754 psi/ft

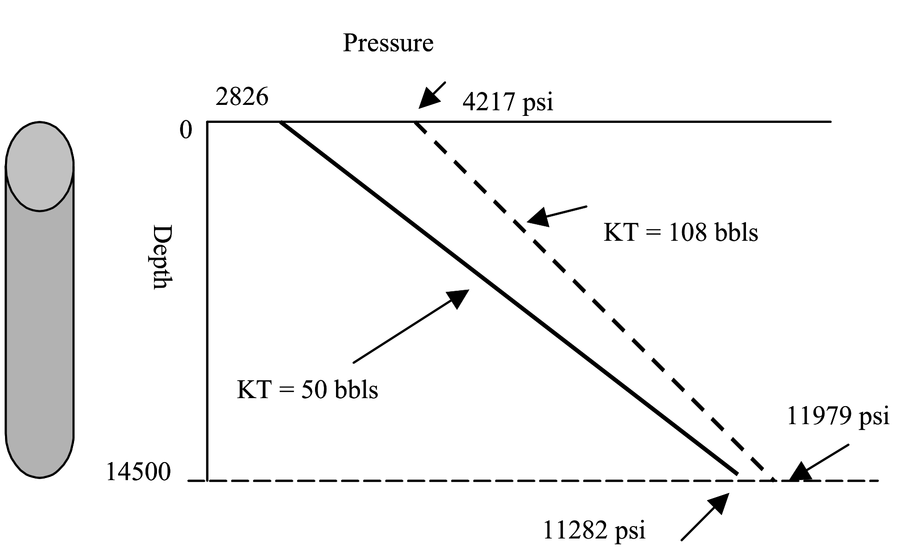
(4) X = 14500 ft

A = 10382 psi

(5) Pshoe = 11,282 psi

Figure 3.7 shows the variations in internal pressure along the casing for a KT of 108 and 50 bbls. It is clear from this example, surface equipment of much reduced rating would be selected on the basis of a realistic and practical kick tolerance.

Figure 3.7 Wellbore Annular Pressures For various Kick Sizes



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12.0 GAS COMPRESSIBILITY FACTORS

In the previous calculations, it was assumed that the gas compressibility factors at surface and at shoe (Zs and Zshoe) to be equal. Strictly speaking this is not true and this assumption introduces an error, usually less than 1% [1].

However, in HP/HT wells, accurate calculations of Zs and Zshoe is necessary as the assumption of these values being equal to one can introduce a significant error. In HP/HT the margin between pore pressure, mud weight and fracture gradient is very small and indeed in some wells both losses and gains are observed in the same zone with minor variations in ECDs.

The ideal gas law can now be re-stated with Z factors:

$$\frac{P_1 \times V_1}{T_1 \times Z_1} = \frac{P_2 \times V_2}{T_2 \times Z_2}$$

For drilling purposes, the Z factors are calculated assuming a gas kick containing mainly methane with specific gravity of 0.65 with respect to air. The Hall-Yarborough method [2] is the most widely used and uses an iterative solution such as the Newton-Raphson method to calculate the Z factors. The Excel kick tolerance sheet included with this CD uses this method. If the gas is not pure methane or forr condensates, Hall-Yarborough [2] provides a simple method for calcualting the actual gas gravity and pseudocritical temperature and pressure.

The Z- factor is calculated from the following equations:

$$Z = \frac{0.06125 \times P_{pr} \times t \times e^{a}}{y} \tag{3.10}$$

where

Z= compressibility factor

$$a = -1.2 \times (1 - t)^{2} \tag{3.11}$$

y = ‘reduced’ density as calculated from the equation below:

$$0 = \frac{-0.06125 \times P_{pr} \times t \times e^{a}}{y} + \frac{(1 + y + y^2 - y^3)}{(1 - y)^3} - (14.76t - 9.76t^2 + 4.58t^3)y$$

$$(90.7t - 242.2t^2 + 42.4t^3) \times y^{(1.18 + 2.282t)} \qquad (3.12)$$

t = reciprocal pseudo reduced temperature

T_{pr} = pseudo reduced temperature, $(\frac{T}{T_{pc}})$

T_{pc} = pseudo critical temperature

T = actual temperature ($^\circ$R)at point of consideration, say surface or casing shoe as calculated without Z factors

The Hall-Yarborough method is applicable to the following range:

$$1.2 \le T_{pr} \le 3.0 \qquad (3.13)$$

$$0 \le P_{pr} \le 24.0 \qquad (3.14)$$

where

P_{pr} = pseudo reduced pressure, $(\frac{P}{P_{pc}})$

P_{pc} = pseudo critical pressure

P = actual pressure (psi) at point of consideration, say surface or casing shoe as calculated without Z factors

For pure methane, the pseudo critical temperature and pressure are 387.5 $^\circ$R and 675.2 psi respectively, giving and effective applicable range of:

$$465^\circ R \le T \le 1162.5^\circ R \qquad (3.15)$$

$$0 \le P \le 16204.8 psi \qquad (3.16)$$

12.1 Method of Solution

1. Assume a small value for $y^{(0)}$, say, 0.001, and calculate the function:

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$$F^{(0)} = 0 = -0.06125 \times P_{pr} \times t \times e^{a} + \frac{(y + y^2 + y^3 - y^4)}{(1 - y^3)} - (14.76t - 9.76t^2 + 4.58t^3)y^2 + (90.7t - 242.2t^2 + 42.4t^3) \times y^{(2.18 + 2.282t)} \quad (3.17)$$

2. Calculate the derivative:

$$\frac{dF}{dy} = \frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1 - y^4)} + (29.25t - 19.52t^2 + 9.16t^3)y \quad (2.18 + 2.82t) \times (90.7t - 242.2t^2 + 42.4t^3)y^{1.18 + 2.28t} \quad (3.18)$$

3. Calculate a new value for y from

$$y = y^{(0)} - \frac{F^{(0)}}{\frac{dF}{dy}} \quad (3.19)$$

4. The new value of y can be used to re-evaluate F and iterate until $F^{(0)}$ is less than a small number

5. Use the final value of y in **Equation (3.10)** to calculate the value of Z.

Example 3.5: Z-Factor

Calculate the Z factor at the casing shoe for a gas kick containing pure methane if the pressure and temperature at the shoe are : 6,532 psi and 272 ∘F (732 ∘R).

Solution

For pure methane, the pseudo critical temperature (T_{pc}) and pseudo critical pressure(P_{pc}) are 387.5 ∘R and 675.2 psi

T_{pr} = pseudo reduced temperature, $\left(\frac{T}{T_{pc}}\right) = \frac{732}{387.5} = 1.889$

t = reciprocal pseudo reduced temperature = $\frac{387.5}{732} = 0.5294$

$a = -1.2 \times (1 - t)^2 = -0.2658$

$-0.06125 \times t \times e^{a} = -0.0249$

$(14.76t - 9.76t^{2} + 4.58t^{3}) = 5.7462$

$(90.7t - 242.2t^{2} + 42.4t^{3}) = -13.5725$

$(2.18 + 2.82t) = 3.6729$

P_{pr} = pseudo reduced pressure, $(\frac{P}{P_{pc}}) = \frac{6532}{675.2} = 9.6742$

1. Guess $y^{(0)} = 0.001$

$F^{(0)} = -0.23946$

2. $dF/dy = 0.99517$

3. $y = y^{(0)} - \frac{F^{(0)}}{\frac{dF}{dy}} = 0.24163$

4. $Z = \frac{0.06125 \times P_{pr} \times t \times e^{a}}{y} = 0.9952$

5. Continue with steps 1 to 4 until the value $F^{(0)}$ is close to zero. After eight iterations, the value of Z = 1.12 ($F^{(0)} = 1.91 \times 10^{-6}$). This is left as an excercise fro the reader.

Usually, a minimum of 10 iterations is required before convergence is obtained and the correct value of Z is calculated.

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13.0 LEARNING MILESTONES

In this chapter, you should have learnt to:

1. List variable affecting kick tolerance
2. List situations when it is required to calculate kick tolerance.
3. Calculate kick tolerance for any well with and without temperature corrections
4. List situations when to increase kick tolerance
5. Understand the influence of FG on KT
6. Use kick tolerance volumes to calculate the expected wellbore pressures during a kick (**Example 3.4**).
7. Plot the above wellbore pressure on a graph of pore pressure and fracture gradient to determine depths of casing seats. No exercise was give for this point, but the KT pressure data was plotted in **Figure 3.7**. **Figure 3.2** shows how to do the above.

14.0 References

1. Rabia, H. "Fundamental of Casing Design" Graham and Trotman, 1987.

2. Hall, K.R and Yarborough, L "How to solve equation of state for Z-factors"

Oil & Gas Journal, 18 Feb. 1974, pp86-88.

15.0 Exercises

1. Define kick tolerance.

2. Name three variables which affect kick tolerance.

3. Write down the ideal gas law with temperature.

4. Calculate the volume of gas at surface for the following well assuming the well is open:

P_1 = 5000 psi, T_1= 240 ° F, V_1 = 1 bbl

P_2 = 14.7 psi, T_2= 60 °F, V2 =?

(Ans: 252.7 bbl)

5. Using the following data:

9 5/8"	= 14,500 ft
Next Hole TD	= 17000 ft
FG at 9 5/8" shoe	= 16 ppg
Temperature gradient	= 0.02 F° /ft
Max. mud weight for next hole	=14.9 ppg
Max formation pressure at next hole	= 14.3 ppg

Assume next hole 8 ½"

5" drillpipe from surface to TD

Calculate

a. height of bubble at shoe

b. capacity of hole/DP

c. volume of kick at shoe

d. kick tolerance for well without temperature

e. kick tolerance for well with temperature

(Ans: 1991 ft, 0.045 bbl/ft, 91.4 bbl, 87.8 bbl, 93.2 bbl)

6. Using data from the above and assuming that a kick of 150 bbls is taken at shoe, calculate

a. height of bubble at TD

b. the factor M

c. annulus pressure at shoe

d. will the well fracture or not?

7. Give two reasons why kick tolerance can not be used in slim holes.

8. Give two uses for kick tolerance in drilling engineering.

9. When does the Z factor become critical in kick tolerance calculations?

10. List two ways of drilling a well with a negative kick tolerance.

4

Casing Properties

Contents

1.0 Functions Of Casing

The functions of casing may be summarised as follows.

1. To keep the hole open and to provide support for weak, vulnerable or fractured formations. In the latter case, if the hole is left uncased, the formation may cave in and redrilling of the hole will then become necessary.

2. To isolate porous media with different fluid/pressure regimes from contaminating the pay zone. This is basically achieved through the combined presence of cement and casing. Therefore, production from a specific zone can be achieved.

3. To prevent contamination of near-surface fresh water zones.

4. To provide a passage for hydrocarbon fluids; most production operations are carried out through special tubings which are run inside the casing.

5. To provide a suitable connection for the wellhead equipment and later the christmas tree. The casing also serves to connect the blowout prevention equipment (BOPS) which is used to control the well while drilling.

6. To provide a hole of known diameter and depth to facilitate the running of testing and completion equipment.

2.0 TYPES OF CASING

In practice, it would be much cheaper to drill a hole to total depth (TD), probably with a small diameter drill bit, and then case the hole from surface to TD. However, the presence of high-pressured zones at different depths along the wellbore, and the presence of weak, unconsolidated formations or sloughing, shaly zones, necessitates running casing to seal off these troublesome zones and to allow the drilling to TD. Thus, different sizes of casing are employed and this arrangement gives a tapered shape to the finished well.

The types of casing currently in use are as follows:

1. Stove Pipe

Stove pipe (or marine-conductor, or foundation-pile for offshore drilling) is run to prevent washouts of near-surface unconsolidated formations, to provide a circulation system for the drilling mud and to ensure the stability of the ground surface upon which the rig is sited. This pipe does not usually carry any weight from the wellhead equipment and can be driven into the ground or seabed with a pile driver. A typical size for a stove pipe ranges from 26 in. to 42 in.

2. Conductor Pipe

Conductor pipe is run from the surface to a shallow depth to protect near surface unconsolidated formations, seal off shallow-water zones, provide protection against shallow gas flows, provide a conduit for the drilling mud and to protect the foundation of the platform in offshore operations. One or more BOPs may be mounted on this casing or a diverter system if the setting depth of the conductor pipe is shallow. In the Middle East, a typical size for a conductor pipe is either 18 5/8 in. (473 mm) or 20 in. (508 mm). In North Sea exploration wells. the size of the conductor pipe is usually 26 or 30 in. Conductor pipe is always cemented to surface. It is used to support subsequent casing strings and wellhead equipment or alternatively the pipe is cut off at the surface after setting the surface casing. Conductor pipes are either driven by a hammer or run in a drilled hole or run by a

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combination of drilling and driving especially in offshore operations where hard boulders are encountered.

3. Surface Casing

Surface casing is run to prevent caving of weak formations that are encountered at shallow depths. This casing should be set in competent rocks such as hard limestone. This will ensure that formations at the casing shoe will not fracture at the high hydrostatic pressures which may be encountered later. The surface casing also serves to provide protection against shallow blowouts, hence BOPs are connected to the top of this string. The setting depth of this casing string is chosen so that troublesome formations, thief zones, water sands, shallow hydrocarbon zones and build-up sections of deviated wells may be protected. A typical size of this casing is 13 3/8 in. (240 mm) in the Middle East and 18 5/8 in. or 20 in. in North Sea operations.

4. Intermediate Casing

Intermediate casing is usually set in the transition zone below or above an over-pressured zone, to seal off a severe-loss zone or to protect against problem formations such as mobile salt zones or caving shales. Good cementation of this casing must be ensured to prevent communication behind the casing between the lower hydrocarbon zones and upper water formations. Multistage cementing may be used to cement this string of casing in order to prevent weak formations from being subjected to high hydrostatic pressure from a continuous, long column of cement. The most common size of this casing is 9 5/8 or 10 ¾ in.

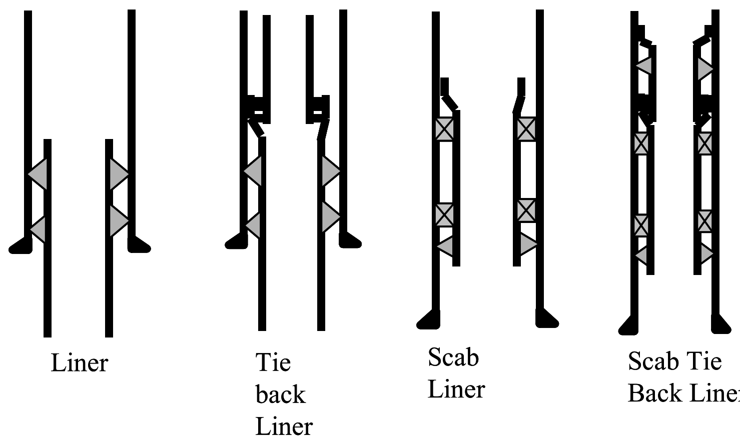
5. Production Casing

Production casing is the last casing string. It is run to isolate producing zones, to provide reservoir fluid control and to permit selective production in multizone production. This is the string through which the well will be completed. The usual sizes of this string are 4 1/2, 5 and 7 in.

6. Liners

A liner is a string of casing that does not reach the surface. Liners are hung on the intermediate casing by use of a liner-hanger. In liner completions both the liner and the intermediate casing act as the production string. Because a liner is set at the bottom and hung from the intermediate casing, the major design criterion for a liner is usually the ability to withstand the maximum expected collapse pressure.

Figure 4.1 Types of Liners



2.1 Types Of Liners

Basic liner systems are shown in **Figure 4.1**.

1. Drilling liners are used to isolate lost circulation or abnormally pressured zones to permit deeper drilling.
2. Production liners are run instead of a full casing to provide isolation across the production or injection zones.
3. The tie-back liner is a section of casing extending upwards from the top of an existing liner to the surface. It may or may not, be cemented in place.
4. The scab liner is a section of casing that does not reach the surface. It is used to repair existing damaged casing. It is normally sealed with packers at top and bottom and, in some cases, is also cemented.

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5. The scab tie-back liner is a section of casing extending from the top of an existing liner but does reach the surface. The scab tie-back liner is normally cemented in place.

2.2 Advantages of a Liner

The main advantages of a production liner are: (a) total costs of the production string are reduced, and running and cementing times are reduced; (b) the length of reduced diameter is reduced which allows completing the well with optimum sizes of production tubings.

Other advantages include:

- Complete wells with less weight landed on wellheads and surface pipe
- A scab liner tie-back provides heavy wall cemented section through salt sections.
- Permits drilling with tapered drillstring.
- Where rig capacity cannot handle full string; when running heavy 9 5/8" casing.
- To provide a PBR (Polished Bore Receptacle) completion. This type of completion is recognised to be the best casing to tubing seal system.
- Improved completion flexibility.
- To provide an upper section of casing (tie-back liner) which had seen no drilling.
- For testing in critical areas where open hole testing is not practised.

The disadvantages of a liner are:

(a) possible leak across a liner hanger; and

(b) difficulty in obtaining a good primary cementation due to the narrow annulus between the liner and the hole.

3.0 CASING (STEEL) PROPERTIES

3.1 PROCESS OF MANUFACTURE

Casing, tubing, drillpipe and line pipe must all conform to API series 5 "Tubular Goods" including API Specs, RP's, Bull and ISO Specs. API 5C2 gives performance properties of casing, tubing and drillpipe.

The API Spec 5A requires that API casing and liners be seamless or electric-welded. Grade P110 must, however, be manufactured by the seamless process only.

Seamless pipe is defined as Wrought steel tubular product made without a welded seam. It is manufactured by hot working steel, or if necessary by subsequently cold finishing the hot-worked tubular product to produce the desired shape, dimensions and properties.

Electric-welded pipe is defined as pipe having one longitudinal seam formed by electric flash welding or electric-resistance, without the addition of extraneous material. The weld seam of electric-welded pipe should be heat treated after welding to a minimum temperature of 1000 F° (538 C°), or processed in such a manner that no untempered martensite remains.

3.2 LENGTH OF JOINT

API has specified three ranges in which a pipe length must lie. These are as follows:

Range	Length (ft)	Average Length (ft)
1	16-25	22
2	25-34	31
3	Over 34	42

3.3 GRADE OF STEEL

The raw steel material used for the manufacturing of casing has no definite microstructure. The microstructure of steel and mechanical properties can be greatly changed by the addition of special alloys and by heat treatment. Thus, different grades of casing can be manufactured

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to suit different drilling situations by adding a variety of alloying minerals such manganese, molybdenum, chromium, nickel and copper.

API lists nine different grades of casing as shown in **Table 4.1**. The grades are given the letters H to Q. At the time of writing this book, a new grade M65 was added by API.

Table 4.1 API casing grades

Grade	Minimum Yield Strength (psi)	Maximum Yield Strength (psi)	Minimum Tensile Strength (psi)
H40	40,000	80,000	60,000
J55	55,000	80,000	70-95,000
K55	55,000	80,000	70-95,000
N80	80,000	110,000	100,000
L80	80,000	95,000	100,000
C90	90,000	105,000	100,000
C95	95,000	110,000	105,000
P110	110,000	140,000	125,000
Q125	125,000	150,000	135,000

The number in the grade designation (e.g. H40) gives the API minimum yield strength in thousands of psi. **Table 4.2** gives the chemical properties of API grades and classes of pipe.

Table 4.2 Chemical properties of API grades

1	2	3	4		5		6		7		8	9	10	11	12
Group	Grade	Type	Carbon		Manganese		Molybdenum		Chromium		Nickel	Cooper	Phosphorus	Sulphur	Silicon
			min.	max.	min.	max.	min.	max.	min.	max.	max.	max.	max.	max.	max.
1	H40												0.03	0.03	
	J55												0.03	0.03	
	K55												0.03	0.03	
	N80												0.03	0.03	
2	L80	1	-	0.43 [a]	-	1.9	-	-	-	-	0.25	0.35	0.03	0.03	0.45
	L80	9Cr	-	0.15	0.3	0.6	0.9	1.1	8	10	0.5	0.25	0.02	0.01	1.00
	L80	13 Cr	0.15	0.22	0.25	1	-	-	12	14	0.5	0.25	0.02	0.01	1.00
	C90	1	-	0.35	-	1.00	0.25 [b]	0.75	-	1.2	0.99	-	0.02	0.01	-
	C90	2	-	0.50	-	1.90	-	N.L	-	N.L	0.99	-	0.03	0.01	-
	C95		-	0.45 [c]	-	1.90	-	-	-	-	-	-	0.03	0.03	0.45
	T95	1	-	0.35	-	1.20	0.25 [d]	0.85	0.40	1.50	0.99	-	0.02	0.01	-
	T95	2	-	0.50	-	1.20	-	-	-	-	0.99	-	0.03	0.01	-
3	P110	-	-	-	-	-	-	-	-	-	-	-	0.03 [e]	0.03 [e]	-
4	Q125	1	-	0.35	-	1.00	-	0.75	-	1.20	0.99	-	0.02	0.01	-
	Q125	2	-	0.35	-	1.00	-	-	-	N.L.	0.99	-	0.02	0.02	-
	Q125	3	-	0.50	-	1.00	-	-	-	N.L.	0.99	-	0.03	0.01	-
	Q125	4	-	0.50	-	1.00	-	-	-	N.L.	0.99	-	0.03	0.02	-

N.L. = No limit. Elements shown must be reported in product analysis

a The carbon content for L80 may be increased to 0.50% max. if the product is oil-quenched.

b The molybdenum content for Grade C90, Type 1 has no minimum tolerance if the wall thickness is less than 0.70 inch.

c The carbon content for C95 may be increased to 0.55% max. if the product is oil-quenched.

d The molybdenum content for Grade T95, Type 1 may be decreased to 0.15% minimum if the wall thickness is less than 0.7 inch.

e The posphorous is 0.02% maximum and the sulfur is 0.01% maximum for EW grade P110

3.4 Description of Most Commonly Used Casing Grades

Table 4.3 gives a description of most commonly used casing grades in the oil industry.

Table 4.3 Description of Most Commonly Used Casing Grades In The Oil Industry

Grade	Brief Description
H40	Lowest casing and tubing grade. Has a maximum yield of 80,000 psi which makes it suitable for H2S.
J55	Both casing and tubing grade. Max. yield is 80,000 psi. Good for H2S.
K55	This is a casing grade only. Classified as carbon type steel. Has a higher tensile strength than J55; 95,000 psi compared to 75,000 psi. Collapse and burst of K55 and J55 are the same: only joint strength is different as it is based on tensile strength rather than yield strength. Good for H2S at all temperatures (Yield Strength = 80,000 psi)
M65	This is a new grade added in December 1999. It has a high toughness and is suitable for H_2S. Yield strength range: 65-80,000 psi. Min. tensile strength is 85,000 psi. Coupling is either L80 or K55 depending on wall thickness. Burst and collapse values exceed those of J55 and K55. Joint strength exceeds that of J55.
L80	This is the most widely used grade in the industry and is also suitable for H_2S. Maximum yield is 95,000 psi and minimum tensile strength is 95,000 psi. Maximum Rockwell hardness is C23. Both casing and tubing grade. Steel must be Q&T (quenched and tempered) and made by seamless or ERW methods.
N80	This grade has a maximum yield of 110,000 psi and minimum tensile strength of 100,000 psi. N80 is an alloy type steel. Due to its high yield, it is not suitable for H_2S at all temperatures

C90	This grade is used mostly in high pressure wells containing H2S. Grade was added in 1983. Both casing and tubing. Maximum yield is restricted to 105,000 psi and minimum tensile strength is 100,000 psi. This is an alloy steel containing chromium and molybdenum and is made by seamless method. Max. Rockwell is C25.
C95	This grade has a maximum yield of 110,000 psi and minimum tensile strength of 105,000 psi. This is a casing grade only and was placed in the Specs to replace grade C75. Can be made by seamless or ERW and steel is an alloy. C95 has no hardness limitation, hence it is not suitable for H_2S at low temperatures due to its high yield strength.
T95	This grade solves the problems with C95. It is both casing and tubing grade. Minimum tensile strength is 105,000 psi and maximum yield strength is 110,000 psi. This is an alloy steel made by seamless method. Max. Rockwell hardness is C25.
P110	This is a casing and tubing grade. Max Yield is 140,000 psi and min. tensile strength of 125,000 psi. Made by seamless and ERW for casing, seamless for tubing. Initially added to solve deep well problems.
Q125	This grade is used mostly in deep wells with high pressures, especially high collapse pressures. Added by API in 1985, classed as Group 4. Made by ERW and seamless. First grade to require impact test to confirm steel toughness. Can be used in H_2S environments at temperatures of 225 °F and hotter.
V150	This is not an API grade. Yield range is 150-180,000 psi. Min. tensile strength is 160,000 psi. Can not be used for H_2S at any temperature.

3.5 Restricted Yield Strength Grades

For sour gas service (or H2S), API recommends two grades; L80 and C95. The chemical requirements and heat treatment for these restricted yield strength grades are shown in **Table**

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4.1 and their description is given in Table 4.3. The effects of H_2S on steel is described in the next section.

3.6 Hydrogen Embrittlement

Free hydrogen ions form on wet metal surfaces as a result of corrosion processes. The majority of these ions combine with themselves to form molecular hydrogen gas (H_2). The hydrogen gas molecules are too large to enter the steel and will bubble off through the fluid. A small proportion of the free hydrogen ions will enter the steel. Once inside the steel, the hydrogen ions reduce the ductility of the steel and cause it to fail in a brittle manner rather than in its familiar ductile failure mode. This type of failure is often described as ***hydrogen embrittlement or hydrogen*** **stress cracking.**

In the presence of H_2S the rate at which the free hydrogen ions can combine is greatly reduced. This results in a larger proportion of free hydrogen ions remaining on the metal surface and eventually entering the steel. Inside the steel, the hydrogen ions can cause small cracks that will lead to sudden brittle failure of steel. In the presence of H_2S, the failure type is described as **s*ulphide s*tress cracking**.

Sulphide stress cracking can only occur if the steel is under tensile stress and when H_2S and water or moisture are present. The higher the stress level to which steel is subjected, the shorter the time to failure in the presence of H_2S.The concentration of H_2S required to affect sulphide stress cracking is quite small: Baroid [6] quotes a figure of 1 ppm; Patton [7] quotes a figure of 0.1 ppm. Other factors such as pH of the solution and temperature have some influence on the cracking tendency.

It should be observed that only high strength steels (yield strength in excess of 100,000 psi) are susceptible to sulphide stress cracking. Steels with yield strength below 90,000 psi and with Rockwell hardness of 26 and below are found to be resistant to sulphide stress cracking.

The effect of H_2S on steel is remarkable. It was observed that steel specimens that did not fail in years while in a CO_2 and salt environment, failed in less than an hour in an H_2S-salt environment.

3.7 Factors Affecting SSC

There are three main factors which affect SSC:

1. Hydrogen sulphide concentration
2. pH; and
3. Temperature

Other factors which have influence include: applied stress, CO_2 content, water content and composition, flow rates, surface condition of steel and presence of corrosion inhibitors.

The tendency for SSC to occur is increased by:

- Presence of microstructures such as martensite. These microstructures tend to be present in high strength, low alloy steels
- Hard microstructures in welds and in low heat input welds

(Casing with Rockwell hardness of 22- 26 was found to be resistant to SSC in sour environments)

3.8 H2S Partial Pressure

At temperatures below 150-175 °F, it takes only a small amount of H_2S to cause SSC. The NACE standards indicate that an environment with H_2S partial pressure of 0.05 psia can cause SSC. Hence the starting point in casing grade selection is to calculate the amount of H_2S in the well, its partial pressure (of the total reservoir pressure) and the prevailing temperature.

For gas reservoirs:

$$H_2S \text{ partial pressure} = \text{mole fraction of } H_2S \text{ x reservoir pressure}$$

For liquid reservoirs

$$H_2S \text{ partial pressure} = \text{Bubble Point Pressure (BPP) x Mole fraction of } H_2S \text{ at BPP}$$

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3.9 Effects of Temperature

Hydrogen embrittlement was found to decrease at higher temperatures. Requirements for SSC materials may be relaxed if the operating temperature is continuously above 65 °C [11].

Above 65 °C, API N-80 (Q&T) and C-95 may be used.

Above 80 °C, API N-80, P-105 and P-110 may be used.

Above 110 °C, API Q-125 may be used.

3.10 Materials Requirements to Avoid SSC

SSC can be prevented by limiting the strength of the material used in the wellbore. This can be done by measuring the bulk hardness of the material using Vickers HV30, Brinell and Rockwell hardness (HRC) indices.**Table 4.3** gives details of the most commonly used casing grades.

The following are guidelines[11] for selecting Oil Country Goods (OCTG) and Non-welded Components for sour environments:

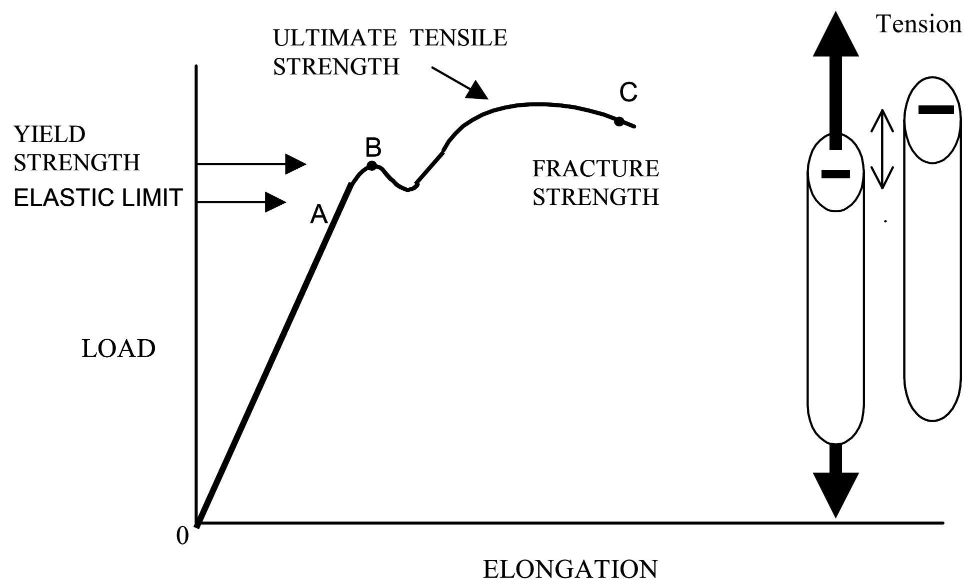
- Quenched and tempered (Q &T) products are preferred for sour service.
- Control hardness to ≤ 250 HV30 at 22 HRC

  (Q &T C90 and T95 may be used up to 270 HV30)
- Hardness distribution is uniform within 10% of maximum value.
- Microstructure is homogeneous and is free from untempered martensite.

4.0 Casing Strength Properties

Casing strength properties are normally specified as: (1) yield strength for (a) pipe body and (b) coupling; (2) collapse strength; and (3) burst strength for (a) plain pipe and (b) coupling.

Figure 4.2 Graph of load against elongation



4.1 Yield Strength

When a steel specimen is gradually loaded by tension or compression, a gradual increase or decrease in its length is observed. If the loading increments are plotted against extension (or contraction), a graph similar to that shown in **Figure 4.2** is obtained.

Up to a certain load, any increase in load will be accompanied by a proportional increase in length, in accordance with Hooke's law:

$$\sigma = E\,\varepsilon$$

where

σ = applied stress = load/cross-sectional area,

ε = deformation (strain) = elongation/original length

E = Young's Modulus.

Hooke's law is only applicable along the straight portion of the graph referred to as the *elastic range,* line OA in **Figure 4.2**. Along this portion, loading results in no damage to the internal structure of the steel and removal of the load will result in the specimen regaining its original length and shape. The elastic limit is the region where casing loading should be confined to.

The point on the load-elongation graph (or σ-ε graph) where Hooke's law is no longer applicable, marks a change from elastic to plastic behaviour. Loading of the specimen along the plastic portion results in permanent deformation and often results in loss of strength. Point B in **Figure 4.2** defines the (upper) yield strength of the material. Most steel have a second yield point lower than point B, called minimum yield strength.

It is important not to exceed the yield strength of casing during running, cementing and production operations, to prevent possible failure of the casing string. The ratio between stress and strain along the portion OA defines Young's Modulus E. Other important properties on the load-deformation graph are shown in **Figure 4.2**. When quoting the strength of casing, it is customary to use the minimum yield strength of casing, normally measured in psi or bar.

API[1] defines the yield strength as the tensile stress required to produce a total elongation of 0.5% of the gauge length of a test specimen, as determined by an extensometer or by multiplying dividers. For grades P- 105 and P- 110 the total elongation of gauge length is 0.6%.

The most common types of casing joint are threaded on both ends and are fitted with a threaded coupling at one end only. The coupling is the box end of the casing joint. The strength of the coupling may be higher or lower than the yield strength of the main body of the casing joint. Hence, manufacturers supply data on both body and coupling strengths to be used in casing design calculations, as will be shown later. There are also available integral casings (i.e. without couplings) in which the threads are cut from the pipe ends to form pin and box.

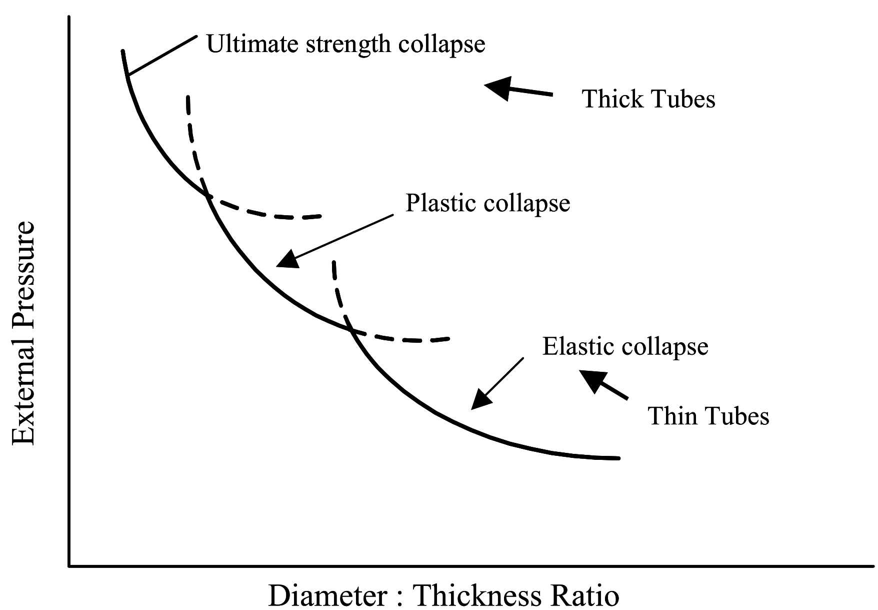
For details of the equations required to calculate joint strength, the reader is referred to API 5C 1,2 3 and 4 [1-4].

4.2 COLLAPSE STRENGTH

Collapse strength is defined as the external pressure required to collapse a specimen of casing. The procedure for determining the collapse strength of casing is detailed in API Bulletin 5C3.[3]

Under the action of external pressure and axial tension,[4-5] a casing cross-section can fail in three possible modes of collapse or buckling: elastic collapse, plastic collapse and failure caused by exceeding the ultimate strength of the material. The transition between the three failure modes is governed by the tube geometry and material properties (see **Figure 4.3**).

Figure 4.3 Illustration Of the Crossover Between Collapse failure Modes



As pointed out by Pattillio,[7] under external pressure only and for reasonable cross-sectional dimensions, it is approximately correct to state that the cross-section's collapse behaviour can be characterised by the hoop stress *(σ_t)* at the instant buckling is initiated. This may readily be seen by reference to the theory of minimum distortional energy and radial and hoop (or circumferential) stresses.

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If the hoop stress corresponding to tube collapse is below the yield strength of the material, the collapse mode is described as *elastic collapse.* When the value of the hoop stress associated with collapse is above the material's yield strength, the collapse mode is described as *plastic collapse.* Finally, if the tube undergoes material failure before instability, then the collapse mode is described as ***ultimate*** strength collapse.

Figure 4.3 shows the transition between the three modes of collapse under external pressure only for different ratios of D/t, where D is the outside diameter of the casing and t is the wall thickness. From this figure it may be concluded that for thin tubes (i.e. large D/t ratio) the collapse failure mode is expected to be elastic. As the ratio D/t decreases, or as the pipe becomes thicker the collapse failure mode changes to plastic (for intermediate D/t ratios) or to ultimate strength (for low values of *D/t).*It can be shown that collapse failures for OD/t ratios >15 occur mostly from elastic-plastic instability and not due to yield on the ID of the casing.

4.3 API Collapse Formulas

The API Bulletin 5C3 [3] reports four formulas for calculating the collapse resistance of tubular goods. The formulas are named according to the type of failure encountered: elastic, transition between elastic and plastic, plastic and yield collapse. It should be noted that the API collapse formulas are intended to predict, statistically acceptable minimum collapse values, not average values. This downgrading of collapse strength provides an added safety factor when designing for collapse pressure.

The API collapse formulas will now be introduced and the origin of each will be discussed in the following section **"Comment On The API Collapse Formulas" on page 120**.

Elastic Collapse

The theoretical elastic collapse pressure, Pc, may be determined from the following formula:

$$P_c = \frac{2 \cdot E}{1 - \nu^2} \times \left(\frac{1}{\frac{D}{t} \times \left(\frac{D}{t} - 1 \right)^2} \right) \tag{4.1}$$

where

E = Young's modulus of steel; ν=Poisson's ratio; t =casing thickness; and D= the outside diameter of the casing.

Equation (4.1) gives an upper boundary for collapse pressures as determined by actual collapse tests. The API recommends the use of a minimum collapse value which is equal to 71.25% of the theoretical value obtained from **Equation (4.1)**. Using this reduction in collapse value, E=30 x10^6 psi and ν =0.3, **Equation (4.1)** simplifies to:

$$P_c = \frac{46.978 \times 10^6}{\frac{D}{t} \times \left(\frac{D}{t} - 1\right)^2} \tag{4.2}$$

Equation (4.2) is applicable for the range of D/t given by:

$$\frac{D}{t} \geq \frac{2 + \frac{B}{A}}{3\left(\frac{B}{A}\right)} \tag{4.3}$$

where

$$A=2.8762 + 0.10679\text{x } 10^{-5}\text{ YP} + 0.21301 \text{ x}10^{-10}\text{ YP}^2 - 0.53132 \text{ x } 10^{-16}\text{ YP}^3 \tag{4.4}$$

$$B=0.026233 + 0.50609\text{x}10^{-6}\text{ YP} \tag{4.5}$$

Transition Collapse Pressure

The collapse behaviour (P_t) of steel in the transition zone between elastic and plastic failure is described by the following formula:

$$Pt = YP\left(\frac{F}{\left(\frac{D}{t}\right)} - G\right) \tag{4.6}$$

where F and G are constants given by:

$$F = \frac{46.95 \times 10^6 \times \left(\frac{3 \cdot B/A}{2 + B/A}\right)^2}{YP \times \left(\frac{3 \cdot B/A}{2 + B/A} - \frac{B}{A}\right) \cdot \left(1 - \frac{3 \cdot B/A}{2 + B/A}\right)^2} \tag{4.7}$$

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$$G = \frac{FB}{A} \tag{4.8}$$

The range of D/t values applicable to **Equation (4.6)** is given by:

$$\frac{YP(A-F)}{C+YP(B-G)} \le D/t \le \frac{2+B/A}{3B/A} \tag{4.9}$$

Plastic Collapse

The minimum collapse pressure (*Pp*) in the plastic range may be calculated from the following equation:

$$Pp = YP\left(\frac{A}{D/t} - B\right) - C \tag{4.10}$$

where

$$C = -465.93 + 0.030867\ YP - 0.10483 \times 10^{-7}\ YP^2 + 0.36989 \times 10^{-13}\ YP^3 \tag{4.11}$$

Equation (4.10) is applicable for the range of D/t values given by:

$$\frac{\left[(A-2)^2 + 8(B + C/YP)\right]^{0.5} + (A-2)}{2(B + C/YP)} \le D/t \le \frac{YP(A-F)}{C + YP(B-G)} \tag{4.12}$$

Yield Strength Collapse Pressure

The yield strength collapse pressure is not a true collapse pressure, but rather the external pressure *Py* that generates minimum yield stress (YP) on the inside wall of a tube as calculated by:

$$Py = 2YP\left[\frac{(D/t)-1}{(D/t)^2}\right] \tag{4.13}$$

The range of D/t values for which **Equation (4.13)** is applicable is given by:

$$D/t \leq \frac{\left[(A-2)^2 + 8(B + C/YP)\right]^{0.5} + (A-2)}{2(B + C/YP)} \tag{4.14}$$

4.4 Comment On The API Collapse Formulas

The API formulas for elastic and yield collapse were derived from a theoretical basis. The API elastic equation was derived by multiplying **Equation (4.1)** by a factor of 71.25% to obtain minimum acceptable values of collapse pressure. The API yield collapse corresponds to the ultimate strength collapse discussed earlier, the difference being that the API uses the initial yield at the inner radius of the tube as the collapse criterion rather the failure associated with exceeding the ultimate strength of the tube.[7]

The API plastic formula was derived empirically using data from 2488 collapse tests carried out on K55, N80 and P110 seamless casing. Statistical regression analysis was used to develop the empirical equation.

The transition collapse formula was derived on an arbitrary basis. This is because the API minimum curves for elastic and plastic collapse do not intersect and in an effort to overcome this anomaly, the transition mode is introduced (see **Figure 4.4**). The reader may recall that the curves for the average elastic and plastic collapse intersect at a particular *D/t* ratio (see **Figure 4.3**) denoting the transition from elastic to plastic collapse.

For an interesting treatment of this subject and the theoretical derivation of the various equations, references 1-7 should be consulted.

4.5 Biaxial Loading

The collapse resistance quoted by the manufactures is for casing under zero axial load. Under field conditions, a given casing section will be under the combined action of external and internal pressures and axial load due to its own weight, or due to its own weight and the weight of sections below if different casing weights are used.

The reader should note that the collapse resistances quoted for casings in API specs or manufacturer's catalogues are for casing under zero tension, effectively for a small length of casing. The collapse resistance of casing will be greatly reduced when casing is under tension as will be explained now.

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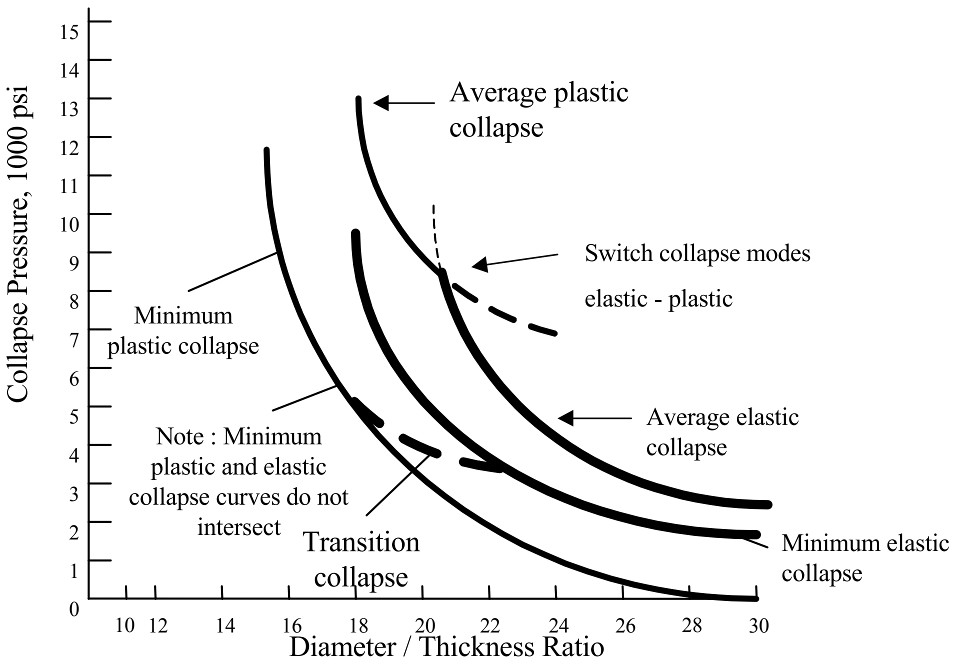
Figure 4.4 Illustration Of Origin Of Transition Collapse Mode For API Minim Collapse Properties, Grade = P110



The addition of axial tension to the casing has the same effect as a reduction in the yield stress of the material. That is, the new yield stress is that of an equivalent grade under zero axial load. The yield strength (Y_{pa}) of an axial stress equivalent grade is given by:

$$Y_{pa} = \left(\sqrt{\left(1 - 0.75 \times \left(\frac{\sigma_a}{YP}\right)^2\right)} - 0.5 \times \frac{\sigma_a}{YP}\right) \times YP \tag{4.15}$$

where

σ_a =axial stress, psi

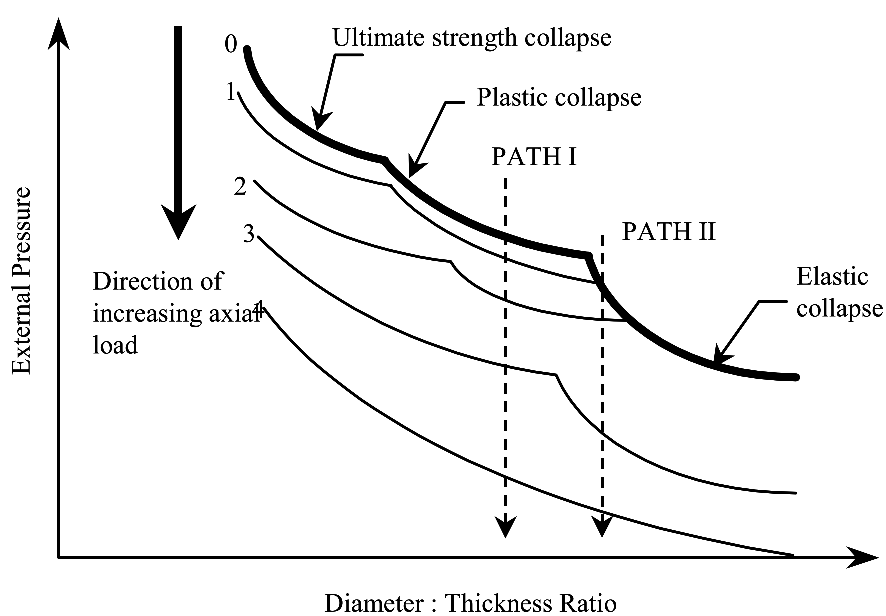
YP =minimum yield strength of the pipe, psi, as given by manufacturers

Y_{pa} =yield strength of axial stress equivalent grade, psi

Referring to equations **Equation (4.1)** to **Equation (4.13)**, it can be seen that with the exception of elastic collapse, the collapse strength of the three remaining modes is directly proportional to the yield strength of the material. It follows that axial tension decreases both the yield strength and the collapse strength of the casing.

Under the combined action of external pressure and axial tension, the transition between the tree modes of collapse failure (i.e. elastic, plastic and ultimate strength) can occur at the same D/t ratio if the applied axial load is increased from zero to a certain critical value. Consider, for example, Path 1 in **Figure 4.5** where the collapse failure mode is initially plastic at zero axial load. As the axial load is increased beyond a certain value, the failure mode switches to ultimate strength collapse, curve 3, **Figure 4.5**. In Path II, it is shown that the collapse failure mode switches from elastic to plastic and finally to ultimate strength with increasing axial load.

Figure 4.5 Manifold Of Collapse Curves In The Presence Of Axial Load, After Reference 7



4.6 Procedure for Determining Collapse Resistance Under Biaxial Loading

The procedure for determining the collapse strength of casing requires two main calculations. First, determine the yield strength of the material when under tension. Second, use this value of yield strength to determine the collapse strength of the material for the appropriate mode of failure.

The following steps should be followed:

(1) Determine the axial stress (σ_a) carried by the section of casing under consideration.

(2) Use **Equation (4.15)** to determine the yield strength of axial stress equivalent grade, Y_{pa}. Under zero axial load, the value of Y_{pa} is exactly equal to yield strength.

(3) Determine the ratio D/t for the given section of casing.

(4) Use equations **Equation (4.4)**,**Equation (4.5)**,**Equation (4.7)**,**Equation (4.8)** and **Equation (4.11)** to calculate factors A, *B, F, G* and C and determine the range for which D/t is applicable.

(5) From parts 2, 3 and 4 determine the applicable collapse failure mode and the applicable equation for calculating the reduced collapse strength.

(See **Example 4.1** and **Example 4.2**)

Example 4.1: Collapse Properties

Casing=13 3/8 in., grade K55

Nominal weight=68 lbm/ft

Internal diameter=12.415 in.

YP (body)=1,069,000 lb

Determine the collapse resistance when (a) the casing is under zero tension, and

(b) when the casing is carrying an axial load of 263,600 lb.

Solution

Part (a)

(1) $\sigma_a = 0$

(2) YP (body)=1,069,000 lb = 1,069,000/[(π/4)(13.375^2 –12.415^2)] =54,975 psi

(3) D/t=13.375/0.480 = 27.865

where

t=(1/2)x(13.475-12.415)=0.480 in.

(4) Use equations **Equation (4.4)**,**Equation (4.5)**,**Equation (4.7)**,**Equation (4.8)** and **Equation (4.11)** to calculate:

A=2.99

B=0.0541

C=1205.44

F=*1.99*

G=0.036

Then determine

$$\frac{2+(B/A)}{3(B/A)} = 37.21........(a)$$

$$\frac{YP(A-F)}{C+YP(B-G)} = 24.997.......(b)$$

$$\frac{\left[(A-2)^2+8(B+C/YP)\right]^{0.5}+(A-2)}{2(B+C/YP)} = 14.808............(c)$$

Hence D/t for elastic collapse = 37.21 and greater

D/t for transition collapse = 24.997 to 37.21

D/t for plastic collapse = 14.808 to 24.997

D/t for yield collapse = 14.808 and less

The actual value of *D/t= 27.865* for our casing falls within the transition collapse range. Hence using **Equation (4.6)**, the reduced collapse resistance is:

$$P_t = YP\left(\frac{F}{\left(\frac{D}{t}\right)} - G\right) = 54{,}975\left[\frac{1.99}{27.865} - 0.036\right] = 1945\,psi$$

Part (b)

(1)

$$\sigma_a = \frac{263,600}{\frac{\pi}{4}(13.375^2 - 12.415^2)} = 13{,}556 \text{ psi}$$

$$\text{YP (body)} = 1{,}069{,}000 \text{ lb} \quad = \frac{1,069,000}{\frac{\pi}{4}(13.375^2 - 12.415^2)}$$

$$= 54{,}975 \text{ psi}$$

(2) From **Equation (4.15)**

$$Y_{pa} = \left(\sqrt{\left(1 - 0.75 \times \left(\frac{13,556}{54,975}\right)^2\right)} - 0.5 \times \frac{13,556}{54,975}\right) \times 54,929 = 46{,}929$$

(3) D/t=13.375/0.480=27.8646

(4) The values of *A to G* are calculated using the equations given previously and the reduced yield strength Ypa=46,929 psi.

A=2.9674

B=0.0500

C=963.36

F=2.0162

G=0.034

Then determine

$$\frac{2+(B/A)}{3(B/A)} = 39.912........(a)$$

$$\frac{YP(A-F)}{C+YP(B-G)} = 26.025........(b)$$

$$\frac{\left[(A-2)^2+8(B+C/YP)\right]^{0.5}+(A-2)}{2(B+C/YP)} = 15.545...........(c)$$

Hence	D/t for elastic collapse	= 39.912 and greater
	D/t for transition collapse	= 26.025- 39.912
	D/t for plastic collapse	= 15.545 -26.025
	D/t for yield collapse	= 15.545 and less

The value of *D/t*= 27.865 falls within the transition collapse. Hence using **Equation (4.6)** the reduced collapse resistance is:

$$P_t = YP\left(\frac{F}{\left(\frac{D}{t}\right)} - G\right) = 46{,}929\left[\frac{2.0162}{27.865} - 0.036\right] = 1800\,psi$$

Example 4.2: Collapse Properties Under Tension

Determine reduced collapse resistance of a section of 7 in casing, given:

Grade=L80

Nominal weight=29 lbm/ft

Axial load=142,880 lbf

Internal diameter=6.184 in

YP =676,000 Ibf = $\dfrac{676{,}000}{\pi/4(7^2 - 6.184^2)}$ = 80,000 psi

Solution

(1)

$$\sigma_a = \frac{142{,}880}{(\pi/4)(7^2 - 6.184^2)} = 16{,}910\,psi$$

(2) From **Equation (4.15)**

$$Y_{pa} = \left(\sqrt{\left(1 - 0.75 \times \left(\frac{16,910}{80,000}\right)^2\right)} - 0.5 \times \frac{16,910}{80,000}\right) \times 70,1999 \quad = \ 70{,}199 \text{ psi}$$

(3) D/t=7/0.408=17.16
where t=1/2(7-6.184)=0.408 in.

(4) The values of *A to G* are calculated using equations **Equation (4.4)**,**Equation (4.5)**,**Equation (4.7)**,**Equation (4.8)** and **Equation (4.11)** and the reduced yield strength Ypa=70,199 psi.

A = 3.0373

B=0.0618

C= 1662

F=1.985

G=0.0404

Then determine

$$\frac{2+(B/A)}{3(B/A)} = 33.119......(a)$$

$$\frac{YP(A-F)}{C+YP(B-G)} = 23.342.......(b)$$

$$\frac{\left[(A-2)^2+8(B+C/YP)\right]^{0.5}+(A-2)}{2(B+C/YP)} = 13.833...........(c)$$

The value of *D/t* falls between (b) and (c). This is the range applicable to the plastic zone as indicated by **Equation (4.12)**. Hence the reduced collapse resistance is:

$$Pp = 70{,}199\left(\frac{3.037}{17.16} - 0.0618\right) - 1662 = 6430\,psi$$

4.7 EFFECTS OF INTERNAL PRESSURE ON COLLAPSE STRENGTH

The procedure given in **Section 4.5** give the collapse (external) pressure when casing is under tension only. In practice, casing contains fluid, the drilling mud or completion fluid, which exerts an internal pressure on the inside of the casing providing resistance to the collapsing effects of external pressures. Pattillio [7] has shown that the treatment of internal pressure is complex and, depending on the theoretical approach adopted, two different answers are possible. Due to this anomaly, most engineers ignore the effects of internal pressure as this assumption will implicitly add an extra safety factor in collapse design.

For marginal designs the following equation may be used to determine the collapse resistance of casing (P^-) under the combined effect of axial loading, internal and external pressures:

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$$P^{-}=P+(1-2t/D)\,Pi \tag{4.16}$$

where

P^{-} =collapse resistance in the presence of internal pressure

P = collapse resistance under external pressure and axial loading

Pi = internal pressure.

4.8 Effects Of Cement On The Collapse Resistance Of Casing

The majority of casing strings are cemented to either the surface or to some specified depth below the surface. Laboratory hydraulic collapse tests carried out by Evans and Harriman[9] have shown that the presence of a full cement sheath behind the casing improves the collapse resistance of casing by up to 23%. However, no improvement in collapse resistance was observed if the cement had a void equal to three inside diameters in the axial direction (i.e. along the casing length). The presence of voids on only one side of casing permit casing to fail as if there was no support from cement. These findings will be incorporated in the casing design theory to be presented in **Chapter 5**.

4.9 Burst (Or Internal Yield) Strength Of Pipe Body

Burst strength is defined as the internal pressure required to cause the steel to yield. Minimum burst resistance of casing is calculated by use of Barlow's formula:

$$P_{burst} = \frac{0.875 \times (2 \cdot YP \cdot t)}{D} \tag{4.17}$$

where

t= thickness of Casing (in.)

D=OD Of casing (in.)

YP= minimum yield strength (psi).

The factor 0.875 in **Equation (4.17)** was introduced by the API to allow a 12.5% variation in wall thickness due to manufacturing defects. This factor obviously introduces an unnecessary derating of casing burst strength and with today’s accurately controlled manufacturing processes, the factor can be relaxed or even eliminated altogether. For this reason, the author recommends using burst strength values as supplied by the manufacturers.

It should also be noted that Barlow's equation is based on internal pressure and does not take into consideration the effects of:

- external pressure
- axial compression
- temperature effects
- H2S

In particular, axial compression and temperature act to reduce the burst strength. The effects of temperature can be easily incorporated by applying Barlow's equation using the reduced yield strength under elevated temperature, **Chapter 15** for further details.

Burst failure occurs by either rupturing of the pipe body or leakage at the coupling. For this reason, API defines two additional internal pressure resistances for casing and tubing. The lowest of the three is taken as the internal pressure resistance of casing or tubing. For full details of the equations, the reader is advised to consult references 1 to 4.

4.10 Internal Yield Pressure for Couplings

The minimum internal yield pressure (P_l) required to avoid leakage due to insufficient coupling strength is given by:

$$P_i = \frac{Y_c(W - d_l)}{W} \tag{4.18}$$

where

Yc = minimum yield strength of coupling, psi

W = nominal outside diameter of coupling rounded to the nearest 0.001 in

d_l = diameter at the root of the coupling thread at the end of the pipe in the power tight position rounded to the nearest 0.001 in, refer to references 1-4 for details.

5.0 CASING SPECIFICATIONS

Casing is usually specified by the following parameters:

(a) outside diameter and wall thickness, e.g. 9 5/8", 0.47 inch

(b) weight per unit length, normally weight per foot or metre, e.g. 53.5 lb/ft.

(c) type of coupling, e.g. buttress, Vam or Fox

(d) length of joint

(e) grade of steel, e.g. L80

(f) strength properties, e.g. yield, collapse and burst

Items d, e and f were discussed earlier in this Chapter.

5.1 OUTSIDE DIAMETER, INSIDE DIAMETER AND WALL THICKNESS

As mentioned earlier in this Chapter, different casing sizes are run at different parts of the hole to allow the drilling of the well to its total depth with minimum risk. Since pressures vary along every section of hole, it is possible to run a casing string having the same outside diameter but with different thicknesses (different ID’s) or strength properties. Thus, a heavy or high-grade casing can be run only along the portions of the hole containing high pressures or near the surface, where tensile stresses are high. This arrangement provides the most economical way of selecting a given casing string.

The full details of API tolerances on outside diameter and weights are given in API SPEC 5CT. The API tolerance on outside diameter for non-upset casing is ±0.031 in. for 4 in. and smaller and ±0.75% for 4.5 in. and larger. The API tolerance on wall thickness is -12.5%.

Under casing dimensions, it is usual to find two values for inside diameter. The first is the inside diameter which is equal to outside diameter minus twice the nominal wall thickness. The second is described as the drift diameter. The latter refers to the diameter of a cylindrical drift mandrel that can pass freely through the casing with a reasonably exerted force equivalent to the weight of the mandrel being used for the test. The API stipulates that the leading edge of the mandrel shall be rounded to permit easy entry into the pipe. The API recommended dimensions of drift mandrels are as follows:

Casing and Liner Size (in)	Drift Mandrel Size			
	Length		Diameter	
	(in)	(mm)	(in)	(mm)
8 5/8" and smaller	6	152	ID*- 1/8	ID- 3.18
9 5/8" to 13 3/8" inclusive	12	305	ID- 5/32	ID – 3.97
16" and larger	12	305	ID – 3/16	ID – 4.76

(* ID: inside diameter)

Example 4.3: Drift Diameter

Calculate the drift diameter for a 7 in. casing, 23 lbm/ft with a wall thickness (t) of 0.317 in.

Solution

ID of casing = OD-2 x t

= 7-2x 0.317 = 6.366 in.

Drift diameter of 7 in. casing = ID- 1/8 (see above table)

= 6.366-0.125 = 6.241 in

The drift diameter is also taken as the maximum size of drill bit which can safely be run through the casing.

5.2 Weight per Unit Length

AP1 defines three types of casing weight: (1) nominal weight; (2) plain end weight, and (3) threaded and coupled weight. The API tolerances on weights are +6.5% and -3.5%. Full details of API tolerances on casing and coupling dimensions are given in API SPEC 5CT.

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Nominal Weight

The term *nominal weight* is used primarily for the purpose of identification of casing types during ordering. It is expressed in lbm/ft or kg/m. Nominal weights are not exact weights and are normally based on the calculated, theoretical weight per foot for a 20 ft length of threaded and coupled casing joint.

Nominal weight, Wn, is calculated using the following formula:

$$Wn = 10.68(D-t)\,t + 0.0722\,D \quad \text{lbm/ft} \tag{4.19}$$

where

D = outside diameter (in.)

t = wall thickness (in.)

Casing weights required for design purposes are usually reported as nominal weights.

Plain End Weight

The plain end weight is the weight of the casing joint without the inclusion of threads and couplings. The plain end weight can be calculated by use of the following formula:

$$W_{pe} = 10.68(D-t)\,t \text{ lbm/ft} \tag{4.20}$$

where

W_{pe} = plain end weight (lbm/ft)

and D and t are as defined previously.

Threaded And Coupled Weight

The threaded and coupled weight is the average weight of a joint of casing including the threads at both ends and a coupling at one end when power-tight. This weight is calculated from the following formula:

$$W = (1/20)\{Wpe\,[20 - (N_L + 2J)/24] + \text{weight of coupling}$$

$$- \text{weight removed in threading two pipe ends}\} \tag{4.21}$$

where

W = threaded and coupled weight (lbm/ft);
N_L = coupling length (in);
J = distance from end of pipe to centre of coupling in the power-tight position (in) and
Wpe = plain end weight, as calculated in **Equation (4.20)**

Details of the axial measurement along API round and buttress threads are given in references 1-4.

6.0 CASING CONNECTIONS (THREADS)

The main function of casing and tubing threads is to contain wellbore pressure. The following is a summary of the main features of casing threads:

- The thread sealing mechanism is one of the connection’s most important features.
- In low pressure wells, gas integrity is not critical and API connections can be used.
- API connector uses a thread dope channel for a seal.
- The dope channel is a path formed by a gap between the root and crest of the trapezoidal thread or the stabbing flanks of the buttress type thread.
- The leak path is a continuous helical channel running the length of the connection.
- The API connectors depend on thread lubricant to block or plug this leak path.
- Viscosity of dope is highly dependent on temperature and pressure. The higher the temperature or pressure, the more quickly the lubricant is extruded through the helical path causing a leak.

Therefore, API connectors are not suitable for wells with high temperatures, cycling temperatures or high pressures or for gas wells.

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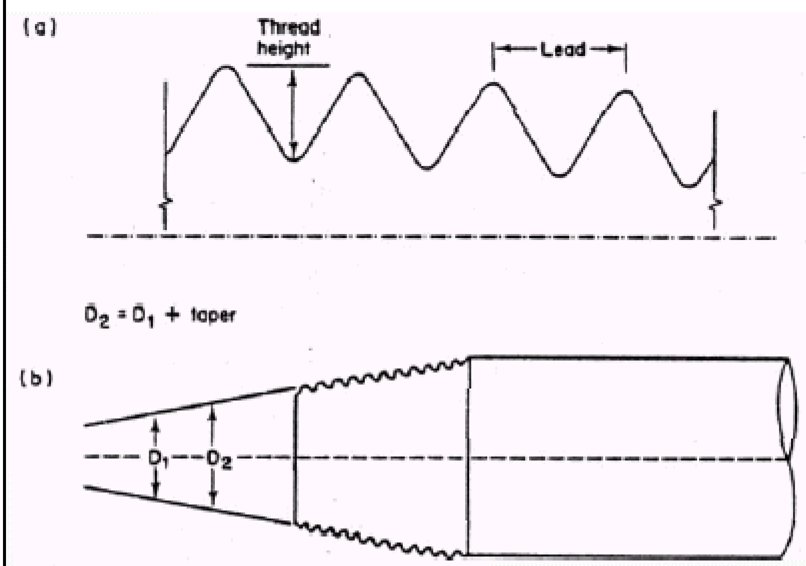
6.1 TYPES OF COUPLING AND ELEMENTS OF THREAD

A coupling is a short section of casing that is used to connect two casing joints. The most common type of a casing joint is externally threaded at both ends. The coupling is internally threaded from each end. API specifies that a coupling should be of the same grade as the pipe body.

Figure 4.6 Thread elements: height, lead and taper



In general, the casing and coupling are specified by the type of threads (or connection) cut in the pipe or coupling. AP1 defines four principal elements of thread, see **Figure 4.6**:

(1) Thread height or depth, defined as the distance between the thread crest and the thread root measured normal to the axis of the thread.

(2) Lead, defined as the distance from one point on the thread to a corresponding point on the adjacent thread as measured parallel to the thread axis.

(3) Taper, defined as the change in diameter of a thread expressed in inches per foot of thread length.

(4) Thread form - most casing threads are squared or V-shaped.

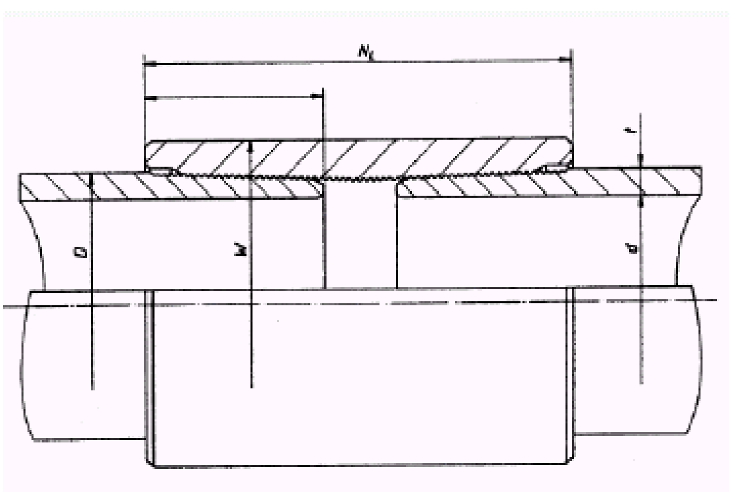
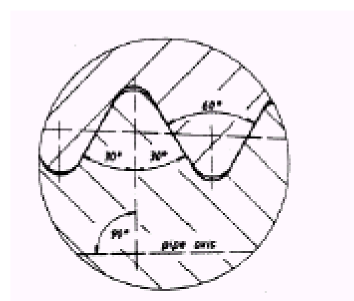
Another thread measurement that is of importance is the *pitch diameter*. The latter is defined as the diameter of an imaginary cone that bisects each thread midway between its crest and root.

The following are the most widely used connections:

(a) API round thread coupling

This coupling has eight round threads per inch, having a V-shape with an included angle of 60 deg as shown in **Figure 4.7**. The threads are cut with a taper of ¾ in per ft of diameter for all pipe sizes. The thread crest and roots are truncated with a radius. When the crest of one thread is mated against the crest of another, the clearance is approximately 0.003 in., which provides a leak path. In practice, a special thread compound is used when making up two joints, to prevent leakage. The API 8 round casing is threaded on both ends of a non-upset pipe, and individual pipes are joined together by means of an internally threaded coupling. API round thread couplings are of two types: short thread coupling (STC); and long thread coupling (LTC). The STC and LTC connections are weaker than the pipe body, the LTC being capable of transmitting higher axial loads. The API round thread is not suitable for gas wells (i.e. not gas tight) and wells with high pressure or high temperature.

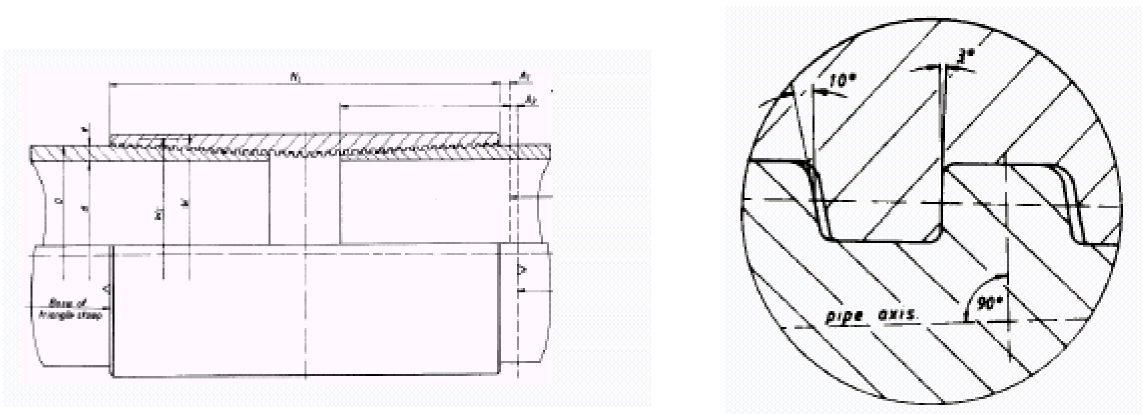
Figure 4.7 Round Thread

(b) Buttress thread coupling

The Buttress thread has a square shape, with five threads per inch and with a thread taper of ¾ in per ft for casing sizes up to 7 5/8 in and a taper of 1 in per ft for casing sizes of 16 in or larger. The individual pipes are again threaded on both ends and joined together by buttress type couplings. **Figure 4.8** shows a cross-section of a buttress connection and a thread profile. The buttress thread is capable of transmitting higher axial loads than the API 8 round thread but still require a thread compound to fill the gaps at the roots after make up to provide effective sealing.

Figure 4.8 Buttress Thread



(c) Extreme line thread coupling

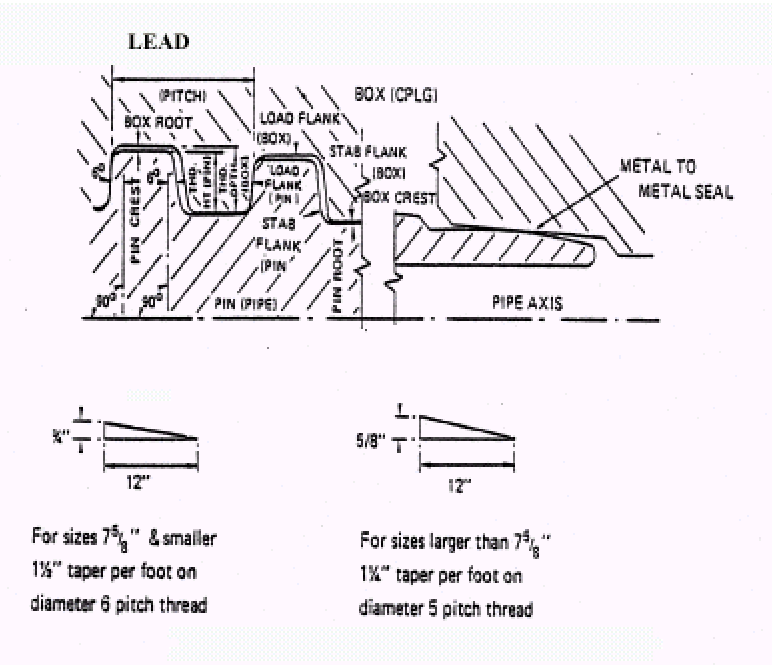
The API extreme line is an integral joint with pin and box ends are cut on the joint itself without the need for couplings. API extreme line casing is externally and internally threaded on internal-external upset ends. The upset ends are specially machined to have increased wall thickness, to compensate for the loss of metal due to threading. The thread profile is trapezoidal, providing metal-to-metal seal at both the pin end and the external shoulder. This makes the extreme line couplings suitable for use in elevated temperatures and pressures and its sealing does not depend on the use of a thread compound. Other features of API extreme line casing include:

6 threads per inch on 1 1/2 in. taper per foot for sizes 5 in. to 7 5/8 in.

5 threads per inch on 1 1/4 in. taper per foot for sizes 8 5/8 in. to 10 3/4 in.

Figure 4.9 shows a section of an extreme line connection and a thread profile.

Figure 4.9 Extreme Line Thread



6.2 PREMIUM THREADS

The main features of premium threads are:

- Designed to improve the sealing characteristic of a connection.
- Reliance on metal to metal seals or a combination of metal to metal and elastomer seals to hold pressure.
- Seal is obtained as one surface of the metal seal contacts the other and the two surfaces are forced together by bearing pressure.
- The bearing pressure on the seal must be greater than the expected wellbore pressure for the metal seal to function properly.
- The primary internal metal seals are located near the pin nose or on the flank of the pin nose.

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- In conical flank seal, seal is affected by interference and reinforced by a reverse torque shoulder. The seal faces contact before the shoulders and the seal interference energises the seal. The reverse torque shoulder then reinforces the seal against internal or external pressures.

There are several proprietary thread brands, including Grant, Hunting, Mannesman, Nippon Steel, Atlas Bradford, Baker Hughes, Hydril etc. Full details of these types can be obtained from the manufacturers.

Essentially all premium threads provide one required function: namely sealability against a harsh environment. The later can high pressure and/or high temperature and high pressure gas and oil wells.

a. VAM thread coupling (Figure 4.10)

This is a modified version of the buttress thread and has a tapered metal to metal seal energised by a reverse angle shoulder at the pin end. **Figure 4.10** shows a VAM-type coupling and thread profile. The thread profile is a modified Buttress design with flat crests and roots parallel to the cone, flanks 3 degrees and 10 degrees to vertical of the pipe axis, and 5 threads per inch on the axis. The coupling is of regular special clearance (reduced OD) design. *Note:* 4 1/2 in. VAM is 'tubing threaded' with 6 threads per inch.

b. Hunting/Kawasaki FOX Casing Connection (Figure 4.11)

The Hunting FOX Casing Connection is externally threaded on both ends of non-upset pipe. The single lengths are joined with an internally threaded coupling with an internal torque shoulder and contoured metal to metal seal between pin and box. Variants of FOX connections with Teflon sealing rings are available.

6.3 Flush Joints

The properties of flush joints are:

- Connection has a tensile efficiency rating from 55% to 65%.
- Failures have occurred as a result of thread jump-out at loads significantly below the rating of the connection.

- These failures occurred in tension or bending. Failures occurred with thin box members and positive load flank threads.
- New generation of flush joints have negative load flanks thread to prevent thread jump out failures.

Figure 4.10 Vallourec NEW VAM Casing Connection

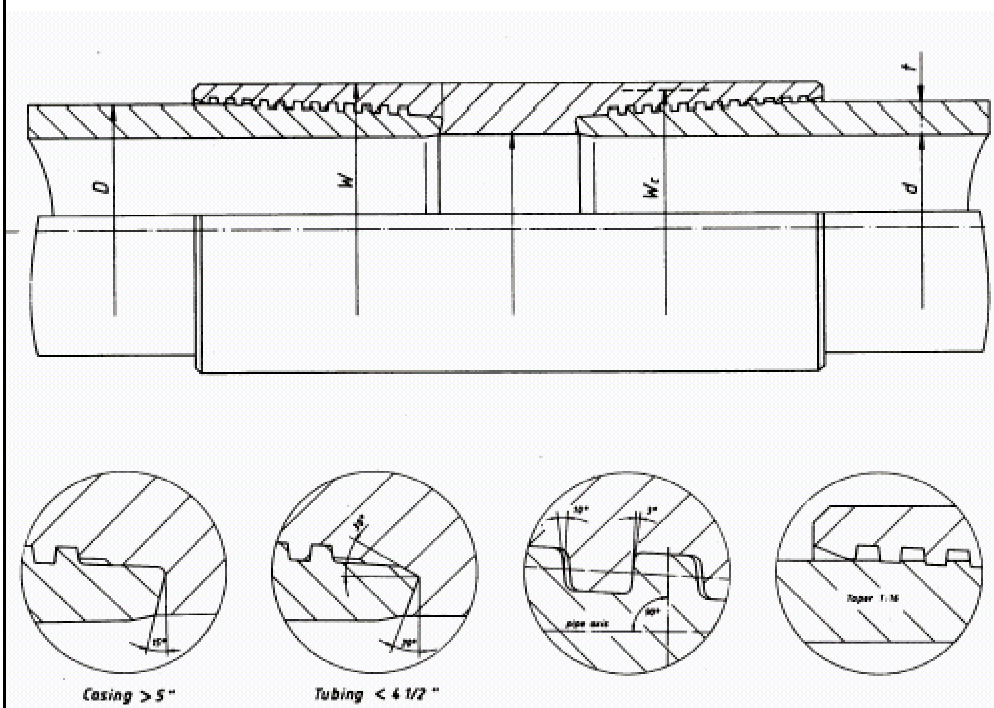

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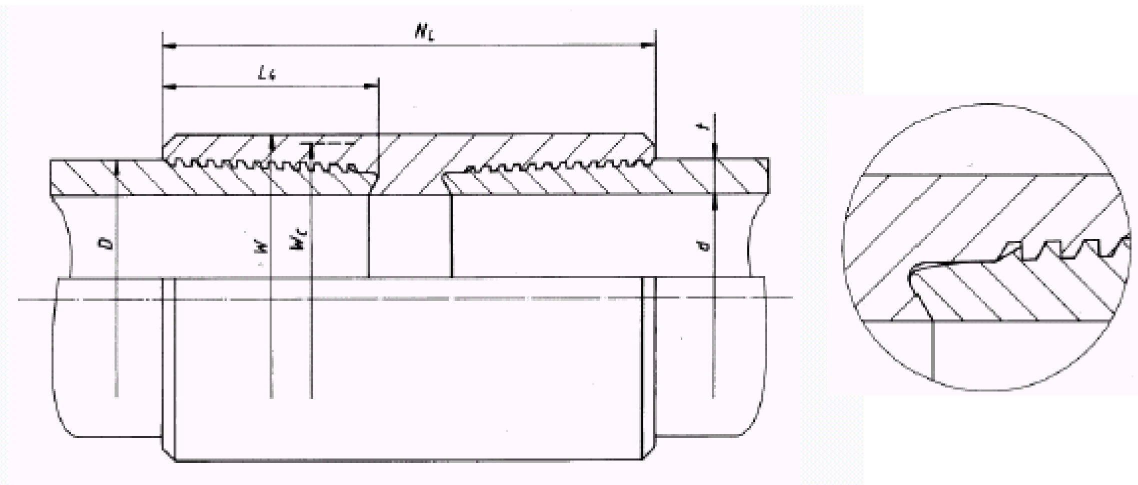
Figure 4.11 Fox connection



7.0 LEARNING MILESTONES

In this chapter, you should have learnt to:

1. List functions of casing
2. Understand different types of casings and liners
3. Understand API casing properties
4. Understand different grades of casing and their description and application
5. Understand effects of H_2S on steel (SSC)
6. Understand the three measured strength properties: yield, collapse and burst
7. Know that the collapse resistance quoted by any source must be corrected, at least, for the effects of tension and preferably also for the effects of wellbore pressures.

8. Understand and apply the theoretical of biaxial loading ("Biaxial Loading" on page 120)
9. Calculate the actual collapse strength under actual loading conditions
10. List the six parameters that specify casing ("Casing Specifications" on page 131)
11. Understand API tolerances on casing OD and thickness
12. Understand difference between drift and internal diameter
13. Understand API and non-API casing (thread) connections

8.0 REFERENCES

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9. Evans, G. W. and Harriman D. W. (1972)" Laboratory rests on collapse resistance of cemented casing" 47th Annual Meeting of the Society of Petroleum Engineers of AIME, San Antonio Texas, October.

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9.0 EXERCISES

Exercise 1

Determine the reduced collapse resistance of a section of 9 5/8 in. casing, given:

Grade=C75

Nominal weight= 43.5 lbm/ft

Axial load= 248,410 lb

Internal diameter= 8.755 in.

YP(body)=942,000 lb=75,000 psi

ANSWER

Failure is in the plastic region (Ypa.=63134, A=3.015; B=0.0582; C=1450; *F*= 1.9824; G=0.0383; and P_P=3478 psi.

Exercise 2

Determine the reduced collapse resistance of a section of 7 in. casing, given:

Grade = L80

Nominal weight = 29 lbm/ft

Axial load = 375,556 lb

Internal diameter = 6.184 in.

YP (body) = 676,000 lb

ANSWER

Failure is in the plastic region, A=2.970; B=0.0505; C=985.866; and

P_P =4883 psi

Exercise 3

Determine the reduced collapse resistance of a section of *185/8* in. casing, given:

Grade = K55

Nominal weight = 96.5 Ibm/ft

Axial load = 100,000 lbf

Internal diameter = 17.653 in.

YP (body) = 1,523,000 lb

ANSWER

Failure is in the elastic region. A=2.985; *B=0.0531; C=1149; F=1.994;*

G=0.0355 and Pc= 880 psi.

5

Casing Design Principles

Content

1.0 Data Collection

Before embarking on a casing design exercise, the essential data must be obtained from various sources including: geologists, petrophysicists, reservoir engineers etc. The format given in Table 5.1 show s where the data may be obtained.

Once the above data is obtained, it may be organised in the format given in **Table 5.2** which would greatly help in casing design calculations. It should be noted that the accuracy of the casing programme is dependent on the accuracy of data used.

Table 5.1 Sources of Data

Data	Source
1. Formation pressure, psi	Offset wells well logs, log analyst
2. Casing setting depths, ft	Offset wells, kick tolerance calculations
3. Fracture gradient (psi/ft) or fracture pressure (ppg or psi) at casing seat	Offset wells, well logs, calculation of fracture gradient
4. Mud density, ppg	As above
5. Mean sea water level, ft	
6. Available casing grades and weights	Stock status report
7. Strength properties (burst, collapse, yield)	API or manufacturer‘s catalogues
8. Geothermal temperatures	Offset wells

2.0 FACTORS INFLUENCING CASING DESIGN

Casing design involves the determination of factors which influence the failure of casing and the selection of the most suitable casing grades and weights for a specific operation, both safely and economically. The casing programme should also reflect the completion and production requirements.

A good knowledge of stress analysis and the ability to apply it are necessary for the design of casing strings. The end product of such a design is a 'pressure vessel' capable of withstanding the expected internal and external pressures and axial loading. Hole irregularities further subject the casing to bending forces which must be considered during the selection of casing grades.

A safety margin is always included in casing design, to allow for future deterioration of the casing and for other unknown forces which may be encountered, including corrosion, wear and thermal effects.

Table 5.2 Essential Data

Casing O.D. inches	18 5/8" (or 20 ")	13 3/8"	9.5/8"	7"
Casing setting depth ft (TVD)				
Casing grade and weight (lb/ft)				
I.D, in				
Drift diameter, in				
Coupling type				
Collapse strength, psi				
Burst strength, psi				
Body yield strength (lbf x 1000)				
Connection parting load (lbf x 1000)				
Mud density to drill hole for this casing, ppg				
Mud density used to drill next hole, ppg				
Expected formation pressure at next TD, psi				
Fracture gradient at casing seat, psi/ft				
Mudline depth, ft				
Geothermal gradient ° F /100 ft				

Casing design is also influenced by:

(a) loading conditions during drilling and production;

(b) the strength properties of the casing seat (i.e. formation strength at casing shoe);

(c) the degree of deterioration the pipe will be subjected to during the entire life of the well; and

(d) the availability of casing.

In general, the cost of a given casing grade is proportional to its weight, the heaviest weight being the most expensive. Since the cost of casing in a given well constitutes a high percentage of the total cost of drilling and completion (in some cases up to 40%), the designer should ensure that the lowest grades and lightest weights, consistent with safety, are chosen as these provide the cheapest casing.

A casing string incorrectly designed can result in disastrous consequences, placing human lives at risk and causing damage and loss of expensive equipment. The entire oil reservoir may be placed at risk if the casing cannot contain a kick which may develop into a blowout resulting in a large financial loss to the operating company and a large depletion of the reservoir's potential.

3.0 Design Criteria

There are three basic forces which the casing is subjected to: collapse, burst and tension. These are the actual forces that exist in the wellbore. They must first be calculated and must be maintained below the casing strength properties. In other words, the collapse pressure must be less than the collapse strength of the casing and so on.

Casing should initially be designed for **collapse, burst and tension**. Refinements to the selected grades and weights should only be attempted after the initial selection is made. The suitability of selected casing depends on the accuracy of data collected in **Table 5.2**.

For directional wells a correct well profile is required to determine the true vertical depth (**TVD**). All wellbore pressures and tensile forces should be calculated using true vertical depth only. The casing lengths are first calculated as if the well is a vertical well and then these t lengths are corrected for the appropriate hole angle.

4.0 COLLAPSE CRITERION

Collapse pressure originates from the column of mud used to drill the hole, and acts on the outside of the casing. Since the hydrostatic pressure of a column of mud increases with depth, collapse pressure is highest at the bottom and zero at the top, see **Figure 5.1**a.

This is a simplified assumption and does not consider the effects of internal pressure.

For practical purposes, collapse pressure should be calculated as follows:

$$\text{Collapse pressure} = \text{External pressure} - \text{Internal pressure} \quad (5.1)$$

The actual calculations involved in evaluating collapse and burst pressures are usually straight forward. However, knowing which factors to use for calculating external and internal pressures is not easy and requires knowledge of current and future operations in the wellbore.

Until recently, the following simplified procedure was used for collapse design:

(1) Casing is assumed empty due to lost circulation at casing setting depth (CSD) or at TD of next hole, see Figure 5.1.

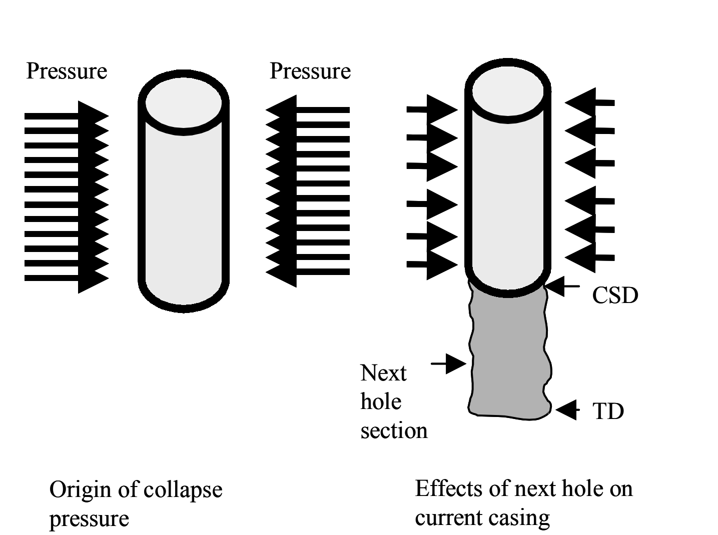
(2) Internal pressure inside casing is zero

(3) External pressure is caused by mud in which casing was run in

(4) No cement outside casing

Hence using the above assumptions and applying **Equation (5.1)**, only the external pressure need to be evaluated.

Figure 5.1 Collapse Criterion



Therefore:

Collapse pressure (C)= mud density x depth x acceleration due to gravity

$$C = 0.052 \times \rho \times CSD \ldots psi \qquad (5.2)$$

where ρ is in ppg and CSD is in ft

The above assumptions are very severe and only occur in special cases. The following sections will provide details on practical situations that can be encountered in field operations.

4.1 Lost Circulation

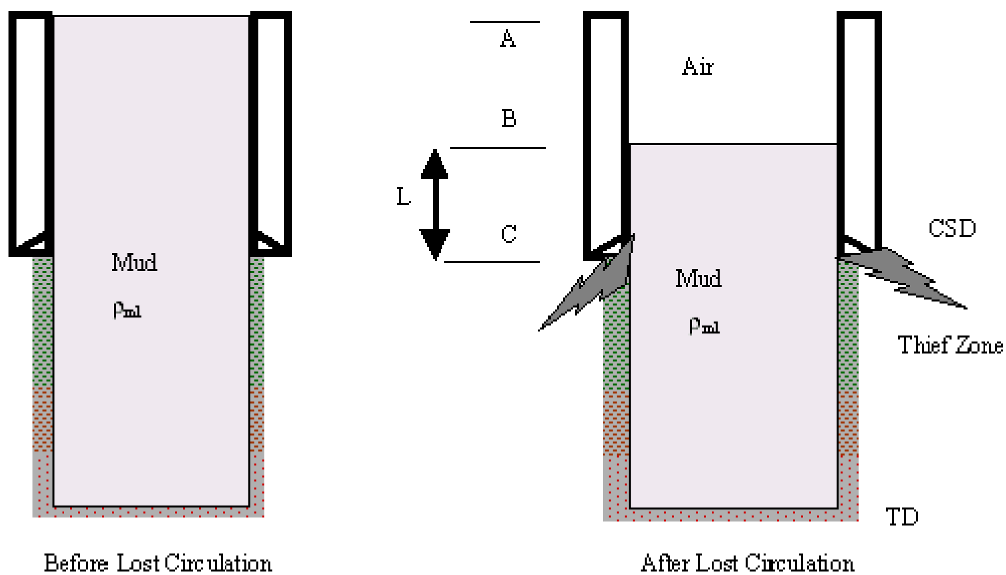
If collapse calculations are based on 100% evacuation then the internal pressure (or back-up load) is to zero. The 100% evacuation condition can only occur when:

- the casing is run empty
- there is complete loss of fluid into a thief zone (say into a cavernous formation), and
- there is complete loss of fluid due to a gas blowout which subsequently subsides

None of these conditions should be allowed to occur in practice with the exception of encountering cavernous formations, see **Chapter 5** for details.

During lost circulation, the mud level in the well drops to a height such that the remaining hydrostatic pressure of mud is equal to the formation pressure of the thief zone. In this case the mud pressure exactly balances the formation pressure of the thief zone and fluid loss into the formation will cease. If the formation pressure of the thief is not known, it is usual to assume the pressure of the thief zone to be equal to 0.465 psi/ft. As discussed in Chapter One, this is the pore pressure of a normally pressured zones where the pressure is hydrostatic.Normally pressured zones are assumed to be connected to the sea or to a large aquifer with normal pressure.

Figure 5.2 Mud level Inside casing After Loss Circulation



The length of the mud column remaining inside the casing can be calculated as follows (refer to Figure 5.2)

Assuming that the thief zone is at the casing seat, then during lost circulation:

$$\text{Pressure in thief zone} = CSD \times 0.465 \quad (5.3)$$

$$\text{Internal pressure at shoe} = L \times p_{m1} \times 0.052 \quad (5.4)$$

where

ρ_{m1} = mud density used to drill next hole (ppg)

P_f = formation pore pressure of thief zone, (psi/ft) (or ppg) (assume = 0.465 psi/ft for most designs)

L = length of mud column inside the casing

CSD = casing setting depth (TVD) of the casing string being designed, ft

Combining Equation (5.3) and Equation (5.4) gives (L), the length of mud column remaining inside casing:

$$L = \frac{CSDx0.465}{0.052x\rho_{m1}} \tag{5.5}$$

$$\text{Depth to top of mud column} = CSD - L \tag{5.6}$$

[Note another method of calculating the internal pressure during lost circulation is to use the formation pressure (Pf) and depth of the loss zone (Dlz) in the calculation. The depth of the loss zone can be any where between the casing setting depth and the TD of next hole.

The depth to top of mud (h) inside casing after loss circulation is given by:

$$h = \left(\frac{\rho_{m1} - \rho_f}{\rho_{m1}}\right) x D_{lz} \tag{5.7}$$

The internal pressure is then calculated from the mud column (L) remaining inside casing: L = (CSD –h)]

Example 5.1: Collapse Calculations

Calculate the collapse pressure for the following casing string assuming lost circulation at the casing shoe:

Current mud = 15 ppg

Casing was run in = 11 ppg

CSD = 10,000 ft

Solution

First find the length of mud column remaining inside the casing:

$$L = \frac{CSD \text{ x } 0.465}{0.052 \text{ x } p_{m1}} = (10{,}000 \text{ x } 0.465) / 0.052 \text{ x } 15 = 5962 \text{ ft}$$

Then reference to figure **Figure 5.2**, three points need to be considered for collapse calculations.

(1) At surface (Point A in Figure 5.2)

Both the external and internal pressures are zero. Hence the effective collapse at surface is zero.

At point A

C1= Zero

(2) At Point B

The internal pressure is zero.This is where the new level of mud starts. Hence collapse pressure is equal to the external pressure only.

$$C2= 0.052\ (CSD\text{-}L)\ p_m$$

$$C2 =0.052 \times 11 \times (10{,}000 - 5962) = 2310 \text{ psi}$$

(3) At Point C

Now both external and internal pressures must be calculated. The external pressure is caused by the mud column in which casing was run. The internal pressure (back-up load) is caused by the length of mud column (L) remaining after lost circulation.

$$C3 = 0.052\ CSD \times p_m \ - 0.052\ L \times p_{m1}$$

$$= 0.052 \times 10{,}000 \times 11 - 0.52 \times 5962 \times 15 = 1070 \text{ psi}$$

4.2 Collapse Calculations For Individual Casing Strings

In order the make the calculations more practical, it will be necessary to present the collapse equations for each casing type. Obviously, the given procedures may be modified to suit local conditions. The reader must always take advantage of previous experience in the area, for example, complete lost circulation can be found in a very few areas below the 13 3/8" casing. If selecting casing in such areas of complete loss circulation, then the 13 3/8" must be designed for external pressure only. Normally, as will be seen later, the 13 3/8" casing is designed for partial loss circulation.

4.2.1 CONDUCTOR

The conductor is usually set at a shallow depth ranging from 100 ft to 1500 ft. Assume complete evacuation so that the internal pressure inside the casing is zero. The external pressure is caused by the mud in which the casing was run.

For offshore operations, the external pressure is made up of two components:

Collapse pressure at mud line=external pressure due to a column of seawater from sea level to mud line

$$=(0.45 \text{ psi/ft}) \text{ x mudline depth} = C1 \quad \text{psi}$$

$$\text{Collapse pressure at casing seat} = C1 + 0.052 \text{ x } p_m \text{ x CSD} \qquad (5.8)$$

4.2.2 SURFACE CASING

If surface casing is set at a shallow depth, then it is possible to empty out the casing of a large volume of mud if a loss of circulation is encountered in the open hole below. Some designers assume the surface casing to be completely empty when designing for collapse, irrespective of its setting depth, to provide an in-built design factor in the design. Other designs in industry assume a 40% evacuation level. Both approaches have no scientific basis and can result in overdesigns.

This overdesign can be significantly reduced if partial loss circulation is assumed and the pressure of the reduced level of mud inside the casing is subtracted from the external pressure to give the effective collapse pressure. The internal pressure is calculated using **Equation (5.4)**.

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4.2.3 Intermediate Casing

Complete evacuation in intermediate casing is virtually impossible. This is because during lost circulation, the fluid column inside the casing will drop to a height such that the remaining fluid inside the casing just balances the formation pressure of the thief zone, irrespective of the magnitude of pore pressure of the thief zone (see **Figure 5.2**).

Three collapse points will have to be calculated using the general form:

Collapse pressure, C=external pressure - internal pressure

(1)Point A: At Surface

$$C1 = \text{Zero} \tag{5.9}$$

(2)Point B: At depth (CSD-L)

$$= 0.052\ (CSD\text{-}L) \times \rho_m - 0$$

$$C2 = 0.052\ (CSD\text{-}L)\ \rho_m \tag{5.10}$$

(3)Point C: At depth CSD

$$C3 = 0.052\ CSD \times \rho_m - 0.052\ L \times \rho_{m1} \tag{5.11}$$

where ρ_m is the mud weight in which casing was run in.

4.2.4 Production Casing

For production casing the assumption of complete evacuation is justified in the following situations:

1. if perforations are likely to be plugged during production as in gas wells. In this case surface pressure may be bled to zero and hence give little pressure support inside the casing.
2. in artificial lift operations. In such operations gas is injected from the surface to reduce the hydrostatic column of liquid against the formation to help production. If

the well pressure were bled to zero at surface, a situation of complete evacuation could exist.

3. in air/gas drilling all casing strings should be designed for complete evacuation.
4. another situation which results in complete evacuation is a blowout which unloads the entire hole.

If none of the above situations are likely in a production casing then partial evacuation should be used for collapse design and equations **Equation (5.9)** to **Equation (5.11)** should be used.

4.3 Collapse Design Across Salt Sections

There are several areas around the world where casing strings have to be set across salt sections. Salt is a sedimentary rock belonging to the evaporite group which is characterised by having no porosity and no permeability. In most cases, salt is immobile and causes no problems while drilling or production.

There are several types of evaporites:

- Halite NaCl
- Gypsum $CaSO_4$ $2H_2O$
- Anhydrite $CaSO_4$
- Sylvite KCl
- Carnalite $KMgCl_3$ $6H_2O$

When a salt section is made up entirely of sylvite or carnalite, then the salt section becomes mobile and behaves like a super-viscous fluid. The mobile salt continues to move during drilling operations, in some cases, at the rate of one inch an hour causing the pipe to be stuck. Salt movement also continues after the casing is set and in some cases results in casing collapse.

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Salt induced casing collapse occurs in many part of the world; Southern North Sea, Red Sea and Offshore Qatar are a few examples. Casing collapse failure caused by salt movement is a catastrophic failure, almost always requiring sidetracking or redrilling of the well.

Currently, there is no accepted analytical method for designing for collapse loads resulting from salt movement.The accepted method is to use an external pressure of 1 psi/ft across the salt section. The reason behind this is that in mobile salts, all the earth stresses become equal to 1 psi/ft.

Hence when designing across mobile salt sections, determine the depth of the salt section, say X, ft, then:

$$\text{External pressure at depth X} = 1 \text{ psi/ft x } \mathbf{X} \tag{5.12}$$

Internal pressure = pressure resulting from partial loss circulation

5.0 BURST CRITERION

In oil well casings, burst occurs when the effective internal pressure inside the casing (internal pressure minus external pressure) exceeds the casing burst strength.

Like collapse, the burst calculations are straightforward. The difficulty arises when one attempts to determine realistic values for internal and external pressures.

In development wells, where pressures are well known the task is straight forward. In exploration wells, there are many problems when one attempts to estimate the actual formation pressure including:

- the exact depth of the zone (formation pressure increases with depth)
- type of fluid (oil or gas)
- porosity, permeability
- temperature

The above factors determine the severity of the kick in terms of pressure and ease of detection.

Clearly, one must design exploration wells for a greater degree of uncertainty than development wells. Indeed, some operators manuals detail separate design methods for development and exploration wells.

In this book, a general design method will be presented and guidelines for its application will be given.

5.1 Burst Calculations

Burst Pressure, B is give by:

B = internal pressure – external pressure

Internal Pressure

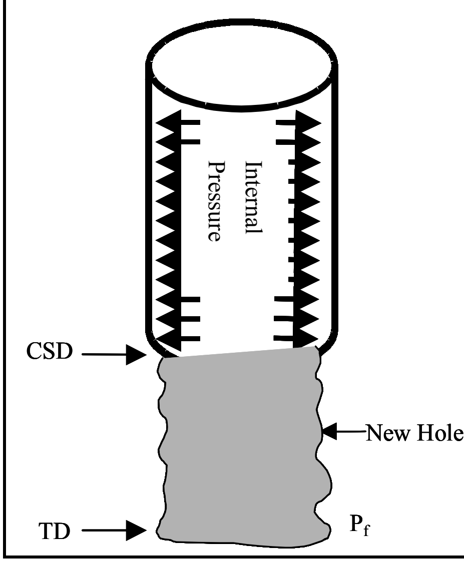
Burst pressures occur when formation fluids enter the casing while drilling or producing next hole. Reference to **Figure 5.3**, shows that in most cases the maximum formation pressure will be encountered when reaching the TD of the next hole section.

For the burst criterion, two cases can be designed for:

1. Unlimited kick

2. Limited kick

Figure 5.3 Burst Design



5.2 Unlimited Kick

The use of unlimited kick (or gas to surface) used to be the main design criterion in burst calculations. Simply stated, the design is based on unlimited kick, usually gas. The kick is assumed to enter the well, displace the entire mud and then the well is shut-in the moment the last mud drop leaves the well. Clearly, this is an unrealistic situation especially in today's technology where kicks as small as 10 bbls can be detected even on semi-submersible rigs.

However, there is one practical situation when this criterion is actually valid. In gas wells, the production tubing is in fact subjected to controlled unlimited kick all the time. Because production occurs under controlled conditions, the flow of gas poses no problems to the surrounding casing. If however, gas leaked from tubing to casing, then the casing will see the full impact of gas during production. This idea will be explored further in this section.

Hence reference to **Figure 5.3**, and assuming a gas kick of pressure P_f from next TD, and the gas fills the entire well then the internal pressures at surface and casing shoe are given by:

$$\text{Internal pressure at surface} = Pf - G \times TD \tag{5.13}$$

$$\text{Internal pressure at shoe} = Pf - G \times (TD - CSD) \tag{5.14}$$

where G is the gradient of gas (typically 0.1 psi/ft).

When a gas kick is assumed, two points must be considered:

1. The casing seat should be selected so that gas pressure at the casing shoe is less than the formation breakdown pressure at the shoe.

2. The gas pressure must be available from reservoirs in the open hole section. In exploration wells where reservoir pressures are not known, formation pressure at TD of the next open hole section is calculated from the maximum anticipated mud weight at that depth. A gas pressure equal to this value is used for the calculation of internal pressures.

In development areas, reservoir pressures are normally determined by use of wireline logs, drill stem testing or production testing. These pressure values should be used in casing design.

5.3 LIMITED KICK DESIGN: KICK TOLERANCE

This method is by far the most widely used and represents realistic conditions for most casings and most wells. The main problem with this method is knowing what realistic values for kick size to use for each hole size and how to distinguish between exploration and development wells. In 1987, detailed limited kick calculations were first presented in a design methodology by Rabia [1].

The calculations involved in this method were given in detail in **Chapter 3**: Kick Tolerance. To apply this method, assume a realistic kick size and calculate the internal pressures at surface and at shoe assuming the kick is being **circulated out** of hole using the driller's method of well control. The method can be easily programmed into an Excel sheet. Further, one can add several scenarios to each casing size including type of kick, swabbed kick or overpressured kick with kick margin, effects of temperature and gas compressibility, type of well etc. Whatever volume of kick is used, a realistic value of formation pressure must be used as this is the variable that affects the calculations most.

5.4 External Pressure For Burst Design

The external pressure (or back-up load) is one of the most ambiguous variables to determine. It is largely determined by the type of casing being designed, mud type and cement density, height of cement column and formation pressures in the vicinity of the casing.

In practice, although casings are cemented (partially or totally to surface), the external pressure is not based on the cement column. At first glance, this seems strange that we go into a great deal of effort and expense to cement casing and not use the cement as a back-up load. The main reasons for not using the cement column are:

1. it is impossible to ensure a continuous cement sheet around the casing
2. any mud trapped within the cement can subject the casing to the original hydrostatic pressure of the cement
3. the cement sheath is usually highly porous but with little permeability and when it is in contact with the formation, it can theoretically transmit the formation pressure to the casing

Because of the above, the exact degree of back-up provided by cement is difficult to determine. The following methods are used by a number of oil companies for calculating external pressure for burst calculations:

1. Regardless of whether the casing is cemented or not, the back-up load is provided by a column of salt saturated water. Hence the

$$\text{external pressure} = 0.465 \text{ psi/ft} \times \text{CSD (ft)} \tag{5.15}$$

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The above method is the simplest and is used by many people in the industry. It assumes all muds and cements behind casing degrade with time to a density equivalent to salt-saturated mud having a density of 0.465 psi/ft. In fact, this assumption is used by some commercial casing design software.

The author suggests using this method for all casings likely to be in the ground for more than five years.

2. If casing is cemented along its entire length and the casing is in contact with a porous formation via a cement sheath, then with time the cement sheath will degrade and the casing will be subjected to the pore pressure of the open formation. Hence

$$\text{External pressure} = \text{maximum expected pore pressure} \tag{5.16}$$

In practice only conductor and shallow surface casings are cemented to surface. Hence the maximum pore pressure is likely to be that of a normally pressure zone of around 0.465 psi/ft.

3. For uncemented casings:

- in the open hole, use a column of mud to balance the lowest pore pressure in the open hole section
- inside another casing, use mud down to TOC and then from TOC to casing shoe use a column of mud to balance the lowest pore pressure in the open hole section

This scenario usually applies to intermediate and production casings. In fact, the author used the above to design high pressure/high temperature wells in the North Sea. Without this realistic assumption, casing of unnecessarily higher grade or weight would be required.

5.5 Burst Calculations For Individual Casing Strings

At the top of the hole, the external pressure is zero and the internal pressure must be supported entirely by he casing body. Therefore, burst pressure is highest at the top and lowest at the casing shoe where internal pressures are resisted by the external pressure originating from fluids outside the casing. As will be shown later, in production casing the burst pressure at shoe can be higher than the burst pressure at surface in situations where the production tubing leaks gas into the casing.

Conductor

There is no burst design for conductors.

Surface and Intermediate Casings

For gas to surface (**unlimited kick size**), calculate burst pressures as follows:

Calculate the internal pressures (P_i) using the maximum formation pressure at next hole TD, assuming the hole is full of gas, (see **Figure 5.3**).

Burst at surface = Internal pressure (Pi) (Equation (5.13)– external pressure

$$\text{Burst pressure at surface (B1)} = Pf - G \times TD \tag{5.17}$$

(note external pressure at surface is zero)

Burst pressure at casing shoe (B2) = internal pressure (Equation (5.14)- backup load

$$= P_i - 0.465 \times CSD$$

$$B2 = Pf - G \times (TD - CSD) - 0.465 \times CSD \tag{5.18}$$

The back-up load is assumed to be provided by mud which has deteriorated to salt-saturated water with a gradient of 0.465 psi/ft.

For the limited kick size, use the appropriate kick size (see **Chapter 3**) to calculate the maximum internal pressures at surface and at shoe when circulating out the kick. Calculate the corresponding values for B1 and B2 as above.

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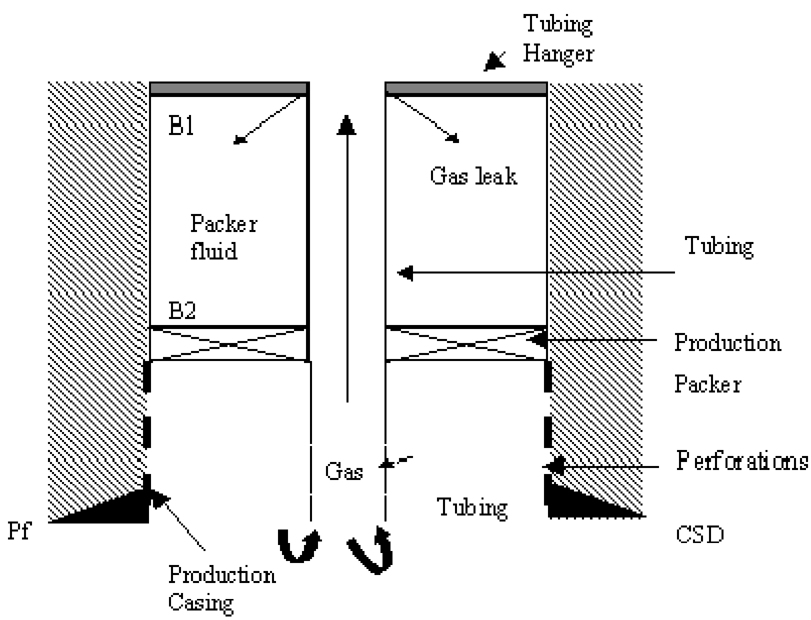
Production Casing

The worst case occurs when gas leaks from the top of the production tubing to the casing. The gas pressure will be transmitted through the packer fluid from the surface to the casing shoe (see **Figure 5.4**).

Figure 5.4 Burst Design For Production Casing



Burst values are calculated as follows:

Burst pressure= Internal pressure - External pressure

Burst at surface (B1) =Pf - G x CSD

(or the maximum anticipated surfacepressure, whichever is the greatest)

$$\text{Burst at shoe (B2)} = B1 + 0.052\,\rho_p \times CSD - CSD \times 0.465 \qquad (5.19)$$

where

G =gradient of gas, usually 0.1 psi/ft

Pf =formation pressure at production casing seat, psi

ρ_p =density of completion (or packer) fluid, ppg

0.465 =the density of backup fluid outside the casing to represent the worst case, psi/ft.

Note that if a production packer is set above the casing shoe depth, then the packer depth should be used in the above calculation rather than CSD. The casing below the packer will not be subjected to burst loading (see Figure 5.4) as it is perforated.

Example 5.2: Production Casing Calculations

Calculate burst pressures for the following well:

CSD = 15000 ft

Pf = 8500 psi

Packer fluid = 15 ppg

Solution

Burst at surface (B1) = Pf - G x CSD

=8500 – 0.1 x 15000

= 7000 psi

Burst at shoe (B2)= B1 + 0.052 p_p x CSD - CSD x 0.465

= 7000 + 0.052 x 15 x 15000 - 15000 x 0.465

= 11,725 psi

5.6 Design & Safety Factors

Casings are never designed to their yield strength or tensile strength limits. Instead, a factor is used to derate the casing strength to ensure that the casing is never loaded to failure. The difference between design and safety factors are given below.

5.6.1 Safety Factor

Safety factor uses a rating based on catastrophic failure of the casing.

$$\text{Safety Factor} = \frac{\text{Failure Load}}{\text{Actual Applied Load}}$$

When the actual applied load equals the failure load, then the safety factor =1 and failure is imminent. Failure will occur if the actual load is greater than the failure load and in this case the safety factor < 1.0. For the above reasons, safety factors are always kept at values greater than 1. In casing design, neither the actual applied load or failure loads are known exactly, hence design factors are used to evaluate the integrity of casing.

5.6.2 Design factor

Design factor uses a rating based on the minimum yield strength of casing.

In the oil industry, safety factors are never intentionally used to design tubulars as they imply prior knowledge of the actual failure load and designing to failure or below failure.

Design factors are usually used for designing tubulars and are based on comparing the maximum service load relative to the API minimum yield strength.Recall that the casing does not actually fail at the the minimum yield strength and, moreover, the minimum yield strength is an average value of several measurements. Hence, the design factor provides a greater scope for safety than safety factor.

$$\text{Design Factor} = \frac{\text{Rating of the pipe}}{\text{Maximum Expected Service Load}}$$

A Design Factor is usually equal to or greater than 1.The design factor should always allow for forces which are difficult to calculate such as shock loads.

The burst design factor (DF-B) is given by:

$$\text{DF-B} = \frac{\text{Burst Strength}}{\text{Burst Pressure (B)}}$$

Similarly, the collapse design factor is given by:

$$\text{DF-C} = \frac{\text{Collapse Strength}}{\text{Collapse Pressure (C)}}$$

5.6.3 Recommended Design Factors

Collapse = 1. 0

Burst = 1.1

Tension = 1.6 –1. 8

Compression = 1.0

Triaxial Design = 1. 1

Industry Range from various operators

Collapse = 1.0 – 1. 1

Burst = 1.1 – 1. 25

Tension = 1.3 –1. 8

Compression = 1.0

Triaxial Design = 1. 1- 1.2

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Example 5.3: Design Factor

If the burst strength (Minimum Internal Yield Strength) of casing is 6300 psi.

What is the maximum burst pressure that this casing should be subjected to in service?

Recommended DF = 1.1

Solution

$$\text{Design burst strength} = \frac{6300}{1.1} = 5727 \text{ psi}$$

5.7 Casing Selection- Burst And Collapse

It is customary in casing design to define the load case for which the casing is designed for. There are several load cases which arise due to drilling and production operations and will be discussed in **"Load Cases" on page 174**.

However before a load case is applied, the casing grades/weights should initially be selected on the basis of burst and collpase pressures, then load cases should be applied.If only one grade or one weight of casing is available, then the task of selecting casing is easy. The strength properties of the casings available are compared with the collapse and burst pressures in the wellbore. If the design factors in collapse and burst are acceptable then all that remains is to check the casing for tension.

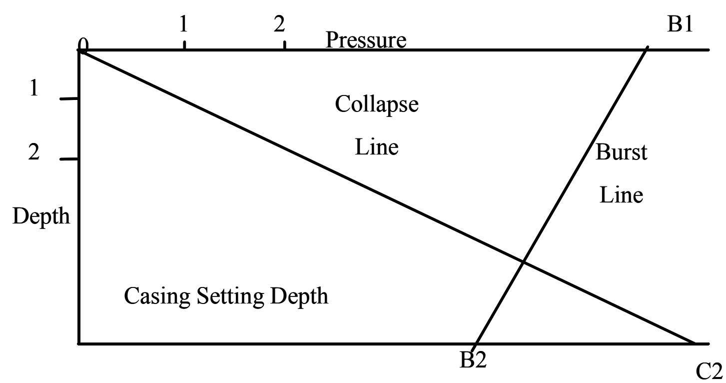
For deep wells or where more than one grade and weight are used, a graphical method of selecting casing is used as follows:

1. Plot a graph of pressure against depth, as shown in Figure 5.5, starting the depth and pressure scales at zero. Mark the CSD on this graph.
2. Collapse Line: Mark point C1 at zero depth and point C2 at CSD. Draw a straight line through points C1 and C2.

3. For partial loss circulation, there will be three collapse points. Mark C1 at zero depth, C2 at depth (CSD-L) and C3 at CSD. Draw two straight lines through these points.

4. Burst Line:Plot point B1 at zero depth and point B2 at CSD. Draw a straight line through point B1 and B2 (see **Figure 5.5**). For production casing, the highest pressure will be at casing shoe.

Figure 5.5 Collpase And Burst Lines



5. Plot the collapse and burst strength of the available casing, as shown in **Figure 5.6**. In this figure, two grades, N80 and K55 are plotted to represent the available casing.

Select a casing string that satisfies both collapse and burst. **Figure 5.6** provides the initial selection and in many cases this selection differs very little from the final selection. Hence, great care must be exercised when producing **Figure 5.6**.

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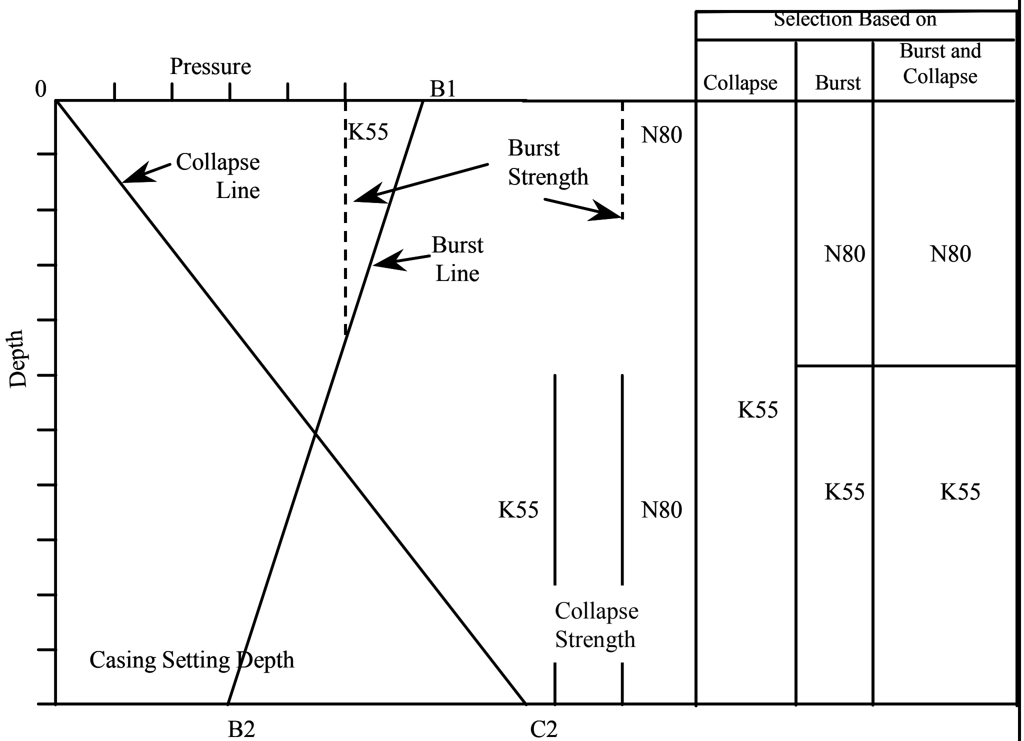
Figure 5.6 Selection Based On Burst And Collapse



6.0 COMBINATION STRINGS

In a casing string, maximum tension occurs at the uppermost joint and the tension criterion requires a high grade or a heavy casing at this joint. Burst pressures are most severe at the top and, again, casing must be strong enough on top to resist failure in burst. In collapse calculations, however, the worst conditions occur at the bottom and heavy casing must, therefore, be chosen for the bottom part to resist collapse failure.

Hence, the requirements for burst and tension are different from the requirements for collapse and a compromise must be reached in casing design. This compromise is achieved in the form of a combination string. In other words, casings of various grades and of differing weights are used at different depths of hole, each grade of casing being capable of withstanding the imposed loading conditions at that depth. Strong and heavy casing is used at the surface, light yet strong casing is used in the middle section, and heavy casing may be required at the bottom to withstand the high collapsing pressure. **Example 5.6** shows how a combination string is selected.

The combination string method represents the most economical way of selecting casing consistent with safety. Although as many grades as possible could be used for a string of casing, practical experience has shown that the logistics of using more than two grades (or two weights) create problems for rig crews.

7.0 Tension Criterion

Most axial tension arises from the weight of the casing itself. Other tension loadings can arise due to: bending, drag, shock loading and during pressure testing of casing.

In casing design, the uppermost joint of the string is considered the weakest in tension, as it has to carry the total weight of the casing string. Selection is based on a design factor of 1.6 to 1.8 for the top joint.

Tensile forces are determined as follows:

1. calculate weight of casing in air (positive value) using true vertical depth;
2. calculate buoyancy force (negative value);
3. calculate bending force in deviated wells (positive value);
4. calculate drag force in deviated wells (this force is only applicable if casing is pulled out of hole);
5. calculate shock loads due to arresting casing in slips; and
6. calculate pressure testing forces

Forces (1) to (3) always exist, whether the pipe is static or in motion. Forces (4) and (5) exist only when the pipe is in motion. The total surface tensile load (sometimes referred to as installation load) must be determined accurately and must always be less than the yield strength of the top joint of the casing. Also, the installation load must be less than the rated derrick load capacity so that the casing can be run in or pulled out of hole without causing damage to the derrick.

In the initial selection of casing, check that the casing can carry its own weight in mud and when the casing is finally chosen, calculate the total tensile loads and compare them with the joint or pipe body yield values, using the lower of the two values. A **design factor** (= coupling or pipe body yield strength divided by total tensile loads) in tension of 1.6 to 1.8 should be used.

7.1 Tension calculations

The selected grades/ weights in **Figure 5.6** provide the basis for checking for tension. The following forces must be considered:

Buoyant Weight Of Casing (Positive Force)

The buoyant weight is determined as the difference between casing air weight and buoyancy force.

$$\text{Casing air weight} = \text{casing weight (lb/ft)} \times \text{hole TVD} \tag{5.20}$$

For open-ended casing, see **Figure 5.7**.

$$\text{Buoyancy force} = Pe\,(Ae - Ai) \tag{5.21}$$

For closed casing, see **Figure 5.7**

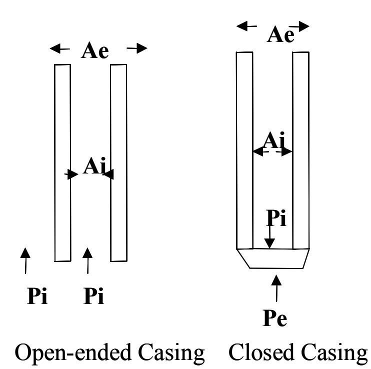
$$\text{Buoyancy force} = Pe\,Ae - Pi\,Ai \tag{5.22}$$

where Pe = external hydrostatic pressure, psi

Pi = internal hydrostatic pressure, psi

Ae and Ai are external and internal areas of the casing

Figure 5.7 Buoyancy Force



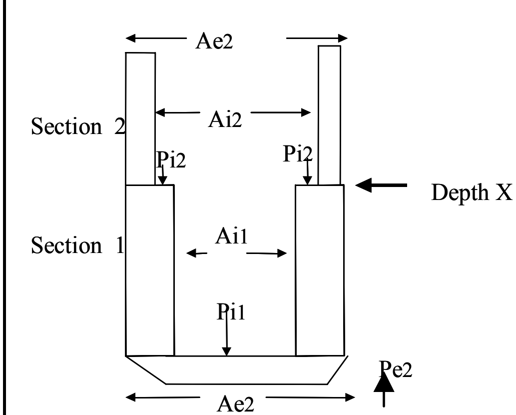
Since the mud inside and outside the casing is invariably the same, the buoyancy force is almost always given by **Equation (5.23)**:

$$\text{Buoyancy force} = Pe\,(Ae - Ai) \tag{5.23}$$

If a tapered casing string is used then the buoyancy force at TD is calculated as above. At a cross-sectional change, the buoyancy force is calculated as follows:

$$\text{Buoyancy force} = Pe_2\,(Ae_2 - Ae_1) - Pi_2\,(Ai_2 - Ai_1) \tag{5.24}$$

Figure 5.8 Buoyancy Force For A tapered String



For most applications, the author recommends calculating the buoyant weight as follows:

Buoyantweight=airweightxbuoyancyfactor(5.25)

One can easily prove that there is very little of accuracy using the above equation except for tapered strings or when the bottom of the casing is landed in compression.

2. Bending Force

The bending force is given by:

$$\text{Bending force} = 63\ Wn \times OD \times \theta \tag{5.26}$$

where
W_n = weight of casing lb/ft (positive force)
θ= dogleg severity, degrees/100 ft

3. Shock Load

Shock loading in casing operations results when:

- Sudden decelerations are applied
- Casing is picked off the slips
- Slips are kicked in while pipe is moving

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- Casing hits a bridge or jumps off an edge downhole

Shock loading is a dynamic force with a very short duration: approximately one second.It can be shown that the shock is given by [1]:

$$\text{Fshock} = 1780 \text{ V As} \tag{5.27}$$

where

As = cross-sectional area

V = pipe running velocity in ft/s, usually taken as the instantaneous velocity

(some operators use V = 5 ft/s as the instantaneous velocity)

The main difficulty with using **Equation (5.27)** is knowing which value to use for casing running speed when shock loading occurs.

The author found that the equation below gives satisfactory results [1]:

$$\text{Shock load (max)} = 1500 \times \text{Wn} \tag{5.28}$$

4. Drag Force

This force is usually of the order of 100,000 lbf (positive force). Because the calculation of drag force is complex and requires an accurate knowledge of the friction factor between the casing and hole, shock load calculations will in most cases suffice.The effect of the drag force lasts for the duration of running a joint of casing; shock loading lasts for only 1 second or so. Hence shock loading and drag forces can not exist simultaneously. In most cases the magnitude of shock and drag forces are approximately the same. Hence calculating one force will be sufficient in most cases.

Both shock and drag forces are only applicable when the casing is run in hole. In fact, drag forces reduce the casing forces when running in hole and increase them when pulling out. However, despite the fact that the casing operation is a one-way job (running in), there are many occasions when a need arises for moving casing uphole, e.g. to reciprocate casing or to pull out of hole due to tight hole. Hence, the extreme case should always be considered for casing selection.

5. Pressure Testing

The casing should be tested to the maximum pressure which it sees during drilling and production operations (together with a suitable rounding margin).

$$F_t = \frac{\pi(ID^2)}{4} \text{ x test pressure} \qquad (5.29)$$

where

Ft = pressure test force, lb

ID = inside diameter of casing, in

7.2 PRESSURE TESTING ISSUES

When deciding on a pressure test value, the resulting force must not be allowed to exceed:

- 80% of the rated burst strength
- the connection pressure rating
- 75% of the connection tensile rating
- triaxial stress rating of the casing

7.3 LOAD CASES

There are three load cases for which the total tensile force should be calculated for: running conditions, pressure testing and static conditions. These load cases are sometimes described as Installation Load cases. Other load cases will be discussed later.

Load Case 1:Running Conditions

This applies to the case when the casing is run in hole and prior to pumping cement:

Total tensile force = buoyant weight + shock load +bending force

Load Case 2: Pressure Testing Conditions

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This condition applies when the casing is run to TD, the cement is displaced behind the casing and mud is used to apply pressure on the top plug. This is usually the best time to test the casing while the cement is still wet. In the past, some operators tested casing after the cement was set. This practice created micro channels between the casing and the cement and allowed pressure communication between various zones through these open channels.

Total tensile force = buoyant weight + pressure testing force +bending force

Load Case 3: Static Conditions

This condition applies when the casing is in the ground, cemented and the wellhead installed. The casing is now effectively a pressure vessel fixed at top and bottom.One can argue that other forces should be considered for this case such as production forces, injection forces, temperature induced forces etc. However, for the sake of clarity these forces will be discussed later in this chapter and also separately in **Chapter 15**.

Total tensile force = buoyant weight + bending force + (miscellaneous forces)

It is usually sufficient to calculate the total force at the top joint, but it may be necessary to calculate this force at other joints with marginal safety factors in tension.

Once again, ensure that the design factor in tension during pressure testing is greater than 1.6, i.e.

$$\text{DF-T} = \frac{\text{Yield Strength}}{\text{Total tensile forces during pressure testing}}$$

Example 5.4: Tensile Forces

Calculate the tensile forces for the following casing string:

20 "casing, ID = 18.71 inch, 133 lb/ft

CSD = 2800 ft

Mud =10 ppg

Test Pressure =2500 psi

Dogleg = 0.75 deg/100 ft

Solution

F1 =Buoyant weight of casing (in 10 ppg mud) = 2800 x 133 x 0.847 = 315,423 lbf

F2 =Shock load = 1500x 133 = 199,500 lbf

F3 =Bending force = 63 casing weight x OD x DLS

= 63x133x20x0.75 = 125,685 lbf

F4 = Pressure test force = $\frac{\pi}{4}$ (casing ID)2 x test pressure

$= \frac{\pi}{4} (18.71)^2 \times 2500$ = 687,349 lbf

The following table may be constructed:

	Running conditions	Pressure Testing Conditions	Static Conditions
F1: Buoyant Weight	315,423	315,423	315,423
F2: Shock Load	199,500	0	0
F3: Bending Force	125,685	125,685	125,685
F4: Pressure Testing Force	0	687,349	0
Total Force (lbf)	530,608	1,128457	441,108

From the above table, it can be seen the maximum force that the top casing joint sees is in fact during pressure testing. Casing pressure testing is usually carried out for approximately 15 minutes. Despite the fact that this force acts for a short duration, it must be used in the

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final selection as the casing could fail if it is subjected to similar pressures during kicks, production, injection, leaks etc.

8.0 SERVICE LOADS DURING DRILLING AND PRODUCTION OPERATIONS

Once the casing is landed and cemented, it will be subjected to additional forces if drilling is continued beyond this casing or if this casing is used as a production casing. These service loads represent extra set of load cases which must be checked before the casing is selected.

To calculate the tensile load on the casing, the base load must first be calculated:

$$\text{Fbase load} = \text{Air weight} - \text{Buoyancy force} + \text{bending force} + \text{pressure testing force} + \text{landing force (if applied)} \tag{5.30}$$

The additional forces that must be added include ballooning force and temperature force.

$$\text{Ballooning force} = 2\,\nu\,(Ai\ \ \Delta Pi - Ae\ \ \Delta Pe) \tag{5.31}$$

where

ν = Poisson's ratio

ΔPi = change in internal pressure inside the casing

ΔPe = change in external pressure outside the casing

$$\text{Force due to temperature change} = -207\ As\ \ \Delta T \tag{5.32}$$

where

ΔT = temperature change, °F

As = cross-sectional area, in^2

To use **Equation (5.31)**, the engineer therefore must define all possible changes in internal and external pressures to calculate the ballooning force. For the majority of conventional wells, the base load case in **Equation (5.30)** provides most of the forces the casing is likely to see in its service life.

Other loadings that may develop in the casing include: (a) bending with tongs during make-up; (b) pull-out of the joint and slip crushing; (c) corrosion and fatigue failure, both of the body and of' the threads; (d) pipe wear due to running wire line tools and drillstring assembly which can be extremely detrimental to casing in deviated and dog-legged holes; and (e) additional loadings arising from treatment operations. The latter operations include acidising, cementing and hydrofracturing operations.

As a design rule, it usually accepted that casings which are subjected to a great deal of wear as a result of drilling and wireline operations should be upgraded to the next weight up. In other words if the design shows that 43.5 lb/ft,95/8" casing satisfy collapse, burst and tension, then it should be upgraded to 47 lb/ft if this casing is expected to see a great deal of wear.

9.0 Compression Loads

Compression loading arises in casings that carry inner strings where the weight of inner strings is transferred to the larger supporting casing. Production casings do not carry inner casing strings and are used, amongst other things, to suspend production tubings which are very light in comparison with casing. Consequently, production casings are not designed for compression loading.

The integrity of surface casing in compression should be checked by adding the buoyant weight of all subsequent strings.This weight is then compared with the compressive strength of casing (assumed equal to the minimum yield strength) to obtain a minimum design factor of 1.1.

10.0 Biaxial Effects

The combination of stresses due to the weight of the casing and external pressures are referred to as 'biaxial stresses [1]. Biaxial stresses reduce the collapse resistance of the casing and must be accounted for in designing for deep wells or combination strings. The determination of the collapse resistance under tensile load was presented in detail in **Chapter 4**.

The procedure for allowing for biaxial effects is as follows:

1. Select grade/weight based on burst/collapse calculations

2. Check the grade/weight satisfy the tension criterion
3. Determine the tension at critical points within the well
4. Apply the procedure in **Chapter 4** to calculate the reduced collapse strength
5. Re-calculate the new design factor in collapse

Example 5.5: Detailed Casing Design - 20" Casing

Given the following well data:

Setting depth = 2200 ft RKB

Mud weight used to drill 26" hole = WM mud 9 ppg

Fracture gradient at 20" shoe depth= 0.78 psi/ft = 16.35 ppg

TD of next section = 7980 ft

Max pore pressure in next section = 9 ppg (3735 psi)

Average cement density =13.5 ppg

Casing to be cemented to seabed

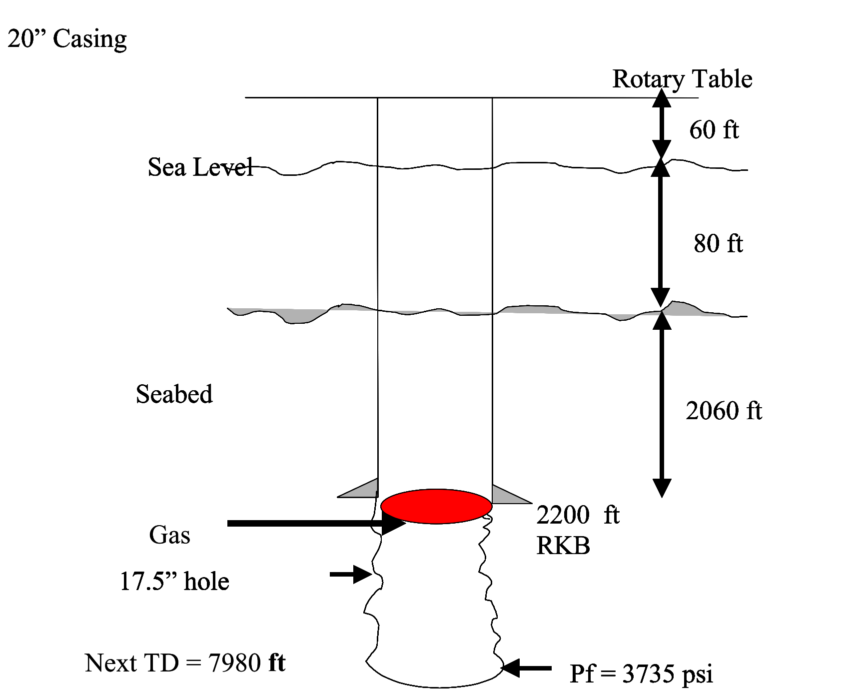
Temperature gradient = 0.01 F /ft

From offset wells, a thief zone could occur any where below the casing setting depth of 2200 ft with severe loss circulation.

You are required to:

1. Calculate collapse and burst pressures
2. Kick tolerance for the well
3. Ascertain if Grade X52, 129.33#, ID = 18.75 in, can be utilised and if not suggest another grade or weight
4. Carry out detailed tension calculations assuming a dogleg of 1deg/100 ft

Figure 5.9 Example 5.5



Solution

First, the well data can be converted to a sketch as shown in **Figure 5.9**

Collapse Loading

(i) **Partial Evacuation** – Since the 20" casing is set 2200 ft it likely that 100% evacuation could occur during lost circulation.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = external pressure – internal pressure

= 0.052x9x2200 – 0 = 1030 psi

During cementation

External pressure at shoe due to cement and water = (2200 – 140) x 13.5 x.052 + 80x.45

= 1482 psi

Internal pressure at shoe = 0.052x 9x 2200 = 1030 psi

Effective collapse pressure at shoe during cementation = 1482 – 1030 = 452 psi

(b) Kick Tolerance

Formation fracture pressure at 20" shoe = 1716 psi

The height of a tolerable kick (H) is given by:

$$H = \frac{0.052 \times Pm\ (TD - CSD) + (FG \times CSD \times 0.052) - Pf}{(0.052 \times \rho_m) - G}$$

$$H = \frac{0.052 \times 9.5 \times (7980-2200) + (15 \times 2200 \times 0.052) - 3735}{(0.052 \times 9.5) - 0.1}$$

= 2123 ft

Hole capacity between 5" DP and 17.5" hole = 1.534 cu ft = 0.273 bbl/ft

V1= volume of kick at shoe = 0.273 x 2123 =579.6 bbls

At the 20" shoe and bottom hole conditions, using $P_1V_1 = P_2V_2$, we obtain:

$$V_2 = \frac{579.6 \times (15 \times 0.052 \times 2200)}{3735} = 266 \text{ bbls}$$

(c) Burst Loading

(i) Gas to surface

Internal Pressure at surface= Pore pressure at next TD - gas to surface

= 0.052x9x7980 - 0.1 x 7980 = 2937 psi

Burst Pressure at surface = internal pressure – external pressure (back-up load)

= 2937 – 0 = 2937 psi

Burst Pressure at casing shoe = internal pressure – back-up load

Internal Pressure= Pore pressure - gas gradient to the shoe

= 3735 – (7980 –2200) x 0.1 = 3157 psi

Back-up load= 2200 x 0.465 = 1023 psi

Burst Pressure at casing shoe= 2134 psi

(ii) Shoe Fracture Consideration

Gas pressure just below the 20" shoe = Pore pressure - gas gradient to the shoe = 3175 psi

Fracture gradient at the 20" shoe = 0.78x 2200 = 1716 psi

The formation is therefore unable to support a full column of gas to the surface.

The maximum allowable surface pressure that can be applied at the wellhead prior to the shoe breaking down with the well evacuated to gas and a seawater backup

= Fracture gradient at shoe - gas gradient - backup load at surface

= (0.78 x2200) - (0.1 x 2200) - 0

= 1496 psi

Maximum surface pressure to breakdown shoe = 1496 psi

The above calculations are shown for illustration only as a maximum allowable surface pressure of 1496 psi implicitly indicates that a kick is being circulated out of the hole and its pressure is reduced when the top of the bubble reaches the surface. In other words control over the kick pressure within the well should be exercised. With today's technology, control can also be made on much a kick volume can be safely taken before the well is shut-in.

(iii) Burst Based on Circulating out a 150 bbls gas kick

In this example we will use a 150 bbl kick for burst calculations.

Formation pressure at the next TD of 7980 ft = 0.052 x 9 x7980= 3735 psi

The burst design will be based on the ability to circulate a 150 bbl kick from 7980 ft. The Drillers method should be used to establish the annular pressures associated with this kick while circulating with the original mud weight (9 ppg).

The annulus pressure at the casing shoe is given by (Refer to **Chapter 3** for details):

The internal pressure at any point:

$$P\ \textit{at any depth} = \tfrac{1}{2}\left[A + \left(A^2 + 4.Pf.M.N.y_f.\rho_m\right)^{0.5}\right]$$

where

A =Pf - *p*m (TD - X) - Pg

Pf = 3735 psi

TD = 7980 ft

CSD = 2200 ft

p_m = 9.5 x 0.052= 0.494 psi/ft

For a 150 bbl kick

$$y_f = \frac{V1}{V2} = \frac{150\ bbl}{\frac{\pi(17.5^2 - 5^2)}{4} x \frac{1}{144\ x 5.62} bbl\ /\ ft} = 549.6\ ft$$

Pg =Pressure in the gas bubble = G y_f = 0.1 x 549.6 = 54.9 psi

At Surface X= 0 ft

$$M = \frac{17.5\text{" hole x 5" DP}}{20\text{"casing x5" DP ann vol}}$$

$$= \frac{1.534}{1.7811} = 0.8613$$

Assume Zs = Zb =1 (gas compressibility factors at surface (S) and at bottom (b))

$$Ns = \frac{\text{Tsurface}}{\text{T bottom hole}}$$

$$= \frac{60 + 460}{(60 + 0.01 \text{x} 7980) + 460} = 0.959$$

A = 3735 – 0.494 x (7980 – 0) –54.9 = - 262 psi

$4.P_f.M.N.y_f\rho_m$ = 4 x 3735 x 0.8613 x 0.959 x 549 x 0.494 = 3,346,747 psi ^{2}

Psurface= ½[-262+ (-262 ^{2} + 3,346,747)$^{0.5}$] = 793 psi = Internal Pressure at surface

At Shoe X= 2200 ft

M =1

Assume Z_{shoe} = Zb =1 (gas compressibility factors at shoe and bottom hole)

$$Ns = \frac{\text{Tshoe}}{\text{T bottom hole}} = \frac{(60 + 0.01 \text{x} 2200) + 460}{(60 + 0.01 \text{x} 7980) + 460} = 0.904$$

$A = 3735 - 0.494 \times (7980 - 2200) - 54.9 = 825$ psi

$4.P_f.M.N.y_f.\rho_m = 4 \times 3735 \times 1 \times 0.904 \times 549 \times 0.494 = 3{,}662{,}843 \text{ psi}^2$

$P_{shoe} = \frac{1}{2}[825 + (825^2 + 3{,}662{,}843)^{0.5}]$

= 1455 psi = Internal Pressure at casing shoe

Summary of Kick Tolerance Calculations

Surface pressure for a 150 bbl kick = 793 psi, and

The gas kick pressure at the 20" shoe =1455 psi

Fracture pressure at the 20" shoe = 1716 psi

Therefore the formation will not break down if a kick of 150 bbls is taken.

Effective burst pressure at the surface = 793 psi

Effective burst pressure at the 20" shoe = 1455 - 0.465 x 2200 = 432 psi

(iv) Pressure Testing

The 20" casing should be tested to a pressure above the maximum anticipated surface pressure of 793 psi from a 150 bbl gas kick. The test pressure must also confirm the competence of the casing, but must be below 80% of the burst strength. The casing will therefore be tested to 1500 psi.

Pressure at casing shoe = Test pressure + MW x shoe depth - Back-up gradient

= 1500 + 9 x 0.052 x 2200 - 0.465 x 2200 = 1506 psi

The 1500 psi will be used as the maximum burst pressure the casing will see.

(d) Casing Selection

Grade X52, 129.33# casing has the following strength properties (from API tables or by calculations using equations in **Chapter 4**).

Burst strength =2840 psi

Collapse strength=1420 psi

Yield Strength=1,978,000 lbf

Design Factors

Burst (pressure test) $= \frac{2840}{1500} = 1.9$

Collapse (lost circulation) $= \frac{1420}{1030} = 1.4$

(e) Tension

F1= Buoyant weight of casing (in 9 ppg mud) = 2200 x 129.33 x 0.862 = 245,261 lbf

F2= Shock load =1500 x 129.33 =193,955 lbf

F3= Bending force = 63 casing weight x OD x DLS = 63x129.33x20 x1 = 162,955 lbf

F4= Pressure test force $= \frac{\pi}{4}(\text{casing ID})^2 \times \text{test pressure}$

$= \frac{\pi}{4}(18.75)^2 \times 1500$ = 414,175 lbf

A summary of the interaction of the above forces is shown in the following table:

	Running conditions	Pressure Testing Conditions	Static Conditions
F1 : Buoyant Weight	245,261	245,261	245,261
F2 : Shock Load	193,955	0	0
F3 : Bending Force	162,955	162,955	162,955
F4 : Pressure Testing Force	0	414,175	0
Total Force (F_t) (lbf)	602,171	1,016,346	408,216
Casing Yield Strength	1,978,000	1,978,000	1,978,000
Design Factor = Yield/Ft	3.3	1.7	4.8
Required safety factor	1.6	1.6	1.6

Therefore, grade X52, 129.33# satisfy the burst, collapse and tension criteria.

Example 5: Production Casing HPHT

Details of this example are given in **Chapter 15**: HPHT wells.

11.0 TRIAXIAL ANALYSIS

In the previous sections, pressure and axial loads were treated separately in what is termed as uniaxial approach. In practice, pressure loads and axial stresses exist simultaneously. For example, in a casing string subjected to collapsing load, the stresses within the string will depend on the magnitude of the external pressure causing the collapse load as well as on the resisting internal pressure and the axial load at the point of interest.

The axial force, external and internal pressure generate triaxial stresses within the casing body. These triaxial stresses are more representative of the loading at any point as they consider the effects of all applied stresses at that point. In other words, tension is not considered separately from burst or collapse. The three generated triaxial stresses are: axial, radial and tangential.

To perform triaxial analysis, the axial, radial and tangential stresses need to be calculated at each point of interest, e.g. at surface, top of cement and shoe. These stresses will also need to be calculated at both the internal and the external radii of the casing at critical points.

11.1 Points of Interest For Triaxial Checks

The following points should be checked:

- At surface
- At top of cement
- At change in casing weight, grade, ID, or OD (ie in combination strings)
- At change in external pressure
- At changes in hole geometry: dogleg severity, washouts etc.

11.2 Conditions for Carrying Out Triaxial Checks

- Pore pressure is greater than 12000 psi
- Bottom hole temperature is greater than 250 °F
- For all HPHT intermediate and production casing strings
- H_2S service
- For casing with OD/t ratio less than 15

11.3 Radial And Tangential Stresses

The presence of fluids inside and outside the casing generate radial and tangential stresses which are given by:

$$\sigma_r = \frac{d_i^2 P_i - d_e^2 P_e}{d_e^2 - d_i^2} - \frac{d_i^2 d_e^2 (P_i - P_e)}{(d_e^2 - d_i^2) r^2} \qquad (5.33)$$

$$\sigma_t = \frac{d_i^2 P_i - d_e^2 P_e}{d_e^2 - d_i^2} + \frac{d_i^2 d_e^2 (P_i - P_e)}{(d_e^2 - d_i^2) r^2} \qquad (5.34)$$

where

r = distance at which σ_r and σ_t are measured.

P_i = Internal pressure, psi

P_e = external pressure

d_i and d_e = internal and external diameter respectively

The magnitude of the radial and tangential stresses depend on the magnitude of external and internal pressures and on the distance r.

11.4 Axial Stress

The effective axial stress is given by:

σ_a = (air weight / casing cross-sectional area) – buoyancy force …….psi (5.35)

11.5 Von Mises Equivalent Stress

The Von Mises (VM) distortion energy theory is used to predict the onset of yielding in ductile materials such as casing. The axial, radial and tangential stresses can be combined into an equivalent triaxial stress (σ_{VM}) acting at a particular point, given by:

$$\sigma_{VM} = \frac{1}{\sqrt{2}}\left[(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a)^2\right]^{0.5} \tag{5.36}$$

The yield criterion is satisfied when the combined VM stress is equal to the material yield stress (YP).In the absence of bending forces, the maximum VM stresses occur at the inner radius, r= di. With bending, the maximum stresses can occur at the inside or outside diameter of the casing.

The calculated VM stress is then compared with the yield strength of the casing and a design factor > 1.25 should be obtained:

$$DF = \frac{\text{Material Yield Stress}}{\sigma_{VM}}$$

11.6 PROCEDURE FOR TRIAXIAL ANALYSIS

1. At a given depth, say at surface, calculate at the inner and outer radii of the casing the three stresses (σ_a, σ_r,σ_t)

$$\sigma_a = \text{axial stress} = \frac{Tensile \quad forces}{cross \quad - \sec \quad tional \quad area}$$

$$\sigma_a = \frac{\text{air weight lb}}{A_s\left(\text{in}^2\right)} - \text{buoyancy force (psi)} \tag{5.37}$$

σ_r,σ_t are given by equations (5.33) and (5.34).

2. Calculate

$$\sigma_{VM} = \frac{1}{\sqrt{2}}\left[(\sigma_a - \sigma_r)^2 + (\sigma_r - \sigma_t)^2 + (\sigma_t - \sigma_a)^2\right]^{0.5}$$

3. Compare σ_{VM} with YP

$$DF = \frac{YP}{\sigma_{VM}} \cong 1.25$$

(Notes: 1. For σ_a , we must add bending and shock loading for running conditions

2. Add bending force for static conditions)

Example 5.6: Example

Carry out a triaxial stress check on the following casing string:

Casing OD = 7" casing

ID = 6.094 "

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As = 9.3173 in^2

Weight = 32 #

Formation pressure = 12231 psi

Setting Depth = 15880 ft

Gas Gradient = 0.184 psi/ft

Cement Density = 16 ppg from 12,915 ft to 15,880 ft.

Mud weight inside casing and at TOC = 15.6 ppg

Solution

Investigate the case of gas to surface

This case could occur after a new section of hole is drilled when a kick is taken from just underneath the casing shoe.

Formation pressure at TD (Pf) = 12231 psi at 15 880 ft

Surface pressure = 12331 – 0.184 x 15880 = 9309 psi

At surface, internal pressure = 9309 psi, external pressure = 0

Evaluate radial and tangential stresses at r = *di*

$$\sigma_r = \frac{6.094^2 x 9309 - 0}{7^2 - 6.094^2} - \frac{6.094^2 x 7^2 (9309 - 0)}{(7^2 - 6.094^2) 6.094^2} = -9309 \text{ psi}$$

$$\sigma_t = \frac{6.094^2 x 9309 - 0}{7^2 - 6.094^2} + \frac{6^2 x 7^2 x (9309 - 0)}{(7^2 - 6.094^2) x 6.094^2} = 67{,}591 \text{ psi}$$

Axial Stress

σ_a = (air weight / casing cross-sectional area) – buoyancy force …….psi

= [32x 15880/ 9.3173] – [16x 0.052x(15880-12915) + 0.052x12915x15.6]

= 54,539- 12,943 = 41,596 psi

$$\sigma_{VM} = \frac{1}{\sqrt{2}}\left[(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a)^2\right]^{0.5}$$

$$\sigma_{VM} = \frac{1}{\sqrt{2}}\left[(41{,}596 - 67{,}591)^2 + (67{,}591 + 9309)^2 + (-9309 - 41{,}596)^2\right]^{0.5} = 67{,}922 \text{ psi}$$

$$DF = \frac{\text{Material Yield Stress}}{\sigma_{VM}}$$

= 110,000 / 67,922 = 1.6

The above analysis can be repeated at r = de at surface and for other critical points along the casing string such as top of cement or shoe. These calculations are left as an exercise for the reader.

The above calculations can also be repeated for the case of a limited gas kick of say 50 bbl.

11.7 BENDING FORCES

In the presence of bending and buckling forces, the axial stress equation should be modified to allow for these forces. The axial stress then becomes:

$$\sigma_a = (\text{air weight / casing cross-sectional area}) - \text{buoyancy force} \pm \sigma_b \pm \sigma_{buckling} \quad (5.38)$$

Both σ_b and $\sigma_{buckling}$ are local stresses and should be calculated and applied at the point of interest, ie at a washout. These stresses should not be applied over the length of the casing string.

In the absence of bending, the peak σ_{VM} occurs always at the ID. In the presence of bending, the peak σ_{VM} can occur on the inside or outside of the casing. As bending causes compression on the inside of the casing and tension on the outside of the casing, four calculations are required in the presence of bending. Two at the inside diameter for minimum σ_a (axial stress less compression) and maximum σ_a (axial stress plus bending). Similarly, two calculations are required for the OD of the casing.

12.0 Triaxial Load Capacity Diagram

The triaxial load capacity diagram is a 2-D representation of the triaxial load capacity of the pipe body, the API load capacity lines and the expected loading modes. The diagram is a representation of the Von Mises stress intensity of the pipe body, represented in the form of axial force against internal or external pressure.

The triaxial load diagram provides on one a page a pictorial view of how close the pipe stresses are to the design limits.

Recall from **Chapter 4** that collapse failures for OD/t ratios >15 occur mostly from elastic-plastic instability and not due to yield on the ID of the casing. The triaxial load diagram (and ellipse of elasticity) is only applicable for casing OD/t ratios ≤ 15. The diagram provides a picture of the triaxial stress operating ellipse.

The triaxial load capacity diagram can be constructed as follows:

1. Establish the API load capacity lines
2. Establish the stress ellipse
3. Establish service loads and plot inside the stress ellipse

12.1 API Load Capacity Lines

These lines are the collapse strength, burst strength and yield strength of the pipe body adjusted by a suitable design factor. The area bounded by these lines is the API operating window.

Construction

1. On a pressure/force graph, mark the upper half of the ordinate as positive and the lower half as negative, see **Figure 5.10**.
2. Repeat step 1 for the x-axis (F-axis).
3. Plot axial design rating lines using:

   F = ±(Yield strength/ design factor) x cross-sectional area
4. Plot an effective burst line on the ordinate using the value: burst strength/design factor
5. Plot an effective collapse line on the ordinate using: collapse strength/design factor
6. Check **Chapter 4** for correcting collapse strength for biaxial effects. Then plot the new collapse values under tension, shown as the dotted line, **Figure 5.11**.
7. For a given loading condition, plot the effective pressure and effective axial force at surface. Plot a second point for the top of cement. Plot a third point representing the shoe,**Figure 5.10**.
8. For a safe design, the line joining the points above should be inside the rectangle,**Figure 5.10**.

Example 5.7: Triaxial design

Using the data in **Example 5.6**, trace a triaxial diagram and the points representing gas to surface.

Solution

F= (± 110 /1.6) x area

= (± 110 /1.6) x 9.3173 = ± 640.564 kips

Effective burst strength = 12,458/ 1.1 = 11, 325 psi = 11.325 ksi

Effective collapse strength = 10,760 / 1= 10.76 ksi

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The above lines are plotted as shown in **Figure 5.10**.

Service load

A service load line is constructed using data from biaxial analysis for internal and external pressures and axial load. Usually three points are required for each service line: surface, top of cement and at shoe. Other critical points may be selected.

The line representing gas to surface is obtained as follows:

Point 1 at Surface:

Psurface = internal pressure – external pressure = 9309 – 0 = 9.309 ksi

Effective tension = (air weight) x buoyancy factor

= (32x 15880) x 0.7615 = 386.95 kips

Point 2: At top of cement at 12915 ft

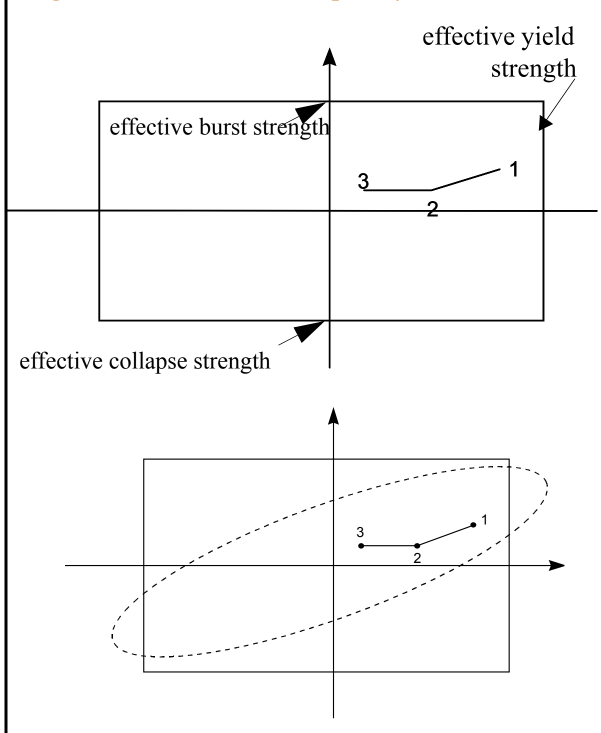
Effective pressure = 12231 – (15880 – 12915) x 0.184 - 12915x 0.465

= 5680 psi = 5.68 ksi

Effective tension = (air weight) x buoyancy factor

= [32x (15880-12915)] x 0.7615 = 72.25 kips

Figure 5.10 API load capacity lines



Point 3: at shoe

Peffective= 12231 – *0.465x 15,880* = 4.85 ksi

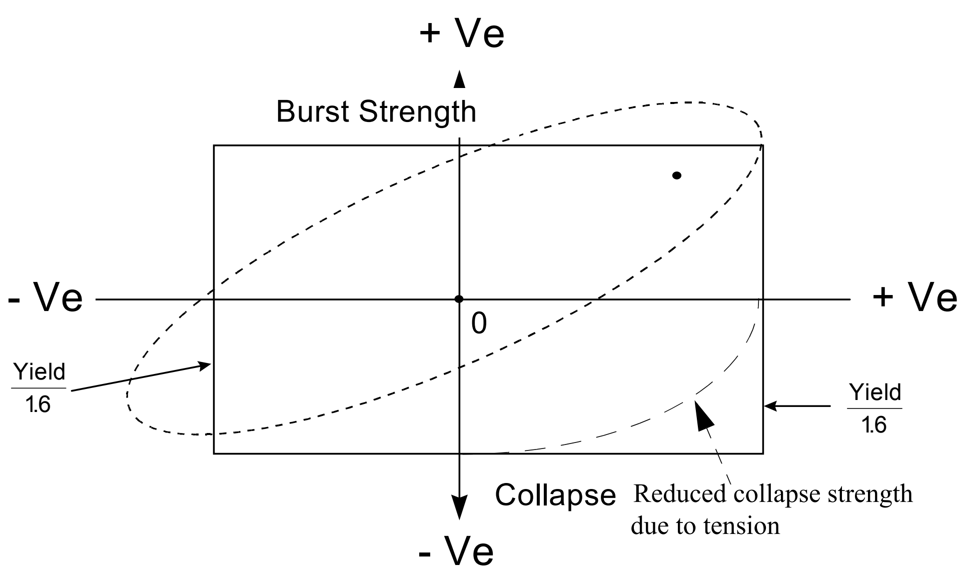
Buoyancy Force = (total air weight – buoyant weight)

$$= 32x\ 15{,}880 - 386{,}950 = 121{,}210 \text{ lbf} = 121.21 \text{ kips}$$

This force is compressive ie = - 121.21 kips

The three points are plotted as shown in **Figure 5.10**. The line joining these points lie within the rectangle indicating the casing is being operated well within the specified safety limits.

Figure 5.11 Ellipse of elasticity with API load lines



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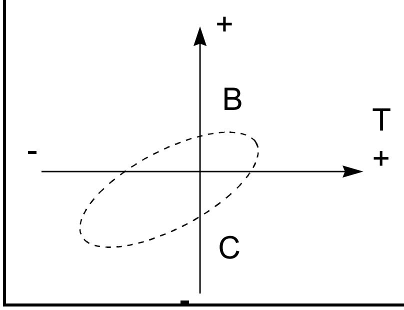
12.2 STRESS ELLIPSE

The VM stress ellipse represents the stress level in the pipe body in terms of axial stress, internal pressure and external pressure.

The construction API ellipse for pipe body is shown below, Figure 5.12.

Figure 5.12 Stress ellipse for pipe body



12.3 ELLIPSE CONSTRUCTION

From Von Mises Equation [2]

$$Y^2 = \sigma_{VM}{}^2 = \frac{1}{2}\left[(\sigma_a - \sigma_r)^2 + (\sigma_r - \sigma_\theta)^2 + (\sigma_\theta - \sigma_a)^2\right]$$

Simplifying

$$\sigma_a{}^2 + \sigma_a\left(C_1 P_i + C_2 P_e\right) + C_3 P_i^2 + C_4 P_e{}^2 + C_5 P_i P_e - Y^2 = 0 \qquad (5.40)$$

In Excel Sheet, calculate:

$$C_1 = 1 - K, \qquad K = \frac{de^2 + di^2}{de^2 - di^2} \qquad (5.41)$$

$$C_2 = 1 + K$$
$$C_3 = K^2 + K + 1$$
$$C_4 = (K + 1)^2$$
$$C_5 = -2K - 1$$

The ellipse has two parts. Solving the above quadratic equation for each half of the ellipse gives a total of four roots.

a. Upper Part

The upper part is constructed by setting the external pressure to zero and the σ_{VM} to the material yield strength. Using internal pressures, for any value of internal pressure, the axial stress is given by:

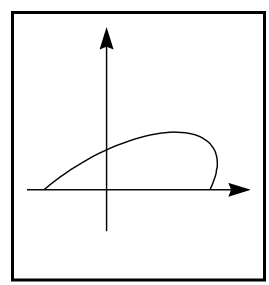
$$\sigma_a = \left[-0.5\,C_1\,P_i \pm 0.5\sqrt{(C_1\,P_i)^2 - 4\left(C_3\,P_i^2 - Y^2\right)}\right] \tag{5.42}$$

Above quadratic equation has +Ve and -Ve roots.

Calculate as follows:

P_i (psi)	$[\sigma_a\,(+\mathrm{Ve})\times A_s]$ lbf	$[\sigma_a\,(-\mathrm{Ve})\times A_s]$ lbf
0		
500		
1000		
1500		
2000		
….		

And then plot upper half of ellipse



b. Lower Part of ellipse

The lower part is constructed by setting the internal pressure to zero and the σ_{VM} to the material yield strength. Hence for any value of external pressure, the axial stress is given by:

$$\sigma_a = \left[-0.5\,C_2\,P_e \pm 0.5\sqrt{(C_2\,P_e)^2 - 4\left(C_4\,P_e^2 - Y^2\right)}\right] \tag{5.43}$$

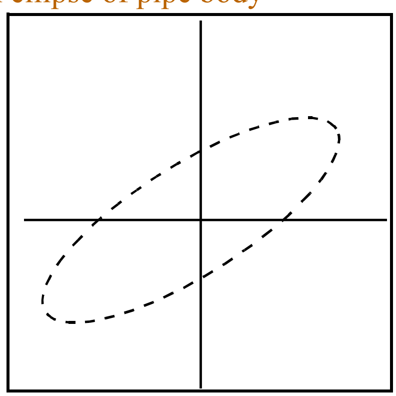
Above equation has +Ve and -Ve roots

Calculate as follows:

P_e (psi)	$\left[\sigma_a (+Ve) \times A_s\right]$ lbf	$\left[\sigma_a (-Ve) \times A_s\right]$ lbf
0		
- 500		
- 1000 - 1500 . .		

And then plot lower half of ellipse

c. The two halves will form an ellipse of pipe body



13.0 LEARNING MILESTONES

In this chapter, you should have learnt to:

1. .List the major steps in the casing design process
2. Name the three types of Load Cases used in Detailed Casing Design
3. Understand the use of design factors
4. Carry out design for burst & collapse loads for both drilling and production casings
5. .Carry out Tensile (Installation) calculations
6. Carry out detailed casing design calculation for a complete casing string
7. Calculate triaxial stresses

14.0 REFERENCES

1. Rabia H (1987) "Fundamentals of Casing Design". Kluwer Group

2. Klementich, E f and Jellison, MJ (1986). A service model for casing strings. SPE Drilling Engineering, April, pp 141-151

15.0 EXERCISES

1. List the major steps in the casing design process
2. List the three major forces in casing design:
3. Shock loading is most influenced by:
    - Hole angle
    - Casing weight
    - Pipe OD

4. When designing casing across salt sections, the effective collapse loading is calculated using:

   - External mud pressure
   - External and internal mud pressure
   - 1 psi/ft external pressure and internal pressure due to mud
   - highest casing available on the market (MUST CASING)

5. The casing sees the maximum surface pressure when:

   - Casing is full of gas and the well is then shut-in
   - When a large kick is detected but the casing is immediately shut-in
   - When an underground blowout occurs
   - 80% burst strength

6. What determines the casing test pressure

6

Cementing

Content

1.0 Functions of Cement

In an oil/ gas well, the primary functions of cement are:

1. Provide zonal isolation
2. Support axial load of casing strings
3. Provide casing support and protection against corrosive fluids
4. Support the borehole

2.0 Cement And Cementing Additives

Cement is made from calcareous and argillaceous rocks such as limestone, clay and shale and any other material containing g a high percentage of calcium carbonate. The dry material is finely ground and mixed thoroughly in the correct proportions.The chemical composition is determined and adjusted if necessary. This mix is called the kiln feed.

The kiln feed is then heated to temperatures around 2600-2800 °F (1427-1538 °C). The resulting material is called clinker. the clinker is then cooled, ground and mixed with a controlled amount of gypsum and other products to form a new product called Portland cement. Gypsum ($CaSO_4 . 2H_2O$) is added to control the setting and hardening properties of the cement slurry.Cement slurry is the mixture produced when dry cement is mixed with water.

Oil well cement is manufactured to API Specification 10 and is divided into 8 classes (A-H) depending upon its properties. Class G and H are basic well cements which can be used with accelerators and retarders to cover a wide range of depths and temperatures. The principal difference between these two classes is that Class H is significantly coarser than Class G.

Additional chemicals are used to control slurry density, rheology, and fluid loss, or to provide more specialised slurry properties.

Additives modify the behaviour of the cement slurry allowing cement placement under a wide range of downhole conditions. Over 100 additives for cement are available and these can be classified under one of the following categories:

Accelerators: chemicals which reduce the thickening time of a slurry and increase the rate of early strength development.

Retarders: chemicals which extend the thickening time of a slurry to aid cement placement.

Extenders: materials which lower the slurry density and increase the yield.

Weighting Agents: materials which increase slurry density.

Dispersants: chemicals which lower the slurry viscosity and may also increase free water.

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Fluid-Loss Additives: materials which prevent slurry dehydration and reduce fluid loss to the formation.

Lost Circulation Control Agents: materials which control the loss of cement slurry to weak or fractured formations.

Miscellaneous Agents: e.g. Anti-foam agents, fibres, latex.

Cement tests are always performed on representative samples of cement, additives and mix water as supplied from the rig.

3.0 Slurry Testing

3.1 Thickening Time

Thickening time tests are designed to determine the length of time which a cement slurry remains in a pumpable state under simulated wellbore conditions of temperature and pressure. The pumpability, or consistency, is measured in Bearden Consistency units (Bc); each unit being equivalent to the spring deflection observed with 2080 gm-cm of torque when using the weight-loaded type calibration device. The measure takes no account of the effect of fluid loss. Thus, thickening times in the wellbore may be reduced if little, or no, fluid loss control is specified in the slurry design.

Results should quote the time to reach 70 Bc - generally considered to be the maximum pumpable consistency.

3.2 Free Water and Sedimentation

The separation of water from a slurry, once it has been placed, can lead to channel formation and gas migration problems - particularly in deviated wells. The free-water test is designed to simulate this using a 250 ml graduated cylinder in which slurry is left to stand for two hours under simulated wellbore conditions. The volume of water collected after this period is expressed as a percentage by volume.

For deviated wellbores, a more critical test is to incline the column at 45 degrees. However, care should be exercised with the results from inclined tests as the migration path for the water is significantly reduced and thus the free water measured will increase. Downhole, this may not be the case due to the presence of the casing string.

The reporting of free-water should be as a percentage. When 'traces' are reported, definition of this term should be sought. For liners and in wells where gas may be present, a zero free-water slurry should be used.

The amount of sedimentation of the slurry should also be reported by measurement of the variation of density over a sectioned column of set cement.

3.3 Fluid-Loss

Fluid-loss tests are designed to measure the slurry dehydration during, and immediately after cement placement. Under simulated wellbore conditions, the slurry is tested for filtrate loss across a standardised filter press at differential pressures of 100 psi or 1000 psi. The test duration is 30 minutes and results are quoted as ml/30 min.

3.4 Compressive Strength

The measurement of the uniaxial compressive strength of two-inch cubes of cement provides an indication of the strength development of the cement at downhole conditions. The slurry samples are cured for 8, 12, 16 and 24 hours at bottom-hole temperatures and pressures and the results reported in psi. Dynamic measurements using ultrasonic techniques correlate well with API test results, but can lead to over-estimation of the strength.

3.5 Rheology

Ensuring that the rheological behaviour of the slurry downhole is similar to that specified in the design is essential for effective cement placement. The slurry viscosity is measured using a rotational viscometer, such as a Fann. The slurry sample should be conditioned for 20 minutes in an atmospheric consistometer before measurements are taken.

Readings should be taken at ambient conditions and at BHCT when possible. Measurements should be limited to a maximum speed of 300 rpm (shear rate 511 $^{1}/s$). Readings should also be reported at 200, 100, 60, 30, 6 and 3 rpm.

4.0 CEMENT EXCESS

The following excess cement volumes are usually applied to the calculated theoretical open hole and casing annulus volumes.

Interval	Calliper	Suggested Cement Volume
CONDUCTOR	None	200% Excess over gauge hole
SURFACE CASING	No Calliper Survey	100% Excess over gauge hole
	4-arm Calliper run	Integrated volume + 20%
INTERMEDIATE CASING	No Calliper Survey	50% Excess over gauge hole *
	4-arm Calliper run	Integrated volume + 10% *
PRODUCTION CASING	No Calliper Survey	50% Excess over gauge hole
	4-arm Calliper run	Integrated volume + 10%
LINER	No Calliper Survey	20% Excess over gauge hole
	4-arm Calliper run	Integrated volume + 10%

* **Note:** Care should be taken to ensure cement does not reach the subsea wellhead or mudline.Volumes pumped may be adjusted to plan the top of cement at 500 ft below seabed.

5.0 CASING AND CEMENTING HARDWARE

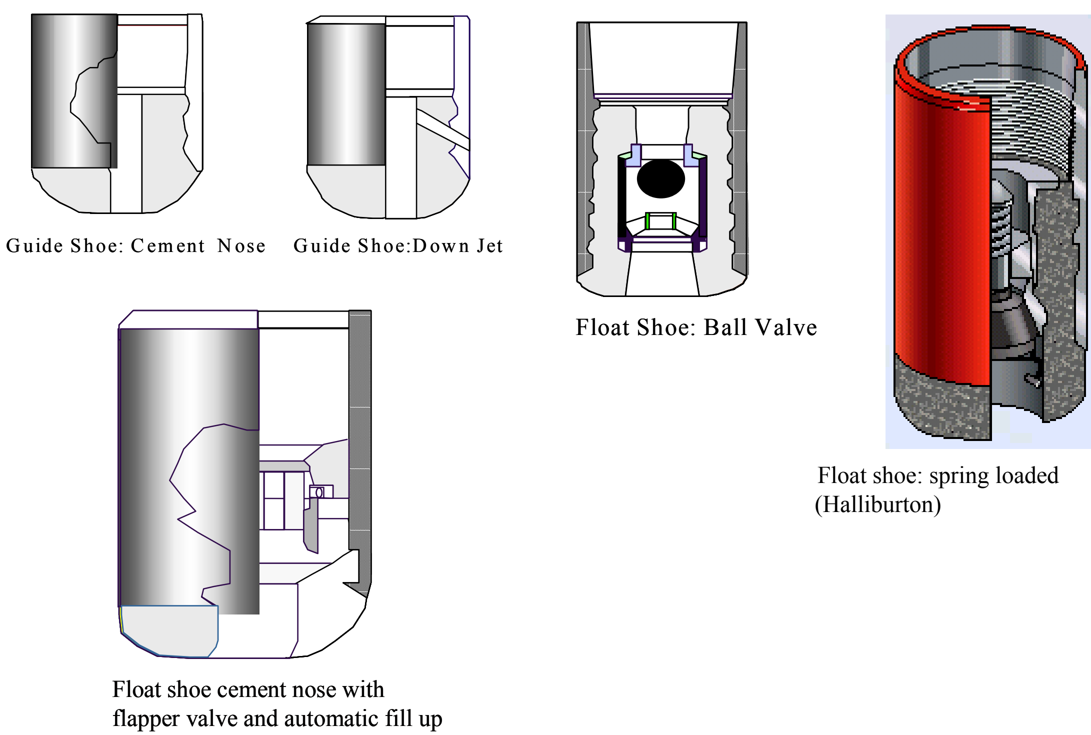
Some or all of the following equipment is used during cementing operations.

1. Guide shoes

A guide shoe is used to guide the casing through the hole, avoiding jamming the casing in washed-out zones, or in deviated wells. It can be a simple guide or may contain a ball valve or flapper valve, **Figure 6.1**. When a guide shoe contains a valve element it is described as a float shoe. A float shoe prevents cement from flowing back into the casing once the cement is displaced behind the casing. Shoes have either inner parts made of aluminium or cement; both being easily drillable, with the advantage that cement is more resistant to impact.

Float shoes have all the advantages of the guide shoes, plus the float valve to avoid back flow and provide casing buoyancy. The main disadvantage of a float shoe is the extra time it takes to run casing in hole (RIH); with casing running operations temporarily stopped to fill the casing from the top. By using an orifice fill shoe (automatic fill-up shoe), RIH time can be reduced as the casing is filled up while running in hole, see bottom illustration in **Figure 6.1**. Once the casing reaches TD, the float valve can be activated by dropping a ball from surface and pressuring on it to remove an insert and activate the valve, **Figure 6.1**.

Figure 6.1 Types of casing shoes



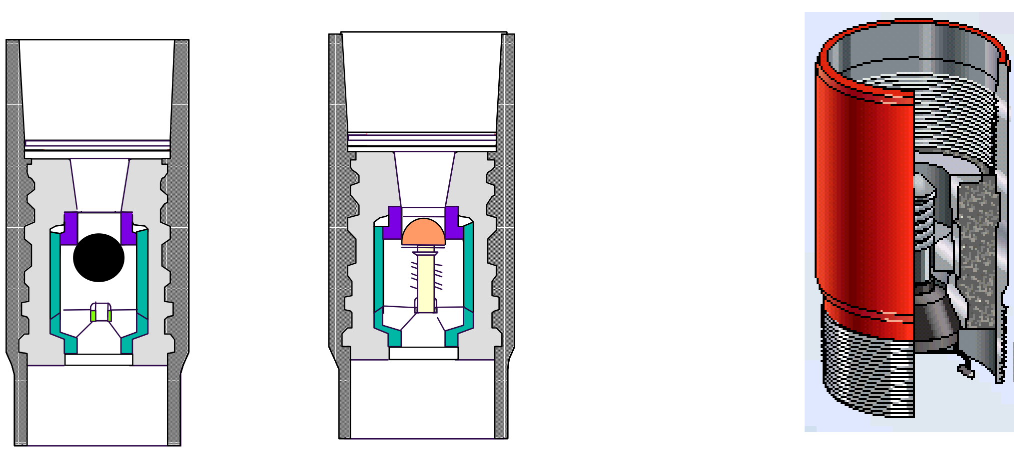
2. Float Collars

A float collar is a one way valve placed at one or two joints above the shoe. The float collar provides the same functions as a float shoe by preventing fluid back flow into the casing: mud backflow during running in hole and cement slurry backflow after cement displacement.

The distance between the shoe and float collar is called Shoe Track.

The float valve can either be a ball type or a flapper, **Figure 6.2**. Flapper type valves are normally used where a small hydrostatic pressure difference is expected, providing a better seal than a ball type valve.

Figure 6.2 Float Collars, Courtesy of Weatherford (left & middle) and Halliburton (right)

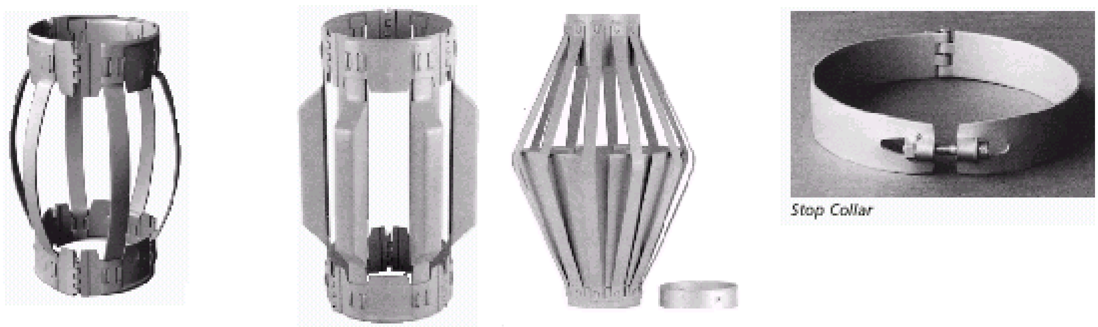


Float collar - Ball Valve   Float collar - Sure Seal   Float collar: Super Seal

3. Baskets and Centralisers

These are used to centralise the casing within the hole to improve the cementing process, **Figure 6.3**.

Figure 6.3 Types of Centralisers, Courtesy of Davis Lynch



a. Non-welded centraliser with bow springs   b. Rigid centraliser   c. Cement basket

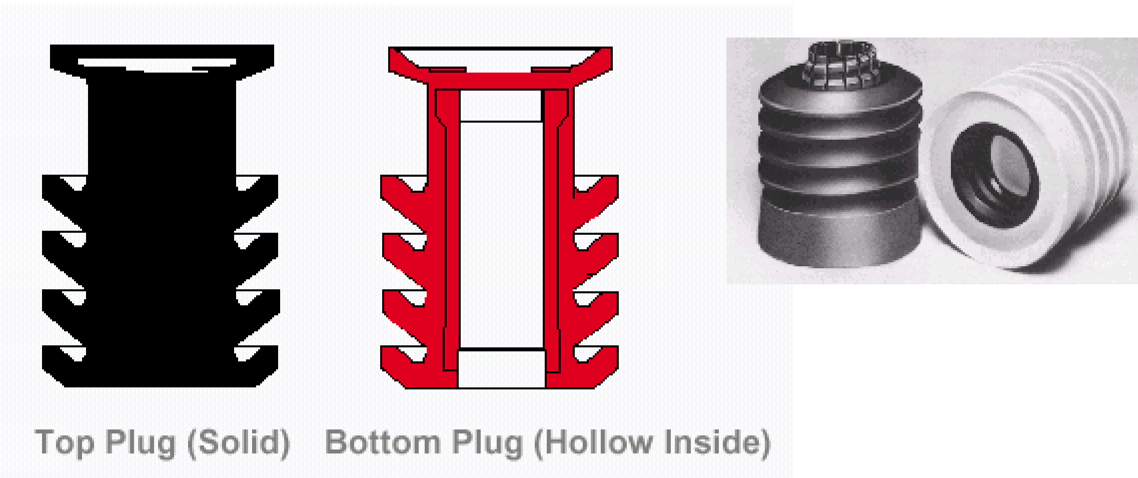
4. Cement Plugs

The main functions of cement plugs are, **Figure 6.4**:

- Separate mud from cement
- Wipe the casing from mud before cement is pumped and then wipe casing from th cement film after the complete volume of cement is pumped.
- Prevent over-displacement of cement
- Give surface indication that cement placement is complete
- Allow the casing to be pressure tested

In effect, the cement plugs act as barriers between mud and cement providing physical separation between the two fluids. Bad cement jobs, especially around the casing shoe, result from cement contaminated with mud.

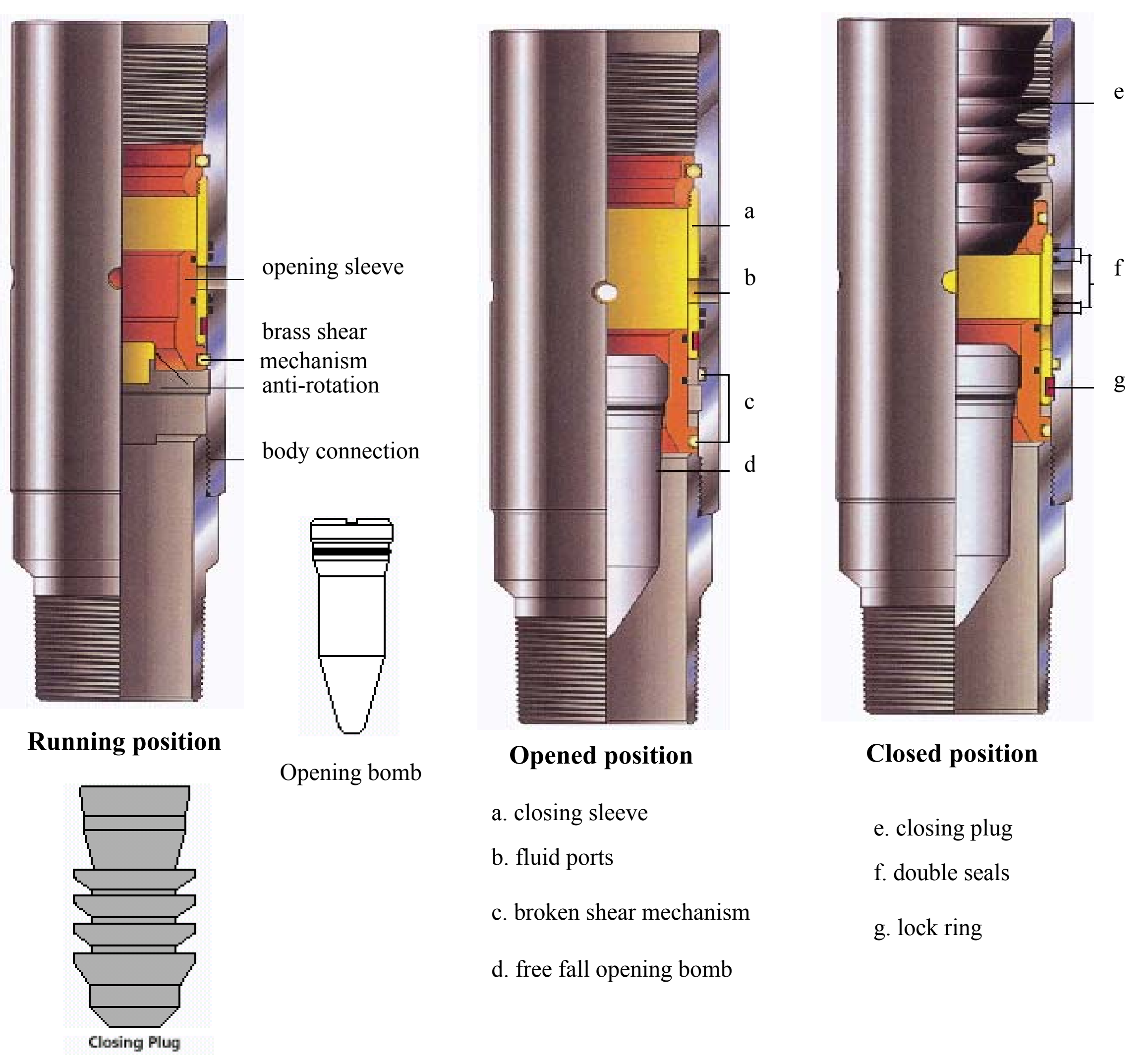
Figure 6.4 Top & Bottom Plugs, Courtesy of Weatherford (left & centre), Davis (right)



6. Multi-Stage Collar

A multi-stage collar (or DV tool) is used to allow the casing to be cemented in two stages to prevent weak formations being subjected to excessive hydrostatic pressure of long cement columns.The tool is actually a small section of casing with the same strength properties as the remaining string. The tool has two internal sleeves and openings which are covered by the lower sleeve,Figure 6.5. The lower sleeve is opened by dropping a bomb which pushes the sleeve down and uncovers the holes. This allows the cement to be pumped through the casing and the holes in the stage collar and placed around the casing. When the required volume of cement is pumped, the holes are closed by dropping a closing plug which pushes an upper sleeve downward to cover the holes in the stage collar.

Figure 6.5 Stage Collar (DV Tool), Courtesy of Davis Lynch



Multi-stage cementing is used to:

- reduce total pumping pressure or pumping time
- reduce total hydrostatic pressure of cement on weak formations or on casing
- allow selective cementing of formations within the open hole

- allow entire length of casing to be cemented

The position of the stage cementer is dictated by the total length of the cement column and the strength of the formations in the open hole.

6.0 Cementing Mechanics

6.1 Conditioning the Drilling Mud

The viscosity of the mud should be reduced to the lowest practical level before the drillpipe is removed from the hole. Effort should be directed at reducing the low shear-rate rheology of the mud (i.e. gel strengths and yield points). However, care must be taken not to reduce the mud rheology below the minimum level required to suspend the weighting agent such as barite.

Once the casing has been run, the mud should be further conditioned to remove gelled mud which will have formed beneath the casing in areas of poor centralisation. Two to three hole volumes are normally considered sufficient conditioning - however, this is highly dependent upon the viscosity of the mud in the hole and the casing centralisation.

If it has not been possible to reduce the mud viscosity to the levels recommended above and casing centralisation is poor, extended conditioning may be required. After conditioning the hole, cementing should start without any break in circulation.

6.2 Centralisation

Good centralisation (**Figure 6.3**) is the most important factor in achieving efficient mud displacement and cement placement. The best possible casing centralisation should be obtained by running a centralisation program.

A minimum standoff of 70% is a good rule-of-thumb to allow unhindered circulation beneath the casing, when the mud rheology and displacement rates have been optimised. Centralisers should be fastened to allow pipe reciprocation, or rotation, in strings where casing movement is to be employed.

If washouts are expected, or are known to have occurred, then the number of centraliser required should be calculated to take the increased hole size into account.

It has been demonstrated that good centralisation can reduce casing running difficulties by helping to prevent differential sticking.

6.3 Casing Movement

Whenever possible the casing should be reciprocated or rotated. Numerous laboratory and field studies have shown that pipe movement increases displacement efficiency by helping to break-up gelled pockets of mud. Movement should be attempted for all stages of the cementing operation - from hole conditioning to displacement. There is still a debate as whether casing reciprocation or casing movement provide the best displacement aid. However, rotation does require special equipment. For liners, rotation is recommended - due to concerns over setting the liner and the increased danger of swabbing gas during the upstroke of reciprocation.

From field experiences the following rules-of-thumb are suggested:

- reciprocate 20-40 ft strokes over a period of 2-5 minutes
- rotation rates of 10-40 rpm.

6.4 Washes and Spacers

Optimal mud removal will be obtained by the use of a simple wash, as this type of fluid will achieve turbulence around the complete annulus at relatively low annular velocities. However, well control considerations may dictate the use of a weighted spacer. In such cases, the use of a thin wash pumped in combination with a weighted spacer may provide good mud removal. When a turbulent wash, or spacer, is used a minimum contact time of 10 minutes must be achieved. This contact time should take account of the effects of U-tubing. Any spacer designed for turbulent flow must be sufficiently viscous to suspend the weighting agent.

If turbulence across the complete annulus cannot be achieved, weighted spacers in laminar flow can provide effective mud displacement. However, the physics of such displacements are complex and the density, viscosity and annular flow rate must be carefully designed -

taking into account the properties of the mud and cement slurry. For laminar displacements, the ideal volume of spacer required can not be predicted and minimum quoted volumes range from 300-1000 ft of annular fill. It is important to use a volume of spacer sufficient to ensure separation of the mud and cement when intermixing of the three fluids is taken into account.

6.5 Displacement Rate

Displacement rates should be maximised to obtain the most effective cement placement. Limiting displacement rates to those necessary to achieve turbulence is not sufficient, due to the inadequacies of estimating the onset of turbulence and the variable casing eccentricity. A useful guideline is to ensure that the annular velocity (assuming concentric casing) is above 260 ft/min.

6.6 Bumping The Plug

The bottom plug (**Figure 6.4**) is first released and is followed by cement. When the bottom plug lands on the float collar a pressure increase on surface is indicated. A small increase in pressure will rupture the bottom plug and allow cement to flow through it, through float collar, shoe track, casing shoe and then around the casing.

Figure 6.6 Plugs in Hole [1]

The top plug is released from surface immediately after the total volume of cement is pumped. The top plug is displaced by the drilling fluid and it, in turn, pushes the cement slurry into the annulus. When the top plug lands on the bottom plug a pressure increase is observed at surface. This is called bumping the plug.Bumping indicates that the total volume of cement is now displaced behind the casing.

Usually, at this time, the casing is pressure tested to a pre-calculated design value (See **Chapter 5**) to check its integrity. Pressure testing casing while the cement is still wet is recommended as this reduces the chances of breaking the set cement or creating micro-channels if the test is carried out a few hours later when the cement sets. **Figure 6.6** shows the plugs arrangement prior to being drilled out.

The following are guidelines on cement displacement and plug bumping:

- Displacement of the plug should be slowed when within 10% of the required strokes to bump the plug to avoid the risk of shearing the relief valve or overpressuring the casing.
- For full casing strings, displacement should continue until the plug is observed to bump. If no bump is detected, the displacement should continue until the cement is circulated out of the hole and clean mud returns are observed. The operation should then be repeated.
- For liners, if no bump is observed, pump the calculated displacement volume plus 50% of the shoe track volume.
- If the plug bumps, the pressure should be increased to the test pressure as specified in the Drilling Programme and held for 15 minutes. The pressure is then released and a check made for back flow. If the floats fail to hold, the volume back flowed will be pumped and the bumping pressure held until the cement thickens.

7.0 DISPLACEMENT THEORY

7.1 INTRODUCTION

Efficient mud displacement is essential in order to achieve a good cement bond and zonal isolation. Incomplete mud removal can lead to cement channelling, allowing hydrocarbon invasion and communication between permeable zones.

7.2 THE EFFECT OF MUD RHEOLOGY

The force required to initiate movement in a mud which has been left to gel can be considerable and will increase with time. The current understanding of how best to mobilise gelled mud is poor, mainly due to the difficulties of characterising the gelation properties of

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muds. The standard 10-minute gel-strength test is unrepresentative of the complex effect of the shear-history of the mud and the prevailing downhole conditions.

Gelled mud can only be removed by applying sufficient shear stress to overcome the gelled strength of the mud. This shear stress can come from pipe movement or from the mobile mud (or other displacing fluids). In the latter case, the required shear stress is generated by frictional pressure drop. Thus, the shear stresses generated can be increased by increasing the mud flow rate, or varying the properties of the mobile fluid.

Ideally, the problem should be minimised by reducing the mud's low shear-rate viscosity and gel-strength during circulation before the casing is run. Once the hole has been circulated clean of cuttings, additional circulation can be used to condition the mud and to remove the gelled and dehydrated mud that becomes far more difficult to remove after a prolonged static period.

7.3 The Effect of Casing Eccentricity

When casing is run in a deviated well, the resulting eccentricity will trap pockets of mud against the low side of the hole resulting in cement channelling and possible incomplete zonal isolation, or gas migration problems.

Stagnant areas form due to the distorted velocity profile that occurs when the casing is eccentric. Flow will favour the wide side of the annulus possibly leading to the situation where turbulent and laminar flow exist in different areas across the annulus.

Laboratory and field experience have shown that once the stand-off falls below about 60% no practical combination of flowrate and fluid viscosity will remove the stagnant mud.The minimum stand off should be at least 70%.

To ensure that the stand-off is greater than 70% at all points along the string, a centraliser programme should be run. The programme should take into account the mechanics of the complete casing string, along with any buoyancy and density differential effects during displacement.

7.4 The Effect of Annular Velocity (Displacement Rate)

Numerous studies have shown that if the displacing fluid is in turbulent flow the displacement will be highly effective. However, in an eccentric annulus ensuring turbulence occurs at all points across the annulus is difficult. More often than not, the turbulent displacement will result in gelled mud remaining in the narrow section of the annulus.

Where turbulence for the spacer/wash can be achieved, the displacement rate should be as high as possible to achieve the best results. Where turbulent flow cannot be achieved it is still possible to achieve effective displacements by using a carefully designed laminar displacement.

7.5 The Effect of Casing Movement

Although the physics of mud removal through casing movement is complex to analyse, the beneficial effects of reciprocating and rotating casing have been shown in laboratory and field tests. Both reciprocation and rotation are beneficial, however, reciprocation suffers the following drawbacks:

(a) Induced swab and surge pressures which can lead to well control problems, especially with small annular clearances.

(b) The risk of the casing becoming stuck.

Typically casing is reciprocated between 20-40 ft over 1-5 minutes. However, the movement downhole can be reduced due to pipe stretch and buckling. Pipe rotation is commonly undertaken for liners at rates between 10-40 rpm.

8.0 Washes And Spacers

In any successful primary cementing operation the cement slurry must displace the fluid surrounding the casing. Mud and cement are often incompatible and contact between them can lead to severe channelling or the formation of an un-pumpable viscous mass. To avoid this problem an intermediate fluid is used as a pre-flush to clean the drilling mud from the annulus.

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The simplest form of pre-flush is a 'wash' - usually water, with the possible addition of a surfactant. Such a pre-flush is very effective in removing mud from the annulus as turbulence can be achieved around the complete annulus. Turbulent flow has been shown to be the most effective way of removing mud from the annulus and minimising mud/cement contamination. When analysis of the ECDs shows that an un-weighted wash will cause well control or stability problems, a weighted spacer must be used.

Spacers are difficult fluids to design. They must be compatible with both mud and cement and have the correct rheological properties to minimise mixing and channelling. Although weighted spacers can theoretically achieve turbulence, care must be exercised in assuming that turbulence will occur beneath eccentric casing, in the narrow section of the annulus. If laminar flow exists beneath the casing and turbulent flow above, channelling will result.

Spacers need to be designed specifically for each cement job. It should never be assumed that a spacer formulation that previously performed efficiently will do so in a different well. This is particularly important in the case of oil-based and pseudo oil-based muds.

8.1 Washes

Washes should only consist of water and possibly a surfactant, unless fluid loss considerations necessitate other additions.

8.2 Spacers

(a) Where a weighted spacer is to be used turbulence is the preferred flow regime. However, it should be noted that with viscous spacers, the theoretical attainment of turbulence is no guarantee of effective mud displacement due to the high probability of laminar flow occurring in the narrow low-side of the annulus.

(b) When using weighted spacers in turbulent flow, the Engineer should ensure that the ECD does not exceed the fracture gradient at the previous casing shoe. A safety margin of 1 ppg should be applied whenever possible.

(c) The use of a weighted spacer in laminar flow requires careful design by the cementing company in order to optimise the spacer density, viscosity and displacement rate.

(d) For laminar displacements the spacer should be weighted above the drilling fluid weight, but below the cement slurry - in order to minimise channelling. In horizontal wells this will not be the case and cement company advice should be followed.

9.0 Cementing Calculations

9.1 Pre-job Calculations

The following calculations are required prior to a cement job:

(a)Lead and Tail slurry volumes mix water and additive volumes

(b)Total quantity of cement

(c)Displacement volume

(d)Hydrostatic pressure for various cement positions

(e)Differential pressure at the end of cement displacement

(f) Collapse pressure at the casing shoe at the end of displacement.

(g) The expected total volume of returns during the cement job, and the expected overall increase in pit volume.

The following sections discuss and illustrate the required calculations.

The following equations are useful for carrying out cement calculations.

1. Thickening time

Thickening time = mixing time + surface time + displacement time + plug release time + safety time (6.1)

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$$\text{Mixing time } T_m = \frac{\text{Volume of dry cement}}{\text{mixing rate}} = \frac{V}{\text{sacks/min}} \qquad (6.2)$$

where V_c = volume of dry cement in sacks

2. Displacement time

$$T = \frac{\text{Amount of fluid required to displace top plug}}{\text{displacement rate}} \qquad (6.3)$$

3. Slurry density

$$\text{Slurry density} = \frac{\text{mass of dry cement + mass of mix water}}{\text{volume of cement + volume of water}} \qquad (6.4)$$

4. Cement strength

Support capability or fracture load (1b)

$$F = 0.969 \times S_c \times d \times H \qquad (6.5)$$

where S_c = compressive strength of cement (psi)

d = outside diameter of casing (in)

H = height of cement column

5. Plugging Back Operations

Volume of cement V = H x (A + C), or

$$H = \frac{V}{A + C} \qquad (6.6)$$

where H = height of cement plug, ft

A = annular capacity between drillpipe (or tubing) and open hole

C = capacity of drillpipe or tubing

9.2 VOLUMES AND SILO CAPACITY

The normal unit volume for cement is 1 sack which corresponds to 94 lbs of weight occupying a packed volume of 1 cubic foot. These are the values to be used when calculating volumes and the required weight or number of sacks of cement. Aerated cement in a silo has an average density of ± 75 lbs/cu. ft. This has important implications when determining the silo capacity for cement i.e., for neat Class G cement, aerated cement will occupy 80% of the silo capacity (A 1000 sack silo will hold 800 sacks of cement).

9.3 BLENDED CEMENTS

The most common blended cement is Class G mixed with 35% by weight of cement (BWOC) silica flour which is used in high temperature situations to prevent strength retrogression of the set cement mass. Class G mixed with 8% BWOC bentonite is sometimes employed when a lightweight slurry is required.

(a) Silica Flour Blend

Bulk density of silica flour	= 70 lbscu.ft
1 sack of cement is equivalent to 94lb	= 1 cu.ft
35% silica is equivalent to 33 lb (0.35 x 94)	= 0.47 cu.ft
Total mass = 94 (cement) + 33 (silica flour)	= 127 lbs
Total volume = 1 (cement) + 0.47 (silica flour)	= 1.47 cu. ft
Average bulk density for the blend $= \frac{127}{1.47}$	= 86.4 lb/cu.ft.

An aerated amount of the above cement will have a bulk density of 0.8 x 86.4 = 69 lb/cu.ft.

This figure can be used to determine the weight of blend that a silo can hold e.g., A 1000 cu.ft silo will hold 1000 x 69 lbs = 69,000 lb = 31.4 metric tonnes (MT).

Note: The slurry yield refers to only the cement in the blend. Therefore if from calculations, 600 sks of cement are required to give a certain yield, then the weight of silica blended cement required is 600 x 127 lb = 34.6 MT.

(b) 8% Bentonite Blend

Bulk density of bentonite = 60 lb/cu.ft

1 sack of cement is equivalent to 94 lb = 1cu.ft

8% bentonite = 7.5 lb = 0.13 cu. ft

Therefore 101.5 lb weight occupies a volume of 1.13 cu.ft

Average bulk density of the blend is 89.8 lb/cu.ft.

An aerated amount of the above cement will have a bulk density of:

$$0.8 \times 89.8 = 71.8 \text{ lb/cu.ft.}$$

9.4 Slurry Density and Yield

The density of a cement slurry is calculated by adding the weights of the separate constituents and dividing by their absolute volumes.

The density of a cement slurry is described in terms of lbm/gal. To determine the density, divide the total pounds weight by the total volume in gallons.

Table 6.1 below lists absolute volumes and specific gravities of common cementing materials.

Table 6.1 Absolute Volume and Specific Gravity of Common Materials

Material	Absolute Volume (gal/lb)	Absolute Volume (m^3/T)	Specific Gravity
Barytes	0.0278	0.231	4.25
Bentonite	0.0454	0.377	2.65
Class G	0.0382	0.317	3.14
Gilsonite	0.1123	0.935	1.06
Hematite	0.0244	0.202	4.95
Silica	0.0454	0.377	2.65
Fresh Water	0.1202	1.00	1.00

Example 6.1: Slurry Density

Calculate the slurry density of Class G cement mixed with 45% fresh water.How much water is required for mixing 100 sacks?

Solution

1 sack of Class G cement = 94 lb which occupies a volume of 3.59 gal

45% BWOC fresh water =0.45x94 =42.3 lb water which occupies a volume of 5.08 gal

Component	Weight (lb)	Volume gals
cement	94	3.59
water	42.3	5.081
Total	136.3	8.67

Slurry density = $\frac{136.3}{8.67} \cdot \frac{\text{lb}}{\text{gal}}$ = 15.72 lb/gal

The *Slurry Yield* is determined by dividing the total volume per sack of cement by the conversion factor of 7.48 gal/ft^3.

Slurry yield = $\frac{8.67}{7.48} \text{x} \frac{\frac{\text{gal}}{\text{sk}}}{\frac{\text{gal}}{\text{ft}^3}}$ = 1.159 gal/ft^3

The amount of mix water required to give a density of 15.72 lb/gal and yield of 1.159 ft^3/sk is = 100 sacks x 5.081 gal/sack = 508 gal

Example 6.2: Density & Yield Calculations

What is the density and yield of the following slurry: Class G (1 sack) + 35% silica flour plus 2% fluid loss additive (absolute volume = 0.0932 gal/lb) plus 44% water.Refer to for **Table 6.1** for details of absolute volumes.

Solution

Component	A. Weight (lb)	B. Absolute Volume (gal/lb)	Volume (A x B) (gals)
Cement	94	0.0382	3.59
Silica Flour	32.9 (=0.35x94)	0.0454	1.49
Fluid Loss Additive	1.88 (=.02x94)	0.0932	0.175
Water	41.36 (=0.44x94)	0.1202	4.97
Total	170.14		10.225

$$\text{Slurry density} = \frac{170.14}{10.225} \cdot \frac{\text{lb}}{\text{gal}} = 16.64 \text{ lb/gal}$$

$$\text{Slurry yield} = \frac{10.225}{7.48} x \frac{\frac{\text{gal}}{\text{sk}}}{\frac{\text{gal}}{\text{ft}^3}} = 1.37 \text{ ft}^3 \text{ /sack}$$

Example 6.3: Amount Of Required Water

Calculate the amount of water per sack required to provide a slurry of 13.0 ppg for a slurry consisting of Class G cement + 8% BWOC Bentonite.

Component	Weight (lb)	Absolute Volume (gal/lb)	Volume gals
Cement	94	0.0382	3.59
Bentonite	7.52	0.0454	0.341
Water	8.34 x	0.1202	x
Total	101.52 + 8.34 x		3.93 + x

$$\text{Slurry density} = 13.0 = \frac{(101.52 + 8.34X)}{(3.93 + X)} \quad \frac{\text{lb}}{\text{gal}}$$

X = volume of water =10.82 gals

Example 6.4: 13 3/8 " Casing Cement Calculations

Calculate the cement volumes for a 13 3/8" casing using the following data:

- subsea well with seabed at 450 ft below Rotary Table (BRT)
- 16" hole (not 17.5")
- Total Depth (TD) is at 6000 ft MD
- 13 3/8" shoe at 5980 ft measured depth (MD)
- 13 3/8" casing is N-80,72 lb/ft, ID = 12.347 in
- 20" shoe at 2000 ft MD
- 20" casing is K55,133 lb/ft, ID = 19.73 in
- Top Of Cement (TOC) to be 500 ft inside 20" casing shoe
- Tail slurry to extend 500 ft above the 13 3/8" shoe
- The shoe track consists of 1 joint.
- 5" rillpipe, 19.5 lb/ft is used as the running string

You are required to base cement volumes on open hole volume plus 30% excess.

Slurry details

Lead Slurry

- Class G cement + 0.3 gals/sk extender + 0.2 gals/sk retarder + 11.35 gals/sk seawater.
- Yield = 1.99 ft^3/sk
- Density = 13.0 ppg

Tail slurry

- Class G cement + 0.05 gals/sk retarder + 0.05 gals/sk dispersant + 4.8gals/sk freshwater.
- Yield = 1.13 ft^3/sk

- Density = 16.00 ppg

Solution

Refer to **Figure 6.7** for details of the well.

(a) Capacities

Capacities will be expressed in ft^3/ft.

20" casing (inside) – 13 3/8" casing (outside)= 1.9175 - 0.9757 = 0.9388 ft^3/ft

16" Hole – 13 3/8" casing (outside)= 1.3963 - 0.9757= 0.4206 ft^3/ft
16" OH = 1.3963 ft^3/ft
13 3/8" casing (inside) = 0.8314 ft^3/ft (0.1480 bbls/ft)
5" 19.5# drillpipe (inside) = 0.0997 ft^3/ft (0.01776 bbls/ft)

(b)Volumes

1. Volume between 20 "/ 13 3/8" casings (volume 1, **Figure 6.7**)
Volume = 500 x 0.9388 =469.4 ft^3

2. 13 3/8" casing/16" open hole volume (volume 2, **Figure 6.7**)

Volume = 1.3 x (5980 - 2000)x0.4206 =2176.2 ft^3

(Note: **1.3** is used to allow for 30% excess)

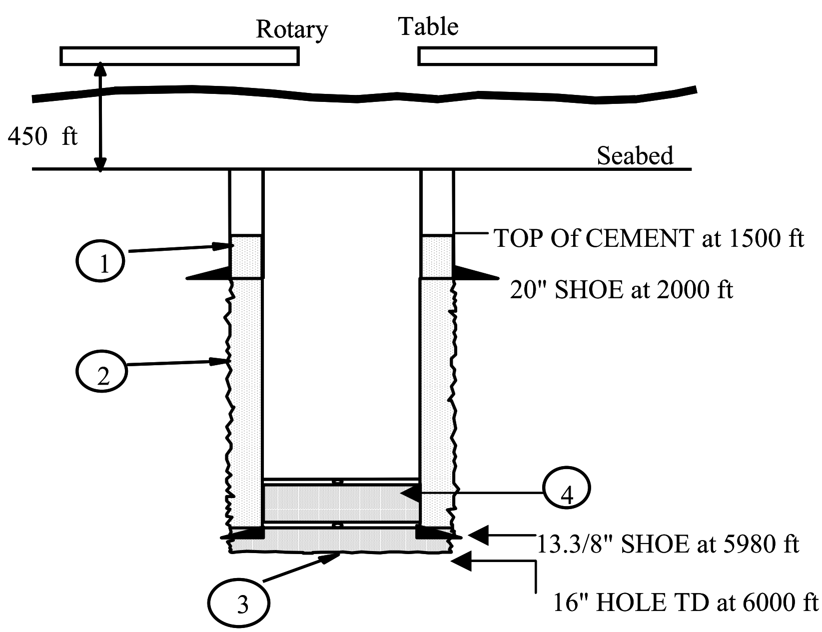
3. Hole sump volume (rat hole) (volume 3 , **Figure 6.7**)

Volume = 20 x 1.3963 = 27.93 ft^3

Note The sump will not always be completely filled with cement, but it is better to include it as a small amount of excess.

4. Shoe track volume (volume 4, **Figure 6.7**)
Volume = 40 x 0.8314 = 33.26 ft^3

Figure 6.7 Example 6.4



5. Total cement volume

Volume = 469.4+2176.2+27.93 +33.26 = 2706.79 ft^3 = 481.63 bbl

6. Tail slurry volume

Volume = 500 ft x 0.4206 ft^3/ft + 33.26 (shoe track) =243.26 ft^3 = 43.28 bbl

7. Lead slurry volume

Volume = (2706.79 - 243.26) ft^3 = 2463.53 ft^3 = 438.35 bbl

8. Displacement volume

Capacity of drillpipe to 13 3/8" casing hanger = 450 ft x 0.01776 bbl/ft = 7.9 bbls

Capacity of 13 3/8" casing from seabed to top of shoe track

= [(5980 - 40) - 450] x 0.1480 = 5490 ft x 0.1480 bbl/ft = 812.52 bbls
(refer to sketch in **Figure 6.7**)

Total Displacement = 7.9 + 812.52 = 820.42 bbls

(c) Lead Slurry Details:

Lead slurry volume = 2463.53 ft^3

Slurry Yield = 1.99 ft^3/sk,

Therefore number of sacks cement required = 2463.53 / 1.99 = 1238

The amount of additives is based on the number of sacks (sks) of cement.

Extender	= 1238 sks x 0.3 gal/sk	= 371.4 gal
Retarder	= 1238 sks x 0.2 gal/sk	= 247.6 gal
Seawater	= 1238 sks x 11.35 gal/sk	= 14,051.3 gal
Total	= 14,670.3 gal = 349.3 bbl	= 35 tanks

Note:The displacement tanks on cement units are of 10 bbls capacity and are calibrated in 0.5 bbls increments. There is however a "dead" volume in the bottom of each tank which should be taken into consideration when adding the first batch of cement additives to the tank, i.e. the first addition of liquid additives has to be slightly increased to maintain the correct concentration.

The amount of each additive has to be divided according to the number of 10 bbl tanks of mix water e.g.

Extender	= 371.4 gals per 35 tanks	= 10.60 gals per tank
Retarder	= 247.6 gals per 35 tanks	= 7.1 gals per tank

(d)Tail Slurry Details

Tail slurry volume = 243.26 ft^3

Slurry Yield = 1.13 ft3/sk

Therefore sacks of cement = 243.26 / 1.13 = 215 sacks

The amount of additives is based on the number of sks of cement.

Dispersant	= 215 sks x 0.05 gal/sk	= 10.75 gal
Retarder	= 215 sks x 0.05 gal/sk	= 10.75 gal
Seawater	= 215 sks x 4.8 gal/sk	= 1032 gal
Total volume		= 25.1 bbl = 2.5 tanks

The amount of each additive has to be divided according to the number of 10 bbl tanks of mix water e.g.

Dispersant	= 10.75 gals per 2.5 tanks	= 4.3 gals per tank
Retarder	= 10.75 gals per 2.5 tanks	= 4.3 gals per tank

Example 6.5: Primary Cementing Of 7 " Production Casing

Hole depth = 13,900 ft

Hole size = 8.5 in

Casing Shoe = 13,891 ft

Mud weight = 11.6 ppg

Casing dimensions= OD/ID = 7 in/6.184 Grade C95 29#

Cement = cement column should be 6,562 ft long, as follows:

From shoe to 656 ft, use API Class G cement

From 656 ft to 6,562 ft, use API Class H cement with 2% bentonite and 0.3% HR-4

(Note: HR-4 is a type of cement retarder)

To prevent contamination of cement by mud, 30 bbl of fresh water should be pumped ahead of the cement.

- Allow 15 min for release of plugs
- Shoe track: 80 ft

Calculate:

1) quantity of cement from each class;

2) volume of mix water;

3) total time for the job;

(Note: Mix cement at the rate of 25 sacks/min and displace cement at 300 gpm

4) pressure differential prior to bumping the plug;

5) annular velocity during chase;

6) total mud returns during the whole cementing operation.

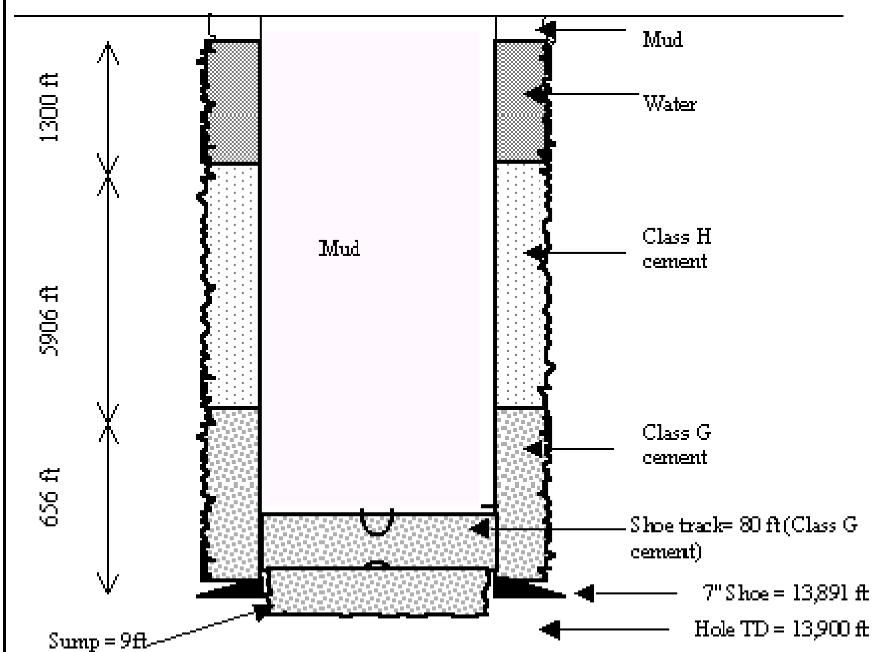
From cementing tables (Halliburton or Dowell Schlumberger), the properties of the two classes of cement including the additives are as follows:

	Class G Cement	Class H Cement
Slurry weight	15.8 ppg	15.5 ppg
Slurry volume	1.15 ft^3/sack	1.22 ft^3/sack
Mix water	5 gal/sack	5.49 gal/sack

Solution

To aid visualisation, the data from this example are sketched out in **Figure 6.8**.

Figure 6.8 Example 6.5



(1) Sacks of cement required

Class G

Volume of Class G slurry = volume of shoe track + volume of pocket below casing shoe

+ volume of 656 ft of annular space

$$= \frac{\pi}{4} \times (6.184)^2 \times \frac{1\,\mathrm{ft}^2}{144 \cdot \mathrm{in}^2} \times (80 \cdot \mathrm{ft}) + \frac{\pi}{4} \times (8.5)^2 \times \frac{1\,\mathrm{ft}^2}{144 \cdot \mathrm{in}^2} \times (9 \cdot \mathrm{ft}) + \frac{\pi}{4} \times (8.5^2 - 7^2) \times \frac{1\,\mathrm{ft}^2}{144 \cdot \mathrm{in}^2} \times (656 \cdot \mathrm{ft})$$

$$= 16.7 + 3.5 + 83.2$$

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$= 103.4\ ft^3$

Number of sacks of Class G cement $= \dfrac{103.5\,ft^3}{1.15\,\dfrac{ft^3}{sack}} = 90$ sacks

<u>Class H</u>

Volume of slurry = (6,562 - 656) x annular capacity

$$= \frac{\pi}{4} \times (8.5^2 - 7^2) \times \frac{1\,ft^2}{144 \cdot in^2} \times (5906 \cdot ft)$$

$= 748.9\ ft^3$

Number of sacks of Class H cement $= \dfrac{748.9\,ft^3}{1.22\,\dfrac{ft^3}{sack}} = 614$ sacks

(2) Volume of mix water

Volume of mix water = water required for Class G and Class H cement.

= (90 sacks x 5 gal/sack) Class G

+ (614 sacks x 5.49 gal/sack) Class H

= 3,820.9 gal = 91 bbl

(3) Total job time

Job time = mix time + time for release of plugs + displacement or chase time

$$= \frac{\text{total number of sacks}}{\text{mixing rate}} + 15 + \frac{\text{inner capacity of casing excluding shoe track}}{\text{pumping rate}}$$

$$= \frac{(614 + 90)\text{sacks}}{25\text{sacks/min}} + 15 + \frac{\frac{\pi}{4}(6.184)^2 x\left(\frac{1}{144}\right)x(13,891 - 80)\text{ft}^3}{300\text{ gal/min x }\frac{\text{ft}^3}{7.48\text{ gal}}}$$

$= 28.2 + 15 + 71.8$

$= 115$ min

(4) Differential pressure

The 30 bbl of water pumped ahead of the cement will occupy in the annulus a height h, given by:

$$h = \frac{30\text{ (bbl) x } 5.62\text{ (ft}^3\text{/bbl)}}{0.1268\text{ (ft}^3\text{/ft)}} = 1{,}330\text{ ft}$$

(annular capacity = 0.1268 ft^3/ft)

A pressure differential exists during the cementing operation due to density differences between mud, cement and the water spacer. The total pressure differential, ΔP, is given by:

ΔP = pressure differential due to density difference between:

(i) mud in casing and cement (Grade G) in annulus for a height of (656 - 80 - 391) = 576 ft.

\+ (ii) mud in casing and cement (Grade H) in annulus for a height of 5,906 ft

\+ (iii) mud in casing and water spacer in annulus for a height of 1,330 ft

Assuming the density of fresh water is 8.3 ppg, then

$\Delta P = 0.052\ [576 \times (15.8-11.6) + 5{,}906 \times (15.5-11.6) + 1{,}330 \times (8.3 - 11.6)]$

$= 1095$ psi

(5) Annular velocity

Using Q = VA (where V = velocity; Q = volume flow rate; A = annular area)

$$V = \frac{Q}{A} = \frac{300\ (\text{gal/min})}{(\pi/4) \times (8.5^2 - 7^2)\ (\text{in}^2)} \times \frac{(\text{ft}^2/7.48\ \text{gal})}{(\text{ft}^2/144\ \text{in}^2)} = 316\ \text{ft/min}$$

(6) Mud returns

Mud returns = steel volume + volume of water ahead + total slurry volume

$$= \frac{\pi}{4} \times (7^2 - 6.184^2) \times 1/144\ (\text{ft}^3/\text{ft}) \times 13{,}891\ \text{ft} + (30\ \text{bbl}) + (748.9 + 103.5)\ \text{ft}^3$$

$= 815.1\ \text{ft}^3 + (30\ \text{bbl} \times 5.62\ (\text{ft}^3/\text{bbl})) + 852.4\ \text{ft}^3$

$= 1{,}836.1\ \text{ft}^3 = 326.7\ \text{bbl}$

10.0 Cementation Of Liners

10.1 Liners

As discussed in **Chapter 4**, a liner is a short section of casing that does not reach the surface. It is hung on the previous casing string using a liner hanger.

10.2 Selection Of Liner Hangers

The following requirements and criteria should be applied when considering liner hanger selection, see **Figure 6.9**.

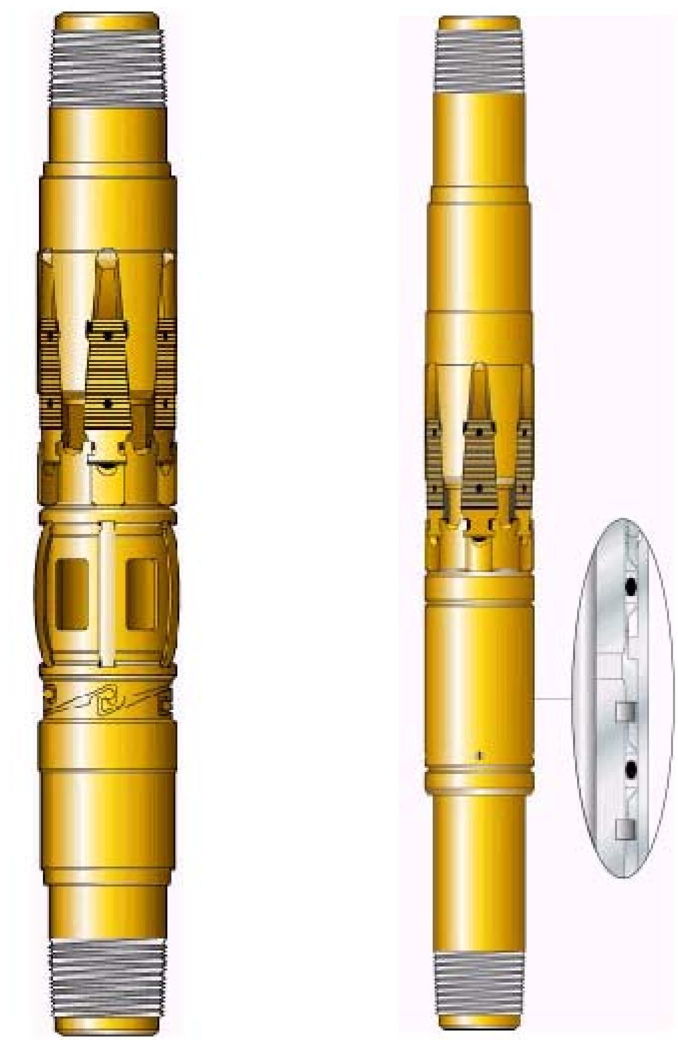
10.3 Hanger Loading Forces

Determine the maximum loading possible on the casing (being hung on) during the hanger setting procedure. The following cumulative forces should be taken into account.

(a) Liner hanging weight

(b) The internal pressure required to initially set the hanger and shear the ball seat

Figure 6.9 Liner Hangers, Courtesy of Baker Hughes Inteq



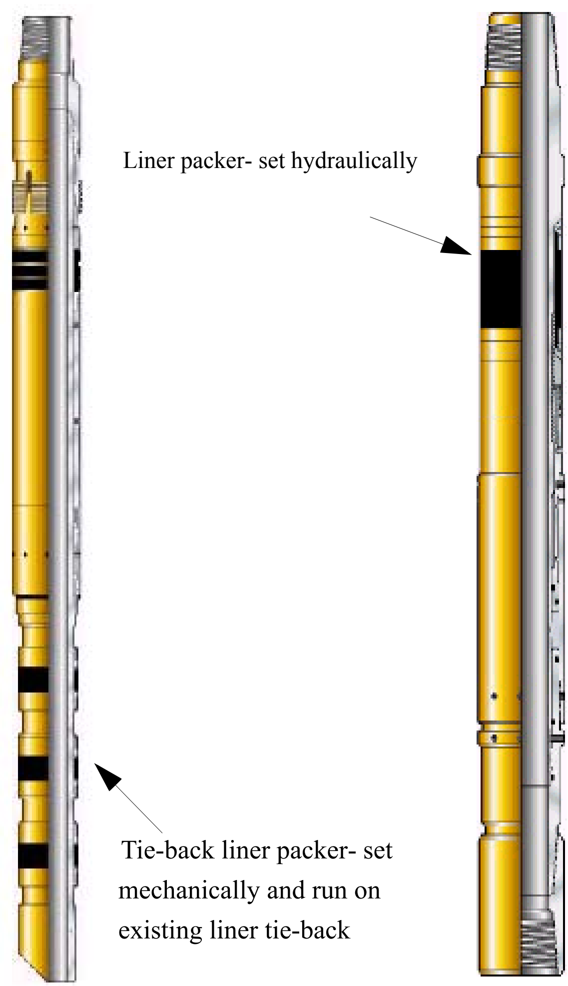
Mechanical liner hanger

Hydraulic liner hanger

(c)Designated pressure to bump the plug (if greater than (b))

(d) Running string set down weight prior to cementing (if required).If calculations indicate that the loadings are within 20% of the casing design loads, alternative hanger designs should be considered. The carrying capacity of the hanger slips should also be checked against the forces developed during pressure testing.

Figure 6.10 Tie-back Packers, Courtesy of Baker Hughes Inteq



10.4 Integral Packers

It is usual to run an integral packer with the liner to avoid sole reliance on the liner lap cement job.

10.5 Tie-back Packers

- A compatible tie back packer should be run if the integral packer is found to be leaking, Figure 6.10.
- Multi-cone hangers are preferred to single cone hangers due to increased loading capacity.

- Both rotating and non-rotating liner hangers may be used. In highly deviated wells rotating hangers are preferred as they allow rotation of the liner during cementation.
- Hydraulically and mechanically set hangers can be used, however, in deep or highly deviated wells, hydraulic set hangers are preferred. Mechanical hangers may be difficult to set or could be accidentally set in these circumstances due to frictional drag of the liner against the casing and hole. If mechanically set liner hangers are used they should be the resetable type.

10.6 Liner Lap Length

The optimum length of the liner lap will depend on the likelihood of obtaining a good cement bond over the liner lap. When a good cement job is anticipated (i.e. vertical wells where the liner can be well centralised), cement will be the main means of isolation between the liner top and the formations below the casing shoe. In this case a 250-500 ft liner lap should be used.

For wells where a good cement job will be difficult to achieve (e.g. highly deviated holes where centralisation of the liner will generally be poor), isolation will be achieved by the use of integral liner packers. As such, the liner lap need only be of the order of 100 ft in length.

10.7 Liner Cementing Guidelines

1. Prior to the cementation the following calculations will be conducted:

- Circulation volume
- Cement volume including excess
- Volume of pre-flush
- Reduction in hydrostatic head due to pre-flush. For the pre-flush in open hole, assume gauge hole to calculate the height of the pre-flush. *There should be sufficient overbalance at all times during the cement job.*

Liner cement calculations are similar to the calculations presented earlier. Problem 2 at the end of this chapter gives the reader a chance to practice these calculations.

2. The running procedures as specified in the liner manufacturer's operating manual must be adopted.

3. Pressure test all cementing lines and equipment to 1000 psi above the maximum expected pressure prior to the job.

4. With the liner at near TD, install the cement Kelly and plug holder head.

5. Break circulation slowly, and then circulate bottoms up + 20% or string volume + 20%, whichever is the greater.

6. After setting the liner, release the liner running tool and set down weight on the liner to confirm release. Remain inside the liner.

7. Pre-mix the cement slurry.

8. Pump the pre-flush and then the cement slurry. Pumping of the slurry must be continuous and without any interruptions.

Monitor the string weight while cementing. If the string begins to pump out of hole, set down extra weight on top of the liner.

9. Release pump down displacement plug. If it is uncertain that the dart has gone, close the Kelly cock and open the plug dropping head to check.

10. Displace pump down plug using the cement unit until it lands and shears out the liner wiper plug.

Ensure that the mud pump is lined up to take over the displacement should the cement unit fail.

11. Continue displacing until both plugs land on the landing collar. Reduce the displacement rate prior to the bump.

If no bump is observed, pump no more than the displacement volume plus 50% of the shoe track volume.

12. Check that the correct amount of fluid has been displaced according to the volume in the mud tanks.

13. Record the static differential pressure prior to the bump. Compared with the theoretical differential pressure.

14. Check floats are holding and that the annulus level remains constant. If backflow occurs, pressure up to see if the plug can be re-bumped.

15. Pressure up drill pipe to ± 100 psi. Pull running tool out of hanger and pull back above the Polished Bore Receptacle (PBR).

16. Reverse circulate to remove any excess cement. Pull out with liner running string.

17. The specified pressure test is a full cased hole test. It should be noted that packers can be run in the string to protect sections of the casing from internal pressures that may deform the casing and create a micro-annulus.

11.0 Cement Plugs

The process of setting a cement plug involves the placement of a relatively small amount of cement slurry inside an open hole or inside casing. The main reasons for setting a cement plug are as follows:

(a) To plug back a zone or abandon a well

(b) To sidetrack above a fish or to initiate a sidetrack

(c) To provide a seal for open hole testing

(d) To cure a lost circulation zone.

The two common techniques for setting a cement plug are:

1. Balanced Plug

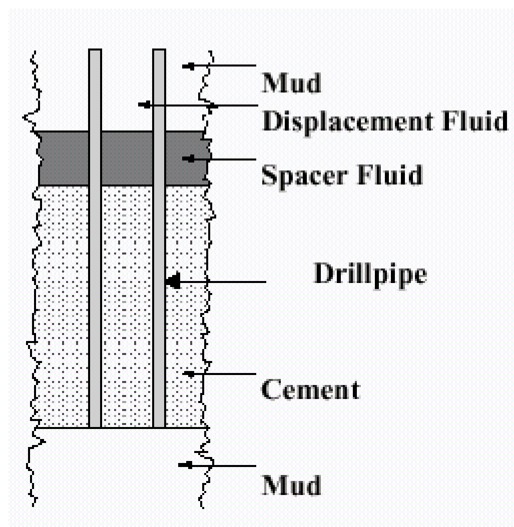
2. Dump Bailer

11.1 Balanced Plug Technique

Tubing or drill pipe is run into the hole to the desired setting depth and the spacers and cement are pumped. The volume of spacer pumped is such that they are equal in height both inside the tubing and the annulus**, see Figure 6.11**. This is to ensure that the hydrostatic pressures inside the drillpipe and the annulus are exactly the same; hence the name balanced plug.

The plug is usually placed with a smaller pipe than the drillpipe, called stinger. The stinger length should be the plug length plus ± 100 ft.

Figure 6.11 Balanced Plug



Setting Procedure:

(a) Run the cement stinger to 300 ft below the bottom setting depth for the plug.

(b) Spot a viscous mud pill having the same density as the mud in hole. The volume of the pill should be sufficient to cover the 300 ft interval. A pill is not required if the cement plug is to be set on bottom, or on top of a bridge plug.

(c) Pull the stinger back 300 ft.

(d) Pump a 10-20 bbl weighted spacer (preflush). The exact volume will depend on the hole size. Water should only be used with Water Based Mud (WBM) and if hydrostatic conditions allow its use.Surfactants are required for Oil Based Mud (OBM). Base Oil on its own can only be used if hydrostatic conditions allow its use. However, its use will greatly enhance the chances of a successful plug.

(e) Pump sufficient volume for a 500 ft plug or as specified in the drilling programme. The slurry should be displaced at maximum rate. The rate should be slowed down to 2 barrels per minute (BPM) when the cement is 10-20 bbls away from the ported sub in the stinger and kept at this rate.

(f) Pump sufficient spacer behind the cement to balance the pre-flush.

(g) Displace with mud to the balanced position.

(h) Pull back slowly to at least 500 ft above the top of the plug and reverse circulate clean.

Note:If a series of plugs are to be set on top of each other, then reverse circulate clean immediately above the bottom plug before attempting to set the next plug.

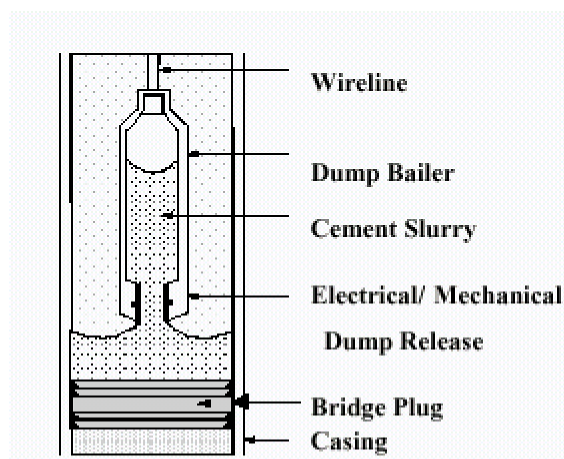
(i) Pull out of hole.

11.2 Dump Bailer Method

This method allows the placement of a cement plug by wireline techniques. The dump bailer containing cement is run on wireline to the desired setting depth. The bailer can be opened electrically or mechanically by touching the top of a bridge plug as shown in **Figure 6.12**. The bridge plug is set below the intended plug zone.

The advantage of this technique, is that the depth control is good and it is a relatively fast and inexpensive means of setting a plug. The disadvantage is that only small volumes can be set due to the limited capacity of the bailer. As a result, it is best suited to small hole sizes.

Figure 6.12 Dump Bailer



Example 6.6: Balanced Plug calculations

It is required to balance 100 sacks of Class G neat cement in an 8.5 open hole by use of a 3.5 in OD/3.068 in ID, 8.9 lb/ft tubing. The hole depth is 6,000 ft and 10 bbl of water is to be used as preflush ahead of the cement slurry.

Calculate:

1) total slurry volume, annular volume and tubing volume

2) height of the balanced plug

3) volume of water to be used as a spacer behind the cement

4) volume of mud chase (or displacement volume)

5) number of strokes required to displace cement to just below the drillpipe shoe,

   assuming that the pump capacity is 0.1 bbl per stroke

6) volume of cement and number of sacks required if the height of the plug is 500 ft.

Solution

Refer to **Figure 6.11** for a sketch.

Using the ID of the tubing, the reader can verify that the capacity of the tubing is 0.04968 ft^3/ft. The annular capacity between 3.5 in tubing and 8.5 in hole is 0.3068 ft^3/ft. The slurry yield of Class G neat cement is determined from services companies' handbooks, of which **Table 6.3** is an example. From **Table 6.3** the slurry yield of Class G neat cement is 1.15 ft^3/sack and the slurry weight is 15.8 ppg.

(1) Total slurry volume = number of sacks x yield per sack

$$= 100 \times 1.15 = 115 \text{ ft}^3$$

Annular volume $C = 0.3068 \text{ ft}^3/\text{ft}$

(Note: By calculation the annular capacity is 0.3272 ft^3/ft, as no account is taken of the tubing collars.

Tubing volume, $A = 0.04968\ ft^3/ft$

2) Height of balanced plug

$$= \frac{V}{A + C} = \frac{115 ft^3}{(0.04968 + 0.03068)\frac{ft^3}{ft}}$$

= 322.6 ft = 323 ft

(3) For a cement plug to be balanced, the height of the spacer inside the tubing must be equal to the height of the preflush in the annulus. Thus,

$$\frac{\text{volume of preflush}}{\text{annular capacity}} = \frac{\text{volume of spacer inside tubing}}{\text{capacity of tubing}}$$

$$\frac{10}{0.3068} = \frac{V}{0.04968}$$

V = 3.1 bbl

In general, the volume of spacer required is calculated from

$$V = \frac{\text{capacity of tubing}}{\text{capacity of annulus}} \text{ x volume of preflush}$$

(4) Height of water inside the tubing

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$$= \frac{3.1 \text{ bbl x } (5.62 \text{ ft}^3/\text{bbl})}{0.049\ 68 \text{ ft}^3/\text{ft}} = 356 \text{ ft}$$

Height of cement and water inside tubing = 323 +356 = 679 ft

Height of mud to fill remaining length of tubing = 6,000 - 679 = 5,321 ft

Table 6.3 API Neat Cement Slurries

Class	Slurry Weight (Ib/gal)	Mixing water (ft^3/sack)	Mixing Water (gal/sack)	Slurry/sack of cement (ft^3/sack)	Slurry weight (lbm/ ft^3)	Percentage mixing water
A	15.60	0.696	5.20	1.18	116.70	46
B	15.60	0.696	5.20	1.18	116.70	46
C	14.80	0.844	6.32	1.32	111.10	56
D	16.46	0.573	4.29	1.05	123.12	38
G	15.80	0.664	4.97	1.15	118.12	44
H	16.46	0.573	4.29	1.05	123.12	38

(5) Displacement volume = 5,321 x capacity of tubing

= 5,321 x 0.04968 = 264.4 ft^3 = 47 bbl

(6) Number of pump strokes to displace cement

$$= \frac{47 \text{ bbl}}{0.1 \text{ bbl/stroke}} = 470$$

(7) Volume of cement = height of plug x hole capacity

$$= 500 \text{ ft} \times \frac{\pi}{4} \times \frac{(8.5)^2}{144} = 197 \text{ ft}^3$$

$$\text{Number of sacks} = \frac{\text{volume of slurry}}{\text{slurry yield}} = \frac{197}{1.15} = 171 \text{ sacks}$$

12.0 Squeeze Cementing

Squeeze cementing is the process of forcing a cement slurry through perforations in the casing to a desired location to provide a seal across an undesired gap. During placement water is driven from the slurry into a permeable formation to form a cement filter-cake which hardens to form a seal. It is a common misconception that the cement actually penetrates the pores of the rock. As cement slurries have a mean particle size of 20-50 microns, it would require a formation with a permeability of between 2-100 darcies for the cement grains to penetrate the formation.

The need for squeeze cementing can arise for a variety of reasons during the drilling and production phases. Some of the most common reasons are as follows:

- The repair of a faulty or inadequate primary cement job
- To shut-off the flow of unwanted water or gas
- The isolation of a zone prior to perforating for production
- To abandon a non-productive or depleted zone
- To repair casing leaks.

12.1 Squeeze Cementing Techniques

12.1.1 Hesitation Squeeze

Building up a cement filter cake inside perforation tunnels requires application of a differential pressure to induce slurry dehydration.

The relatively small amount of filtrate lost from the slurry makes continuous pumping, at a rate slow enough to replace the volume lost to the formation, impractical. The only procedure that makes the dehydration of small quantities of cement into perforations or formation cavities possible is the intermittent application of pressure, separated by a period of pressure leak-off caused by the loss of filtrate into the formation. As the filter cake builds up, the time for the pressure to bled off will steadily increase.

12.1.2 Low Pressure Squeeze

Cement slurry is forced through the perforations at pressures below the formation fracture pressure. The aim of this operation is to fill perforation cavities and interconnected voids with dehydrated cement. The volume of cement is small since no slurry is actually pumped into the formation.This is usually the recommended practice.

12.1.3 High Pressure Squeeze

In some instances a low pressure squeeze will not accomplish the objective of the job. Channels behind the casing may not be directly connected with the perforations, or small cracks or microannuli may permit the flow of gas but not of a cement slurry. Additionally, many low pressure operations cannot be performed because of the impossibility of displacing plugging fluids (drilling muds, solids-carrying completion brines, etc.) from ahead of the cement slurry or from inside the perforations.

Placement of the cement slurry behind the casing is accomplished by breaking down formations at, or close to, the perforations. Fluids ahead of the slurry are displaced into the fractures, allowing cement to fill the desired spaces. Further application of the hesitation technique will dehydrate the slurry against the formation walls leaving all the channels, from fractures to perforations, filled with cement cake.

The preferred method of the above is the hesitation squeeze. This method involves the pumping of between ¼ and ½ barrel of cement at 10 minute intervals to allow the cement to gel before squeezing.

12.2 Placement Techniques

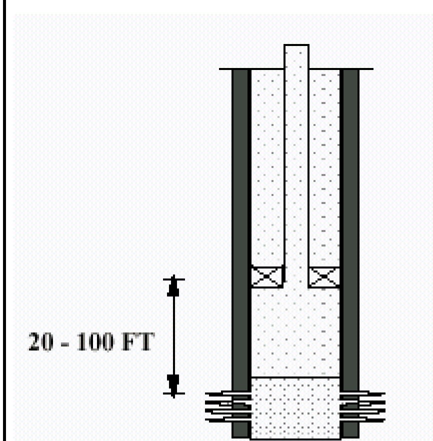
There are 3 main placement techniques for carrying out a squeeze:

1. Retrievable squeeze packer
2. Drillable cement retainer
3. Bradenhead placement.

12.2.1 Retrievable Squeeze Packer

The main objective of using a packer is to isolate the casing and wellhead while high pressure is applied downhole. The advantage of the retrievable packer is the fact that it can be set and released many times,(**Figure 6.13 and Figure 6.14**).

Figure 6.13 Retrievable packer Near Perforations



Retrievable squeeze packers can be either compression set or tension set. Compression set packers are generally preferable based on industry experience.

Squeeze packers have a by-pass valve to allow circulation of fluids while running in and pulling out of the hole (to prevent high swab and surge pressures) and also when the packer has been set (for reversing out of excess cement without excessive pressures).

Drillable or retrievable bridge plugs can be set to isolate the casing below the zone to be treated.When running the retrievable bridge plug, it is normal to drop frac sand on top of the plug to prevent cement setting in the release mechanism.

12.2.2 Drillable Cement Retainer

Cement retainers (**Figure 6.14**)are drillable packers provided with a two-way valve that prevents flow in either or both directions. The valve is operated by a stinger run at the end of a work string.

Drillable cement retainers run on wireline are used instead of packers to prevent backflow when no dehydration of cement is expected, or when high negative differential pressures may disturb the cement cake.

Figure 6.14 Retrievable Packer With Tailpipe

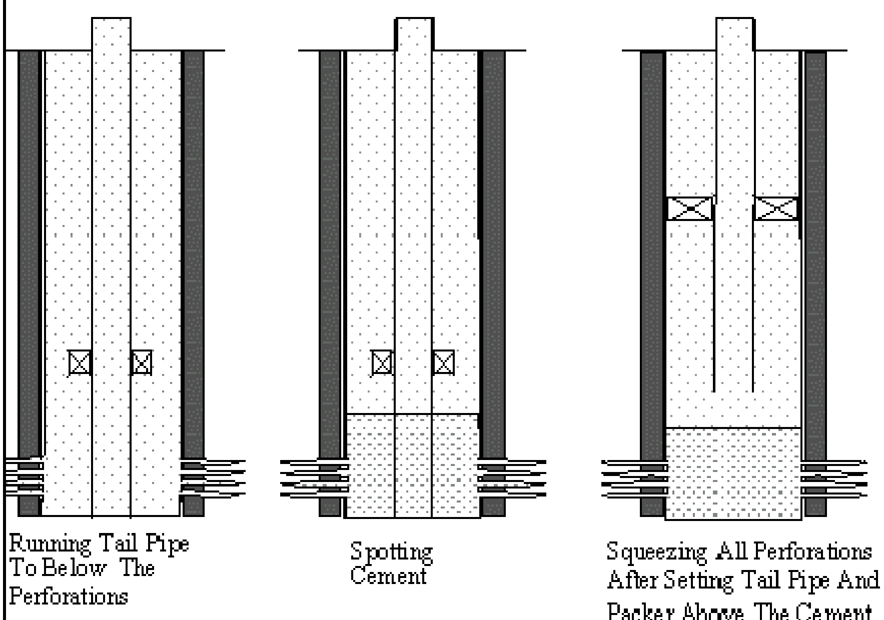
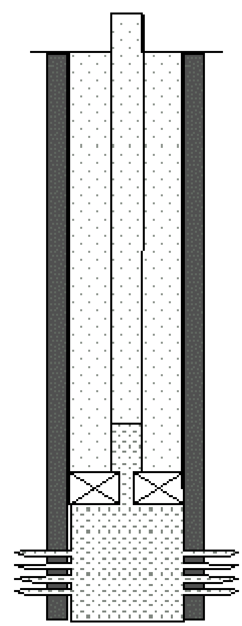


Figure 6.15 Drillable cement retainer



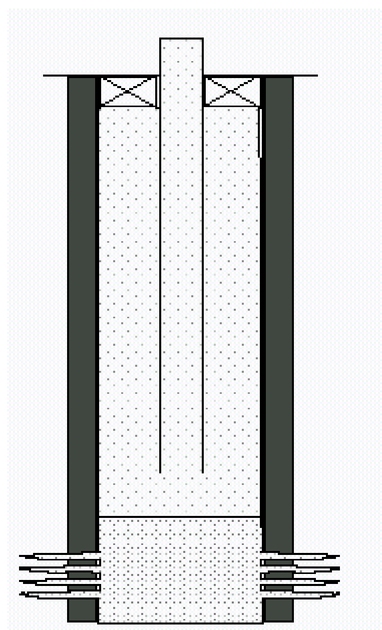
When cementing multiple zones, the cement retainer isolates the lower perforations and subsequent zone squeezing can be carried out without having to wait for the cement to set. These retainers are also used for well abandonment purposes.

12.2.3 Bradenhead Placement Method

This squeeze technique (**Figure 6.16**) is the simplest of the squeeze techniques and does not use a packer. It is to be only practised with the Low Pressure Squeeze Technique.

Open ended tubing is run to the desired depth, the slurry is placed using the balanced plug method and the string raised above the plug. The rams are closed and squeeze pressure applied.

Figure 6.16 Bradenhead Placement Method



13.0 Cement Evaluation Tools

The following tools are used to evaluate the quality of the cement and the bond between the cement and the casing:

- Cement Bond Log (CBL)

- Variable Density Log (VDL)
- Cement Evaluation Tool (CET)
- Ultrasonic Borehole Imaging (USI)
- Segmented Bond Tool (SBT)

Cement generates a considerable amount of heat during the hydration process. A temperature survey can be used to indicate the presence of cement and TOC. Temperature surveys cannot be used for a quantitative evaluation of the job. They generally must be run within 24 hours of the cement job.

The temperature survey is used to determine TOC where a CBL is not planned or may be unreliable due to size of casing.

The temperature log can sometimes be used for detecting flowing fluids immediately outside the casing. When run in combination with a noise log, relative volumes and fluid composition can be estimated. Analysis of the frequency spectrum and the amplitude of the noise received enables fluid types and their location to be estimated. Departure of the temperate from the normal geothermal gradient can be related to the volume of fluid and its rate of flow.

(a) Cement Bond Log (CBL)

The CBL log provides a measure of the cement to casing bond and cannot be used to quantify the amount of cement present. The principle of measurement is to record the transit time and attenuation of an acoustic wave after propagation through the borehole fluid and the casing wall. The CBL gives a continuous measurement of the amplitude of the first casing arrivals from a 3 ft transmitter/receiver spacing. This reading is a maximum in unsupported pipe, and a minimum for well cemented casing. The absolute reading is a function of casing size and thickness, cement bond quality, wellbore fluid, tool type and tool centring. Generally most of these parameters will be constant so that cement bond quality can be directly related to the amplitude measured.

The tool is used to evaluate the percentage of the pipe circumference bonded by cemented, and the cement compressive strength. The output is only valid however, if the tool is properly centralised and there is no microannulus.

An important feature when using the CBL is to provide a correlation to the open hole logs. This is achieved by running a Gamma Ray (GR) and Casing Collar Log (CCL) in combination with the CBL to provide a correlation for any subsequent operations e.g. perforating. Where a micro-annulus is suspected the CBL must be run under pressure.

The following conditions are required for a reliable CBL/VDL log:

(i) Casing sizes preferably 9 5/8" or less.

(ii) Good centralisation. At least 3 centralisers must be used to ensure that the transmitter and receiver are within 1/8" of the pipe centre. On deviated wells the CBL/CET must be centralised and run specifically for each string.

(iii) No microannulus between the casing and cement.

(iv) A minimum cement thickness of 1".

(b) Variable Density Log (VDL)

The VDL provides a graphical representation of the actual sonic wave form recorded at a 5 ft transmitter/receiver spacing. This trace should be used to better discriminate between casing and formation arrivals. The VDL is generally used to assess the cement to formation bond and helps to detect the presence of channels and the intrusion of gas.

A poor cement bond is noted by strong parallel black and white vertical striped. A good cement bond is generally noted by a dull grey featureless response when the casing signal is expected.

The CBL/VDL output is affected by: tool eccentricity; micro-annuli; fast formations; the presence of gas; and thin cement sheaths.

(c) Cement Evaluation Tool (CET)

The CET is an ultrasonic tool consisting of eight focused transducers arranged in a helical pattern around the body of the tool. While CBL tools measures the attenuation of a sonic compression wave propagating axially along the casing, the CET induces casing resonance by transmitting a broad band pulse (270 Hz to 650 kHz) normal to the casing wall.

The energy returning to the transducers from the induced casing resonance is related to the acoustic impedances of the materials in contact with the inner and outer surfaces of the casing. As the only unknown is the acoustic impedance of the material in the annulus, knowledge of the energy emitted from the transducer allows this to be calculated. The compressive strength of the cement in the annulus can then be estimated.

The radial arrangement of the transducers allows an estimation of the cement distribution to be made. As the transducers are of 1-inch diameter, the percentage of casing circumference investigated will vary depending upon the casing size (approximately 36% for 7" liners to 26% for 9 5/8" casing).

The CET is unaffected by water filled microannuli up to 0.1 mm and can detect channelling in the cement (only when the channel is in contact with the casing). However, the CET is badly affected by corrosion inside the casing.

(d) Ultrasonic Borehole Imaging (USI)

The USI operates in a similar way to the CET but provides full 360^{o} coverage of the casing circumference by use of a rotating transducer acting as both transmitter and receiver.

(e) Segmented Bond Tool (SBT)

The SBT quantitatively measures the cement bond integrity in six angular segments around the casing. The acoustic transducers are mounted on six pads positioned in contact with the interior casing wall to provide compensated attenuation measurements. Acoustic attenuation is measured in two directions, using an arrangement of two transmitters and two receivers on four adjacent arms. The two measurements are combined to derive a compensated value that does not depend on receiver sensitivities or transmitter power. This measurement process is repeated for each of the six segments.

For ease of interpretation, the SBT measurements are displayed in two log presentations. The primary presentation is available in the logging mode as the SBT data are acquired, processed, and plotted in real time. The secondary presentation consists of six 60 degrees segmented arrays, variable-attenuation "cement" map, and a tool orientation trace overlay.

14.0 Annular Gas Migration

14.1 The problem

Annular gas flow can be defined as formation gas migrating to surface or to a lower pressure zone. Remedial cementing to prevent annular gas migration is relatively unsuccessful. Therefore it is better to prevent annular gas migration with effective primary cementing.

Gas migration is a complex problem and is controlled by the following factors:

- Mud displacement
- Displacement fluid and slurry densities
- Cement gel strength
- Cement hydration
- Fluid loss
- Free water
- Cement permeability
- Micro-annuli (formation and casing bonds)
- Applied annulus pressure

14.2 Techniques for Minimising Annular Gas Problems

In areas where annular gas migration may be a problem, every effort should be made to ensure that good cementing practices are used and that the slurry is designed with the likely cause of gas migration in mind. The automatic use of a gas-block slurry will not solve annular gas problems.

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14.2.1 Mud Displacement

The best possible mud displacement practices should be used when cementing. In particular, attention should be paid to:

- Mud conditioning (before running casing)
- Casing centralisation
- Casing movement
- Proper choice of spacers and washes
- Proper choice of spacer and wash volume (contact time)
- Annular flow rates (use a computer simulation)

14.2.2 Density Control

Density differences between the mud, spacer, and cement slurry will affect the hydraulic pressure exerted on the formation during cement placement. If, during cement placement, the hydrostatic pressure falls below the formation pressure then gas can enter the well. Any gas entering the well will flow upwards, expanding and permanently damaging the cement sheath. The 'U-tubing' that often occurs during cement placement further complicates the pressure analysis.

14.2.3 Cement Gel Strength

During and immediately after placement, the cement slurry behaves as a liquid and so fully transfers hydrostatic pressure. At this point, any reduction in cement slurry volume, through filtrate loss and hydration, will be fully compensated for by downward movement of the cement slurry. As the cement hydrates, gelation between the particles in the cement slurry begins, resulting in shear stresses at the walls of the annulus that eventually become high enough to support the cement column. The resulting fall in the hydrostatic pressure transmitted by the cement column may allow gas to enter the annulus and create a migration path. The period from the start of gelation until the slurry is sufficiently set to prevent gas percolation is known as the transition time.

Where gas migration is a possible problem short transition time slurries should be used (see below: Right-Angle Set Cements). Thixotropic and high gel strength slurries can also be effective in certain circumstances.

14.2.4 Fluid Loss

Loss of fluid from the slurry reduces the slurry volume and may also cause localised rapid hydration of the cement. Loss of slurry volume lowers the hydrostatic head of the whole cement column, possibly allowing gas to enter the slurry. Localised rapid hydration can lead to patches of prematurely set cement that can cause hydrostatic isolation of the cement beneath with the same result.

To reduce the possibility of gas invasion and lower the cement permeability, the 30 minute High Pressure/High Temperature (HP/HT) API fluid loss should be below 50ml.

14.2.5 Free Water

For a deviated gas-prone well the free water should be as low as possible. Any free water in the cement slurry will migrate to the top side of the annulus and form an uncemented channel the length of the cement sheath. Gas will readily flow through such a channel.

14.2.6 Applied Annulus Pressure

Pump pressure applied to the annulus from the surface can be effective in preventing annular gas flow. However, the potential of lost circulation limits the maximum allowable pump pressure. Pressure should be applied soon after the top wiper plug bumps and held at least until the cement begins to set.

14.2.7 Micro-annuli (formation and casing bonds)

If a micro-annulus has developed at the cement to casing or the cement to formation contact, then gas will flow along it. Gas may also break down weak cement to casing and cement to formation bonds.

The main cause of poor bonding are:

- Lack of casing and formation roughness
- Cement bulk volume shrinkage
- Mud films or channels at the cement to casing and cement to formation surface contacts
- Free water layers in deviated wells
- Downhole thermal stresses
- Downhole hydraulic stresses
- Downhole mechanical stresses.

Cement shrinkage after initial setting is only a few tenths of a per cent and not likely to produce a significant continuous micro-annulus. Increasing the casing roughness can help reduce these localised flaws in the bond.

Downhole temperature and pressure changes will cause the casing to deform. These deformations may degrade the cement to formation and cement to casing bond. Any actions which may generate mechanical stresses in the casing should be eliminated until the cement has set. Any pressure testing after the cement has set should be carried out in a manner that minimises the pressures seen by the casing.

14.2.8 Cement Slurry Formulation

(a) Compressible Cements

Compressible cements maintain the cement pore pressure above that of the formation gas pressure. Two general cement types are available:

- Foam cements
- Gas generating cements.

Foam cements do not work well at high pressure and are therefore limited to use at shallow depths.

Gas generating cements maintain cement pore pressure by chemically producing gas downhole (usually hydrogen). To avoid these gas bubbles coalescing and creating channels, the slurries must be carefully designed.

(b) Expansive Cements

Expansive cements may be effective in eliminating small gaps between the cement and the casing or formation, but are unlikely to be effective in eliminating large channels.

There are two main techniques for expanding Portland cements:

- Gas generation
- Crystal growth.

Gas generating expansive cements work in the same way as gas generating compressible cements, but with less gas-generating material added.

Crystal growth expansive cements depend on the growth of added minerals within the set cement.

Formulating these cements must be carefully controlled. Uncontrolled mineral expansion can disrupt and fracture set cement.

14.3 Thixotropic and High Gel Strength Cements

Thixotropic and high gel strength cements resist gas percolation. However, if the gas bubbles are smaller than the cement pore space gas migration can occur without slurry deformation. In such a case gel strength is not a controlling factor. The inherent fluid loss of thixotropic slurries tends to be high and must be controlled.

14.4 Right-Angle Set Cements

Right-angle set (RAS) cement slurries do not gel progressively, they set rapidly. The cement transmits full hydrostatic pressure through the cement column up to when the cement begins to set, and develops a low permeability matrix rapidly enough to prevent gas invasion. RAS slurries can be difficult to design for temperatures below 250 deg F. In RAS slurries, the heat

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generated from the rapid hydration that occurs is produced over a short period - possibly leading to the formation of micro-annuli.

14.5 Impermeable Cements

Reducing the cement matrix permeability prevents gas migration through the cement column. Several methods are available to do this:

- Viscosify the interstitial water of the cement slurry
- Prevent the interstitial water by using bridging agents and polymers
- Use latex additives that coalesce in the pore spaces when they contact gas.

14.6 Surfactants

Under the right circumstances surfactants added to the cement slurry entrain invading gas and create a stable foam. This foam resists gas migration through the slurry.

15.0 Cementing Horizontal And High Angle Sections

15.1 Slurry Design and Testing

It is generally considered more difficult to effectively cement a horizontal section than it is a vertical section. When cementing a horizontal section the slurry designs are not that different to those used on vertical or near vertical sections but the control of slurry properties must be more stringent. Batch mixing is recommended to maintain close control and consistency of slurry properties.

Mixing on the fly subjects slurries to a short period of high rate shearing, batch mixing to a long period of low rate shearing. Cement slurry properties are sensitive to the duration and rate of shearing they undergo. Because the control of slurry properties is more stringent, care must be taken that testing methods and conditions model, as well as possible, the mixing regime to be used.

API tables of BHCTs based on BHSTs and depth do not provide good estimates of the BHCTs of highly deviated or horizontal wells. Therefore, a good computer simulation should be run.

Current API test procedures do not adequately evaluate settling stability. Therefore, a British Petroleum (BP) settlement test should be carried out. This test is now a standard throughout the industry and is likely soon to be incorporated into the API test specifications. For slurries to be used on horizontal sections:

- A settlement less than 3mm is acceptable
- A settlement of more than 5mm is unacceptable
- A gradient of less than 0.5lb/gal is acceptable
- A gradient of more than 1.0lb/gal is unacceptable.

One of the most important criteria to consider when cementing horizontal sections is the free water content. Design cement slurries to contain no more than a trace of free water; zero free water is recommended. The API operating free water test (see section 3.3 Slurry Testing) is the preferred API test. Inclining the test container at forty-five degrees is a variation of the free water test that may be more applicable to cementing horizontal wells.

Fluid loss is important in horizontal wells because it is likely that the slurry is exposed to long permeable sections of formation. Through an impermeable section an API fluid loss of around 150ml/30min is adequate. However, if the section is through a length of highly permeable formation the API fluid loss should be 50ml/30min or less.

The rheology should be consistent with a stable slurry. The Yield Point (YP) should not be less than 5lb/100 sq ft. Dispersants affect slurry stability and should therefore be used with care.

16.0 Learning Milestones

In this chapter, you should have learnt to:

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1. List functions of cement
2. Understand functions of cement additives
3. List parameters measured when testing a cement slurry
4. Explain the functions of casing hardware required while cementing
5. Understand the significance of bumping the plug
6. List factors affecting mud displacement
7. Carry out cement calculations
8. Understand factors affecting liner hanger selection
9. Understand significance of liner lap
10. Understand and carry out cement plug calculations
11. Understand squeeze cementing
12. Understand principle of cement evaluation tools
13. Understand reasons for annular gas migration

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18.0 EXERCISES

Exercise 1: Two Stage Cementing

The following data are given:

Casing size = 9 5/8"

Hole size = 12 1/4"

Hole depth = 10400 ft

Casing Grades = 0-3200ft, C95, 53.5#,

ID = 8.681", 0-3200 ft

ID= 8.535", 3200-10400ft, L80, 47.0#

Mud Weight = 9.8 ppg

Shoe Track = 80 ft

Pumping Rate = 450 gal/min

Mixing Rate = 25 sack/min

Time for release of plugs = 15 min.

This casing is to be cemented in two stages as follows:

Stage One: Shoe to 5480 ft from surface

Stage Two: From 5480 ft to 3000 ft from surface. The stage collar is at 5480 ft.

Two classes of cement are to be used. Class G is to be used for shoe track and from shoe to 600 ft. Class H is to be used elsewhere. Allow 50% excess for the first stage for Class G and 150% for Class H during the first stage only.

Calculate

1. Quantity of cement of each class, using the following data for:

	Class G Cement (Bentonite 2%)	Class H Cement
Slurry Density:	15.8 lb/cu.ft	15.4 lb/cu.ft
Slurry Yield:	1.15 cu.ft/sack	1.22 cu.ft/sack
Mix Water:	5.00 gal/sack	5.49 gal/sack

2. Volume of mix water

3. Job time for each stage

4. Pressure differential which exists at the end of the first stage

5. Weight of casing string in air and in mud

6. Dynamic derrick load, assuming 10 lines strung with an efficiency factor of 0.811, weight of blocks etc. of 22000 lb, and K = 0.9615

7. Safety factor for block line, assuming the line to be 1 1/8 "extra improved plough steel with a breaking strength of 130,000 lb.

8. Ton-miles after running the casing.

(Answers: 1. 274 sacks of class G, 1664 sacks of Class H (stage 1), 637 sacks of Class H (stage 2; 2. 337 bbl; 3. 163 min stage one, 76.6 min stage 2; 4. 1423 psi; 5. 433,603 lb; 6. 565,796 lb; 7. 23.; 8. 258 TM)

Exercise 2:Liner Cementing

The following data are given.

Hole size	= 8.5 in
Liner setting depth	= 8,289 ft
Liner OD	= 7 in
Liner ID	= 6.276 in
Liner weight	= 26 lb/ft
Length of liner	= 1,689 ft
Length of landing collar	= 90 ft
Casing setting depth	= 6,880 ft
Casing OD	= 9.625 in
Casing ID	= 8.65 in

Length of overlap between 7 in liner and 9.625 in casing = 280 ft

Height of cement inside casing = 200 ft

Drillpipe OD = 5 in, ID= 4.276 in Weight= 19.5 lb/ft Length= 6,600 ft

Mud weight	= 10 ppg
Pump factor	= 0.092 bbl/stroke
Pumping rate	= 300 gpm
Mixing rate	= 10 sacks/min
Time for release of plugs	= 10 min
Cement: API G	
Cement weight	= 15.8 ppg
Cement water requirement	= 5 gal/sack
Cement yield	= 1.47 ft^3/sack
Percentage excess in open hole = 150	
Additives	= 35% silica hour

Calculate

1. Total cement volume
2. Number of sacks
3. Weight of silica hour
4. Displacement volume and number of strokes to displace combined plug to landing collar
5. Chase time
6. Job time
7. Hook load before cementing

(Answers: 1.587 ft^3; 2. 399 sacks; 3. 13,127 lb (142 sacks); 4. 177.5 bbl, 1930 strokes; 5. 25 min; 6. 75 min; 7. 146,204 lb)

3. List functions of cement.

4. List the main parameters measured when testing a cement slurry.

5. Why do we need to bump the plug

6. List factors affecting mud displacement

7. What is the minimum length for a liner lap in a vertical and directional well.

8. When do we use squeeze cementing?

9. What is the principle used in cement evaluation tools?

10. What are the factors that control annular gas migration

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7

Drilling Fluids

Contents

Introduction

Drilling mud is one of the most important elements of any drilling operation. The mud has a number of functions which must all be optimised to ensure safety and minimum hole problems. Failure of the mud to meet its design functions can prove extremely costly in terms of materials and time, and can also jeopardise the successful completion of the well and may even result in major problems such as stuck pipe, kicks or blowouts.

There are basically two types of drilling mud: water-based and oil-based, depending on whether the continuous phase is water or oil. Then there are a multitude of additives which are added to either change the mud density or change its chemical properties.

1.0 Drilling Fluid Selection: data Requirements

The following information should be collected and used when selecting drilling fluid or fluids for a particular well. It should be noted that it is common to utilise two or three different fluid types on a single well.

- Pore pressure /fracture gradient plots to establish the minimum / maximum mud weights to be used on the whole well, see Chapters One and Two for details.
- Offset well data (drilling completion reports, mud recaps, mud logs etc.) from similar wells in the area to help establish successful mud systems, problematic formations, potential hazards, estimated drilling time etc.
- Geological plot of the prognosed lithology.
- Casing design programme and casing seat depths. The casing scheme effectively divides the well into separate sections; each hole section may have similar formation types, similar pore pressure regimes or similar reactivity to mud.
- Basic mud properties required for each open hole section before it is cased off.
- Restrictions that might be enforced in the area i.e. government legislation in the area, environmental concerns etc.

2.0 DRILLING FLUID FUNCTIONS

The drilling mud must perform the following basic functions:

1. To control sub-surface pressures by providing hydrostatic pressure greater than the formation pressure. This property depends on the mud weight which, in turn, depends on the type of solids added to the fluid making up the mud and the density of the continuous phase.
2. To remove the drilled cuttings from the hole. The removal of cuttings depends on the viscous properties called "Yield Point" which influences the carrying capacity of the flowing mud and "gels" which help to keep the cuttings in suspension when the mud is static. The flow rate of mud is also critical in cleaning the hole.
3. To cool and lubricate the drill bit and drillpipe.

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4. To prevent the walls of the hole from caving. This function is provided by the formation of a stable mud cake on the walls of the wellbore, somewhat like plastering the walls of a room to keep them from flaking.

5. To release the drilled cuttings at the surface.

6. To prevent or minimise damage to the formations penetrated by having minimum fluid loss into the formation.

7. To assist in the gathering of the maximum information from the formations being drilled.

8. To suspend the cuttings and weighing material when circulation is stopped (gelation). This property is provided by gels and low shear viscosity properties.

9. To minimise the swelling stresses caused by the reaction of the mud with the shale formations. This reaction can cause hole erosion or cavings resulting in an unstable wellbore (See **Chapter 13**). Minimisation of wellbore instability is provided by the "inhibition" character of the drilling mud.

The chemical additives required to achieve the above functions will be explained in the following section.

3.0 DRILLING FLUID ADDITIVES

There are many drilling fluid additives which are used to develop the key properties of the mud.

The variety of fluid additives reflect the complexity of mud systems currently in use. The complexity is also increasing daily as more difficult and challenging drilling conditions are encountered.

We shall limit ourselves to the most common types of additives used in water-based and oil-based muds. These are:

- Weighting Materials

3.1 WEIGHTING MATERIALS

Weighting materials or densifers are solids material which when suspended or dissolved in water will increase the mud weight. Most weighting materials are insoluble and require viscosifers to enable them to be suspended in a fluid. Clay is the most common viscosifier.

Mud weights higher than water (8.3 ppg) are required to control formation pressures and to help combat the effects of sloughing or heaving shales that may be encountered in stressed areas.

Table 7.1 gives a list of the most commonly used weighting materials. The specific gravity of the material controls how much solids material (fractional volume) is required to produce a certain mud weight. For example, to produce a mud weight of 19 ppg (2.28 gm/cc), the solids content from using only barite (sg = 4.2) is 39.5% compared with haematite (sg = 5.2) with solids content of 30%.

Table 7.1 : Materials used as densifiers, After Reference [1]

Material	Principal Component	Specific Gravity	%Acid Soluble
Galena	PbS	7.4-7.7	0
Haematite	Fe_2O_3	4.9-5.3	50+
Magnetite	Fe_3O_4	5.0-5.2	0
Illmenite	$FeO.TiO_2$	4.5-5.1	20
Barite	$BaSO_4$	4.2-4.6	0
Siderite	$FeCO_3$	3.7-3.9	95+

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Celestite	$SrSO_4$	3.7-3.9	0
Dolomite	$CaCO_3.MgCO_3$	2.8-2.9	99
Calcium Carbonate	$CaCO_3$	2.6-2.8	99

3.1.1 Description of Most Commonly Used Weighting Materials

1. Barite

Barite (or barytes) is barium sulphate, $BaSO_4$ and it is the most commonly used weighting material in the drilling industry. Barium sulphate has a specific gravity in the range of 4.20 - 4.60. The specific gravity of Most commercial barite contain impurities including quartz, chert, calcite, anhydrite, and various silicates which slower its specific gravity. It is normally supplied to a specification where the specific gravity is about 4.2.

Barite is preferred to other weighting materials because of its low cost and high purity. Barite is normally used when mud weights in excess of 10 ppg are required. Barite can be used to achieve densities up to 22.0 ppg in both water- based and oil -based muds. However, at very high muds weights (22.0 ppg), the rheological properties of the fluid become extremely difficult to control due to the increased solids content.

2. Iron Minerals

Iron ores have specific gravities in excess of 5. They are more erosive than other weighting materials and may contain toxic materials. The mineral iron comes from several iron ores sources including: haematite/magnetite, illmenite and siderite.

The most commonly used iron minerals are:

Iron Oxides: principally haematite, Fe_2O_3. Haematite can be used to attain densities up to 22.0 ppg in both water- based and oil -based drilling fluids. Iron oxides have several disadvantages including: magnetic behaviour which influences directional tool and magnetic logs, toxciticity and difficulty in controlling mud properties.

Iron Carbonate: Siderite is a naturally occurring ferrous carbonate mineral ($FeCO_3$). It has a specific gravity ranging from 3.70 - 3.90. Both water- based and oil- based muds can be successfully weighted with siderite to 19.0 ppg.

Illmenite: The mineral illmenite, ferrous titanium oxide ($FeTiO_3$), has a specific gravity of 4.60. It is inert but abrasive. Ilmenite can be used to attain densities up to 23.0 ppg in both water-based and oil- based drilling fluids. Illmenite is the main source of titanium.

3. Calcium Carbonates

Calcium carbonate (CaCO3) is one of the most widely weighting agents especially in non-damaging drilling fluids. Its main advantage comes from its ability to react and dissolve in hydrochloric acid. Hence any filter cake formed on productive zones can be easily removed thereby enhancing production. It has a specific gravity of 2.60 - 2.80 which limits the maximum density of the mud to about 12.0 ppg

Calcium carbonate is readily available as ground limestone, marble or oyster shells.

Dolomite is a calcium - magnesium carbonate with a specific gravity of 2.80 - 2.90. The maximum mud density achieved is 13.3 ppg.

4. Lead Sulphides

Galena (PbS) has a specific gravity of 7.40 - 7.70 and can produce mud weights of up to 32 ppg. Galena is expensive and toxic and is used mainly on very high pressure wells.

5. Soluble Salts

Soluble salts are used to formulate solids free fluids and are used mainly as workover and completion fluid. Depending on the type of salt used, fluid densities ranging from 9.0 - 21.5 ppg (sg =1.08 - 2.58) can be prepared. **Table 7.2** gives the maximum densities that can be attained for single salt systems.

Table 7.2 Maximum Densities Of Single Salt Brines, After Baroid [1]

Material	g/cm^3	lb/gal

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Potassium Chloride (KCl)	1.16	9.7
Sodium Chloride (NaCl)	1.20	10.0
Sodium Formate ($NaHCO_2$)	1.33	11.1
Calcium Chloride ($CaCl_2$)	1.42	11.8
Potassium Formate ($KHCO_2$)	1.60	13.3
Calcium Bromide ($CaBr_2$)	1.85	15.4
Caesium Formate	2.36	19.7
Zinc Bromide ($ZnBr_2$)	2.46	20.5

3.2 VISCOSIFIERS

The ability of drilling mud to suspend drill cuttings and weighting materials depends entirely on its viscosity. Without viscosity, all the weighting material and drill cuttings would settle to the bottom of the hole as soon as circulation is stopped. One can think of viscosity as a structure built within the water or oil phase which suspends solid material. In practice, there are many solids which can be used to increase the viscosity of water or oil. The effects of increased viscosity can be felt by the increased resistance to fluid flow; in drilling this would manifest itself by increased pressure losses in the circulating system.

A list of some of the materials used to provide viscosity to drilling fluids is given in **Table 7.3.** We will begin our discussion of viscosifers with clay minerals.

Table 7.3 Materials used as viscosifiers, After Reference 1

Material	Principal Component
Bentonite	Sodium/Calcium Aluminosilicate
CMC	Sodium Carboxy-methyle cellulose
PAC	Poly anionic Cellulose
Xanthan Gum	Extracellullar Microbial Polysaccharide
HEC	Hyroxy-ethyl Cellulose
Guar Gum	Hydrophilic Polysaccharide Gum
Resins	Hydrocarbon co-polymers
Silicates	Mixed Metal Silicates
Synthetic Polymers	High molecular weight Polyacrylamides/polyacrylates

3.2.1 CLAYS

Clays are defined as natural, earthy, fine-grained materials that develop plasticity when wet. They are formed from the chemical weathering of igneous and metamorphic rocks. The major source of commercial clays is volcanic ash; the glassy component of which readily weathers very readily, usually to bentonite.

A clay particle has a characteristic atomic structure in which the atoms form layers, see **Figure 7.1**. There are three layers which give the clays their special properties:

- tetrahedral layers: These are made up of a flat honeycomb sheet of tetrahedra containing a central silicon atom surrounded by four oxygens. The tetrahedra are linked to form a sheet by sharing three of their oxygen atoms with adjacent tetrahedra.
- Octahedral layers: These are sheets composed of linked octahedras, each made up of an aluminium or magnesium atom surrounded by six oxygens. Again, the links are made up by sharing oxygen atoms between two or three neighboring octahedras.
- Exchangeable layers: These are layers of atoms or molecules bound loosely into the structure, which can be exchanged with other atoms or molecules. These exchangeable atoms or molecules are very important as they give the clays their unique physical and chemical properties.

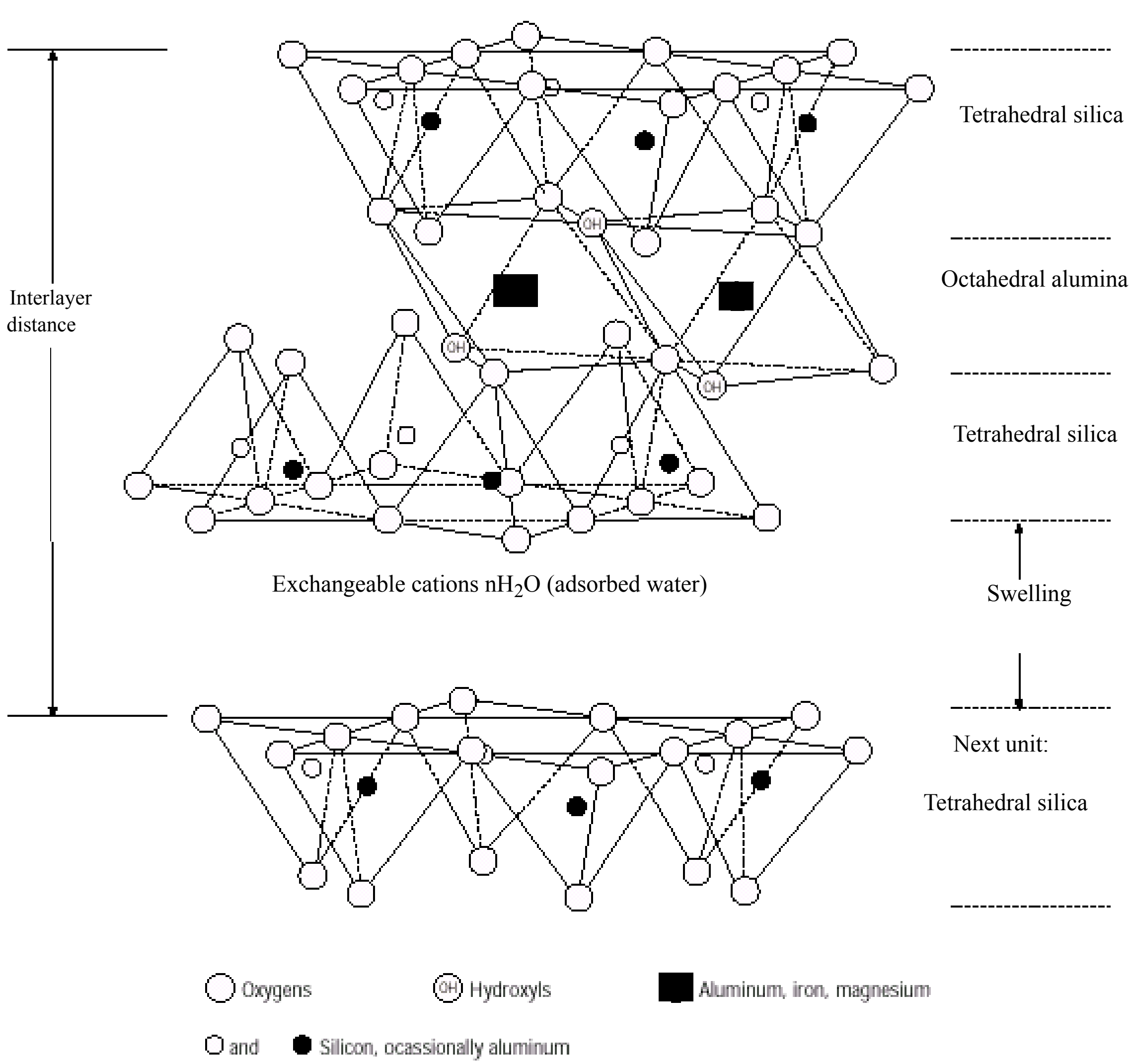
The nature of the above layers and the way they are stacked together define the type of clay mineral. For this reason, they are several types of clays available. The most widely used clay is bentonite.

Bentonite

This is the most widely used additive in the oil industry. The name, bentonite, is a commercial name used to market a clay product found in the Ford Benton shale in Rock Creek, Wyoming, USA.

Bentonite is defined as consisting of fine-grained clays that contain not less than 85% Montmorillonite which belongs to the class of clay minerals known as smectites. Bentonite is classified as sodium bentonite or calcium bentonite, depending on the dominant exchangeable cation. In fresh water, sodium bentonite is more reactive than calcium bentonite and hence, in terms of performance, bentonite is classed as "high yield" (Sodium Bentonite) or "low yield" (Calcium Bentonite).

Figure 7.1 Atomic structure of smectite clays, after reference 2



Bentonite is used to build viscosity in water which is required to suspend weighting materials and drillcuttings. When clay is dispersed in water, viscosity is developed when the clay plates adsorb water layers on to their structure. Each or several stacked water layers are shared by two clay plates; these repeating structures of clay plates and their attached water layers result in a viscous structure. The dispersion process will only take place in fresh water. If the clay is used in salt muds it has to be prehydrated in fresh water.

Attapulgite

Attapulgite belongs to a quite different family of the clay minerals. In this family, the tetrahedra in the tetrahedral sheets of atoms do not all point in the same way, but some tetrahedra in the sheets are inverted. Instead of crystallising as platy crystals, attapulgite forms needle-like crystals.

Attapulgite-based muds have excellent viscosity and yield strength and retain these properties when mixed with salt water. However, they have the disadvantage of suffering high water loss thereby giving poor sealing properties across porous and permeable formations.

Organophillic Clays [1]

Organophillic clays are made from normal clays (bentonite or attapulgite) and organic cations. The organic cations replace the sodium or calcium cations originally present on the clay plates. Organophillic clays can be dispersed in oil to form a viscous structure similar to that built by bentonite in water.

3.2.2 POLYMERS

Polymers are used for filtration control, viscosity modification, flocculation and shale stabilisation. When added to mud, polymers cause little change in the solid content of the mud.

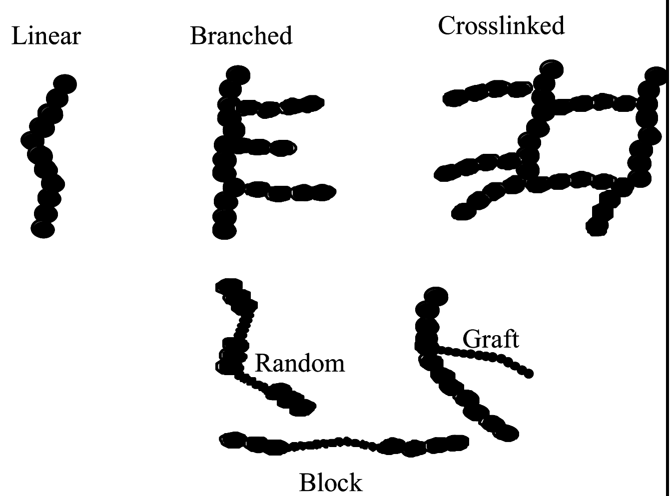
Polymers are chemicals consisting of chains made up of many repeated small units called monomers.Polymers are formed from monomers by a process called polymerization. The repeating units (monomers) that make up the polymer may be the same, or two or more monomers may be combined to form copolymers. Structurally, the polymer may be linear or branched and these structures, either linear, branched, or both, may be cross-linked, i.e. tied together by covalent bonds [1], see **Figure 7.2**.

Types of Reactive Groups

The chemical reactivity of polymers is mainly dependent on the type of groups that are attached to the molecule and the number of groups. The groups that can be attached to the polymer can be divided into three groups:

1. Nonionic or neutral
2. Anionic or negatively charged
3. Cationic or positively charged

Figure 7.2 Structure of Polymers



Examples of Polymers

Starches

Starch is a natural polymer used in drilling muds primarily to reduce filtrate loss and to provide viscosity. Starch is the principal component of the seeds of cereal grains (such as corn, wheat and rice) and of tubers (such as potato and tapioca). Starches[1] are subject to fermentation by many micro organisms (yeasts, molds, bacteria) and unless a mud containing starch is saturated with salt or the pH is about 12, a biocide should be added.

Starch disperses in water to form a swollen particle that physically blocks the pore spaces. This action is independent of the salt level in the mud. The addition level of starch is relatively high in the region of 3-6 lb/bb.

Chemical modification of starch can significantly increase its stability to temperature and mechanical shear and the correct type of starch must be selected to match the prevailing bottom hole temperatures.

Guar Gum[1]

Guar gum is a natural polymer produced from the seeds of guar gum plants. Guar gum is an nonionic polysaccharide polymer with a molecular weight of about 220,000. Guar gum can also be attacked by micro organisms unless protected by high pH, high salinity, or a biocide. Guar gum flocculates drilled cuttings when added in low concentrations while drilling with water.

Xanthan Gum

Xanthan gum **(Microbial Polysaccharides)** is a water-soluble biopolymer produced by the action of bacteria on carbohydrates The bacteria are killed after the fermentation process and the gum extracted by precipitation with isopropyl alcohol. After the alcohol is recovered, the gum is dried and milled. The polymer has a molecular weight of around 5,000,000.

Xanthan gum can build viscosity in fresh, sea and salt water without the assistance of other additives. Uniquely the molecule forms a rigid rod like structure in solution. This gives very high viscosities or gels at low shear rates. Consequently, xanthan polymer gives excellent suspension properties that cannot be matched by other polymers at equivalent concentrations.

Xanthan gum polymer muds are resistant to contamination by anhydrite, gypsum and salt. This polymer[1] has particular application in clay free, potassium based fluids where it will increase the carrying capacity of mud without increasing its viscosity. The polymer also has application in completion fluids where suspension of weighting materials is required

Carboxymethylcellulose (CMC)

Sodium carboxymethylcellulose (usually abbreviated as CMC) is an anionic polymer produced by the treatment of cellulose with caustic soda and then monochloro acetate. The molecular weight ranges between 50,000 and 400,000.

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Being anionic, CMC easily adsorbs on clay surfaces. Filtration is sharply reduced by low concentrations of CMC in clay based drilling fluids. Higher molecular weight CMC is most effective in filtration control. CMC is used for viscosification and filtration reduction in heavily weighted muds and wherever little viscosification of the fluid phase of the mud is desirable.

Polyanionic Cellulose [1]

Polyanionic cellulose (PAC), is a semi-synthetic polymer which has been modified to increase its tolerance to salt (up to saturation) and calcium.

Hydroxyethyl Cellulose

Hydroxyethyl cellulose (HEC) is made by a similar process to CMC but with ethylene oxide after the caustic soda. Its main advantage lies in its ability to hydrate in all types waters.

The polymer [1] does not contain any ionic groups and therefore it is ideally suited as a viscosifier for clear fluid completion and other brine- based fluids. The polymer exhibits highly developed thioxotropy or shear thinning characteristics, but does not exhibit any yield stress or gellation properties.

3.3 Filtration Control Materials

Filtration control materials are compounds which reduce the amount of fluid that will be lost from the drilling fluid into a subsurface formation caused by the differential pressure between the hydrostatic pressure of the fluid and the formation pressure. Bentonite, polymers, starches and thinners or deflocculants all function as filtration control agents.

Bentonite imparts viscosity and suspension as well as filtration control. The flat, "plate like" structure of bentonite packs tightly together under pressure and forms a firm compressible filter cake, preventing fluid from entering the formation

Polymers such as Polyanionic cellulose (PAC) and Sodium Carboxymethylcellulose (CMC) reduce filtrate mainly when the hydrated polymer chains absorb onto the clay solids and plug the pore spaces of the filter cake p preventing fluid seeping through the filter cake and formation. Filtration is also reduced as the polymer viscosifies the mud thereby creating a viscosified structure to the filtrate making it difficult for the filtrate to seep through.

Starches function in a similar way to polymers. The free water is absorbed by the sponge like material which aids in the reduction of fluid loss. Starches form very compressible particles that plug the small openings in the filter cake.

Thinners and deflocculants function as filtrate reducers by separating the clay flock's or groups enabling them to pack tightly to form a thin, flat filter cake.

3.4 Rheology Control Materials

When efficient control of viscosity and gel development cannot be achieved by control of viscosifier concentration, materials called "thinners", "dispersants", and/or "deflocculants" are added. These materials cause a change in the physical and chemical interactions between solids and/or dissolved salts such that the viscous and structure forming properties of the drilling fluid are reduced.

Thinners are also used to reduce filtration and cake thickness, to counteract the effects of salts, to minimize the effect of water on the formations drilled, to emulsify oil in water, and to stabilize mud properties at elevated temperatures.

Materials commonly used as thinners in clay- based drilling fluids are classified as: (1) plant tannins, (2) lignitic materials, (3) lignosulfonates, and (4) low molecular weight, synthetic, water soluble polymers.

3.5 Alkalinity and pH Control Materials

The pH affects several mud properties including:

- detection and treatment of contaminants such as cement and soluble carbonates
- solubility of many thinners and divalent metal ions such as calcium and magnesium

Alkalinity and pH control additives include: NaOH, KOH, $Ca(OH)_2$, $NaHCO_3$ and $Mg(OH)_2$. These are compounds used to attain a specific pH and to maintain optimum pH and alkalinity in water base fluids.

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3.6 Lost Circulation Control Materials

See **Chapter 13** for details.

3.7 Lubricating Materials

Lubricating materials are used mainly to reduce friction between the wellbore and the drillstring. This will in turn reduce torque and drag which is essential in highly deviated and horizontal wells. Lubricating materials include: oil (diesel, mineral, animal, or vegetable oils), surfactants, graphite, asphalt, gilsonite, polymer and glass beads

3.8 Shale Stabilizing Materials

There are many shale problems (see **Chapter 13**) which may be encountered while drilling sensitive highly hydratable shale sections.

Essentially, shale stabilization is achieved by the prevention of water contacting the open shale section. This can occur when the additive encapsulates the shale or when a specific ion such as potassium actually enters the exposed shale section and neutralises the charge on it.

Shale stablisers include: high molecular weight polymers, hydrocarbons, potassium and calcium salts (e.g. KCl) and glycols.

Field experience indicates that complete shale stabilisation can not be obtained from polymers only and that soluble salts must also be present in the aqueous phase to stabilize hydratable shales.

4.0 Drilling Fluid Types

A drilling fluid can be classified by the nature of its continuous fluid phase. There are three types of drilling fluids:

1. Water Based Muds
2. Oil Based Muds
3. Gas Based Muds

4.1 WATER BASED MUD

These are fluids where water is the continuous phase. The water may be fresh, brackish or seawater, whichever is most convenient and suitable to the system or is available.

The following designations are normally used to define the classifications of water based drilling fluids:

1. Non-dispersed-Non - inhibited
2. Non-dispersed - Inhibited
3. Dispersed - Non-inhibited
4. Dispersed - Inhibited

Non-Inhibited means that the fluid contains no additives to inhibit hole problems.

Inhibited means that the fluid contains inhibiting ions such as chloride, potassium or calcium or a polymer which suppresses the breakdown of the clays by charge association and or encapsulation.

Dispersed means that thinners have been added to scatter chemically the bentonite (clay) and reactive drilled solids to prevent them from building viscosity.

Non-Dispersed means that the clay particles are free to find their own dispersed equilibrium in the water phase.

Non-dispersed-non-inhibited fluids do not contain inhibiting ions such as chloride (Cl^-), calcium (Ca^{2+}) or potassium (K^+) in the continuous phase and do not utilize chemical thinners or dispersants to affect control of rheological properties.

Non-dispersed- inhibited fluids contain inhibiting ions in the continuous phase, however they do not utilize chemical thinners or dispersants.

Dispersed-non-inhibited fluids do not contain inhibiting ions in the continuous phase, but they do rely on thinners or dispersants such as phosphates, lignosulfonate or lignite to achieve control of the fluids' rheological properties.

Inhibited dispersed contain inhibiting ions such as calcium (Ca^{2+}) or potassium (K^{+}) in the continuous phase and rely on chemical thinners or dispersants to control the fluids rheological properties.

4.1.1 Non-Dispersed, Non-Inhibited Mud Systems

Spud Gel Mud: Used for top hole drilling, usually in 40 to 50 bbls pills on each connection, and hole volume sweeps and displacement at hole TD. The mud is prepared by pre-hydrating bentonite at 30 ppb (pounds per barrel) for 4-6 hrs prior to use to allow time for the clay to yield.

CMC Gel Mud: Used as an alternative to the spud mud when the mud system is closed in. The CMC added at 1 to 3 ppb, offers some fluid loss control, however, this mud system should only be used in areas of unreactive formations and will be subjected to high levels of dilution.

4.1.2 Dispersed, Non-Inhibited Systems

Lignite, Lignosulphonate or Phosphate Muds: This is a clay- based fresh water mud which requires high treatment dilution levels while drilling reactive clays. Extra caustic soda needs to be added because of acidic tendencies of system. This is a cheap and easy mud system to maintain, however, it is not common in the oil industry today.

4.1.3 Dispersed Inhibited Systems

Lime /Gypsum Muds: These muds are built from fresh water but can also be built using seawater. Lime/gypsum muds are often used in areas where shale hydration and swelling result in significant borehole instability. The presence of calcium ions in mud help to stabilise the open shales and prevent sloughing and heaving.

4.1.4 Non-Dispersed, Inhibited Systems.

These mud systems are the most common in drilling problematic formations like reactive clays, sloughing heaving shales and halite salt sections. The mechanisms of inhibition vary according to the type of inhibitive product being used. It is common to utilise two or more products in the same mud system. These mud systems also minimise the reaction with the drilled cuttings and therefore help to avoid the high dilution rates exhibited by other fluid groups.

Salt Saturated Mud: In this system, the continuous phase, water, is saturated with salt (sodium chloride) usually at 180 mg/L, and mud viscosity is developed with PAC (for filtration) and XC Polymer (for viscosity) and starch is used to control fluid loss. Attapulgite clay can be used for viscosity particle distribution. This system is used for drilling salt sections to balance the formations and avoid wash-outs. This system has a minimum mud weight of 10 ppg.

It should be noted that the solubility of salt increases with temperature, so the system should be mixed with slightly extra salt to compensate for the increased temperature at downhole conditions. If the drillstring becomes stuck whilst drilling a salt section, spot a fresh water pill across the zone and allow the salt to dissolve.

KCl Polymer Mud: This mud consists of Potassium Chloride (KCl) dissolved in fresh or salt water. Both the potassium and the polymer are used to reduce shale hydration by ion substitution using the potassium ions and encapsulation of the shale by the polymer.

Potassium is a smaller and more highly charged ion than the sodium ion but has a low charge density and is less hydrated than the sodium ion. Hence, the substitution of sodium ions on the shale surface by the potassium ions enable the shale platelets to be closer together and, in addition to this, the potassium ion fits inside the volume of the ion spacing on the clay surface, thereby neutralising the negative charge on the clay surface with a greater strength. This results in shale drill cuttings being easier to remove and less contamination in the system. Wellbore stability is also increased by the addition of potassium to mud as a result of creating a non-reactive wellbore.

During drilling, the potassium ion is being readily used up on the wellbore and cuttings and further additions of potassium is required to to maintain the potassium concentration in the mud system.

PHPA Muds: PHPA (Partially Hydrolysed Polyacrylamide) is a high molecular weight polymer and is used as a cuttings and wellbore stabiliser. The PHPA molecules bond on clay sites and inhibit the dispersion of solids into the mud system by encapsulating the clay particles. This aides the solids removal process on surface.

The PHPA concentration should be held in excess in the system by 2 to 4 ppb at all times. This system can be used in conjunction with KCl for added inhibition.

Clay inhibition can also be obtained from products like Glycols, Cations and Mixed Metal Hydroxides.

4.2 Completion and Workover Fluids

These are fluids are designed to be non-damaging to the reservoir during the completion of and workover a well. They are usually brines (salty water) which can be made up with up to three different salts depending on the required density. Commonly seawater or sodium chloride is used. Below is a list of salt types and their density ranges [1]:

Sodium Chloride	8.4 to 10.0 ppg
Calcium Chloride	8.4 to 11.63 ppg
Sodium Chloride /Calcium Chloride	9.0 to 11.23 ppg
Calcium Chloride / Calcium Bromide	10.83 to 13.33 ppg
Calcium Bromide / Zinc Bromide	13.33 to 18.33 ppg

4.3 Oil Based Muds

An oil based mud system is one in which the continuous phase of a drilling fluid is oil. When water is added as the discontinuous phase then it is called an invert emulsion. These fluids are particularly useful in drilling production zones, shales and other water sensitive formations, as clays do not hydrate or swell in oil. They are also useful in drilling high angle/horizontal wells because of their superior lubricating properties and low friction values between the steel and formation which result in reduced torque and drag.

Invert emulsion fluids (IEFs) are more cost-effective than water muds in the following situations:

- Shale stability
- Temperature stability

- Lubricity
- Corrosion resistance
- Stuck pipe prevention
- Contamination
- Production protection

Oil based muds are subject to strict Government Legislations and so serious thought should be given to alternative systems.

There are two types of oil based muds:

- Invert Emulsion Oil Muds
- Pseudo Oil Based Mud

4.3.1 Invert Emulsion Oil Mud

The basic components of a typical low toxicity invert emulsion fluid are:

Base Oil: Only low toxic base oil should be used as approved by the authorities (such as the DTI in the UK). This is the external emulsion phase.

Water: Internal emulsion phase. This gives the Oil/Water Ratio (OWR), the% of each part as a total of the liquid phase. Generally, a higher OWR is used for drilling troublesome formations. The salinity of the water phase can be controlled by the use of dissolved salts, usually calcium chloride. Control of salinity in invert oil muds is necessary to "tie-up" free water molecules and prevent any water migration between the mud and the open formation such as shales.

Emulsifier: Often divided into primary and secondary emulsifiers. These act at the interface between the oil and the water droplets. Emulsifier levels are held in excess to act against possible water and solid contamination.

Wetting Agent: This is a high concentration emulsifier used especially in high density fluids to oil wet all the solids. If solids become water wet they will not be suspended in the fluid, and would settle out of the system.

Organophillic Clay: These are clays treated to react and hydrate in the presence of oil. They react with oil to give both suspension and viscosity characteristics.

Lime: Lime is the primary ingredient necessary for reaction with the emulsifiers to develop the oil water interface. It is also useful in combating acidic gases such as CO_2 and H_2S. The concentration of lime is usually held in excess of 2 to 6 ppb, depending on conditions.

4.3.2 Pseudo Oil Based Mud

To help in the battle against the environmental problem of low toxicity oil based muds and their low biodegradability, developments have been made in producing a biodegradable synthetic base oil. A system which uses synthetic base oil is called a Pseudo Oil Based Mud (SOB) and is designed to behave as close as possible to low toxic oil based mud (LTOBM). It is built in a fashion akin to normal oil based fluids, utilising modified emulsifiers.

SOB muds are an expensive systems and should only be considered in drilling hole sections that cannot be drilled using water based muds without the risk of compromising the well objectives.

The base oil that is being changed out can be one of the following:

Detergent Alkalates, Synthetic Hydrocarbon, Ether and Ester. These have been listed in increasing order of cost, biodegradability and instability.

Synthetic base fluids include Linear Alpha Olefins (LAO), Isomerised Olefins (IO), and normal alkanes. Other synthetic base fluids have been developed and discarded such as ethers and benzene based formulations.

Esters are non-petroleum oils and are derived from vegetable oils. They contain no aromatics or petroleum-derived hydrocarbons. The primary advantage of an ester-based fluid is that it biodegrades readily, either aerobically or, more importantly, from a mud cuttings disposal viewpoint, anaerobically.

4.4 Gas Based Fluids

There are four main types of gas based fluids:

1. Air
2. Mist
3. Foam
4. Aerated Drilling Fluid

These are not common systems as they have limited applications such as the drilling of depleted reservoirs or aquifers where normal mud weights would cause severe loss circulation. In the case of air the maximum depth drillable is currently about 6-8,000 ft because of the capabilities of the available compressors. Water if present in the formation is very detrimental to the use of gas-based muds as their properties tends to break down in the presence of water.

5.0 Drilling Mud Properties

The properties of a drilling fluid can be analysed by its physical and chemical attributes. The major properties of the fluid should be measured and reported daily in the drilling morning report.

Each mud property contributes to the character of the fluid and must be monitored regularly to show trends, which can be used to ascertain what is happening to the mud whilst drilling. There are many tests a fluid can have; the major ones are explained below.

5.1 Mud Weight or Mud Density

Unit: pounds per gallon (ppg or lb/gal).

Alternatives:Specific Gravity SG (g/cm^3),Kpa/m, psi/ft

Figure 7.3 Mud balance, Ref 2

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ppg = sg x8.33
= KPa/m x 1.176
= psi/ft x 0.052

Apparatus:Mud balance, or where gases may be entrapped in the mud due to high weights or thick mud, then a Pressure Balance should be used. Each should be calibrated at the start of the job to weigh 8.33 ppg with fresh water.As shown in **Figure 7.3** a cup is filled with a sample of mud and is then balanced on the mud balance which is calibrated to read mud weight directly.

Additives: Increasing mud density should only be done with additions of a weight material, e.g. barytes, haematite or acid soluble, calcium carbonate, and not through build up of drilled solids. Decreasing mud density should only be done by dilution and acceptable solids control practices.

Below are some useful formulae for calculating changes in the fluid volume or density as a result of addition of solids or dilution:

Weight increase using barytes

$$X = 1470*(W2 - W1) / (35 - W2) \tag{7.1}$$

Volume increase using Barytes

$$V = 100*(W2 - W1) / (35 - W2) \tag{7.2}$$

where

X = No of 100 lbs sacks per 100 bbls of mud

V = No of bbls increase per 100 bbls of mud

W1 = Initial mud weight (ppg)

W2 = Desired mud weight (ppg)

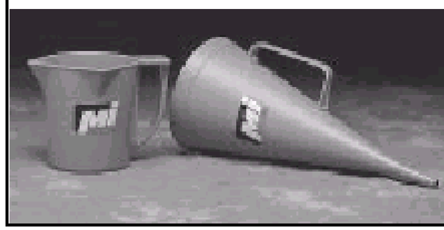
5.2 Funnel Viscosity

Unit:Seconds per quart (sec/qt).

Alternatives: Seconds per litre (sec/lt).

Apparatus:Marsh Funnel. This is usually calibrated to read 26 ± 0.5 seconds when testing with fresh water.

Figure 7.4 Marsh Funnel, Ref 2

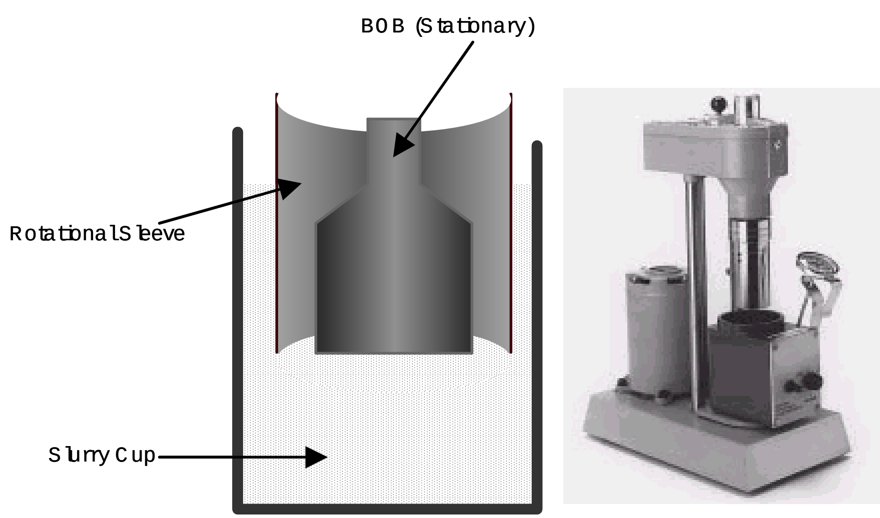


The March Funnel is a simple device used for the routine monitoring of the viscosity, and should be performed alongside the mud weight check. Marsh funnel readings are affected by mud weight, solids content and temperature. The value from the Marsh funnel should only be used for comparison purposes and for monitoring trends.

5.3 Plastic Viscosity (PV)

Apparatus:

Figure 7.5 Fann viscometer



Viscometer or rheometer is a device used to measure the viscosity and yield point of mud, Figure 7.5. A sample of mud is placed in a slurry cup and rotation of a sleeve in the mud gives readings which can be mathematically converted into plastic viscosity (PV) and yield point (YP)[6]. Multi-speed rheometer are recommended whenever possible since readings can be obtained at 600,300,200,100,6 and 3 rpm. PV (in cP) is measured by taking the difference between the dial readings taken at the two highest speeds of 600 rpm and 300 rpm.

$$PV = \theta 600 - \theta 300 \tag{7.3}$$

If temperature is a factor, then the mud sample should be tested at 120 ^{o} F, with the mud in a heating cup

5.4 YIELD POINT

Unit: lbf/100sq ft

Alternatives:Pascals (Pa) = lbs/100sq.ft x 0.48

Apparatus: Same equipment as used for measurement of plastic viscosity. Yield Point (YP) is calculated from the following:

$$YP = \theta 300 - PV \tag{7.4}$$

Both PV and YP are mathematical values which can be used for calculating the pressure loss in the circulating system as will be discussed in **Chapter 8**. When plastic viscosity rises, this is usually an indication that the solids control equipment are running inefficiently. Ideally, the yield point should be just high enough to suspend the cuttings as they are circulated up the annulus.

5.5 GEL STRENGTHS

Unit:Same as Yield Point.

Alternatives: Same as Yield Point.

Apparatus: Six speed viscometer. There are two readings for gel strengths, 10 second and 10 minute with the speed of the viscometer set at 3 rpm. The fluid must have remained static prior to each test, and the highest peak reading will be reported.

Applications: The gel strength quantifies the thixotropic behaviour of a fluid; its ability to have strength when static, in order to suspend cuttings, and flow when put under enough force. Ideally the two values of gel strength should be close rather than progressively far apart.

5.6 Fluid Loss and Filter Cake

Fluid loss:

Unit: ml / 30 minutes at100 psi (for API test) or 500 psi and BHT (°F) for high temperature/high pressure (HTHP).

Filter cake thickness is measured in $^{1}/_{32}$".

Apparatus: Both tests work on filling a cell with drilling fluid, and sealing it shut. Inside the cell is a filter paper that has been placed between the mud and the aperture in the cell. Pressure is applied to the cell which forces the mud and solids through the filter paper. The solids accumulating on he filter paper form a filter cake and the the filtrate passing through the paper is collected in a graduated cylinder. The mud in the cell is pressurised for 30 min and the fluid or filtrate is collected and measured. The filter paper is also collected, washed, then examined and the deposited filter cake is measured. HPHT tests with the cell put under heat are usually carried out on wells where the temperature is greater than 200^{o} F.

Applications: The fluid loss gives a representation of the fluids interaction with the well bore under simulated pressure and temperature conditions. Ideally the fluid should form a thin, flexible, impermeable layer (filter cake) against the wall and prevent fluid (filtrate) from entering the rock and reacting with the formations. A mud system with a low value of filtrate loss cause minimum swelling of clays and minimum formation damage.

The filter cake should be in the region of 1 to 2 $/_{32}$" and should never be greater than $3/_{32}$", even in an HPHT test with WBM.

Filtration control additives include:

- Starch
- Carboxymethylcellulose (CMC)
- Polyanionic Cellulose (PAC)

6.0 Drilling Fluid Problems

6.1 Contaminations

The vast majority of problems associated with drilling fluids can be directly attributed to the detrimental effects of some type of contamination that enters the mud system.Contaminants can be solid or liquid.

6.2 Calcium / Magnesium Contamination

Calcium / Magnesium contamination causes excessive viscosity and fluid loss increases, especially in fresh water clay based systems. Calcium (Ca^{2+}) and /or Magnesium (Mg^{2+}) may originate from the make-up water, formation water or during the drilling of evaporite formations.

Treatments

If the contamination is from the make-up, or formation water it is usual to treat it out with Soda Ash at 0.000931 ppb of soda per 1.0 mg/L of Ca^{2+}. The addition of soda ash also increases the pH of the mud system which will help decrease the solubility of calcium.

Magnesium contamination is most often encountered when seawater is used as the make-up water. It causes similar effects to mud system as calcium, but is treated with Caustic Soda at 0.00116 ppb Caustic Soda per 1.0 mg/L of Mg^{2+}. Note that nearly all the magnesium in the system will be precipitated out when pH > 10.5.

Anhydrite / Gypsum Contamination. The addition of calcium ions from the drilling of anhydrite and gypsum formations causes flocculation and filtration control problems due to increased calcium concentration in the mud. If the effect is relatively small then the same treatment as for calcium will be sufficient. If a large bed of anhydrite / gypsum is being drilled, it might be prudent to change over to a lime or gyp system.

6.3 Cement / Lime Contamination

Cement contamination occurs when drilling out a cement plug or shoe. If the cement has not cured or set, then it is said to be green and in this state will cause the greatest amount of problems to a drilling fluid. Cement reacts with water to form calcium hydroxide which can yield up to 80% lime. Lime will flocculate freshwater bentonite systems causing increases in viscosity and fluid loss. Treating lime contamination involves reducing the pH and controlling the calcium concentration. The difference between lime and anhydrite contamination is that anhydrites will not increase the pH of mud.

Treatment:

- Add Sodium Bicarbonate. This will react to form insoluble calcium carbonate.
- Add SAPP (Sodium Acid Pyrophosphate), which reacts with lime to form an insoluble calcium phosphate.

6.4 Sodium Chloride Contamination

Salt contamination can come from make-up water, saltwater flows, salt domes or evaporite formations. The most common form is sodium chloride (NaCl), but chlorides of potassium, magnesium or calcium or combinations of all types can also enter the mud system.

Salt will flocculate a fresh water based mud causing high viscosities and filtration control problems. In some cases the available ions may cause a shrinkage effect on the clay plates and decrease the viscosity.

Treatment

Salt cannot be precipitated by chemical means and so the only method to treat it is by dilution with fresh water.

6.5 Carbonate / Bicarbonate Contamination

Carbonates may exist in three forms depending on the pH: carbonic acid, bicarbonate, or carbonate. They can originate from:

- Over treatment to remove calcium cement contamination.
- CO_2 build-up from formation gas and mud mixing equipment.
- Thermal degradation of organic compounds at high temperature.
- Contaminated barytes.

Treatment

This contamination can be removed by adding some form of calcium to form a precipitate and caustic soda to increase the pH if lime is not used.

6.6 Hydrogen Sulphide (H_2S) Contamination

Hydrogen sulphide is a highly poisonous and corrosive gas. Small concentrations in the air can be fatal in minutes, and hence protective measures should be taken whenever there is a possibility that this gas will be encountered. H_2S has adverse effects on many of the fluid properties. It is measured using a Garrett Gas Train or a Drager tube.

H_2S can enter the system from various sources, including hydrocarbon reservoirs, sulphides formations reaction with mud from bacteria within the mud. Sulphide reducing bacteria (SRB) has been identified as the source of H_2S in some drilling operation. The bacteria is introduced to the well from contaminated mud tanks and the bacteria either react with the formation or with mud downhole producing free H_2S.

Invert emulsion fluids are often used to drill H_2S bearing formations since their properties are relatively unaffected by the gas, and the drill pipe is maintained in an "oil wet" condition which minimizes corrosion. H_2S intrusions remove lime from an invert emulsion fluids and may cause emulsion instability.

Treatment

The pH should be kept at a minimum of 10.0 using Lime, not caustic, at all times. A filming amine can be used to protect the metal from corrosion and / or Ironite Sponge which acts as a sacrificial material.

6.7 Water flows

A water flow causes a decrease in the base fluid water ratio of the mud and, possibly, increases in the funnel viscosity, plastic viscosity, and yield point. A water flow can cause the solids in the mud to become water wet.

7.0 SOLIDS CONTROL EQUIPMENT

Recall mud is made up of fluid (water, oil or gas) and solids (bentonite, barite etc).The aim of any efficient solids removal system is to retain the desirable components of the mud system by separating out and discharging the unwanted drilled solids and contaminants.

Solids in drilling fluids may be classified in two separate categories based on specific gavity, (or density) and particle size.

Solids, classified by specific gravity, may be divided into two groups:

- High Gravity Solids (H.G.S.) sg = 4.2
- Low Gravity Solids (L.G.S.) sg = 1.6 to 2.9

The solids content of a drilling fluid will be made up of a mixture of high and low gravity solids. High gravity solids (H.G.S) are added to fluids to increase the density,e.g. barytes, whilst low gravity solids (L.G.S) enter the mud through drilled cuttings and should be removed by the solids control equipment.

Mud solids are also classified according to their size in units called microns (μ). A micron is 0.0000394 in or 0.001 mm. Particle size is important in drilling muds for the following reasons:

- The smaller the particle size, the more pronounced the affect on fluid properties.
- The smaller the particle size, the more difficult it is to remove it or control its effects on the fluid.

The API classification of particle sizes is:

Particle Size (μ)	Classification	Sieve Size (mesh)
> 2000	Coarse	10
2000 - 250	Intermediate	60
250 - 74	Medium	200
74 – 44	Fine	325

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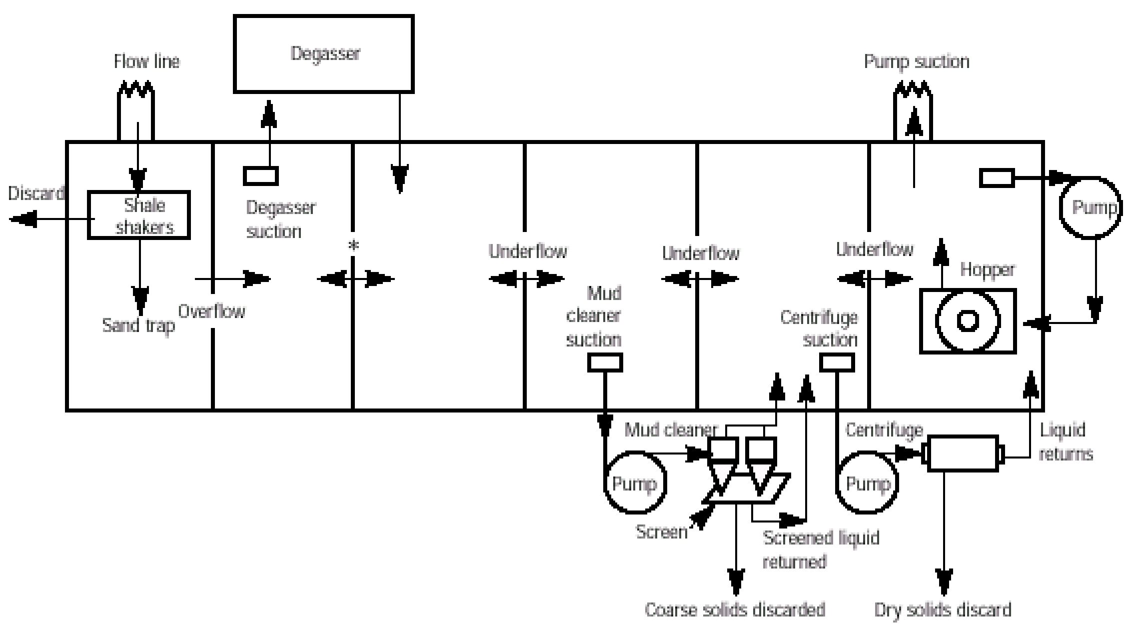
44 - 2	Ultra Fine	-
2 - 0	Colloidal	-

7.1 SOLIDS CONTROL EQUIPMENT

Solids contaminants and gas entrapped in mud can be removed from mud in four stages:

- Screen separation: shale shakers, scalper screens and mud cleaner screens.
- Settling separation in non-stirred compartments: sand traps and settling pits.
- Removal of gaseous contaminants by vacuum degassers or similar equipment
- Forced settling by the action of centrifugal devices including hydrocyclones (desanders, desilters and micro-cones) and centrifuges.

Figure 7.6 Complete mud removal system with mud cleaner and centrifuge, after reference 2

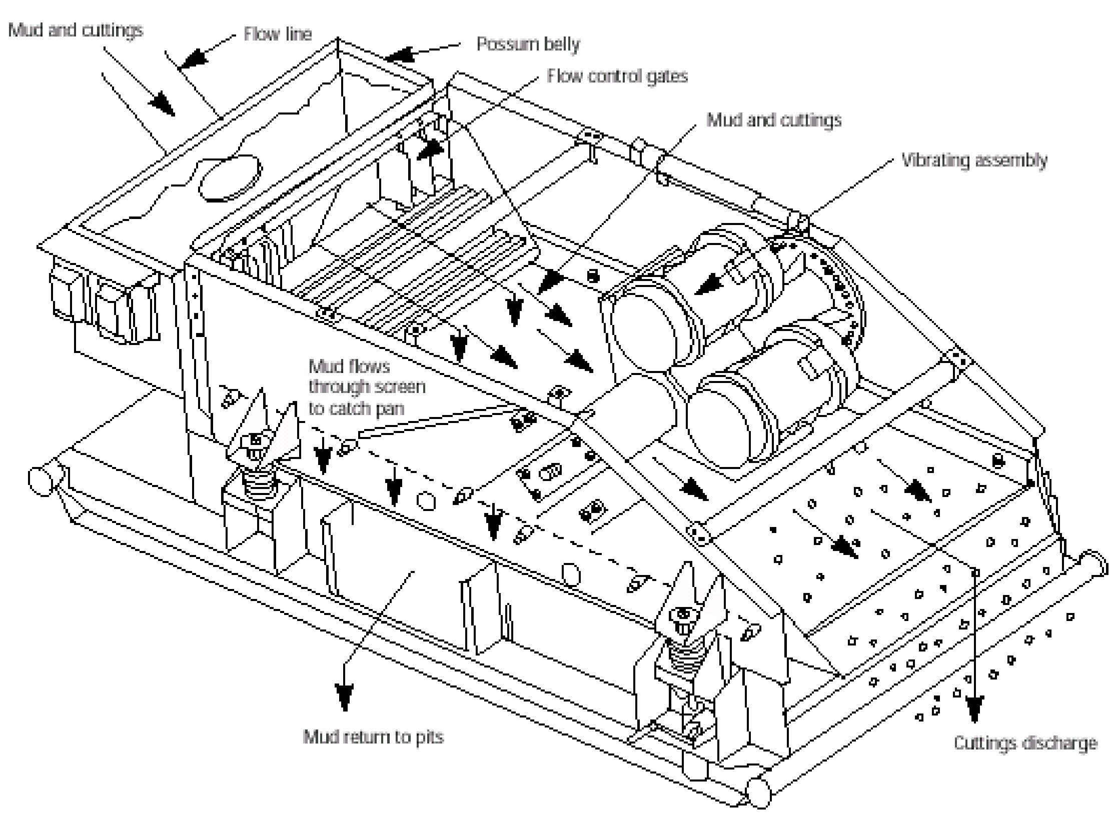


7.1.1 Screen Separation Devices

Figure 7.6 shows a layout for solids control equipment for a weighted mud system.

Shale shakers and scalper screens (Gumbo shakers) can effectively remove up to 80% of all solids from a drilling fluid, if the correct type of shaker is used and run in an efficient manner. Mud laden with solids passes over the vibrating shaker (Figure 7.7) where the liquid part of mud and small solids pass through the shaker screens and drill cuttings collect at the bottom of the shaker to be discharged.

Figure 7.7 Linear shale shaker, courtesy of MI [2]



There are two types of shaker operation: elliptical and linear motion. Field experience indicate that elliptical shakers work better with water based muds and linear motion shakers are more suited to oil based muds.

An absolute minimum of three shale shakers is recommended and that these shakers are fitted with retrofit kits to allow quick and simply replacements.

The shakers should also be in a covered, enclosed housing with a means of ventilation and each shaker fitted with a smoke hood.

7.1.2 SETTLING SEPARATION IN NON-STIRRED COMPARTMENTS

The solids control pits work on an overflow principle. The sand traps (**Figure 7.6**) are the first of the solids control pits and are fed by the screened mud from the shale shakers. There should be no agitation from suction discharge lines or paddles. Any large heavy solids will settle out here and will not be carried on into the other pits.

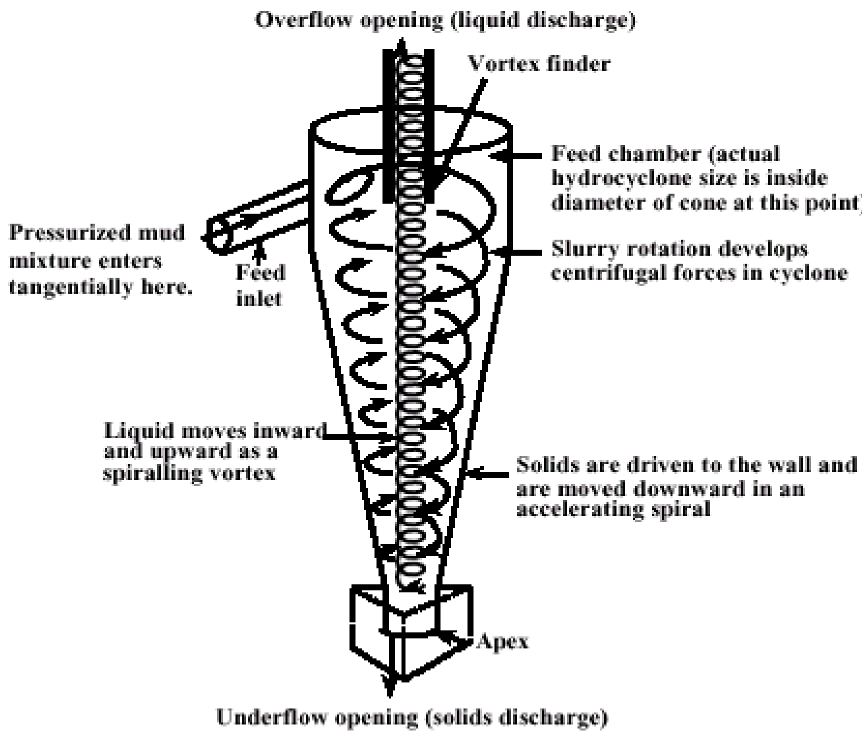
7.1.3 REMOVAL OF GASEOUS CONTAMINANTS

Gas entrapped in mud must be removed in order to maintain the mud weight to a level needed to control down hole formation pressures. Gas is removed from mud using a vacuum degasser, see **Figure 7.8**. The latter is a simple equipment containing a vacuum pump and a float assembly. The vacuum pump creates a low internal pressure which allows gas-cut mud to be drawn into the degasser vessel and it then flows in a thin layer over an internal baffle plate. The combination of low internal pressure and thin liquid film causes gas bubbles to expand in size, rise to the surface of the mud inside the vessel and break from the mud. As the gas moves toward the top of the degasser it is removed by the vacuum pump. The removed gas is routed away from the rig and is then either vented to atmosphere or flared.

Figure 7.8 Vacuum degasser, Courtesy of Brandt

7.1.4 Forced Settling by Centrifugal Devices

Figure 7.9 Principle of hydrocyclone, after Baroid [1]



Desanders and desilters are hydrocyclones and work on the principle of separating solids from a liquid by creating centrifugal forces inside the hydrocyclone. Mud is injected tangentially into the hydrocyclone and the resulting centrifugal forces drive the solids to the walls of the hydrocyclone and finally discharges them from the apex with a small volume of mud, Figure 7.9. The fluid portion of mud leaves the top of the hydrocyclone as an overflow and is then sent to the active pit to be pumped downhole again.

(a) Desanders

Desanders are hydrocyclones with 6 in ID or larger.The primary use of desanders is in the top hole sections when drilling with water based mud to help maintain low mud weights. Use of desanders prevents overload of the desilter cones and increases their efficiency by reducing the mud weight and solids content of the feed inlet. Desanders should be used if the sand content of the mud rises above 0.5% to prevent abrasion of pump liners.

Desanders should never be used with oil based muds, because of its very wet solids discharge.The desander makes a cut in the 40 to 45 micron size range. With a spray

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discharge, the underflow weight should be between 2.5 to 5.0 ppg heavier than the input mud.

(b) Desilters

Desilters, in conjunction with desanders, should be used to process low mud weights used to drill top hole sections, **Figure 7.10**. If it is required to raise the mud weight this must be done with the additions of barytes, and not by allowing the build up of low gravity solids. Desilters should never be used with oil based muds.

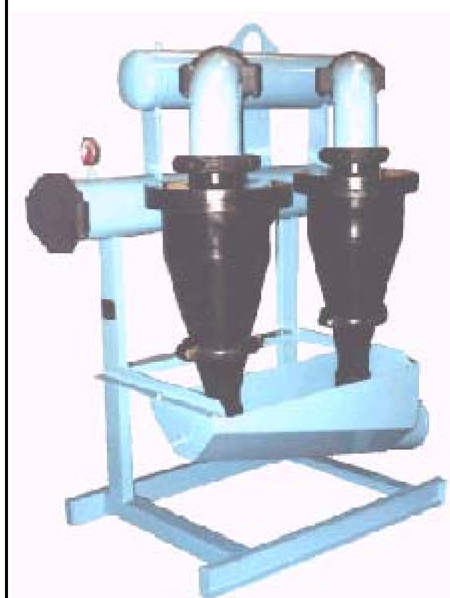
The desilter makes a cut in the 20 to 25 micron size range.

Typical throughput capacities are as follows:

Desanders	12"cone	500 gpm per cone.
	6" cone	125 gpm per cone.
Desilters	4"cone	50 gpm per cone.
	2" cone	15 gpm per cone.

As a visual check to see that the hydrocyclone operations are at an optimum, the discharge should be in the form of a fine spray and a suction should be felt at the apex when covered with the hand. A rope discharge means than the mud has lost its circular motion and the cone is not working properly.

Figure 7.10 Desilters, courtesy of Brandt

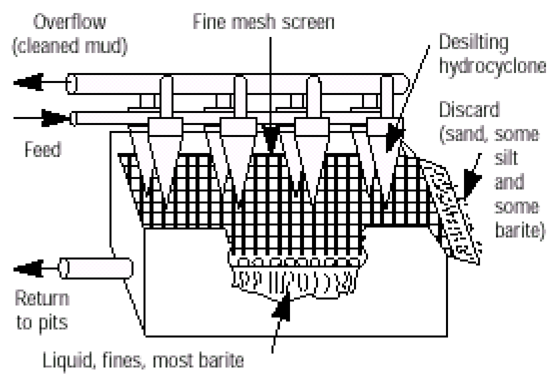


(c) Mud Cleaners

A mud cleaner consists of a battery of hydrocyclones placed above a high energy vibrating screen, **Figure 7.11**. Mud cleaners must only be used when it becomes impossible to maintain low mud weights by use of the shale shakers alone. It is far more efficient to use desilters and process the underflow with a centrifuge than to use the screens of a mud cleaner.

The use of mud cleaners with oil based muds should be minimised since experience has shown that mud losses of 3 to 5 bbls/hr being discharged are not uncommon, coupled with the necessity to adhere to strict environmental pollution regulations.

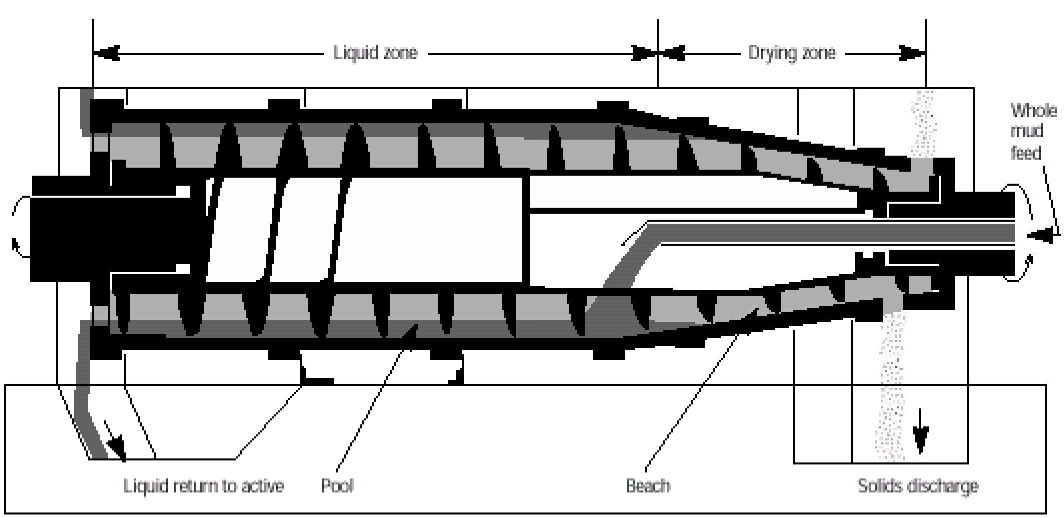
Figure 7.11 Mud cleaner, after reference 2



(d) Centrifuges

Centrifuges use centrifugal forces to remove heavy solids from the liquid and lighter components of the mud. A decanting centrifuge consists of a horizontal conical steel bowl rotating a high speed, see **Figure 7.12**. The bowl contains a double-screw type conveyor which rotates in the same direction as the steel bowl, but at a slightly lower speed. When mud enters the centrifuge, the centrifugal force developed by the bowl holds the mud in a pond against the walls of the pond. In this pond the silt and sand particle settle against the walls and the conveyor blade scrapes and pushes the settled solids towards the narrow end of the bowl where they are collected as damp particles with no free liquid. The liquid and clay particles are collected as as overflow from ports at the large end of the bowl.

Figure 7.12 Decanting centrifuge, after reference 2



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It is recommended to have at least one centrifuge on the rig site during all drilling operations. For expensive muds or long term drilling operations, two centrifuges may prove economical.

When dealing with low weight muds, the solids underflow is discarded as a means of solids control to obtain desirable particle size distribution and reduce mud weight. Processing capacity of the centrifuge may limit its use for this purpose to lower hole sections where the circulation rates are low as the bowl speed must be at a maximum, so lower capacities can be dealt with. It can also be used to process the underflow from desilters, returning an expensive or environmentally harmful liquid phase to the active mud system, and discarding relatively dry solid fines.

With weighted muds, the solids underflow containing barytes may be returned to the mud system and the liquid phase containing viscosity building colloids discharged. However it is unlikely to be used for this purpose with oil based muds for both economic and environmental reasons.

Centrifuge efficiency is affected predominantly by the feed flow rate, but it is also affected by the following operating parameters:

- Bowl speed (rpm).
- Bowl conveyer differential speed (rpm).
- Pool depth.

8.0 LEARNING MILESTONES

In this chapter, you should have learnt to:

1. List sources of information required to develop a mud programme
2. List functions of drilling mud
3. Describe types and functions of weighting additives
4. Describe types and functions of viscosifiers
5. Describe basic structure of smectite clays

6. Describe types and functions of water-based muds
7. Describe types and functions of oil-based muds
8. Describe various mud contaminants
9. Describe mud solids removal equipment

9.0 References

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Practical Rig Hydraulics

8

Content

Introduction

This chapter deals with practical methods of calculating pressure losses in the various parts of the circulating system and the selection of nozzle sizes. Several models exist for the calculation of pressure losses in pipes and annuli. Each model is based on a set of assumptions which cannot be completely fulfilled in any drilling situation. The Bingham plastic, Power law and Herschel-Bulkley models are the most widely used in the oil industry.

1.0 Pressure losses

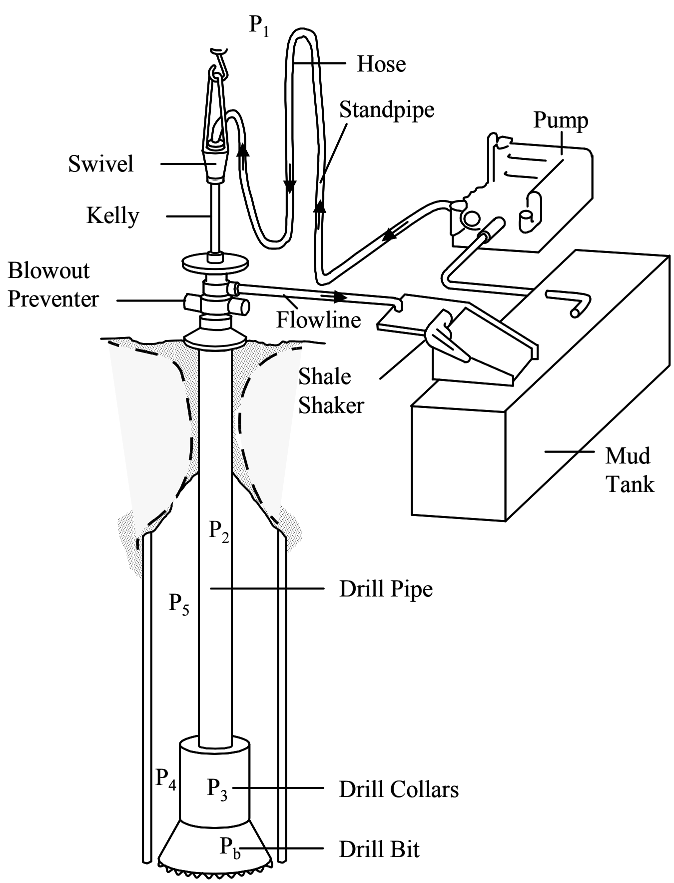
Figure 8.1 gives a schematic of the circulating system. We shall divide the circulating system into four sections:

1. Surface connections.

2. Pipes including drillpipe, heavy walled drillpipe and drill collars.
3. Annular areas around drillpipes, drillcollars, etc.
4. Drillbit.

Our objective is to calculate the pressure (energy) losses in every part of the circulating system and then find the total system losses.This will then determine the pumping requirements from the rig pumps and in turn the horse power requirements.

Figure 8.1 Schematic of the circulating system



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1.1 SURFACE CONNECTION LOSSES (P_1)

Pressure losses in surface connections (P_1) are those taking place in standpipe, rotary hose, swivel and kelly. The task of estimating surface pressure losses is complicated by the fact that such losses are dependent on the dimensions and geometries of surface connections. these dimensions can vary with time, owing to continuous wear of surfaces by the drilling fluids. The following general equation may be used to evaluate pressure losses in surface connections:

$$P_1 = E \times \rho^{0.8} \times Q^{1.8} \times PV^{0.2} \text{ psi} \tag{8.1}$$

where

ρ = mud weight (lbm/gal)
Q = volume rate (gpm)
E = a constant depending on type of surface equipment used
PV = plastic viscosity (cP)

In practice, there are only four types of surface equipment; each type is characterised by the dimensions of standpipe, kelly, rotary hose and swivel. **Table 8.1** summarises the four types of surface equipment.

Table 8.1 Types of surface equipment

Case	Standpipe	Hose	Swivel, etc.	Kelly	Eq. Length 3.826-in. ID
1	40 ft long, 3-in. ID	45 ft long, 2-in. ID	20 ft long, 2-in. ID	40 ft long, 2.25-in. ID	2,600 ft
2	40 ft long, 3.5-in. ID	55 ft long, 2.5-in. ID	25 ft long, 2.5-in. ID	40 ft long, 3.25-in. ID	946 ft
3	45 ft long, 4-in. ID	55 ft long, 3-in. ID	25 ft long, 2.5-in. ID	40 ft long, 3.25-in. ID	610 ft
4	45 ft long, 4-in. ID	55 ft long, 3-in. ID	30 ft long, 3-in. ID	40 ft long, 4-in. ID	424 ft

The values of the constant E in **Equation (8.1)** are given in **Table 8.2**.

Table 8.2 Values of constant E

Surface equipment type	Value of E	
	Imperial units	Metric units
1	2.5 x 10-4	8.8 x 10-6
2	9.6 x 10-5	3.3 x 10-6
3	5.3 x 10-5	1.8 x 10-6
4	4.2 x 10-5	1.4 x 10-6

1.2 Pipe and Annular Pressure Losses

Pipe losses take place inside the drillpipe and drill collars and are designated in **Figure 8.1** as P_2 and P_3, respectively. Annular losses take place around the drill collar and drillpipe and are designated as P_4 and P_5 in **Figure 8.1**. The magnitudes of P_2, P_3, P_4 and P_5 depend on:

(a) dimensions of drillpipe (or drill collars), e.g. inside and outside diameter and length; (b) mud rheological properties, which include mud weight, plastic viscosity and yield point; and (c) type of flow, which can be laminar, or turbulent.

It should be noted that the actual behaviour of drilling fluids downhole is not accurately known and fluid properties measured at the surface usually assume different values at the elevated temperature and pressure downhole. Another point to remember is the large possible discrepancy between the pressure values calculated using the annular flow models (see later).Three models will be discussed: Bingham Plastic, Power law and Herschel-Bulkley. These models approximate the annulus as two parallel plates, with the effects of rotation being ignored. In this chapter the Power law and Bingham Plastic models will be used to calculate the annular pressure losses. They are chosen primarily because they are widely applied in the oil drilling industry.

1.3 Pressure drop across bit

As will be discussed in **Chapter 11**, drillbits are provide with nozzles to provide a jetting action, mainly required for cleaning and cooling, but can also help with rock breakage in soft formations. The largest nozzle is one inch in size, often termed open, but more often the nozzles used are a fraction of an inch. Hence, the pressure requirements to pass, say 1000 gpm, through such small nozzles will be large.

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For a given length of drill string (drillpipe and drill collars) and given mud properties, pressure losses P_1, P_2, P_3, P_4 and P_5 will remain constant. However, the pressure loss across the bit is greatly influenced by the sizes of nozzles used, and volume flow rate. For a given flow rate, the smaller the nozzles the greater the pressure drop and, in, turn the greater the nozzle velocity.

For a given maximum pump pressure, the pressure drop across the bit is obtained by subtracting P_c $(= P_1 + P_2 + P_3 + P_4 + P_5)$ from the pump pressure. If the hydraulics at the bit is to be optimised, then the pressure drop across the bit will have to be calculated using the methods presented in "Optimisation of Bit Hydraulics" on page 327.

The equations necessary for the calculation of jet velocity, pressure drop across bit and nozzle sizes are given later in this chapter.

2.0 Hydraulics Fundamentals

The following are definitions of terms required to understand the various hydraulics equations [a,b,c]. The symbols and units are given with the definitions.

Shear rate, γ (sec $^{-1}$): This is a term most applicable to laminar flow. It refers to the change in fluid velocity divided by the width of the channel through which the fluid is flowing in laminar flow.

Shear stress, τ (lb/100 ft^2): The force per unit area required to move a fluid at a given shear rate.

Viscosity, μ (centipoises (cP)): This is the ratio of shear stress to shear rate.

Plastic viscosity, PV (cP): Plastic viscosity represents the contribution to total fluid viscosity of a fluid under dynamic flowing conditions. Plastic viscosity is dependent on the size, shape, and number of particles in a moving fluid. PV is calculated using shear stresses measured at 600 and 300 rpm on the Fann 35 viscometer.

Effective viscosity, μ (cP): This term takes account of the geometry through which the fluid is flowing and is therefore a more descriptive term of the flowing viscosity.

Yield point, YP (lb/100 ft ^{2}):The minimum force required to initiate flow, see Bingham Plastic model.

Yield stress (lb/100 ft^2): This is the calculated force required to initiate flow and is obtained when the rheogram (a plot of shear stress vs shear rate) is extrapolated to the y-axis at $\gamma = 0$ sec $^{-1}$. In practice the yield point is calculated using **Equation (8.2)**.

(Note [a]: Yield stress is a time-independent measurement and is usually denoted in the Herschel-Bulkley (yield-power law [YPL]) model as τ_o and Bingham model as YP. It can also be considered a gel strength at zero time.)

Gel strength (lb/100 ft^2): All drilling fluids build a structure when at rest. The gel strength is a time-dependent measurement of the fluid shear stress when under static conditions. Gel strengths are commonly measured after 10 seconds, 10 minutes, and 30 minutes intervals.

Reynolds number, Re: This is a dimensionless umber which determines whether a flowing fluid is in laminar or turbulent flow. A Reynolds number greater than 2,100 marks the onset of turbulent flow in most drilling fluids.For laminar flow (Re < 2,100) and for turbulent flow (Re > 2,100).

Critical Reynolds number, Rec: This value corresponds to the Reynolds number at which laminar flow turns to turbulent flow.

Friction factor (f) [a]: This is a dimensionless term used for power law fluids in turbulent flow and relates the fluid Reynolds number to a "roughness" factor for the pipe.

3.0 FLOW REGIMES

There are three basic types of flow regimes:

5. Laminar
6. Turbulent
7. Transitional

Laminar flow: In laminar flow, fluid layers flow parallel to each other in an orderly fashion. This flow occurs at low to moderate shear rates when friction between the fluid and the channel walls is at its lowest. This is a typical flow in the annulus of most wells.

Turbulent flow: This flow occurs at high shear rates where the fluid particle move in a disorderly and chaotic manner and particles are pushed forward by current eddies. Friction between the fluid and the channel walls is highest for this type of flow. This is a typical flow inside the drillpipe and drillcollars.

Unlike laminar flow, mud parameters (viscosity and yield point) are not significant in calculating frictional pressure losses for muds in turbulent flow.

Transitional flow occurs when the fluid flow changes from laminar to turbulent or vice versa.

4.0 Fluid Types

There are two basic types of fluids: Newtonian and non-Newtonian.

Newtonian fluids are characterised by a constant viscosity at a given temperature and pressure.

Common Newtonian fluids include:

- Water
- Diesel
- Glycerin
- Clear brines

Non-Newtonian fluids have viscosities that depend on measured shear rates for a given temperature and pressure. Examples of non-Newtonian fluids include:

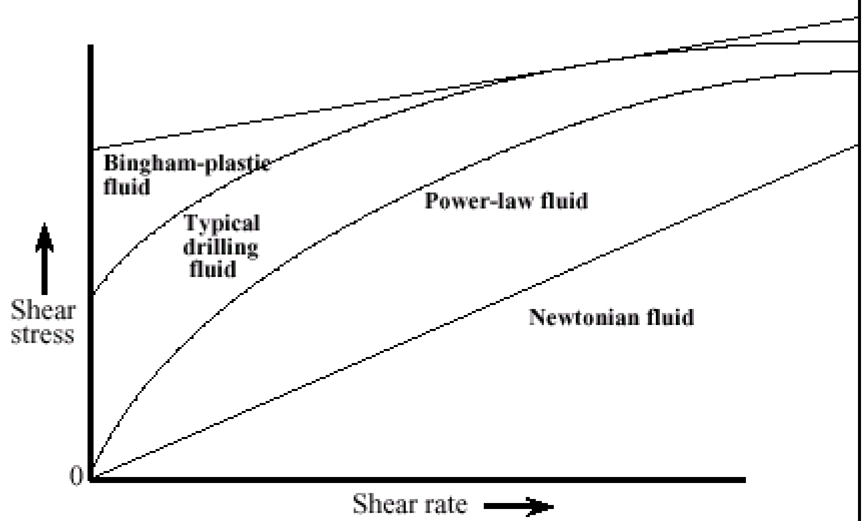
- Most drilling fluids
- Cement slurries

In drilling operations, practically all drilling fluids are non-Newtonian. Even brines which are used as completion fluids are not truly Newtonian fluids, as the dissolved solids in them make them behave in a non-Newtonian manner.

5.0 RHEOLOGICAL MODELS

Rheological models (**Figure 8.2**) are mathematical equations used to predict fluid behaviour across a wide range of shear rates and provide practical means of calculating pumping (pressure) requirements for a given fluid. Most drilling fluids are non-Newtonian and pseudoplastic and, therefore, hydraulic models use a number of approximations to arrive at practical equations.

Figure 8.2 Rheological models, after Baroid [a]



The three rheological models that are currently in use are:

1. Bingham Plastic model
2. Power Law model
3. Herschel-Bulkley (yield-power law [YPL]) model

Full mathematical derivations of all the above model can be found in reference (c), written by the author of this book.

6.0 BINGHAM PLASTIC MODEL

The Bingham Plastic model describes laminar flow using the following equation:

$\tau = YP + PV \times (\gamma)$

where

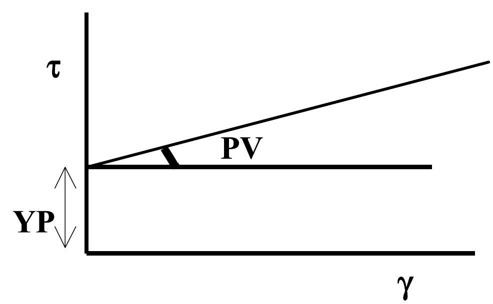
τ = measured shear stress in lb/100 ft^2

YP = yield point in lb/100 ft^2

PV = plastic viscosity in cP

γ = shear rate in sec^{-1}

Figure 8.3 Bingham Plastic model



The values of YP and PV are calculated using the following equations:

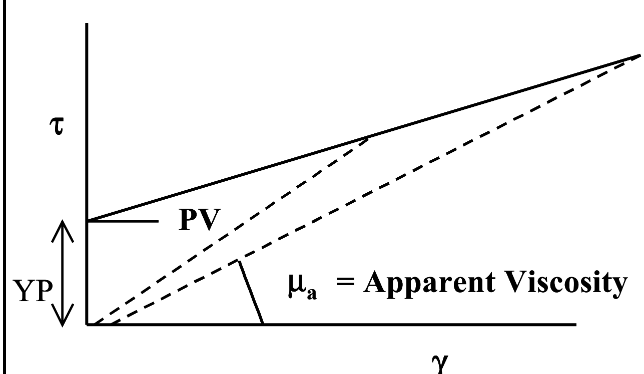
$$PV = \theta 600 - \theta 300 \quad (8.2)$$

$$YP = \theta 300 - PV \quad (8.3)$$

$$YP = (2 \times \theta 300) - \theta 600 \quad (8.4)$$

Figures **8.3**, **8.4** and **8.5** describe the Bingham Plastic model. The slope of a line connecting any point on the straight line to the origin is described as the apparent viscosity at that particular shear rate, **Figure 8.4**.

Figure 8.4 Bingham Plastic model



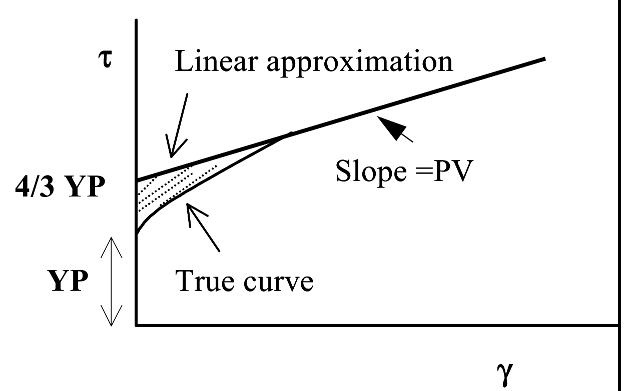
The Bingham Plastic model usually overpredicts yield stresses (shear stresses at zero shear rate) by 40 to 90 percent.

The following equation produces more realistic values of yield stress at low shear rates:

YP (Low Shear Rate)= (2 × θ3) - θ6

This equation assumes the fluid exhibits true plastic behaviour in the low shear-rate range only [a].

Figure 8.5 Bingham Plastic model



7.0 Power Law Model

The Power Law model assumes that all fluids are pseudoplastic in nature and are defined by the following equation:

$$\tau = K(\gamma)^n \qquad (8.5)$$

where

τ = Shear stress (dynes / cm^2)

K = Consistency Index

γ = Shear rate (sec-1)

n = Power Law Index

$$n = 3.32\log\left(\frac{\theta_{600}}{\theta_{300}}\right) \qquad (8.6)$$

$$K = \frac{\theta_{300}}{(511)^n} \qquad (8.7)$$

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The constant “n” is called the POWER LAW INDEX and its value indicates the degree of non-Newtonian behaviour over a given shear rate range. If 'n' = 1, the behaviour of the fluid is considered to be Newtonian. As 'n' decreases in value, the behaviour of the fluid is more non-Newtonian and the viscosity will decrease with an increase in shear rate.The constant “n” has no units.

The “K” value is the CONSISTENCY INDEX and is a measure of the the thickness of the mud.The constant 'K' is defined as the shear stress at a shear rate of one reciprocal second. An increase in the value of 'K' indicates an increase in the overall hole cleaning effectiveness of the fluid. The units of 'K' are either lbs/100ft^2, dynes-sec or N/cm^2.

The constants n and K can be calculated from Fann VG meter data obtained at speeds of 300 and 600 rpm through the use of **Equation (8.6)** and **Equation (8.7)**.

Hence the Power Law model is mathematically more complex than the Bingham Plastic model and produces greater accuracy in the determination of shear stresses at low shear rates.

The Power Law model actually describes three types of fluids, based on the value of 'n':

i) n = 1: The fluid is Newtonian

ii) n < 1: The fluid is non-Newtonian

iii) n > 1: The fluid is Dilatent

8.0 HERSCHEL-BULKLEY (YIELD-POWER LAW [YPL]) MODEL

The Herschel-Bulkley (yield-power law [YPL]) model describes the rheological behaviour of drilling muds more accurately than any other model using the following equation:

$$\tau = \tau o + K \times (\gamma)^{n} \qquad (8.8)$$

where

τ = measured shear stress in lb/100 ft^2

τo= fluid's yield stress (shear stress at zero shear rate) in lb/100 ft^2

K = fluid's consistency index in cP or lb/100 ft sec^2

n = fluid's flow index

γ= shear rate in sec^{-1}

The YPL model reduces to the Bingham Plastic model when n = 1 and it reduces to the Power Law model when **τo** = 0.

The YPL model is very complex and requires a minimum of three shear-stress/shear-rate measurements for a solution [c].

9.0 Practical Hydraulics Equations

The procedure for calculating the various pressure losses in a circulating system is summarised below:

1. Calculate surface pressure losses using **Equation (8.1)**
2. Decide on which model to use: Bingham Plastic or Power Law
3. Calculate pressure loses inside the drillpipe first then inside drillcollars as follows:
   - Calculate critical velocity of flow
   - Calculate actual average velocity of flow
   - Determine whether flow is laminar or turbulent by comparing average velocity with critical velocity. If average velocity is less than critical velocity the flow is laminar.If average velocity is greater than critical velocity the flow is turbulent.
   - Use appropriate equation to calculate pressure drop
4. Divide the annulus into an open and cased sections
5. Calculate annular flow around drillcollars (or BHA) as follows:
   - Calculate critical velocity of annular flow
   - Calculate actual average velocity of flow in the annulus

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- Determine whether flow is laminar or turbulent by comparing average velocity with critical velocity. If average velocity is less than critical velocity the flow is laminar.If average velocity is greater than critical velocity the flow is turbulent.
- Use appropriate equation to calculate annular pressure drop

6. Repeat step four for flow around drillpipe in the open and cased hole sections.
7. Add the values from step 1 to 5, call this system losses
8. Determine the pressure drop available for the bit = pump pressure - system losses
9. Determine nozzle velocity, total flow area and nozzle sizes

The following equations are given for the Bingham Plastic and Power Law models. The field units used here are:

OD = outside diameter (in),ID = inside diameter (in),L = length (ft),ρ = density (ppg)

V = velocity (ft/sec) or (ft/min),PV = viscosity (cP),YP = yield point (lbf/100ft^2)

9.1 Bingham Plastic Model

A. Pipe Flow

Determine average velocity and critical velocity(V' and V_c):

$$V' = \frac{24.5Q}{D^2} \tag{8.9}$$

$$V_c = \frac{97xPV + 97\sqrt{PV^2 + 8.2\rho D^2 YP}}{\rho D} \tag{8.10}$$

If $V' > V_c$, flow is turbulent; use

$$P = \frac{8.91 \times 10^{-5} \times \rho^{0.8} \times Q^{1.8} \times (PV)^{0.2} \times L}{D^{4.8}} \tag{8.11}$$

If $V' < V_c$, flow is laminar; use

$$P = \frac{L \times PV \times V'}{90,000 \times D^2} + \frac{L \times YP}{225 \times D} \qquad (8.12)$$

B. Annular Flow

Determine average velocity and critical velocity(V' and Vc):

$$V' = \frac{24.5Q}{D_h^2 - OD^2} \qquad (8.13)$$

$$V_c = \frac{97PV + 97\sqrt{PV^2 + 6.2\rho D_e^2 YP}}{\rho D_e} \qquad (8.14)$$

where De = D_h - OD

If $V' > V_c$, flow is turbulent; use

$$P = \frac{8.91 \times 10^{-5} \times \rho^{0.8} \times Q^{1.8} \times (PV)^{0.2} \times L}{(D_h - OD)^3 (D_h + OD)^{1.8}} \qquad (8.15)$$

If $V' <$ Vc, flow is laminar; use

$$P = \frac{L \times PV \times V'}{60,000 \times D_e^2} + \frac{L \times YP}{225 \times D_e} \qquad (8.16)$$

9.2 Power Law Model

Determine n and K from:

$$n = 3.32 \log\left(\frac{\theta_{600}}{\theta_{300}}\right) \qquad (8.17)$$

$$K = \frac{\theta_{300}}{(511)^n} \qquad (8.18)$$

where $\theta 600 = 2$ PV + YP and $\theta 300 =$ PV + YP

A. Pipe Flow

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Determine average velocity and critical velocity(V' and Vc)

$$V' = \frac{24.5Q}{D^2} \quad \textbf{Equation (8.9)}$$

$$V_c = \left(\frac{5.82 \times 10^4 \times K}{\rho}\right)^{\left(\frac{1}{2-n}\right)} \times \left(\frac{1.6 \times (3n+1)}{D \times 4n}\right)^{\left(\frac{n}{1-n}\right)} \tag{8.19}$$

:If $V' > Vc$, flow is turbulent; use

$$P = \frac{8.91 \times 10^{-5} \times \rho^{0.8} \times Q^{1.8} \times (PV)^{0.2} \times L}{(D_h - OD)^3 (D_h + OD)^{1.8}} \quad \textbf{Equation (8.10)}$$

If $V' < V_{c,}$ flow is laminar; use

$$P = \left(\frac{KL}{300D}\right) \times \left(\frac{1.6V' \times (3n+1)}{D \times 4n}\right)^n \tag{8.20}$$

B. Annular Flow

Determine average velocity and critical velocity(V' and Vc):

$$V' = \frac{24.5Q}{D_h^{\ 2} - OD^2} \quad \textbf{Equation (8.13)}$$

$$V_c = \left(\frac{3.878 \times 10^4 \times K}{\rho}\right)^{\left(\frac{1}{2-n}\right)} \times \left(\frac{2.4 \times (2n+1)}{D_e \times 3n}\right)^{\left(\frac{n}{1-n}\right)} \tag{8.21}$$

where $D_e = D_h - OD$

If $V' > V_c$, flow is turbulent; use

$$P = \frac{8.91 \times 10^{-5} \times \rho^{0.8} \times Q^{1.8} \times (PV)^{0.2} \times L}{(D_h - OD)^3 (D_h + OD)^{1.8}} \quad \textbf{Equation (8.15)}$$

If $V' < Vc$, flow is laminar; use:

$$P = \left(\frac{KL}{300D_e}\right) \times \left(\frac{2.4V' \times (2n+1)}{D_e \times 3n}\right)^n \quad (8.22)$$

9.3 Pressure Loss Across Bit

The object of any hydraulics programme is to optimise pressure drop across the bit such that maximum cleaning of bottom hole is achieved.

For a given length of drill string (drillpipe and drill collars) and given mud properties, pressure losses P_1, P_2, P_3, P_4 and P_5 will remain constant. However, the pressure loss across the bit is greatly influenced by the sizes of nozzles used, and the latter determine the amount of hydraulic horsepower available at the bit. The smaller the nozzle the greater the pressure drop and the greater the nozzle velocity.

In some situations where the rock is soft to medium in hardness, the main objective is to provide maximum cleaning and not maximum jetting action. In this case a high flow rate is required with bigger nozzles. These points are discussed later under “Optimisation of Bit Hydraulics” on page 327".

To determine the pressure drop across the bit, add the total pressure drops across the system, i.e. $P_1 + P_2 + P_3 + P_4 + P_5$, to give a total value of P_c (described as the system pressure loss). Then determine the pressure rating of the pump used. If this pump is to be operated at, say, 80-90% of its rated value, then the pressure drop across the bit is simply pump pressure minus P_c.

Procedure

A. From previous calculations, determine pressure drop across bit, using

$$P_{bit} = P_{standpipe} - (P_1 + P_2 + P_3 + P_4 + P_5)$$

B. Determine nozzle velocity (ft/s)

$$V_n = 33.36\sqrt{\frac{P_{bit}}{\rho}} \quad (8.23)$$

C. Determine total area of nozzles (in^2)

$$A = 0.32\frac{Q}{V_n} \tag{8.24}$$

D. Determine nozzle sizes in multiples of 32 seconds

Example 8.1: Hydraulics calculations

Using the Bingham plastic and power-line models, determine the various pressure drops, nozzle velocity and nozzle sizes for a section of 12.25 in (311mm) hole. Two pumps are used to provide 700 gpm (2650 1/min).

Data:

plastic velocity	=	12 cP
yield point	=	12 lb/100 ft^2
mud weight	=	8.8 lb/gal
drillpipe ID	=	4.276 in
OD	=	5 in
length	=	6,480 ft
drill collars ID	=	2,875 in
OD	=	8 in
length	=	620 ft (189 m)

Last casing was 13.375 in with an ID of 12.565 in. 13.375 in casing was set at 2,550 ft. The two pumps are to be operated at a maximum standpipe pressure of 2,200 psi. Assume a surface equipment type of 4.

Solution

The solution to this example will be presented in Imperial units only.

1. Bingham Plastic Model

a. Surface losses

Surface losses in surface equipment P_1 are given by

$P_1 = E \times \rho^{0.8} \times Q^{1.8} \times PV^{0.2}$ Equation (8.1)

From **Table 8.2**, the value of the constant E for type 4 is 4.2×10^{-5}; hence, Equation (8.1) becomes

$P_1 = 4.2 \times 10^{-5} \times \rho^{0.8} \times Q^{1.8} \times PV^{0.2}$

$= 4.2 \times 10^{-5} \times 8.8^{0.8} \times 700^{1.8} \times 12^{0.2} = 52$ psi

b. Pipe losses

Pressure losses inside drillpipe

$$V' = \frac{24.5Q}{D^2} = \frac{24.5Q \times 700}{(4.276)^2} = 937.97 \text{ ft/min}$$

Critical velocity

$$V_c = \frac{97PV + \sqrt{PV^2 + 8.2\rho D^2 YP}}{\rho D}$$

$$V_c = \frac{97x12 + 97\sqrt{12^2 + 8.2 \times 8.8 \times 4.276^2 \times 12}}{8.8 \times 4.276} = 356 \text{ ft/min}$$

Since $V' > V_c$, flow is turbulent and pressure drop inside drill pipe is calculated from:

$$P = \frac{8.91 \times 10^{-5} \times \rho^{0.8} \times Q^{1.8} \times (PV)^{0.2} \times L}{D^{4.8}}$$

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$$= \frac{8.91 \times 10^{-5} \times 8.8^{0.8} \times 700^{1.8} \times 12^{0.2} \times 6{,}480}{(4.276)^{4.8}}$$

$= 670$ psi

Pressure losses inside drill collars

Following the same procedure as for drillpipe losses, we obtain

$$V' = \frac{24.5Q}{D^2} = \frac{24.5Q \times 700}{(2.875(4.276))^2} = 2{,}074.9 \text{ ft/min}$$

$$V_c = \frac{97 \text{x} 12 + 97\sqrt{12^2 + 8.2 \times 8.8 \times 2.875^2 \times 12}}{8.8 \times 2.875} = 373 \text{ ft/min}$$

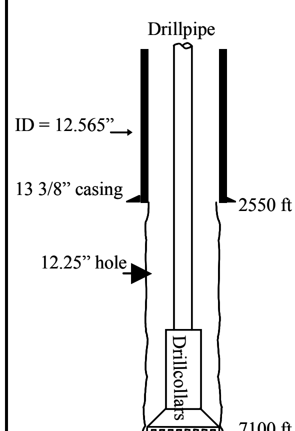
Since $V' > V_c$, flow is turbulent and pressure loss inside drill collars P_3 is determined from

$$P3 = \frac{8.91 \times 10^{-5} \times 8.8^{0.8} \times 700^{1.8} \times 12^{0.2} \times 620}{(2.875)^{4.8}} = 431 \text{ psi}$$

Annular pressure losses

A rough sketch always helps in simplifying the problem. From **Figure 8.6** it can be seen that part of the drillpipe is inside the casing and the rest is inside open hole. Hence, pressure loss calculations around the drillpipe must be split into (a) losses around the drillpipe inside the casing and (b) losses around the drillpipe in open hole.

Figure 8.6



Pressure losses around drillpipe: Cased hole section

$$V' = \frac{24.5Q}{ID_c^{\ 2} - OD_{dp}^{\ 2}}$$

where the subscripts $'_c'$ and $'_{dp}$ refer to casing and drillpipe respectively.

$$V' = \frac{24.5 \times 700}{12.565^2 - 5^2} = 129.1 \text{ ft/min}$$

$$V_c = \frac{97PV + 97\sqrt{PV^2 + 6.2\rho D_e{}^2 YP}}{\rho D_e}$$

$$V_c = \frac{97x12 + 97\sqrt{12^2 + 6.2x8.8x(12.565 - 5)^2 x12}}{8.8x(12.565 - 5)} = 299.6 \text{ ft/min}$$

Since $V' < V_{c,}$ flow is laminar and the pressure loss around the drillpipe in the cased hole is determined from:

$$P = \frac{L \times PV \times V'}{60,000 \times D_e{}^2} + \frac{L \times YP}{225 \times D_e}$$

(where L=2,500 ft)

$$P_a = \frac{2550 \times 12 \times 129.01}{60,000 \times (12.565 - 5)^2} + \frac{2,550 \times 12}{225 \times (12.56 - 5)} = 21 \text{ psi}$$

Open hole section- Around Drillpipe

$$V' = \frac{24.5 \times 700}{12.25^2 - 5^2} = 137 \text{ ft/min}$$

V_c= 300.4 ft/min

Since $V' < V_{c,}$ flow is laminar and the pressure loss around the drillpipe in the open-hole section is determined from:

$$P_b = \frac{3,930 \times 12 \times 137}{60,000 \times (12.25 - 5)^2} + \frac{3,930 \times 12}{225 \times (12.25 - 5)} = 35 \text{ psi}$$

(where L = 6,480 - 2,550 = 3,930 ft, and L = length of drillpipe in the open-hole section).

Hence, total pressure drop around drillpipe is the sum of P_a and P_b. Thus,

$P_5 = P_a + P_b = 21 + 35 = 56$ psi

Pressure losses around drill collars

$$V' = \frac{24.5 \times 700}{12.25^2 - 8^2} = 199.3 \text{ ft/min}$$

$V_c = 314$ ft/min

Since $V' < Vc$, flow is laminar and pressure loss around drill collars is calculated from:

$$P_4 = \frac{620 \times 12 \times 199.3}{60,000 \times (12.25 - 8)^2} + \frac{620 \times 12}{225 \times (12.25 - 8)} = 10 \text{ psi}$$

Pressure drop across bit

Total pressure loss in circulating system, except bit.

$= P_1 + P_2 + P_3 + P_4 + P_5$

$= 52 + 670 + 431 + 10 + 56 = 1,219$ psi

Therefore, pressure drop available for bit (P_{bit})

$= 2,200 - 1,219 = 981$ psi

Determine nozzle velocity (ft/s)

$$V_n = 33.36\sqrt{\frac{P_{bit}}{\rho}} = 33.36\sqrt{\frac{981}{8.8}} = 351.7 \text{ ft/s}$$

Determine total area of nozzles (in^2)

$$A = 0.32\frac{Q}{V_n} = 0.32x\frac{700}{351.7} = 0.6369 \text{ in}^2$$

Nozzle size (in multiples of (1/32)

$$= 32 \times \sqrt{\frac{4 \times A}{3x\pi}} = 16.64$$

Hence, select two nozzles of size 17 and one of size 16. The total area of these nozzles is 0.6397 in^2, which is slightly larger than the calculated area of 0.6369 in^2.

2. Power Law Model

Surface losses

$P_1 = 4.2 \text{ x } 10^{-5} \text{ x } \rho^{0.8} \text{ x } Q^{1.8} \text{ x } PV^{0.2} = 52$ psi

$\theta_{600} = 2 \text{ x } PV \text{ x } YP = 2 \text{ x } 12 + 12 = 36$

$\theta_{300} = PV + YP = 12 + 12 = 24$

$$n = 3.32\log\left(\frac{\theta_{600}}{\theta_{300}}\right) = 0.585$$

$$K = \frac{\theta_{300}}{(511)^n} = 0.626$$

Remaining calculations are left as an exercise.

($P_2 = 670$, $P_3 = 431$, $P_4 = 5$, $P_5 = 19$, $P_{bit} = 1023$, Nozzles= 2 x 16's and one 17)

3. Comparison of the two models

From the above results, it is obvious that the two models produce different nozzle sizes: the Bingham plastic model produced two 17s and one 16, whereas the power law model produced two 16s and one 17. In practice, this difference is not considered serious, and if the mud pumps are capable of producing more than 2,200 psi, then it is likely that three nozzles of size 16 will be chosen.

The reader should note also that the turbulent flow equations presented here use a turbulent viscosity term equal to (PV)/3.2 and not the plastic viscosity. If the plastic viscosity term is used instead, then pressure losses will be 26% higher than those calculated by our turbulent flow equation. It is the author's experience that the use of the turbulent viscosity term (i.e. (PV/3.2) provides pressure loss values that are in agreement with field results.

10.0 Optimisation of Bit Hydraulics

All hydraulics programmes start by calculating pressure drops in the various parts of the circulating system. Pressure losses in surface connections, inside and around the drillpipe, inside and around drill collars, are calculated, and the total is taken as the pressure loss in the circulating system, excluding the bit. This pressure loss is normally given the symbol P_c.

10.1 Surface Pressure

Once the system pressure losses, $P_{c,}$ is determined, the questions is how much pressure drop can be tolerated at the bit (P_{bit}). The value of P_{bit} is controlled entirely by the maximum allowable surface pump pressure.

Most rigs have limits on maximum surface pressure, especially when high volume rates - in excess of 1000 gpm are used. In this case, two or three pumps are used to provide this high quantity of flow. On land rigs typical limits on surface pressure are in the range 2,500 - 3000 psi for well depths of around 12,000 ft. For deep wells, heavy duty pumps are used which can have pressure ratings up to 5,000 psi.

Hence, for most drilling operations, there is a limit on surface pump pressure, and the criteria for optimising bit hydraulics must incorporate this limitation.

10.2 Hydraulic Criteria

There exist two criteria for optimising bit hydraulics: (1) maximum bit hydraulic horsepower (BHHP); and (2) maximum impact force (IF). Each criterion yields difference values of bit pressure drop and, in turn, different nozzle sizes. The engineer is faced with the task of deciding which criterion he is to choose. Moreover, in most drilling operations the flow rate for each hole section has already been fixed to provide optimum annular velocity and hole cleaning. This leaves only one variable to optimise: the pressure drop across the bit, P_{bit}. We shall examine the two criteria in detail and offer a quick method for optimising bit hydraulics.

10.3 Maximum Bit Hydraulic Horsepower

The pressure loss across the bit is simply the difference between the standpipe pressure and P_c. However, for optimum hydraulics the bit pressure drop must be a certain fraction of the maximum available surface pressure. For a given volume flow rate, optimum hydraulics is obtained when the bit hydraulic horsepower assumes a certain percentage of the available surface horsepower.

In the case of limited surface pressure, the maximum pressure drop across the bit, as a function of available surface pressure, produces maximum hydraulic horsepower at the bit for an optimum value of flow rate as shown below:

$$P_{bit} = \frac{n}{(n+1)} \times P_s \tag{8.25}$$

In the literature several values of n have been proposed, all of which fall in the range 1.8 - 1.86. Hence, when n = 1.86, Equation (8.25) gives $P_{bit} = 0.65\ P_s$. In other words, for optimum hydraulics, the pressure drop across the bit should be 65% of the total available surface pressure.

The actual value of n can be determined in the field by running the mud pump at several speeds and reading the resulting pressures. A graph of $P_c(=P_s - P_{bit})$ against Q is then drawn. The slope of this graph is taken as the index n.

10.4 Maximum Impact Force

In the case of limited surface pressure, it can be shown [c] that for maximum impact force, the pressure drop across the bit (P_{bit}) is given by:

$$P_{bit} = \frac{n}{(n+2)} \times P_s \tag{8.26}$$

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where n = slope of P_c VS Q

P_s = maximum available surface pressure.

The bit impact force (IF) can be shown to be a function of Q and P_{bit} according to the following equation.

$$IF = \frac{Q \times \sqrt{\rho \times P_{bit}}}{58} \qquad (8.27)$$

where ρ = mud weight (ppg)

10.5 Nozzle Selection

Smaller nozzle sizes are always obtained when the maximum BHHP method is used, as it gives larger values of P_{bit} than those given by the maximum IF method. The following equations may be used to determine total flow area and nozzle sizes:

$$TFA = (0.0096 \times Q)\sqrt{\frac{\rho}{P_{bit}}} \qquad (8.28)$$

$$d_n = 32\sqrt{\frac{4xTFA}{3x\pi}} \qquad (8.29)$$

where

TFA = total flow area (in^2)

d_n = nozzle size in multiples of 1/32 in.

10.6 Optimum Flow Rate

THE optimum flow rate is obtained using the optimum value of P_c, n and maximum surface pressure, P_s. For example, using the maximum BHHP criterion, P_c is determined from

$$P_c = P_s - P_{bit} \qquad (8.30)$$

$$P_c = P_s - \left(\frac{n}{n+1}\right)P_s \qquad (8.31)$$

$$P_c = \left(\frac{1}{n+1}\right)P_s \qquad (8.32)$$

The value of n is equal to the slope of the P_c - Q graph. The optimum value of flow rate, Q_{opt} is obtained from the intersection of the P_c value and the P_c - Q graph.

Example 8.2: Hydraulics Optimisation

Hydraulic Horse power of pump =1211 hp

Maximum permitted surface pressure P_s = 3500

Hole size = 12.25", Mud density = 13 ppg

Drillpipe= 5"/4.276"

$Pc = K\,Q^{n}$, K =0.01, n =1.86

Use the BHHP to calculate:

Pc, Pbit, BHHP and IF

Solution

1.BHHP Criterion

$$P_{bit} = \frac{n}{(n+1)} \times P_s$$

$$P_{bit} = \frac{1.86}{(1.86+1)} \times 3500 = 2276 \text{ psi}$$

$$\% \text{ Power at bit} = \frac{2276}{3500} = 65$$

$$P_c = P_s - P_{bit} = 3500 - 2276 = 1224 \text{ psi}$$

$$P_c = kQ^n$$

$$1225 = 0.01 x Q^{1.86n}$$

$$Q = 544 \text{ gpm}$$

Hence the optimised values are: P_c = 1224 psi, Q = 544 gpm and P_{bit} = 2276 psi

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$$TFA = (0.0096 \times Q)\sqrt{\frac{\rho}{P_{bit}}}$$

$$TFA = (0.0096 \times 544)\sqrt{\frac{13}{2276}} \quad = 0.3947 \text{ in}^2$$

$$d_n = 32\sqrt{\frac{4 x TFA}{3 x \pi}} = 32\sqrt{\frac{4 x 0.3947}{3 x \pi}} = 13.1$$

(ie select three 13's nozzles for a tricone drillbit)

$$IF = \frac{Q \times \sqrt{\rho \times P_{bit}}}{58}$$

$$IF = \frac{544 \times \sqrt{13 \times 2276}}{58} = 1613 \text{ lbf}$$

11.0 Mud Carrying Capacity

11.1 Introduction

For effective drilling, cuttings generated by the drill bit must be removed immediately. The drilling mud carries the drill cuttings up the hole and to the surface, to be separated from the mud.

The carrying (or lifting) capacity of mud is dependent on several parameters including fluid density, viscosity, type of flow, annulus size, annular speed, particle density, particle shape and particle diameter. Other factors such as pipe rotation, pipe eccentricity also have some influence on the carrying capacity of mud.

The effects of the above parameters on the carrying capacity of mud and, in turn, hole cleaning were studied in great detail by several authors, Williams and Bruce[9], Moore[4], Sample and Bourgoyne[10,11].

Important conclusions from their work can be summarised as follows:

1. Turbulent flow is most desirable for efficient removal of cuttings.

2.Low viscosity, low gel strength of mud are desirable properties for removal of cuttings.

3.High mud density helps to efficiently remove cuttings.

4.Pipe rotation aids the removal of cuttings.

11.2 HOLE CLEANING

Efficient hole cleaning is directly dependent on the ability of mud to suspend and carry the drill cuttings to the surface. The problems associated with inefficient hole cleaning include:

1. Decreased bit life and slow penetration rate resulting from regrinding of drill cuttings.

2. Formation of hole fills near the bottom of the borehole during trips when the mud pump is off.

3. Formation of bridge in the annulus which can lead to pipe sticking.

4. Increase in annular density and, in turn, annular hydrostatic pressure of mud. The increased hydrostatic pressure of mud may cause the fracture of an exposed weak formation resulting in lost circulation.

In practice, efficient hole cleaning is obtained by providing sufficient annular velocity to the drilling mud and by imparting desirable fluid properties.

11.3 SLIP VELOCITY

A rock particle falling through mud tends to settle out at constant velocity (zero acceleration) described as slip or terminal velocity and is given by:

For transitional flow:

$$V_s = 174.7\frac{d_p \times (\rho_p - \rho_f)^{0.667}}{\rho_f^{0.333} x \mu_e^{0.333}} \tag{8.33}$$

For turbulent flow, the equation becomes:

$$V_s = 92.6 \times \frac{((\rho_p - \rho_f) \times d_p)^{0.5}}{\rho_f} \tag{8.34}$$

where

ρ_p = density of particle, ppg

ρ_f = density of drilling fluid, ppg

μ_e = effective viscosity of fluid, cp

d_p = equivalent diameter of drill cutting, in

11.4 Transport Velocity

Transport or lift velocity is defined as the difference between the annular velocity of mud and the slip velocity of particle; ie

$$V_t = V_a - V_s \tag{8.35}$$

where

V_t = transport velocity

V_a = annular velocity = $\frac{24.5Q}{D_h^2 - OD_p^2}$

D_h = hole diameter

OD_p = outside diameter of pipe

It is obvious that for efficient hole cleaning, V_a must be greater the V_s. Sample et al [10,11] observed that at annular velocities of less than 100 ft/min, particle slip velocity in both Newtonian and non-Newtonian fluids is independent of the fluid annular velocity. Above an annular velocity of 100 ft/min, there appears to be a dependence of slip velocity on annular velocity.

Example 8.3: Transport Velocity

Determine the slip velocity and transport velocity for the following well:

Depth = 9,000 ft

Hole diameter	= 12.25 in
Drill pipe	= 5 in/4.276 in
Flow rate	= 500 gpm
Mud density	= 10 ppg
Density of rock	= 21 ppg
Average particle size	= 0.28 in
Viscometer readings: θ_{600}	= 90
θ_{300}	= 50

Solution

Assume the fluid to obey a power law model.

$$n = 3.32\log\left(\frac{\theta_{600}}{\theta_{300}}\right) = 0.848$$

$$K = \frac{\theta_{300}}{(511)^n} = 0.253$$

Effective viscosity is given by:

$$\mu_e = \left[\frac{2.4 \times V' \times (2n+1)}{(D_h - OD_p)3n}\right]^n \times \frac{200K(D_h - OD_p)}{V'} \tag{8.36}$$

Average Velocity around drillpipe

$$V' = \frac{24.5Q}{D_h^2 - OD^2} = \frac{24.5(500)}{12.25^2 - 5^2} = 98 \text{ ft/min}$$

$$\mu_e = \left[\frac{2.4 \times 98 \times (2x0.848 + 1)}{(12.25 - 5)x3x0.848}\right]^{0.848} \times \frac{200x0.253(12.25 - 5)}{98}$$

= 20.08 x 3.743 = 75 cp

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Using **Equation (8.33)** for the transitional flow to calculate the slip velocity, we obtain:

$$V_s = 174.7\frac{0.28 \times (21-10)^{0.667}}{10^{0.333} x 75^{0.333}} = 27 \text{ ft/min}$$

Transport velocity = V_a - V_s

= 98 - 27 = 71 ft/min

11.5 Drill Cuttings Concentration

To prevent hole problems, it is generally accepted that the volume fraction of cuttings (or concentration) in the annulus should not exceed 5%. Therefore, the design programme for mud carrying capacity should also include a figure for the drill cuttings concentration in the annulus. The cuttings concentration is given by:

$$C_a = \frac{1}{60} \times \frac{ROP x D_h^2}{(V_a - V_s) \times (D_h^2 - OD_p^2)} \tag{8.37}$$

where

C_a = drillcuttings concentration

ROP = penetration rate, ft/hr

Example 8.4: Cuttings Concentration

Using the same data as given in **Example 8.3** determine the concentration of cuttings in the annulus.Assuming:

ROP = 40 ft hr

D_h = 12.25 in

Solution

$$C_a = \frac{1}{60} \times \frac{40 x 12.25^2}{(98-27) \times (12.25^2 - 5^2)} = 0.011 \text{ or } = 1.1\%$$

In this example, the concentration of cuttings is well below the maximum of 5% and one can increase penetration rate to 177.5 ft/hr without causing hole problems. The figure 177.5 ft/hr is obtained by manipulating **Equation (8.37)** as follows:

$$ROP = \frac{60 \times C_a \times (V_a - V_s) \times (D_h^{\ 2} - OD_p^{\ 2})}{D_h^{\ 2}}$$

$$ROP = \frac{60 \times 0.05 \times (98 - 27V_s) \times (12.25^2 - 5^2)}{12.25^2} = 177.5 \text{ ft/hr}$$

12.0 Learning Milestones

In this chapter, you should have learnt to:

1. Describe types of flow in an oil well
2. Describe three rheological models
3. Apply hydraulic equations to calculate pressure drops in the circulating system
4. Calculate nozzle sizes
5. Apply two hydraulic optimisation criteria
6. Calculate slip and transport velocities
7. Calculate effective viscosity in the annulus
8. Calculate cuttings concentration and optimum ROP

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14.0 EXERCISES

Exercise 1

Using the Bingham plastic model, calculate the various pressure drops, nozzle velocity and nozzle sizes for a section of 8.5 in hole.

Data:

hole depth	=	13,000 ft
plastic viscosity	=	35 cP
yield point	=	25 lb / 100 ft^2
mud weight	=	13 lb / gal
flow rate	=	400 gpm
drillpipe ID	=	4.276 in
OD	=	5 in
Drill collars ID	=	2.875 in
OD	=	6.5 in
length	=	500 ft
Previous casing	=	$9^5/_8$ in
ID	=	8.755 in set at 10,000 ft
Pump pressure	=	3000 psi
Surface equipment type	=	4

(Answers: Circulating pressure = 1573 psi, Pbit = 1427 psi, Nozzles = 2 x 13 and one 12)

2. List the factors that control hole cleaning.

3. What is meant by hydraulics optimisation?

9

Drill Bits

Contents

1.0 Bit Selection Guidelines

During the planning stage, the Drilling Engineer makes a thorough review of offset well data and records bit performance and bit grading characteristics in formations comparable to the well be designed. All occurrence of gauge wear, tooth dulling characteristics and premature bit failures should be noted. This will help determine the bit type suitable for the formations to be drilled, i.e., for insert bits whether the inserts were worn or broken in the offset wells.

Data required for the correct bit selection include the following:

1. Prognosed lithology column with detailed description of each formation
2. Drilling fluid details
3. Well profile

Formation characteristics should be studied in detail to assess the type of cutting structure required to successfully drill the formation. The existence of abrasive and hard minerals such as chert or pyrite nodules should be identified. This will impact on the aggressiveness of the selected milled teeth or insert bits and, in the case of PDC bits, the requirement for hybrid design bits.

When drilling directional wells the Directional Contractor should be asked to provide an assessment of the required BHA changes, motor requirements and any limitations on bit operating parameters which may impact on the selection of bits. In addition bit characteristics in terms of walk, build and drop tendencies will need to be assessed for their impact on the well path.

When using a mud motor in the assembly all tri-cone bits should have a motor bearing system which allows extended use at high motor RPM‘s or a fixed cutter bit should be selected.

Due consideration should always be given to the jet system of the bit. When drilling soft shale sections where the major limitations on ROP is bottom hole and cutter cleaning, the use of centre jet, extended jets or lateral jet bits should be considered.

When drilling abrasive sections, a degree of gauge protection should be specified. For highly abrasive sections the use of insert bits with diamond enhanced gauge protection has proved successful in limiting the occurrence of undergauge hole. This has led to a reduction in the degree of reaming on subsequent bit runs and thus reduces premature wear of the subsequent bit.

2.0 Roller Cone Bits

2.1 Basic Features

As the name implies, roller cone bits are made up of (usually) three equal-sized cones and three identical legs which are attached together with a pin connection. Each cone is mounted on bearings which run on a pin that forms an integral part of the bit leg. The three legs are welded together and form the cylindrical section which is threaded to make a pin connection. The pin connection provides a means of attachment to the drill string.

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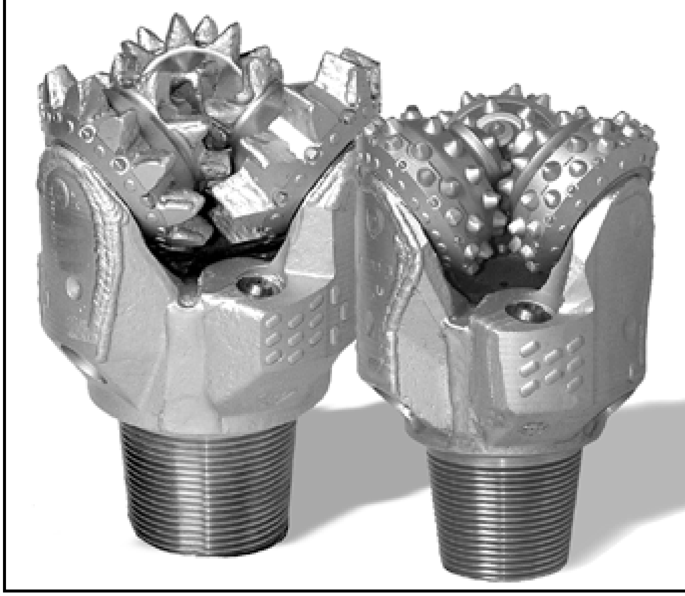
Each leg is provided with an opening for fluid circulation. The size of this opening can be reduced by adding nozzles of different sizes. Nozzles are used to provide constriction in order to obtain high jetting velocities necessary for efficient bit and hole cleaning. Mud pumped through the drillstring passes through the bit pin bore and through the three nozzles, with each nozzle accommodating one third of the total flow, if all the nozzles were of the same size.

Figure 9.1 Roller Cone Bits- Left: Milled tooth and right Insert bit, Courtesy of Hughes Christensen



There are two types of roller cone bits:

- **Milled tooth bits**: Here the cutting structure is milled from the steel making up the cone
- **Insert bits**: The cutting structure is a series of inserts pressed into the cones.

2.2 DESIGN FACTORS

The drill bit design is dictated by the type of rock to be drilled and size of hole. The three legs and journals are identical, but the shape and distribution of cutters on the three cones differ. The design should ensure that the three legs must be equally loaded during drilling.

The following factors are considered when designing and manufacturing a three-cone bit:

- Journal angle
- Offset between cones
- Teeth
- Bearings

3.0 Milled Tooth Bits

Milled tooth bit design depends on the geometry of the cones and the bit body and geometry and composition of the cutting elements (teeth).

The geometry of the cones and of the bit body depend on:

- Journal Angle
- Cone Profile
- Offset Angle

The geometry and composition of the teeth depend on:

- Journal Angle
- Angle of Teeth
- Length of Teeth
- Number of Teeth
- Spacing of Teeth
- Shape of Teeth
- Tooth Hardfacing

3.1 Journal Angle

The bit journal is the bearing load-carrying surface. The journal angle is defined as the angle formed by a line perpendicular to the axis of the journal and the axis of the bit, see **Figure 9.2**.

Figure 9.2 Journal Angle, Courtesy of Reed Hycalog

The magnitude of the journal angle directly affects the size of the cone; the size of the cone decreases as the journal angle increases. The journal angle also determines how much WOB the drill bit can sustain; the larger the angle the greater the WOB. The smaller the journal angle the greater is the gouging and scraping actions produced by the three cones. The optimum journal angles for soft and hard roller cone bits are 33 degrees and 36 degrees, respectively.

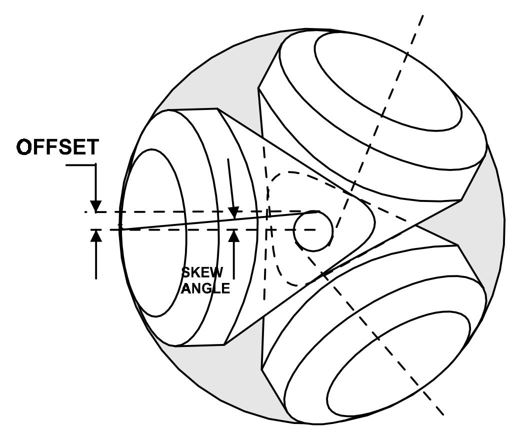
3.2 Cone Profile

The cone profile determines the durability of the drillbit. Cones with flatter profile are more durable but give lower ROP, whilst a rounded profile delivers a faster ROP but is less durable

3.3 Cone Offset

The degree of cone offset (or skew angle) is defined as the horizontal distance between the axis of the bit and a vertical plane through the axis of the journal. A drill bit with zero offset has the centre lines of the three cones meeting at the centre of the drillbit, see **Figure 9.3**. Skew angle is an angular measure of cone offset.

Figure 9.3 Cone Offset: Courtesy of Baker Inteq

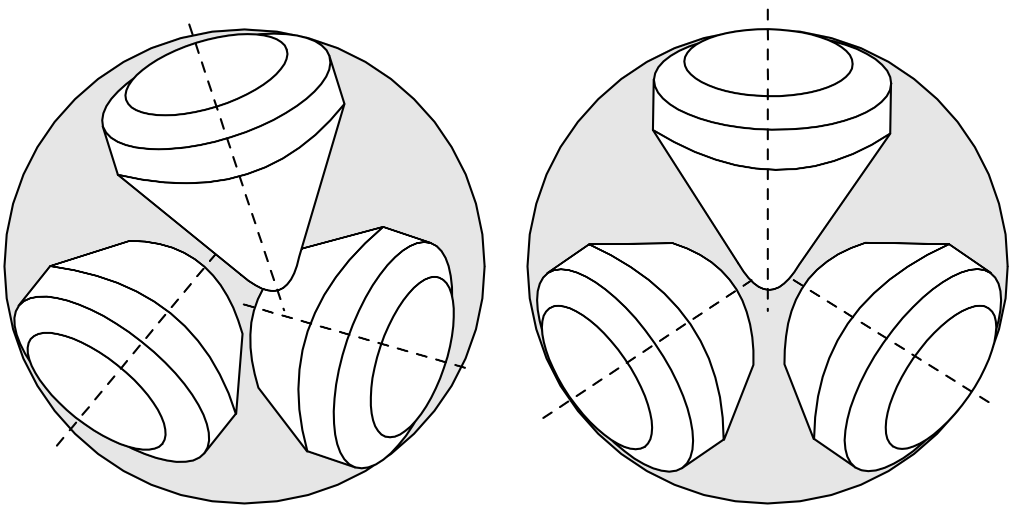


A cone with zero offset has a true rolling action as the cone moves in a circle centred at the cone apex and bit centre.

If the cone is offset from the bit centre, then when the drillbit is rotated from surface, the cone attempts to rotate around its own circle which is not centred at the bit centre. The cone is forced by the much bigger drillstring to rotate about the centreline of the bit and drillstring and this results in the cone slipping as it is rotating. This slipping produces tearing and gouging actions which are beneficial in drilling soft rocks as it removes a larger volume of rock.

The amount of offset is directly related to the strength of rock being drilled. Soft rocks require a higher offset to produce greater scraping and gouging actions. Hard rocks require less offset as rock breakage is dependent on crushing and chipping actions rather than gouging, **Figure 9.4**. Cone offset increases ROP but also increases tooth wear, especially in the gauge area, and increases the risk of tooth breakage.

Figure 9.4 Cone Offset (left) and Non-Offset Cones (right)

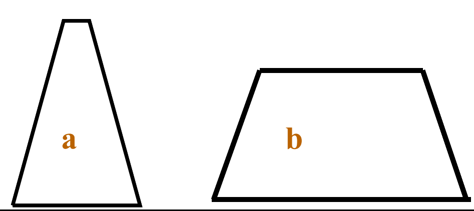


3.4 Tooth Angle and Length

As shown in **Figure 9.5**, drill bits can have slender and long teeth (figure a) or short and stubby teeth (figure b).

The long teeth are designed to drill soft formations with low compressive strength where the rock is more yielding and easily penetrated. Penetration is achieved by applying weight on bit (WOB) which forces the teeth into the rock by overcoming the rock compressive strength. Rotation of the bit helps to remove the broken chips.

Figure 9.5 Tooth Shape



Harder rocks have high compressive strength and can not be easily penetrated using typical field WOB values. Hard rock bits therefore have much shorter (and more) teeth with a larger bearing area., therefore the short teeth will be less likely to break when they are subjected to drilling loadings. The teeth apply load over a much larger area and break the rock by a combination of crushing, creation of fractures and chipping. The teeth are not intended to penetrate the rock, but simply to fracture it by the application of high compressive loads.

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3.5 Tooth Number and Spacing

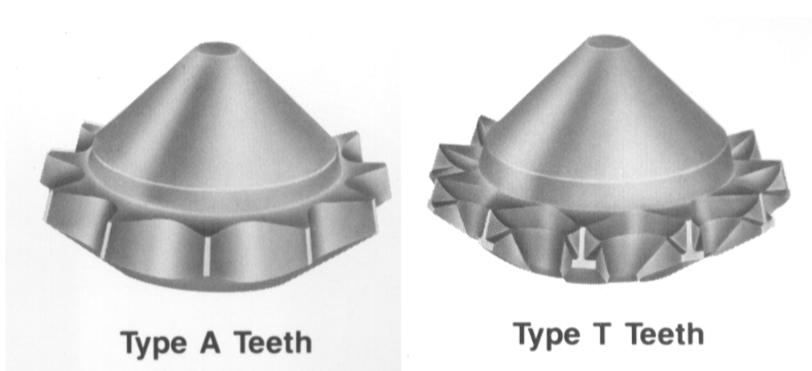
As discussed above, a soft rock requires long and a few teeth allowing the WOB to be distributed over fewer teeth. The teeth are widely spaced to reduce the risk of the bit being balled up when drilling water sensitive clays and shales. Wider spacing also allows the rows of teeth from one cone to engage into the space of equivalent row of the adjacent cone and thereby help to self clean the cutting structure of any build up of drilled cuttings.

For hard formations, the teeth are made shorter, heavier and more closely spaced to withstand the high compressive loads required to break the rock.

3.6 Tooth Shape

Viewed from the side most teeth appear like an A without the crosspiece [1]. There are other design such as the T-,U-, or W-shape which are more durable and are usually found at the gauge area of the bit. **Figure 9.6** shows this.

Figure 9.6 Tooth Shape, Courtesy of Reed Hycalog



3.7 Tooth Hardfacing

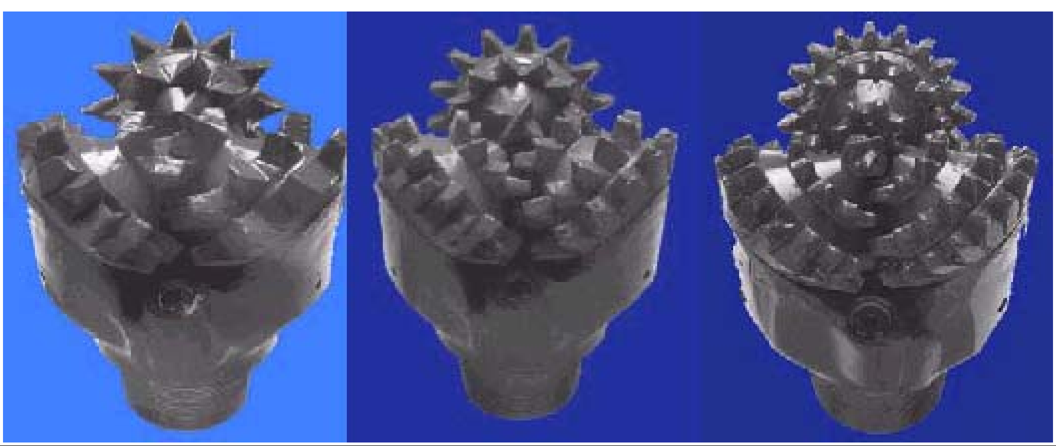
To increase the life of the cutting tooth, hard metal facing (usually tungsten carbide) was initially applied to one side of the tooth to encourage preferential wear of the tooth. As the bit drills away, the tooth wears on one side (the uncovered steel side) thereby always leaving a sharp cutting edge on the metal faced side.This style is known as **self-sharpening hardfacing.**

Nowadays [1], most toothed bits use **Full Coverage Hardfacing**, in which the entire tooth is covered with hardmetal. This practice provides greater durability of the tooth and offers sustained ROP's.

3.8 BIT STYLES

The previous bit design features[1] can now be seen in the three bits illustrated in **Figure 9.7**,below, ranging from an aggressive 1-1 cutting structure, through a 1-3, to a durable 2-1 cutting structure. The numbers 1-1 etc. are actually IADC bit coding designed to distinguish various bit types. For example, soft bits designed to drill very soft rocks are given the number one for the cutting structure. The IADC code is further subdivided to reflect the varying rock strength with each category. Hence code of 1-1 reflects long teeth designed to drill very soft rocks, see **"IADC Bit Classification For Roller Cone Bits" on page 353** for more details on IADC coding.

Figure 9.7 Various Bit Styles, Courtesy of Reed Hycalog



4.0 INSERT BITS

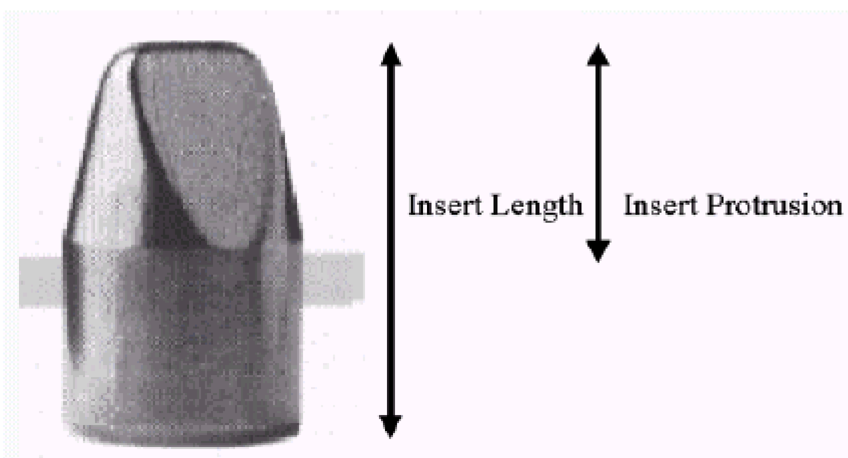
The design factors relating to cone offset, bit profile and cone profile discussed above for milled tooth bits apply equally to insert bits.

The cutting structure of insert bit relies on using tungsten carbide inserts which are pressed into pre-drilled holes in the cones of the bit. The following relates to the various design features of inserts which are designed to suit various rock types.

4.1 INSERT PROTRUSION

Insert protrusion refers to the amount of insert protruding from the cone and is always less than the total length of the insert, **Figure 9.8**.

Figure 9.8 Insert Protrusion, Courtesy of Reed Hycalog

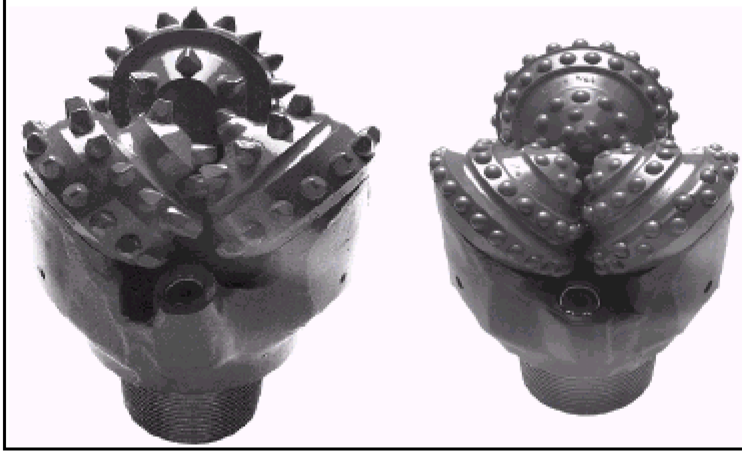


Inserts with large protrusions are suitable for soft rocks as would be seen on a 4-3 type cutting structure and to a limited protrusion as on the insert as on an 8-3 cutting structure, see **"IADC Bit Classification For Roller Cone Bits" on page 353**.

4.2 Insert Number, Diameter And Spacing

The same argument used in milled tooth bits applies here. Soft insert bits have fewer and longer inserts to provide aggressive penetration of the rock. Durable, hard formation bits have many, small diameter inserts with limited protrusion, see **Figure 9.9**.

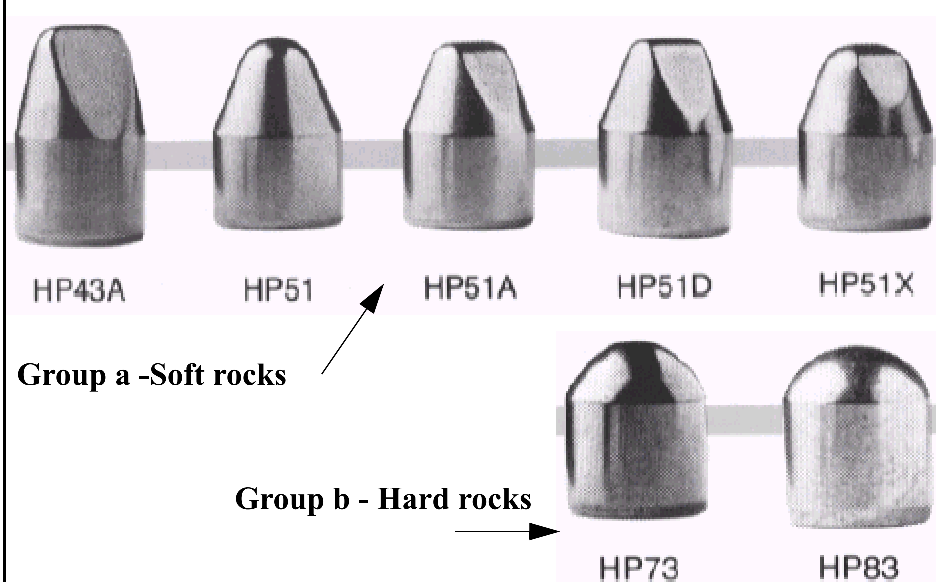
Figure 9.9 Insert Bit Styles [1]



4.3 Insert Shape

For soft formation bits, the inserts have chisel shapes to provide aggressive drilling action. In soft, poorly consolidated formations the chisel shape is more efficient at penetrating the formation than a more rounded conical shape. **Figure 9.10 a** shows five shapes

Figure 9.10 Insert Shape [1]



for use on 5-1 type inserts, the longer, chisel shape is for soft rocks The conical rounded shape is for hard rocks, **Figure 9.10 b.**

4.4 INSERT COMPOSITION

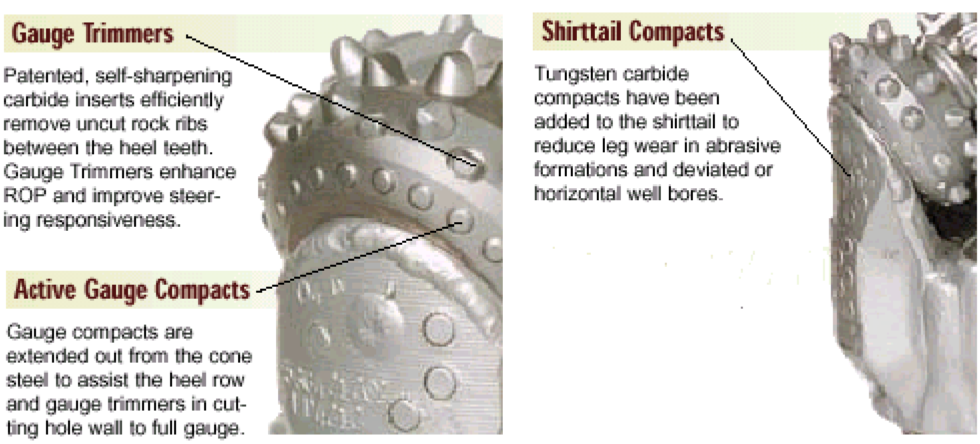
The composition of the inserts [1] can be varied by altering grain size or cobalt concentration. In general changes that increase the wear resistance of the insert will make it more likely to break, while tougher inserts, less prone to breakage, may wear more rapidly.

4.5 ADDITIONAL FEATURES

Additional enhancing features (**Figure 9.11**) include:

- Gauge trimmers to assist in cutting a gauge hole
- Shirttail compacts to reduce leg wear in abrasive formations

Figure 9.11 Additional enhancing design features, courtesy of Hughes Christensen



Gauge Retention

The majority of the drillbit work is spent around the heel and gauge area and therefore this part suffers the greatest amount of wear.

trimmers are used to maintain bit gauge (diameter). this achieved by the use of T-shaped teeth on milled tooth bits and very short inserts in the gauge row. The gauge inserts may be diamond coated.

Figure 9.12 shirttail Inserts, courtesy of Reed Hycalog[1]

Shirttail Protection

All drill bits [1] may have tungsten carbide inserts placed in the heel area of the bit. A worn shirttail [1] (**Figure 9.12**) may expose the seal, leading to seal wear and bearing failure. Various devices may be used to limit or delay shirttail wear. Tungsten Carbide Inserts may be placed in the shirttail itself.Lug pads may be added to the upper part of the shirttail. A band of hardmetal can be added to the margin of the shirttail.

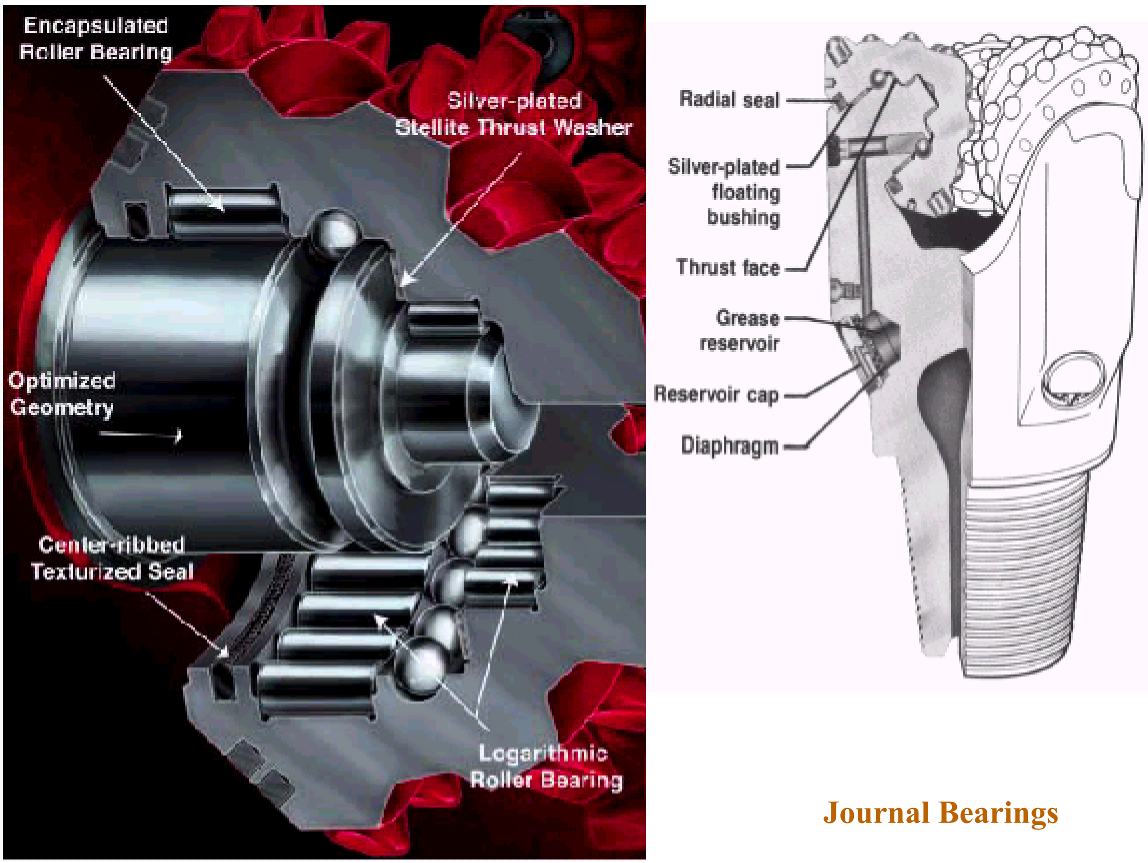
4.6 Bearings and Seals

Bit bearings are used to perform the following functions:

- support radial loads
- support thrust or axial loads
- secure the cones on the legs

The bearings must take the loads generated as the bit cutting structure (and gauge area) engage with the formation as weight (on bit) is applied. These loads cane be resolved into radial and axial forces. The principal radial load is taken by the main journal and the axial load by the thrust face and, in some cases, the ball bearings.

Figure 9.13 Roller and journal bearings, Courtesy of Reed Hycalog



Journal Bearings

Roller Bearings

There are two bearing types, roller and friction (or journal). Roller bearings may be sealed or unsealed whilst friction bearings are always sealed. In roller bearings, the loads applied to the cutting structure is transmitted to the journal through a series of rollers, see **Figure 9.13**. There may be one, two or three of these roller races depending upon the size of the bit.

The main feature of the friction or journal bearing (**Figure 9.13**) that distinguishes it from roller bearings is that the load placed on the cutting structure is transmitted directly to the journal over a wide surface area, hence the name. Friction bearing journal experiences a more even, continuous load compared to roller bearings and can handle high drilling loads. In contrast, the journal surface on a roller bearing bit is subjected to cyclic loading as each roller passes over a given point. With time and at high loads, the roller bearings surface will fail in fatigue.

The even continuous load on journal bearings makes them suffer much higher sliding velocities than roller bearings and consequently can withstand higher temperatures[1]. Small diameter friction bearing bits can handle relatively high rpm without suffering the damaging high temperatures that would occur with the same rpm on a larger diameter friction bearing bit

Because of the above, roller bearings [1] are the common bearing down to 12 ¼" diameter and friction bearings are the standard up to this size; 12 ¼" is the cross-over from friction to roller.

Friction bearing bits are always sealed: the close tolerances and the area contact lead to rapid wear if solid contaminants, such as cuttings or mud solids, get into the bearing. Roller bearing bits can tolerate such contamination more readily and so may be left unsealed.

Bearing life is affected by:

- heavy reaming which reduces bearing life
- directional effects which produce high side loadings
- severe Drillstring and bit vibrations

4.7 Bearing Lubrication System

A sealed bearing system is lubricated by a sealed grease reservoir as shown in **Figure 9.13** (Journal Bearing). The pressure of grease within the bearing must be the same as that outside in the mud.

The lubrication system works as follows [1]:

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An elastomer pressure diaphragm communicates annular pressure to the grease in a grease reservoir (inside the leg) and then, via grease passages to the grease within the bearing itself. Thus zero differential pressure is maintained across the seal at all times. Some leakage of the grease may occur due to rapid pressure changes resulting from axial movement of the cone on the journal. The grease reservoir has enough fluid to allow for minor leakages.

4.8 Seals

Unsealed bearings are still used, generally on large diameter bits where run length is limited and the bearings are of a size that can endure substantial wear and high temperatures.

Most bits have their bearings sealed (**Figure 9.13**) from the mud using a variety of designs including [1]: **'O' Ring and Radial**, **V-Ramp Seal**, **Wave Seal** (shaped seal pushing pockets of grease around the sealing area) and **Metal Face Seal.**

Seals should offer resistance to abrasion by mud solids and cuttings and resistance to temperature, both in situ and that generated by sliding.

5.0 IADC Bit Classification For Roller Cone Bits

In 1972, the International Association of Drilling Contractors (IADC) established a three code system for roller cone bits.

The first code or digit defines the series classification relating to the cutting structure. The first code carries the numbers 1 to 8.

For milled tooth bits, the first code carries the numbers 1 to 3, which describes soft, medium and hard (and semi-abrasive or abrasive) rocks respectively. This number actually signifies the compressive strength of rock.

For insert bits, the first code carries the numbers 4-8.

The second code relates to the formation hardness subdivision within each group and carries the numbers 1 to 4. These numbers signify formation hardness, from softest to hardest within each series. The second code is a subdivision of the first code (1 to 8)

The third code defines the mechanical features of the bit such as non-sealed or sealed bearing. Currently there are seven subdivisions within the third code:

1. Non-sealed roller bearing
2. Roller bearing air cooled
3. Sealed roller bearing
4. Sealed roller bearing with gauge protection
5. Sealed friction bearing
6. Sealed friction bearing with gauge protection
7. Special features - category now obsolete.

As an example, a code of 1-2-1 indicates (**Figure 9.7**):

Code 1: long, slim and widely spaced milled tooth bit

Code 2: medium soft formations (if this number was 4, then it is hard soft formation)

Code 3: non-sealed bearings

6.0 POLYCRYSTALLINE DIAMOND COMPACT (PDC) BITS

6.1 DESIGN FACTORS

A polycrystalline diamond compact (PDC) bit employs no moving parts (i.e. there are no bearings) and is designed to break the rock in shear and not in compression as is done with roller cone bits. Rock breakage by shear requires significantly less energy than in compression, hence less weight on bit can be used resulting in less tear and wear on the rig and drillstring.

A PDC bit employs a large number of cutting elements, each called a PDC cutter. The PDC cutter is made by bonding a layer of polycrystalline man-made diamond to a cemented tungsten carbide subtrate in a high pressure, high temperature process. The diamond layer is composed of many tiny diamonds which are grown together at random orientation for maximum strength and wear resistance [2].

6.2 Bit Design Elements

There are many details relating to bit design which can not all be covered in detail here. Reference to manufacturers catalogues is recommended for the interested reader.

The PDC design is affected by:

1. Body design: can either be steel-bodied or tungsten carbide (matrix)
2. Cutters Geometry
   - Cutters
   - Number of Cutters and spacing of cutters
   - Size of Cutters
   - Back Rake
   - Side Rake
3. Geometry of Bit
   - Number of Blades
   - Blade Depth
4. Diamond table
   - Substrate interface
   - Composition
   - Shape

6.2.1 Bit Body

The bit body may be forged or milled from steel (steel-bodied bits) or constructed in a cast from tungsten carbide (matrix bit).

From a practical standpoint, steel bodies bit are preferable as they can be easily repaired but suffer from erosion. Matrix bits are more resistant to erosion but are prone to bit balling in soft clay formations due to their low blade height compared with steel bodied bits.

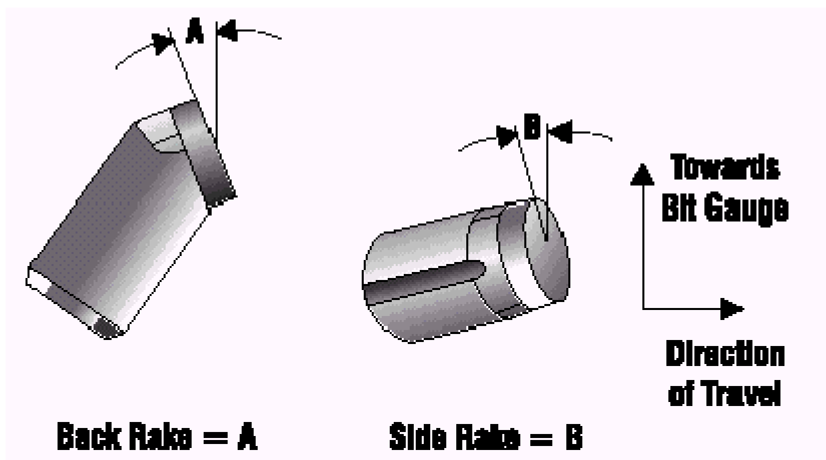
6.2.2 Cutter Geometry

Cutter geometry depends on:

1. Number of Cutters

Soft rocks can be penetrated easily and hence fewer cutters are used on soft PDC bits as each cutter removes a greater depth of cut. More cutters must be added to hard PDC bits for harder formation to compensate for the smaller depth of cut.

Figure 9.14 Back rake and side rake angles, courtesy of Reed Hycalog



2. Cutter Size

Large cutters are used on softer formation bits and smaller cutters on the harder formation bits. Usually a range of sizes is used, from 8mm to 19mm is used on any one bit.

3. Back Rake [1]

Cutter orientation is described by back rake and side rake angles.Back rake is the angle presented by the face of the cutter to the formation and is measured from the vertical, see **Figure 9.14**.

The magnitude of rake angle affects penetration rate and cutter resistance to wear.

As the rake angle increase, ROP decreases but the resistance to wear increases as the applied load is now spread over a much larger area.

PDC cutters with small back rakes take large depths of cut and are therefore more aggressive, generate high torque, and are subjected to accelerated wear and greater risk of impact damage. Cutters with high back rake have the reverse of the above.

Back rake angles vary between, typically, 15° to 45°. They are not constant across the bit, nor from bit to bit.

4. Side Rake [1]

Side rake is an equivalent measure of the orientation of the cutter from left to right. Side rake angles are usually small. The side rake angle assists hole cleaning by mechanically directing cuttings toward the annulus.

5. Cutter Shape

The edge of the cutters may be bevelled or chamfered to reduce the damage caused by impacts.

6.2.3 Bit Geometry

The factors affecting bit geometry include:

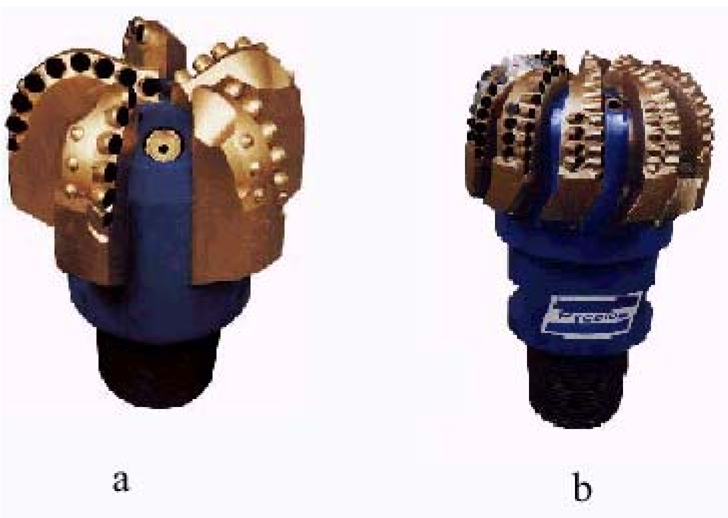
1.Number of Blades

Using the same analogy for roller cone bits, a PDC bit designed for soft rocks has a fewer blades (and cutters) than one designed for hard rocks.

The soft formation PDC bit will therefore have a large junk slot area to remove the large volume of cut rock and to reduce bit balling in clay formations, **Figure 9.15 a**.

A hard PDC bit with many blades requires many small cutters, each cutter removing a small amount of rock, **Figure 9.15** b.

Figure 9.15 PDC bit design features, courtesy of Reed Hycalog



2.Blade Height

A soft formation PDC bit will have a lager blade height than a hard PDC bit with a consequent increase in junk slot area. Higher blades can be made in steel bodied- bits than matrix bits, because of the greater strength of steel over that of matrix.

3.Blade Geometry

PDC bits can be manufactured with a variety of blade shapes ranging from straight to complex curve shapes. Experience has shown that curved blades provide a greater stability to the bit especially when the bit first contacts the rock.

4.Bit Profile

Bit profile affects both cleaning and stability of the bit. The two most widely used profiles are: double cone and shallow cone, **Figure 9.16**.

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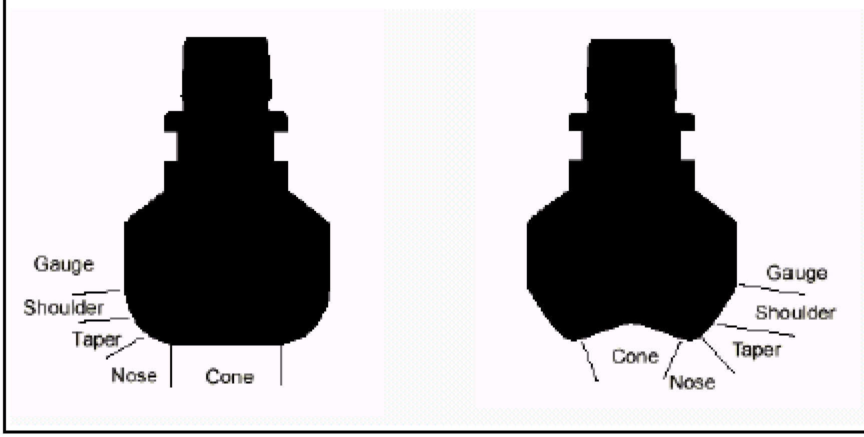
The double cone profile allows more cutters to be placed near the gauge giving better gauge protection and allowing better directional control. The shallow cone profile gives faster penetration but has less area for cleaning. In general a bit with a deep cone will tend to be more stable than a shallow cone.

Figure 9.16 PDC bit profiles, Courtesy of Reed Hycalog



5.Bit Length [1]

This is important for steerability. Shorter bits are more steerable. The two bits on the left of **Figure 9.17** are sidetrack bits, with a short, flat profile. The 'Steering Wheel' bit on the right of **Figure 9.17** is designed for general directional work

.

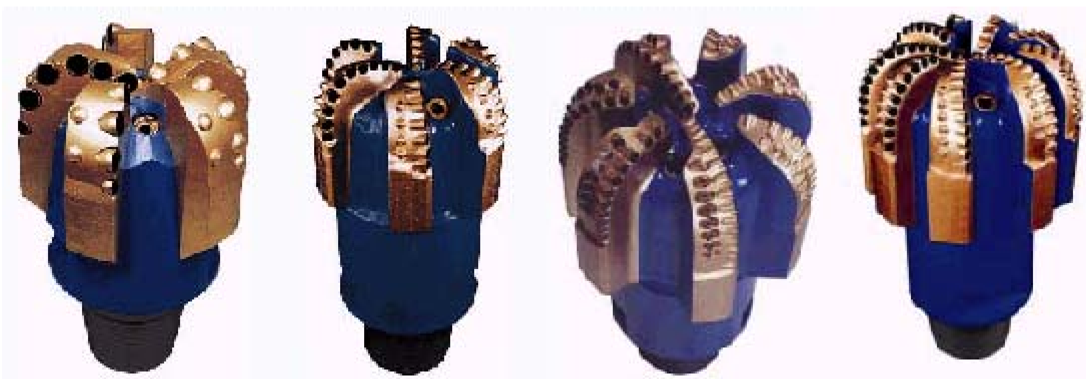
Figure 9.17 PDC bit length, Courtesy of Reed Hycalog

6.Bit Style

When all of the above features are put together, a variety of bit styles emerge as shown in **Figure 9.18**.

The bit on the extreme left of **Figure 9.18** is a light set bit with a few, high blades and a few but large cutters with small back rake angles. Thus light set bits typically have a few, high blades, with few large cutters, probably with low back

Figure 9.18 PDC bit styles, Courtesy of Reed Hycalog



For hard rocks, PDC bits will have more blades, with smaller and more numerous cutters, and this trend continues to the heavy set bits on the extreme right of **Figure 9.18.**

6. Gauge Protection

As discussed before, the greatest amount of work is done on the heel and gauge of the drillbit. A PDC bit that wears more on the gauge area will leave an undergauge hole which will require reaming from the next bit. Reaming is time consuming and costly and in some cases can actually destroy an entire bit without a single foot being drilled.

Hence maintaining gauge is very important. One or more PDC cutters may be positioned at the gauge area. Pre-flatted cutters are used to place more diamond table against gauge. Tungsten carbide inserts, some with natural or synthetic diamonds embedded in them, may be placed on the flank of the bit [1].

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A major advantage with fixed cutter bits over roller cone bits, is that the gauge on fixed cutter bits may be extended to a larger length of the drill bit.

6.3 PDC Bits Applications

PDC bits have been used extensively and successfully over a wide range of formation types. The lack of rotating parts leads to greater life expectancy and as such long bit runs are achievable with resultant time and cost savings. A thorough review of the economics of running a PDC bit needs to be performed prior to selection due to its increased cost. The following guidelines list the typical applications of PDC bits.

1 PDC bits are typically useful for drilling long, soft to medium shale sequences which have a low abrasivity. In such formations they typically exhibit high ROP and extended life enabling entire sections to be drilled on one run.

2 PDC bits are not usually appropriate for highly abrasive well cemented sand sequences. When drilling tight siliceous formations the incidence of PDC chipping and breaking is dramatically increased resulting in less than expected ROP and bit life.

3 When drilling heterogeneous formations containing alternating shales and or shale limestone sequences the use of hybrid PDC bits is encouraged. This bit incorporates the use of back-up diamond studs behind the PDC cutter. When drilling harder abrasive strings, the diamond stud absorbs the increased weight required to drill the stringer and prevents premature damage and wear to the PDC cutter.

4 The use of bladed hybrid PDC bits is recommended for drilling hard formations. The deep watercourse on these bits enable optimum fluid flow across the cutter to efficiently reduce the friction temperatures induced. This efficient cooling will help minimise fracture of the PDC cutters.

5 When drilling mobile, plastic formations such as salt sections the use of eccentric PDC bits should be considered. These bits have proved successful in preventing incidence of stuck pipe in many areas where salt flow problems are experienced.

6 When planning the use of mud motors or turbines, the use of long tapered profile bits should be considered. In addition, radial jetting bits reduce the potential for friction induced high cutter temperatures when run on a motor or turbine which reduces temperature degradation of the cutter.

6.4 Running PDC Bits

The following guidelines are produced to highlight the major considerations when running a PDC bit in order to achieve optimum performance.

1. Junk in Hole

Make sure the bottom of the hole is free of junk and debris as the PDC cutters will be destroyed if drilling steel elements are left in the hole.

2. Fully evaluate the previous bit for gauge deterioration.

Prior to running a PDC bit it is important to check the gauge on the bit which has just been pulled out of the hole. PDC bits should not be used for reaming as this will result in possible chipping of the PDC cutters and will wear out the gauge before reaching bottom and commencing drilling. If reaming has to be performed circulate at the maximum rate and ream with very low WOB and RPM.

3. Bit Preparation

Put the bit into the bit breaker and make up to same torque as rock bit, having first removed the rotary bushing from the rotary table.

4. Use of mud screens

To prevent nozzle plugging due to foreign objects in drilling field, install a Kelly mud screen prior to circulating the drilling fluid.

5. Tripping Procedures

(a) When running in hole, extreme caution should be exercised when tripping through the open hole section. The driller should be advised to slow the running speed in open hole.

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(b) Be cautious of any tight spots. All tight spots should be very carefully reamed with full circulation, very low WOB and RPM. The tight spot should be reamed carefully to ensure clean gauge hole.

(c) Reaming should be eliminated when possible. Do not ream long intervals with PDC bits. During reaming, gauge cutters absorb all the applied weight. If considerable reaming is needed in medium hard and abrasive formations, the bit should be pulled and a tricone bit used for reaming purposes.

(d) Do not apply more than 5000 pounds WOB when reaming. The rotary speed should not be more than 50 to 60 rpm.

(e)It is recommended to ream the last joint to bottom in order to avoid nozzle plugging from any down hole fill.

(f)Use the lightest bit weight possible to locate the bottom of the hole and then pull one or two feet off the bottom. Circulate at full rate for 10-15 minutes.

6. Initial Drilling Procedures

(a) The rotary should be kicked in before the bit touches bottom. Let the bit touch bottom lightly and put 2000-4000 pounds of weight on the bit with 50 to 60 rpm. Set desired stand-pipe pressure and flow rate for cleaning power.

(b)Once the bit has been bedded in, a Drill-Off Test should be performed where appropriate to determine the optimum drilling parameters to be run. This should be repeated after any major change in lithology which is prognosed to persist over a considerable interval.

6.5 Drilling Casing Flotation Equipment With PDC Bits

General Considerations

1. It is now possible to drill out casing flotation equipment with PDC bits using rotary or turbine drilling techniques. This eliminates the need to perform a separate casing clean-out trip. This will only be attempted if the next section of open hole is suited to PDC drilling.

2. On exploration/appraisal wells, when the nature of the formations are uncertain, it may be advisable to drill out the float equipment and open hole with a re-run or repaired PDC bit in the first instance.

3. It must be certain that there is no junk, such as rock bit teeth or side coring bullets, lying below the casing shoe. The risk of casing accessories producing junk must also be taken into consideration. Beware of damaging a PDC bit where there is a high dogleg in the shoe track.

4. It is advisable to use a PDC bit with a minimum of PDC cutters on the gauge area. Gauge cutters, if present, should be of the flat profile type rather than the circular profile type in order to avoid damage while rotating in the casing.

5. Casing float equipment must be thread locked to overcome the greater right hand torque produced by the PDC cutting action.

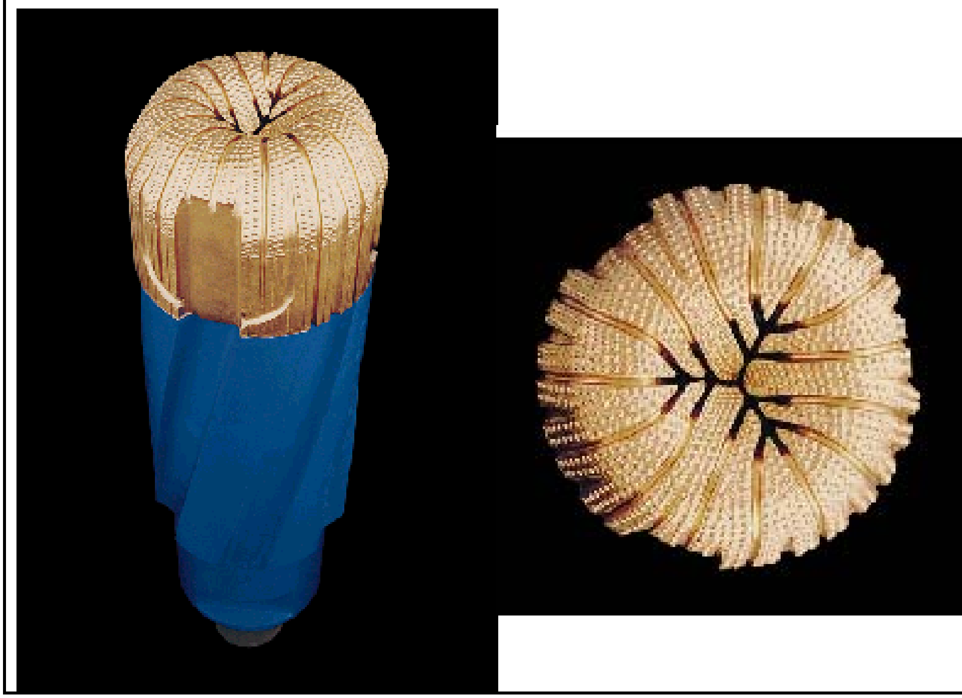
6. Consideration should be given to usage of non-rotating float and plugs.

7.0 DIAMOND AND TSP BITS

Diamond is the hardest mineral known to man with a value of 10 on the Mohs scale of mineral hardness. The Mohs scale ranges from 1 for very soft rocks such as talc to 10 for diamond. Diamond also posses the highest thermal conductivity of any other mineral allowing it to dissipate heat very quickly. This is a desirable property from a cutting element to prevent it from burning or thermal fracture due to overheating.

Diamond and TSP (thermally stable PDC) bits (**Figure 9.19**) are used for drilling hard and abrasive formations and particularly useful in turbine drilling applications. ROP's achieved with diamond bits are generally low due to the nature of the formations that they are designed to drill. Due to their fixed cutter design, greater endurance is achieved with diamond bits as compared with similar formation rated insert bits.

Figure 9.19 Natural diamond bit, Courtesy of Reed Hycalog



The cutting elements of a diamond bit consists of a large number of small-sized diamonds geometrically distributed across a tungsten carbide body. The bit does not employ moving parts and is especially suited to drilling hard and abrasive formations (such as quartzite) and when longer bit runs are required to reduce trip times.

Diamond bits are manufactured as either drilling or coring bits.

Diamond bits comprise: natural diamond bits, TSP bits and impregnated bits. They share several features:

- similar profiles
- common drilling mechanism – grinding
- hydraulics dominated by flow through waterways

- application in hard and very hard formations, with corresponding poor performance in soft rocks.

The central design elements for diamond bits are the diamond size, diamond quality, the hydraulics pattern and the bit profile. The hydraulic energy (HSI) at the bit should be optimised to keep the face of the bit cool (to save the diamonds) and to provide efficient hole cleaning, see **Chapter 8**.

Various grades and shapes of diamonds are used depending on the application of the bit. These grades and shapes vary in relation to their resistance to wear and to breakage.

As the formations get harder the diamond size gets smaller. Soft formations (ROP > 10 ft/hr) require 1-1 1/2 carat diamonds, while very hard drilling (ROP <2 ft/hr) may require 6-8 stones/carat.

The following guidelines are useful when selection diamond bits:

1. When drilling highly abrasive formations, high diamond density bits should be used. For formations which exhibit medium abrasiveness a light to medium density bit may be used.

2. When using a turbine in conjunction with a diamond bit, TSP diamonds are preferred due to their increased temperature stability.

3. A bit with a turbine sleeve type body with a long tapered profile should be considered for turbine applications.

8.0 DRILL-OFF TESTS

Drill-off tests are carried out to optimise WOB and RPM (where appropriate) of a given drillbit. The following procedure may be used:

1. Prior to running bit, check the Drilling Programme for the recommended parameters to be used with the bit. This will typically be a range suitable for the bit type to be used and the information is taken from manufacturers recommendations or offset wells.

2. Check the rotary speed of the rotary table or top drive.

3. Mark and measure drill-off interval on Kelly, L, such that L/ROP = 0.1. (This is to prevent excessive time spent drilling with less than optimum parameters; the test should take approximately 6 minutes).

4. Set and maintain a predetermined WOB at the light end of the range whilst measuring time taken to drill interval L.

5. Calculate ROP in ft/hr and plot graphically against RPM.

6. Increase rotary speed in 10 rpm increments and plot the resultant ROP. Select the point at which an increase in rpm does not give a proportional increase in ROP. From the graph of data points generated, select the rpm which corresponds to the maximum ROP. Monitor and record the level of torque throughout test.

7. Repeat steps 1 through 6 above, maintaining the selected rpm whilst varying WOB in 2K increments. Plot the WOB against ROP for each increment. If increased WOB does not result in a proportional increase in ROP, reduce WOB to the previous optimum level. Plot graph of data points to select optimum WOB. Monitor torque through test.

8.1 Hydraulics Optimisation

Where ECD conditions permit, pump parameters can be optimised by drill-off tests to achieve optimum bit performance. This is particularly important when running PDC bits which require efficient hydraulics to maintain a clean cutting structure and achieve effective bottom hole solids removal. The following procedure may be used:

1. Use the optimum WOB and RPM as selected in the above drill-off test.

2. Increase the pump rate in 20 stroke increments and record the resultant ROP. Plot the data points and determine the optimum flow rate which results in the optimum ROP.

NB: Two drill-off tests must be conducted per tour when drilling the same formation with one additional test when any formation change is encountered.

9.0 IADC Dull Bit Grading

This section applies to:

- Natural diamond, PDC and TSP bits, otherwise known as ‘Fixed Cutter Bits’, and
- Roller Cone Bits.

The 1987 IADC dull grading system and subsequent revision can be used to accurately describe dulled tungsten carbide insert and steel tooth roller cone bits as well as fixed cutter bits. It describes the condition of the cutting structure, the primary (with location) and secondary dull characteristics, the bearing condition (where applicable), the gauge condition and the reason the bit was pulled.

Figure 9.20 illustrates the formats and dull characteristics for all types of dull bit grading.

9.1 The IADC System for Roller Cone Bits

The format of the dull grading system is shown in **Figure 9.20**. It contains all the codes needed to dull grade roller cone bits, as described below:

1. Column 1(I) is used to report the condition of the cutting structure on the inner 2/3rds of the bit.

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Figure 9.20 IADC dull grading system

Cutting Structure				Bearings/Seals	Gauge	Other Dull Char	Reason Pulled
Inner	Outer	Dull Char.	Location				
1	2	3	4	5	6	7	8

1. Inner Cutting Structure
(All inner rows)

2. Outer Cutting Structure
In columns 1 and 2 a linear scale from 0 to 8 is used to describe the condition of the cutting structure according to the following:

Steel Tooth Bits
A measure of lost tool height due to abrasion
0 - No Loss of Tool Height
8 - Total Loss of Tooth Height

Steel Tooth Bits
A measure of lost tool height due to abrasion
0 - No Loss of Tool Height
8 - Total Loss of Tooth Height

Insert Bits
A measure of total cutting structure reduction due to lost, worn and/or broken inserts.
0 - No Loss, Worn and/or Broken Inserts
8 - All Inserts Lost, Worn and/or Broken.

4. Location

Roller Cone

N - Nose Row	Cone one #
M- Middle Row	1
G – Gauge Row	2
A - All Rows	3

Fixed Cutter

S- Shoulder
C- Cone
N – Nose
S -Shoulder
G – Gauge
T - Taper
A - All Areas

5. Bearings/Seals

Non-Sealed Bearing
A linear scale estimating baring life used.
(**0** -No life used, **8** - All life used, i.e., no bearing life remaining.)

Sealed Bearing

E - Seals Effective
F - Seals Failed
N- Not able to grade
X- Fixed cutter bit (bearingless)

Figure 9.20 continued

Fixed Cutter Bits

A measure of lost, worn and /or broken cutting structure.

0 - No Lost, Worn Cutting Structure
8 - All of Cutting Structure Lost, Worn and/or Broken

3. Dull Characteristics
(use only cutting structure related codes)

***BC** -Broken Cone
BF -Bone Failure
BT -Broken Teeth/Cutters
BU -Balled Up Bit
***CC** -Cracked Cone
***CD** -Cone Dragged
CI -Cone Interference
CR -Cored
CT -Chipped Teeth/Cutters
ER -Erosion
FC -Flat Crested Wear
HC -Heat Checking
JD -Junk Damage
***LC** -Lost Cone
LN -Lost Nozzle
LT -Lost Teeth/Cutters
OC -Off-Centre Wear
PB -Pinched
PN -Plugged Nozzle/Flow Passage
RG -Rounded Gage
RO -Ring Out
FM -Formation Change
SS -Self Sharpening Wear
TR -Tracking
WO -Washed Out Bit
WT -Worn Teeth/Cutters
NO -No Dull Characteristic

***Show Cone # under location 4**

6. Gauge Measured in fractions of an inch.

1 - In Gauge
1/16 - 1/16 Out of Gauge
2/16 - 1/8 Out of Gauge
4/16 - 1/4 Out of Gauge

7. Other Dull Characteristic
Refer to Code **3**

8. Reason Pulled or Run Terminated

BHA -Change Bottom Hole Assembly
DMF -Downhole Motor Failure
DTF -Downhole Tool Failure
DST -Downhole String Failure
DST -Drill Stem Test
LOG -Run Logs
LIH -Left in Hole
RIG -Rig Repair
CM -Condition Mud
CP -Core Point
DP -Drill Plug
FM -Formation Change
HR -Hours on Bit
PP -Pump Pressure
PR -Penetration Rate
TD -Total Depth/Casing Depth
TQ -Torque
TW -Twist Off
WC -Weather Conditions

2. Column 2 (O) of **Figure 9.20** is used to report the condition of the cutting structure on the outer 1/3rd of the bit. In columns 1 and 2 a linear scale from 0-8 is used to describe the conditions of the cutting structure, based on the initial usable cutter height.

Steel Tooth Bits

0 - indicates no loss of tooth height due to wear or breakage.
8 - indicates total loss of tooth height due to wear or breakage.

Insert Bits

0 - indicates no lost, worn and/or broken inserts
8 - indicates total reduction of cutting structure due to lost, worn and/or broken inserts.

3. Column 3 (D) uses a two-letter code to indicate the major dull characteristics of the cutting structure. **Figure 9.20** lists the two letter codes for the dull characteristics to be used in this column.

4. Column 4 (L) uses a letter code to indicate the location on the face of the bit where the major cutting structure dulling characteristics occurs.

Figure 9.20 lists the codes to be used for describing locations on roller cone bits.

5. Column 5 (B) uses a letter or a number code, depending on bearing type, to indicate bearing condition on roller cone bits. For non-sealed bearing roller cone bits a linear scale from 0-8 is used to indicate the amount of bearing life that has been used. A ‘0’ indicates that no bearing life has been used (a new bearing), and an ‘8’ indicates that all of the bearing life has been used (locked or lost). For sealed bearing (journal or roller) bits a letter code is used to indicate the condition of the seal. An ‘E’ indicates an effective seal, and a ‘F’ indicates a failed seal(s).

6. Column 6 (G) is used to report on the gauge of the bit. The letter ‘I’ indicates no gauge reduction. If the bit does not have a reduction in gauge it is recorded in 1/16th of an inch. The ‘2/3rds rule’ will be used for three-cone bits.

NoteThe 2/3rds Rule, as used for three-cone bits, requires that the gauge ring be pulled so that it contacts two of the cones at their outer most points. Then the distance between the outermost point of the third cone and the gauge ring is multiplied by 2/3rds and rounded to the nearest 1/16th of an inch to give the correct diameter reduction.

7. Column 7 (O) is used to report any drilling characteristics of the bit, in addition to the major cutting structure dulling characteristics listed in Column 3 (D). Note that this column is not restricted to only cutting structure dulling characteristics. Use the two-letter codes in column 3 to report drilling characteristics for column 7.

Column 8 (R) is used to report the reason for pulling the bit out of the hole.

Figure 9.20 lists the two or three-letter codes to be used in this column.

9.2 IADC System for Fixed Cutter Bits

The format of the dull grading system is shown in **Figure 9.20 and Figure 9.21**. These figures contain all the codes needed to dull grade fixed cutter bits, as described below.

1. Column 1 (I) of **Figure 9.20** is used to report the condition of the cutting structure on the inner 2/3rds of the bit.

2. Column 2 (O) is used to report the condition of the cutting structure on the outer 1/3rd of the bit.

In columns 1 and 2 a linear scale from 0-8 is used to describe the condition of the cutting structure, based on the initial usable cutter height.

The amount of cutter wear represented by 0 through 7 is shown schematically in **Figure 9.21**. An ‘8’ means there is no cutter left. This same scale is used for TSP and natural diamond bits, with ‘0’ meaning - no wear, ‘4’ meaning -50% wear, and so on.

When grading a dull PDC bit, the average amount of wear in each area should be recorded. For example, in **Figure 9.21**, the five cutters in the inner area would be graded a ‘2’. This is calculated by averaging the grades of the individual cutters in the inner area as follows:

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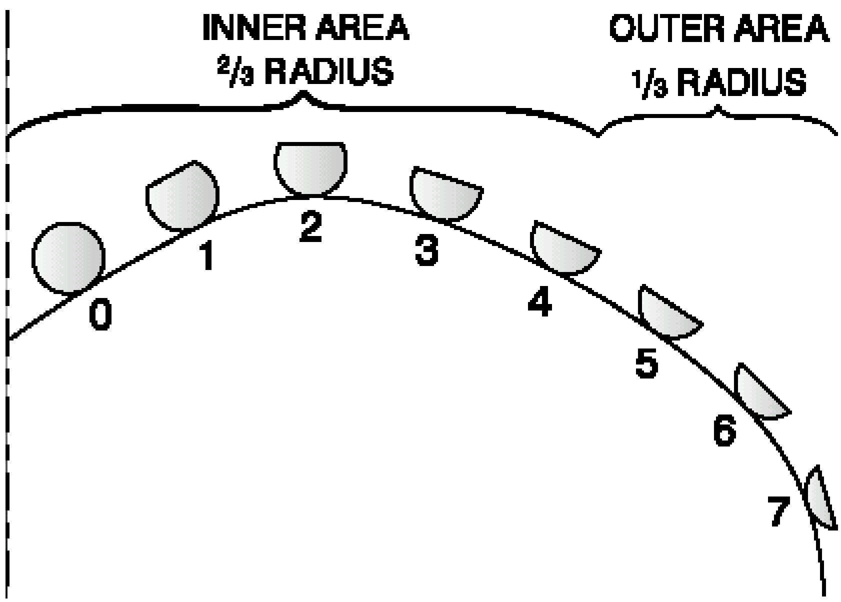
$$(4+3+2+1+0)/5=2$$

Figure 9.21 Cutter wear in PDC bits, Courtesy of Reed Hycalog



Similarly, the grade of the outer area would be a ‘6’.

3. Column 3 (D) uses a two-letter code to indicate the major dull characteristic of the cutting structure. **Figure 9.20** lists the two-letter codes for the dull characteristics to be used in this column. **Figure 9.16** shows fixed cutter profiles with the different areas labelled.

4. Column 4 (L) uses a letter code to indicate the location on the face of the bit where the major cutting structure dulling characteristic occurs. **Figure 9.20** lists the codes to be used for describing locations on fixed cutter bits.

5. Column 5 (B) will always be an ‘X’ for fixed cutter bits, since there are no bearings.

6. Column 6 (G) is used to report on the gauge of the bit. The letter ‘I’ indicates no gauge reduction. If the bit does have a reduction in gauge it is to be recorded in 1/16ths of an inch.

7. Column 7 (O) is used to report any dulling characteristics of the bit, in addition to the major cutting structure dulling characteristic listed in Column 3 (D). Note that this column is not restricted to only cutting structure dulling characteristics. **Figure 9.20** lists the two-letter codes to be used in this column.

8. Column 8 (R) is used to report the reason for pulling the bit out of the hole. **Figure 9.20** lists the two or three-letter codes to be used in this column.

10.0 DRILLING COST CALCULATIONS

10.1 COST PER FOOT

The criterion for bit selection is normally based on cost/ft (C) and this is determined using the following equation:

$$C = \frac{B + (T + t) \times R}{F} \ (\$/ft) \qquad (9.1)$$

Equation (9.1)shows that cost/ft is controlled by five variables and for a given bit cost (B) and hole section (F), cost/ft will be highly sensitive to changes in rig cost per hour (R), trip time (T) and rotating time (t).

The trip time (T) is the sum of RIH and POH times. If the bit is pulled out for some reason, say, to casing shoe for a wiper trip, such duration, if added, will influence the total trip time (T) and, in turn, cost/ft. Bit performance, therefore, can be changed by some arbitrary factor and for accurate comparisons of different bit types, the tip time should be based on the time required for straight RIH and POH. Rotating time is the total time the drill bit is rotating on bottom while drilling.

The rig cost (R) will greatly influence the value of cost/ft. For a given hole section in a field that is drilled by different rigs, having different values of 'R', the same bit will produce different values of cost/ft, assuming the same rotating hours are used in all rigs. It should be pointed out that if the value of R is taken as arbitrary (say 2000 $/hr), then **Equation (9.1)** will yield equivalent values of cost/ft for all rigs. The value of cost/ft in this case is not a real value and does not relate to actual or planned expenditure, it is merely used for comparison.

The criterion for selection of bits on the basis of cost/ft is to choose the bit which consistently produces the lowest value of C in a given formation or hole section.

Example 9.1: Calculation of Cost /ft

Determine the cost/ft for the following bit types which were used to drill the same type of formation in three wells. Which bit would you select for the next well?

Well No.	Bit Type	Depth in (ft)	Depth out (ft)	Footage Drilled	Rotating Time (hrs)	Trip Time (hrs)
1	XX	5,468	8,138	2,670	144	8
2	XY	4,973	7,795	2,822	180	8

Assume bit cost = \$10,000 and rig cost= 900 \$/hr

Solution

Using $$\text{cost/ft} = \frac{B + (T + t) \times R}{F}$$

Bit XX

$$\text{cost/ft} = \frac{10{,}000 + (8 + 144) \times 900}{2{,}670}$$

$$= 54.9 \text{ \$/ft}$$

Bit XY

$$\text{cost/ft} = \frac{10{,}000 + (8 + 180) \times 900}{2{,}822}$$

$$= 63.5 \text{ \$/ft}$$

On the basis of cost/ft, bit type XX is more economical than bit XY and should be used in the next well.

10.2 Break-even Analysis

The break-even analysis is usually used to investigate the economics of replacing a current cheap bit by a more expensive bit or vice versa. The comparison is normally based on a graph of footage against rig hours. The graph is established as follows:

1. Calculate the number of rig hours equivalent to bit cost using:

$$A = \frac{\text{Cost of new bit (\$)}}{\text{Rig cost (\$)}} \qquad (9.2)$$

2.Add trip time to A to obtain the total number of rig hours corresponding to the cost of the new bit before drilling commences. Call this time B.

$$B = \text{trip time} + A \qquad (9.3)$$

Mark this point on the left-hand side of the X-axis, (i.e. rig hours axis), **Figure 9.22.**

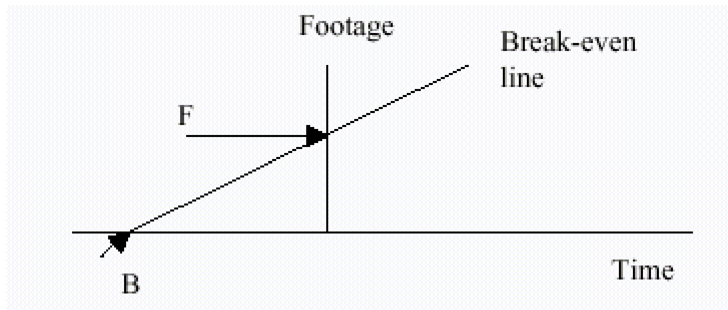
3.Calculate the number of feet of hole at break-even cost using:

$$F = \frac{\text{Cost of new bit + trip cost}}{\text{Offset cost/ft}} \qquad (9.4)$$

Mark point F on the Y-axis (i.e. footage axis).

4.Draw a straight line through points B and F, **Figure 9.22**.

Figure 9.22 Break-even analysis



This line is the break-even line. Any footage and hour combination on this line is a break-even point. Above this line, the new bit will produce lower cost/ft than the offset bit and below this line the new bit is more expensive to run.

Example 9.2: Break-even analysis

A milled tooth bit drilled 2,461 ft of limestone in 150 rotating hours. Other relevant data for this bit is:

Trip time (T) = 8 hrs

Bit cost (B) = $3,000

Rig cost = 900 $/hr

It is proposed to replace this bit with an insert-type bit costing 8,500.

Prepare a break-even graph.

Solution

$$1.\ A = \frac{8{,}500}{900} = 9.4 \text{ hrs}$$

2. B = trip time + A = 8 + 9.4 = 17.4 hrs

3. Calculate F

$$F = \frac{\text{(cost of new bit + trip time cost) (\$)}}{\text{offset cost (\$/ft)}} \quad \text{(ft)}$$

$$\text{Offset cost/ft} = \frac{3{,}000 + (8 + 150) \times 900}{2{,}461} = 59 \text{ \$/ft}$$

Trip cost = 8 hrs x 900 \$/hrs = 7,200 \$

Total cost = 7,200 + 8,500 = 15,700 \$

$$F = \frac{15,700}{59} = 266 \text{ ft}$$

The break-even line is drawn through points B = 17.4 hrs and F = 266 ft, as shown in **Figure 9.22**. Any combination of footage and hours above this line will result in cheaper cost/ft for the new bit.

Example 9.3: Break-even analysis

Using data from **Example 9.2**, calculate the rotating time required of the new bit at break-even cost for equal penetration rates.

Solution

For break-even cost

Cost/ft (milled tooth bit) = cost/ft (insert bit)

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$$\frac{B1 + (T + t_1)\,R}{F_1} = \frac{B2 + (T + t_2)\,R}{F_2}$$

where subscript 1 refers to offset bit

and subscript 2 refers to new bit

or

$$C = \frac{B_2 + (T + t_2)R}{F_2}$$

where C = cost/ft for offset bit

Hence,

$$t_2 = \frac{C\,F_2 - B_2 - TR}{R} \qquad (9.5)$$

The term (F_2) can conveniently be replaced by a penetration rate term, ROP x t_2.

Hence, the above equation becomes:

$$t_2 = \frac{B_2 + TR}{C \times ROP - R} \qquad (9.6)$$

From **Example 9.2**:

C = 59 $/ft

and if penetration rate of milled-tooth bit = penetration rate of insert bit

then $ROP = \dfrac{2461\,\text{ft}}{150\ \text{hr}} = 16.4\ \text{ft/hr}$

$$t_2 = \frac{B_2 + TR}{C \times ROP - R}$$

$$= \frac{8500 + 8 \times 900}{959 \times 16.4 - 900} = 232 \text{ hrs}$$

Hence, for the new bit to be competitive, it must drill as fast as the offset bit for 232 hrs.

Example 9.4:

If the milled tooth bit in **Example 9.2** were replaced by a PDC bit costing $30,000 with a potential penetration rate of 50 ft/hr, calculate the rotating hours required for break-even cost.

Solution

Using

$$t_2 = \frac{B_2 + TR}{C \times ROP - R}$$

$$= \frac{30{,}000 + 8 \text{ X } 900}{59 \times 50 - 900} = 18.1 \text{ hrs}$$

11.0 Learning Milestones

In this chapter, you should have learnt to:

1. Describe the main design features of a tricone bit

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2. Describe main design features of a tricone bit.
3. List the steps required for systematic bit selection.
4. List the important variables that should be considered when selecting a drillbit based on data from offset wells.
5. Optimise drill bit performance.

12.0 References

1. Reed Tool Company (1999) Electronic Reference Guide

2. Baker Hughes catalog manual (1999)

3. Christensen Diamond Compact Manual (1982)

13.0 Exercises

1. Explain the roles of cone offset (skew) and journal angle in bit design.
2. What are the main differences between a milled-tooth bit and and insert bit?
3. List the features of a light set and heavy set PDC bits.
4. Explain the importance of cutter back rake and side rake in PDC bit design.
5. List features of bit design that may improve gauge protection for both roller cone and PDC bits.
6. List the steps required for systematic bit selection.
7. List the important variables that should be considered when selecting a drillbit based on data from offset wells.
8. How do you optimise drill bit performance?

10

Drillstring Design

Contents

1.0 Introduction

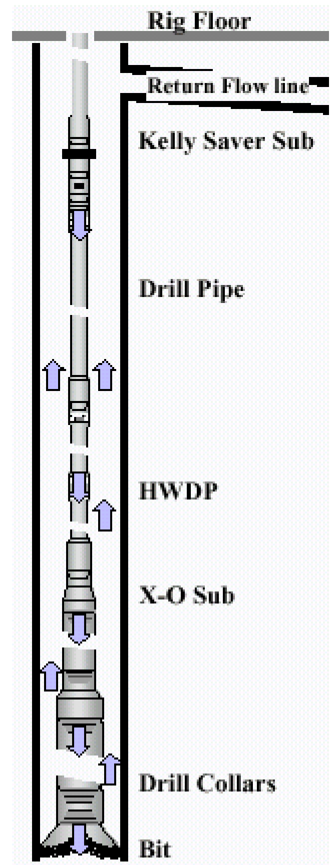
The drill string is the mechanical linkage connecting the drillbit at the bottom of the hole to the rotary drive system on the surface. The drillstring serves the following functions:

1. transmits rotation to the drillbit
2. exerts weight on the bit; the compressive force necessary to break the rock
3. guides and controls the trajectory of the bit; and
4. allows fluid circulation which is required for cooling the bit and for cleaning the hole.

The components of the drillstring (**Figure 10.1**) are:

1. Drillpipe
2. Drillcollars
3. Accessories including:
    - Heavy-walled drillpipe (HWDP)
    - Stabilisers
    - Reamers
    - Directional control equipment

Figure 10.1 Drillstring components



1.1 KELLY/TOP DRIVE

Strictly speaking the Kelly or top drive are not components of the drill string.

The Kelly is the rotating link between the rotary table and the drill string. Its main functions are:

- transmits rotation and weight-on-bit to the drillbit
- Supports the weight of the drillstring
- connects the swivel to the uppermost length of drillpipe; and
- conveys the drilling fluid from the swivel into the drill string.

The Kelly comes in lengths ranging from 40 to 54 ft with cross sections such as hexagonal (most common), square or triangular. The Kelly is usually provided with two safety valves, one at the top and one at the bottom, called upper and lower Kelly cocks, respectively. The Kelly cock is used to close the inside of the drillstring in the event of a kick. The lower Kelly cock is always manual

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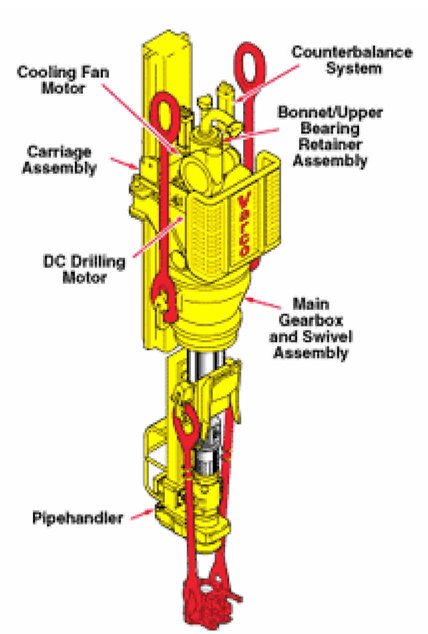
The top drive is basically a combined rotary table and Kelly.The topdrive consists of a DC drive motor that connects directly to the drillstring without the need or a rotary table. The topdrive is mounted on the rig's swivel, the swivel attachesto the travelling block and supports the drillstring weight. The topdrive has a pipe handler consisting of a torque wrench and a conventional elevator to assis in pipe handling during connection and roud trip operations.The elevator and elevator links are supported on a shoulder located on the extended swivel stem.

The top drive functions in the same way as the Kelly. However, it has many advantages over the Kelly system including circulating while back reaming, circulating while running in hole or pulling out of hole in stands. The Kelly system can only do this in singles; i.e. 30 ft.

Figure 10.2 Top Drive, Courtesy of Varco



2.0 Drill Pipe Selection

2.1 Drill Pipe Grade

The grade of drill pipe describes the minimum yield strength of the pipe, Table 8.1. API defines five grades: D,E, X,G and S. However, in oilwell drilling, only grades E,G and S are actually used. In most drillstring designs, the pipe grade is increased if extra strength is required.

Table 10.1 Drillpipe Grade And Yield Strength

Grade		Minimum Yield Strength, psi
Letter Designation	Alternate Designation	
D	D-55	55,000
E	E-75	75,000

Table 10.1 Drillpipe Grade And Yield Strength

X	X-95	95,000
G	G-105	105,000
S	S-135	135,000

2.2 DRILL PIPE CLASSIFICATION

Drill pipe, unlike other oilfield tubulars such as casing and tubing, is re-used and therefore often worn when run. As a result the drill pipe is classified to account for the degree of wear.

The API has established guidelines for pipe classification in API RP7G. A summary of the classes follows.

New:No wear, has never been used.

Premium:Uniform wear and a minimum wall thickness of 80% of new pipe.

Class 2: Drill pipe with a minimum wall thickness of 65% with all the wear on one side so long as the cross sectional area is the same as the premium class.

Class 3: Drill pipe with a minimum wall thickness of 55% with all the wear on one side.

Drill pipe classification is an important factor in the design and use of drill pipe since the degree of wear will affect the pipe properties and strengths. API RP7G [1] provides a series of tables which detail the strengths and properties of the various grades and classes of pipe.

For ordering purposes, drill pipe is also identified by its nominal weight. As stated in API 5C3"Nominal weight is approximately equal to the calculated theoretical weight per foot of a 20 foot length of threaded and coupled pipe based on the dimensions of the joint in use for the class of product when the particular diameter and wall thickness was introduced". The same nominal weight is therefore used for all types of connection.

The approximate weight of drillpipe can be calculated from the formulae given in section **"Approximate Weight Of Drillpipe And Tool joint" on page 391**.

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2.3 Tool Joints

A drillpipe joint is an assembly of three components: drillpipe with plain-ends and a tool joint at each end. One tool joint acts as the pin and the other acts as the box. Drillpipes are connected together by applying a certain calculated torque which depends on the size of the pipe and its grade.

All API tool joints have a minimum yield strength of 120,000 psi regardless of the grade of the drillpipe they are used on (E, X, G, S). API sets tool joint torsional strength at 80% of the tube torsional strength: this is the torsional strength ratio of 0.8.

The make up torque is determined by pin ID or box OD. The make up torque is 60% of the tool joint torsional capacity.

2.4 Thread Types & Numbered Connections (NC)

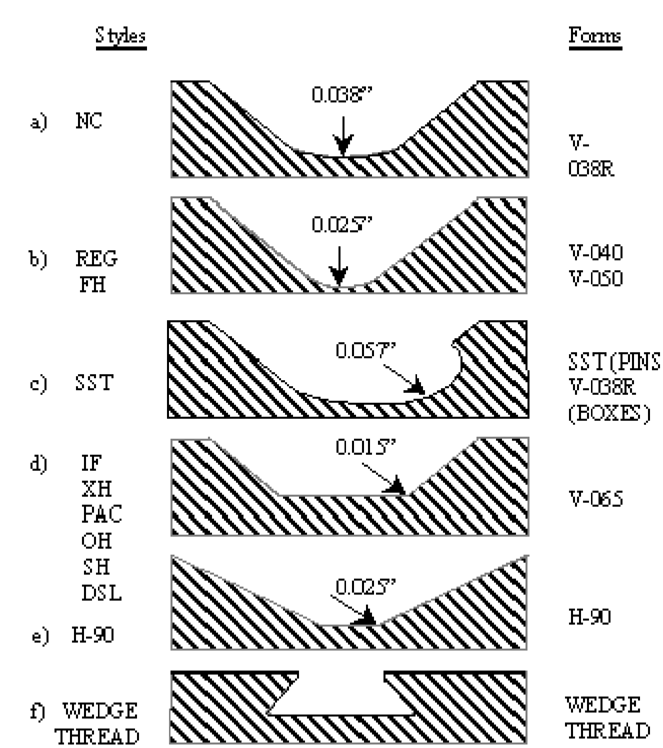
Figure 10.3 shows the different thread styles and forms used in the oil industry. The most common thread style is the Numbered Connection (NC). The thread has a V-shaped form and is identified by the pitch diameter, measured at a point 5/8 inches from the shoulder; the gauge point, multiplied by 10, see **Figure 10.3**.

Thus NC 50 has a gauge point pitch diameter of 5.0417 inches. The first two digits of this last number identify this thread as NC50.

There are 17 NC's in use: NC-10 (1 1/16") through NC-77 (7 3/4").NC-23 and above use the V-38R thread form.

Typical sizes:

Figure 10.3 Thread Styles & Forms, Ref 4



NC 50 for tool joints with 61/2" OD for 5" pipe

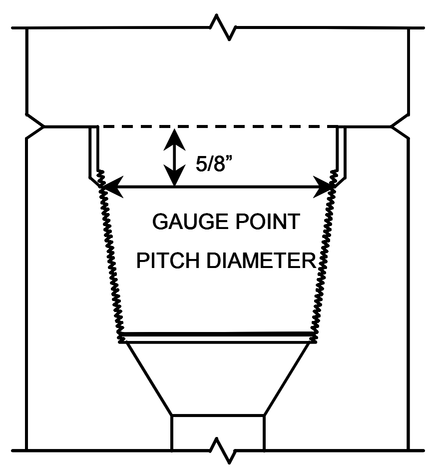
NC 38 for 4 3/4" OD tool joints on 3 1/2" pipe.

There are obsolete connections which are still used in the oil industry.These obsolete connections were replaced in 1968 by the API by 17 NC ‘s equivalents: NC23 through NC-77. Obsolete connections include:

- 4-1/2 IF
- X-Holes
- Open Holes
- Slim Holes
- External Flushes, PAC’s, H-90

The thread styles and forms corresponding to the above connections are shown in **Figure 10.3**

Figure 10.4 Gauge Point Pitch Diameter, Ref 4



Old Connections which are still in use:

API Full Hole (FH)[4]

Still used on 5 ½" and 6 5/8" drillpipe.

API Regular Connection[4]

Used mainly on BHA components because they have sharper root radius. The number before Reg i.e. 6 5/8" Reg refers to drillpipe size on which the connection was cut.

H-90 Connections

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This connection is a propriety product of Hughes Tool Company. The thread has a shallow 90 degree thread angle.

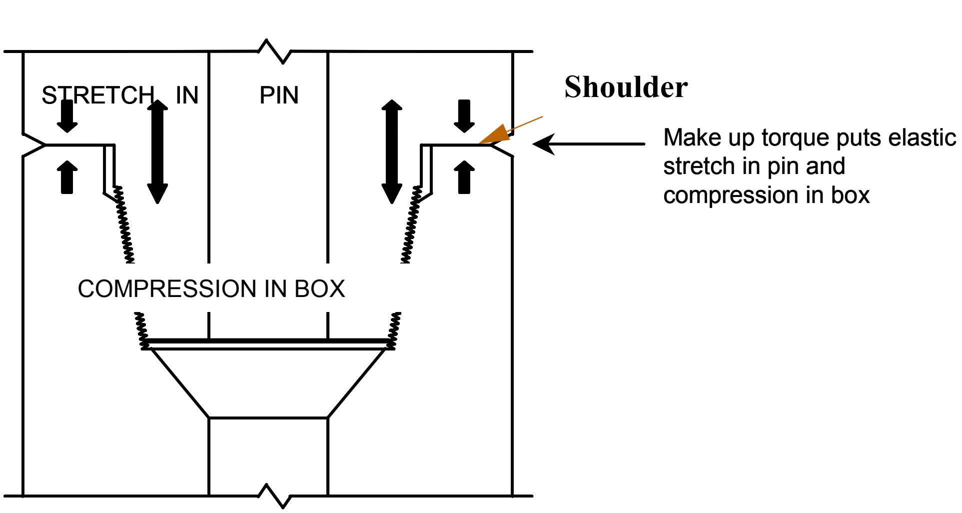
PAC Connection[4]

Mostly used on 2 3/8" and 2 7/8" drillpipe and smaller diameter drill collars. The thread has a low tensile and torsional capacity. PAC uses V-065 thread form which is prone to fatigue failure. The PAC-HT has increased torsional capacity and is used on slimhole equipment. Torsional capacity is increased by placing another torque shoulder on the pin tip.

2.5 Washouts in Drillstrings

Tool joint failure is one of the main causes of fishing jobs in the drilling industry. This failure is due entirely to the tool joint threads not holding or not being made properly. The make up torque puts the pin in tension and the box in compression, see Figure 10.5. If the pin and box are not properly torqued, then the seals may separate under downhole conditions allowing the a leak path for the mud.

Figure 10.5 Make Up Torque, After Ref 4



Each drillpipe joint has a pin and a box. Hence for a length of 1000 ft of drillstring there are 66 separate pins and boxes that need to mad up and broken regularly. The threads of the tooljoints seal at the shoulder area only. This feature requires that enough torque is applied during make-up to reduce the risk of having a loose connection in the drillstring. Leak paths within the tool joints develop if the seal is broken or if improper torque is applied. The leak path will lead to tool joint erosion by the drilling mud and if this erosion is severe enough that causes the surface of the pipe to be broken, the pipe is said to have a "washout".

Washouts can also develop due to cracks developing within the drillpipe due to severe drilling vibrations or cyclic loading, **Figure 10.7**. This is especially true in drillstrings rotating at RPM's matching the drillstring natural (harmonic) frequencies.

Washouts are usually detected by a decrease in the standpipe pressure, between 100-300 psi over 5-15 minutes. This is easily distinguished from sudden drops in pump pressure which could be due to a lost jet nozzle or some surface leak.

Figure 10.7 Washouts

If a decrease in pump pressure is seen at surface, drilling should stop, pumping resumed. If the pump pressure is still less than before and a bit jet is not suspected to have been lost or no surface leaks detected, then the drillstring should be pulled out of a hole and the defective drillpipe joint should be replaced.

Drilling records show that in some cases when a washout is suspected and the the pipe was POH, no cracks or washouts could be visibly seen on any of the drillpipe joints. The reason that the cracks could not been seen at surface is that under pumping and drilling conditions, the cracks open letting mud out and reduce the pump pressure requirements. When at surface, however, the drillpipe is under zero tension and the cracks therefore close escaping detection by the observer on the rig floor.

The author has come across several such situations when a washout is detected and when the drillstring POH, no defective pipe is seen. When the drillstring is re-run in hole, the pump pressure was still lower than before and in some cases it continued to drop. If drilling was

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resumed a twist off usually occurs resulting in a fishing job. To overcome this, it has been found useful in practice to pump a soft plastic line prior to POH. The soft line wedges itself into the crack(s) while the pipe is still down hole and whilst pumping, **Figure 10.7**. When the pipe is POH to surface, the defective drillpipe joint is easily noticed by the presence of the soft plastic line in the cracks.

The reader should note that there are other reasons for pressure drops:

- on deep and narrow wells, if a big slug had been pumped before coming out of the hole, then a pressure drop could be seen as the slug left the hole. The pressure would then settle.
- plugging up of the suction to the mud pump will have the same affect as a washout in the string; a slow drop in pressure, but unlike air in the pump, plugging will not be heard.

2.6 Other Features Of Tool Joints

Casing wear is caused mainly by the rotation of drillpipe tool joints against the walls of the casing. Some casing wear is also produced by wireline tools.

The life of a tool joints can be tripled if the tool joints is hardfaced with composites of steel and tungsten carbide. The hard-facing bands are welded onto the tool joints box close to the elevator shoulder. The pin tool joint is not hardfaced to protect the make-up tongs. The hardfacing on the box tool joint should be flush with the tool joint OD instead being raised above the OD to minimize casing wear.

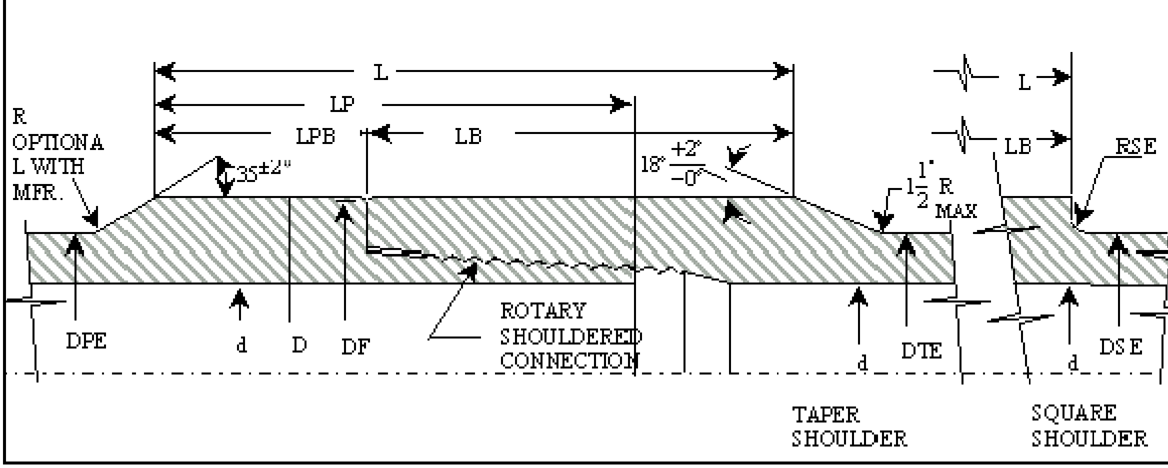
Unprotected tool joints can cause:

- severe casing wear by adhesion under certain mud conditions; and
- severe wear of tool joint surface if it comes in contact with abrasive formation

2.7 Approximate Weight Of Drillpipe And Tool joint

Nominal weight of drillpipe is always less than the actual weight of the drillpipe and tool joint because of the extra weight added by the tool joint and due to the extra metal added at the pipe ends to increase the pipe thickness. This increased thickness is called "Upset" and is used to decrease the frequency of pipe failure at the point where the pipe meets the tool joint. The drillpipe can have internal upsets (IU), external upsets (EU) and internal and external upsets (IEU). The procedure for calculating the weight of drillpipe and tool joints uses mathematical equations and the dimensions shown in Figure 10.8. Table 10.2 gives tool joint dimensions for typical drillpipe sizes.

Figure 10.8 Tool joint dimensions, after reference 2



2.7.1 Calculations Of Approximate Weight Of Tool Joint And Drillpipe Assembly

(a) Approximate adjusted weight of drillpipe

$$= \text{Plain end weight} + \frac{\text{upset weight}}{29.4} \tag{10.1}$$

(b) Approximate adjusted weight of tool joint

$$= 0.222 \times L\left(D^2 - d^2\right) + 0.167 \times \left(D^3 - D^3_{TE}\right) - 0.501 \times d^2 \times \left(D - D_{TE}\right) \tag{10.2}$$

where

L = combined length of pin and box (in)

D = outside diameter of pin (in)

d = inside diameter of pin (in)

D_{TE} = diameter of box at elevator upset (in)

(c) Approximate adjusted weight of drillpipe assembly

$$= \frac{\text{approx. adjusted wt. drillpipe} \times 29.4 + \text{approx. wt. tool joint}}{29.4 + \text{tool joint adjusted length}} \tag{10.3}$$

where

$$\text{tool joint adjusted length} = \frac{L + 2.253 \times (D - D_{TE})}{12} \text{ ft} \tag{10.4}$$

Table 10.2 Tool Joint Dimensions, After Reference 2

	Drillpipe			Outside dia of pin and box D	Inside dia of pin and box d	Dia of box at elevator upset DTE	Combined length of pin and box L
	Size and style	Nominal weight (lbm/ft)	Grade				
NC50 (4 1/2 IF)	5 IEU	19.5	E75	6 3/8	3 3/4	5 1/8	17
			X95	6 3/8	3 1/2	5 1/8	17
			G105	6 1/2	3 1/4	5 1/8	17
			S135	6 5/8	2 3/4	5 1/8	17
	5 IEU	25.6	E75	6 3/8	3 1/2	5 1/8	17
			X95	6 1/2	3	5 1/8	17
			G105	6 5/8	2 3/4	5 1/8	17
NC46 (4 IF)	4 1/2 IU	13.75	E75	6	3 3/8	4 11/16	17
	41/2 IEU	16.6	E75	6 1/4	3 1/4	4 11/16	17
			X95	6 1/4	3	4 11/16	17
			G105	6 1/4	3	4 11/16	17
			S135	6 1/4	2 3/4	4 11/16	17

Example 10.1: Approximate Weight Of Drillpipe And Tooljoint

Calculate the approximate weight of tool joint and drillpipe assembly for 5 in OD, 19.5 lbm/ft Grade E drillpipe having a 6.375 in OD 3.5 in ID. With NC 50 tool joint. Assume the pipe to be internally-externally upset (IEU) and the weight increase due to upsetting to be 8.6 lb.

Solution

Referring to **Table 10.2**, NC50, 6.375 in OD, 3.5 in ID tool joint for a 19.5 lbm/ft nominal weight drillpipe is available in Grade X95.

Thus, L = 17 in, D_{TE} = 5.125 in, D = 6.375 in, and d = 3.5 in.

(a) Approximate adjusted weight of tool joint

$$=0.222 \times L\left(D^2-d^2\right)+0.167\times\left(D^3-D^3{}_{TE}\right)-0.501\times d^2\times\left(D-D_{TE}\right)$$

$$= 0.222x17x(6.375^2-3.5^2)+0.167x(6.375^3-5.125^3)-0.501x3.5^2x(6.375-5.125) = 120.27 \text{ lb}$$

(b) Approximate adjusted weight of drillpipe

$$= \text{plain}-\text{end weight} + \frac{\text{upset weight}}{29.4}$$

$$= \frac{\pi}{4}\left(5^2 - 4.276^2\right)\times\frac{1}{144}\times 489.5 + \frac{8.6}{29.4}$$

$$= 17.93 + 0.293 = 18.22 \text{ lbm/ft}$$

Adjusted length of tool joint

$$= \frac{L + 2.253\times\left(D - D_{TE}\right)}{12}$$

$$= \frac{17 + 2.253\times\left(6.375 - 5.125\right)}{12}$$

$$= 1.651$$

(c) Hence, approximate weight of tool joint and drillpipe assembly

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$$= \frac{18.22x29.4 + 120.27}{1.651 + 29.4} = 21.12 \text{ lbm/ft}$$

3.0 BHA Selection

3.1 Drill Collar Selection

Drill collars are the predominant component of the bottom hoe assembly (BHA). Both slick and spiral drill collars are used. In areas where differential sticking is a possibility spiral drill collars and spiral heavy-walled drillpipe (HWDP) should be used in order to minimise contact area with the formation.

The drill collars are the first section of the drillstring to be designed. The length and size of the collars will affect the grade, weight and dimensions of the drill pipe to be used. Table 10.3 illustrates typical sizes of collars to be run in each hole section.

Table 10.3 Drillcollars And Hole Sizes

Hole Section	Recommended Drill Collar OD(ins)
36	9½ + 8
26	9½ + 8
17½	9½ + 8
16	9½ + 8
12¼	8
8½	6¼
6	4¾

Drill collar selection is usually based on buckling considerations in the lower sections of the string when weight is set on the bit. The design approach that satisfies this criteria is the buoyancy factor method.

3.2 Buoyancy Factor Method

Drill collars are used to provide weight for use at the bit and at the same time keep the drill pipe in tension. Drill collars have a significantly greater stiffness when compared to drill pipe and as such can be run in compression. Drill pipe, on the other hand will tend to buckle when run in compression. Repeated buckling will eventually lead to early drill pipe failure by fatigue. Since elastic members can only buckle in compression, fatigue failure of pipe can be eliminated by maintaining drill pipe in tension.

Research and field experience proved that buckling will not occur if weight on bit is maintained below the buoyed weight of the collars. In practice weight on bit should not exceed 85% of the buoyed weight on the collars.

3.2.1 Procedure For Selecting Drillcollars

4. Determine the buoyancy factor for the mud weight in use using the formula below:

$$BF = 1 - \frac{MW}{65.5} \tag{10.5}$$

where

BF=Buoyancy Factor, dimensionless

MW=Mud weight in use, ppg

65.5=Weight of a gallon of steel, ppg

5. Calculate the required collar length to achieve the desired weight on bit:

$$WOB = \text{air weight of drillcollars} \times BF \times 0.85 = DC_{length} \times W_{dc} \times BF \times 0.85$$

$$DC_{Length} = \frac{WOB}{0.85 \times BF \times W_{dc}} \tag{10.6}$$

where:

WOB=Desired weight on bit, lbf (x 1000)

BF =Buoyancy Factor, dimensionless

W_{dc} =Drill collar weight in air, lb/ft

0.85 =safety factor.

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The 0.85 safety factor ensures that only 85% of the buoyant weight of the drillcollars is used as weight on bit. Hence the neutral point remains within the collars when unforeseen forces (bounce, minor deviation and hole friction) cause fluctuations on the WOB.

6. For directional wells:

$$\text{DC Length} = \frac{\text{DC Length vertical}}{\cos I} \tag{10.7}$$

where: I=well inclination

Note that for horizontal wells drill collars are not normally used and BHA selection is based entirely on the prevention of buckling, see Chapter 11.

Example 10.2: Number And Size Of Drillcollars

Determine the size and number of drillcollars required to provide a weight-on-bit of 55,000 lbf assuming

Hole deviation = 0°

Mud density = 12 ppg

Solution

$$\text{Air weight of drillcollars} = \frac{\text{WOB}}{\text{Buoyancy Factor}}$$

$$BF = 1 - \frac{12}{489.5} = 0.817$$

$$= \frac{55{,}000}{0.817} = 67{,}319 \text{ lbf}$$

In practice only 85% of the drillcollar weight is used as weight-on-bit. The remaining 15% of drillcollar weight is placed in tension. This ensures that the neutral point is in the drillcollars and that the drillpipe is always in tension.

Hence, required weight of drillcollars

$$= \frac{67{,}319}{0.85} = 79{,}199 \text{ lbf}$$

Assume that the available drillcollar size is OD/ID, 9/3 in. From calculations, the weight per foot for this size is 192 lb/ft. Most drillcollars come in 30 ft lengths.

One drillcollar weighs = 30 x 192 = 5,760 lb

Number of drill collars $= \frac{79,199}{5,760} \approx 14$

Example 10.3: Drillcollars For A Directional Well

Repeat the above calculations using the same data, as given in example (9) except that the hole is deviated at 30° to the vertical.

Solution

BF= 0.817, θ = 30 degrees

$$\text{Air weight of drillcollars} = \frac{WOB}{BF \times \cos\theta}$$

$$= \frac{55,000}{0.817 \times \cos 30} = 77,734$$

For 15% safety factor

$$= \frac{77,734}{0.85} = 91,452 \text{ lbf}$$

Again assume we will be using 9"/3" drillcollars

Therefore, number of 30 ft, 9/3 in drillcollars

= 91,452/5,760 = 15.9 or 16 drillcollars

3.3 Bending Strength Ratio

The bending strength ration (BSR) is defined as the ratio of relative stiffness of the box to the pin for a given connection [1]. From field experience, a BSR value of 2.5 gives a balanced connection. Above 2.5 BSR, there is a risk of premature failure in the pin and a BSR of below 2.5 gives a risk of premature failure in the box.

Large OD's drillcollars (8" and above) suffer mainly from box failure caused by fatigue cracks despite the fact that they are operated at a BSR of 2.5. Higher BSR's may therefore be used for large OD drillcollars [1,4,5]. Large OD drillcollars provide greater stiffness and reduces hole deviation problems.

3.4 Stiffness Ratio (SR)

The stiffness ratio (SR) is defined as follows:

SR = Section Modulus of lower section tube /Section modulus of upper section tube

$$SR = OD_2\,(OD_1^2 - ID_1^2) \,/\, OD_1\,(OD_2^2 - ID_2^2) \qquad (10.8)$$

From field experience, a balanced BHA should have:

SR = 5.5 for routine drilling

SR = 3.5 for severe drilling or significant failure rate experience

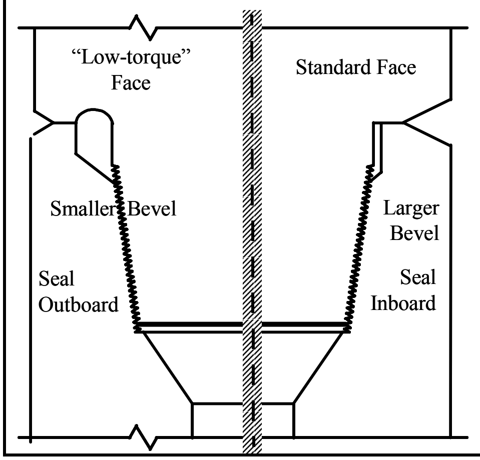
3.5 Stress Relief Features

Drillpipe connections (threads) have no stress relief features[5] as during bending the limber drillpipe body bends easily and takes up the majority of the applied bending stress. The drillpipe connections are therefore subjected to less bending than the drillpipe body.

Drillcollars and BHA components are however much stiffer than the drillpipe and under bending much of the bending stresses are transferred to the connections. These bending stresses can cause fatigue failure at the connections.

The effects of bending stresses on the connections can be reduced by having "STRESS RELIEF PIN" or "BOREBACK BOX" (or by having both) features[5].These features (**Figure 10.9**) are produced by having metal removed from pin and box to cause a redistribution of load and stress away from most critical areas and also eliminate the stress concentration effects on unengaged thread roots; usually first and last engaged threads in the box and pin [5].

Figure 10.9 Low Torque Feature on



In the boreback box, metal is removed from unengaged threads and portions of some engaged threads by machining a cylindrical bore in the back of the box.[4,5].

The boreback box also makes the area next to the connection more limber and for a given bending force, less bending is transferred to the connection. These features result in longer fatigue life for the drillcollar connections.

Stress relief features are used on all drillcollars 6" and above.Other stress relief features include:

Coldworked Thread Roots [4,5]

Cold working leaves a residual compressive stress in the connection thread roots which increases resistance to fatigue failure. Under a given bending stress, this residual compressive force lowers the tensile stress in the thread root and lengthens fatigue life.

Low Torque Face [4,5]

On large diameter drillcollars (9" and above), an extremely high make-up torque is required to achieve adequate shoulder load (and bearing stress). This will stress the pin to the point that fatigue failure will occur very rapidly. Hence on large drillcollars, a low torque feature is introduced to decrease the required make-up torque and to increase the bearing stress on the shoulder. This is achieved by machining the box counterbore to a larger diameter thereby reducing the compressive stress area of the box member, **Figure 10.9**.

3.6 Drill Collar Profiles,

3.6.1 Slick Drill Collars

As the name implies, slick drillcollars have the same nominal outside diameter over the total length of the joint, **Figure 10.10**.

These drill collars usually have the following profiles:

- a slip recess for safety, and
- an elevator recess for lifting.

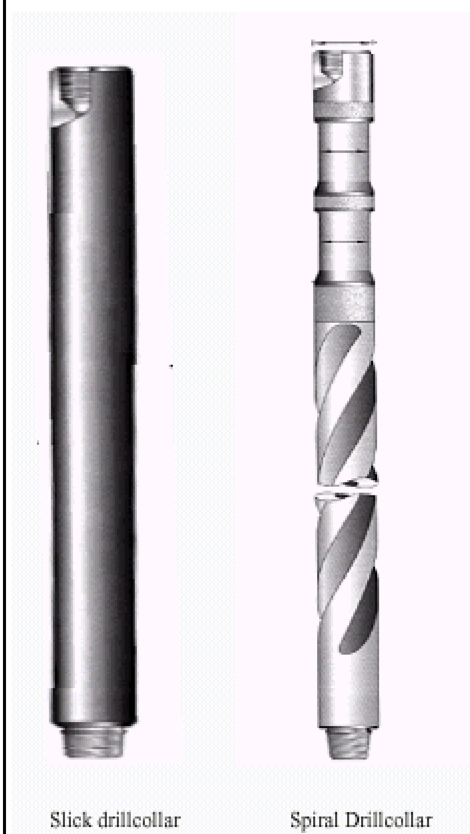
3.6.2 Spiral Drill Collars

Spiral drillcollars are used primarily to reduce the risk of differential sticking. The spirals reduce the weight of the collar by only 4 -7% but can reduce the contact area (proportional to sticking force) by as much as 50%.

3.6.3 Square Drill Collars

These are used in special drilling situations to reduce deviation in crooked hole formations. They are used primarily due to their rigidity.

Figure 10.10 Drillcollar Profiles

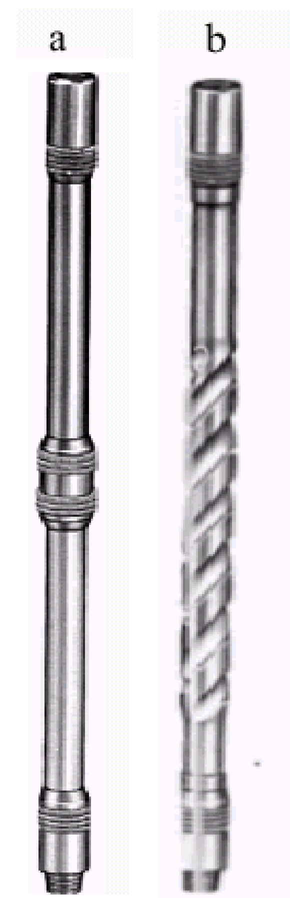


3.7 HEAVY-WALLED DRILLPIPE (HWDP)

The HWDP has the same OD as a standard drillpipe but with much reduced inside diameter (usually 3") and has an extra tool joint, **Figure 10.11**; figure a is a standard HWDP and figure b is a spiral type. HWDP is used between standard drillpipe and drillcollars to provide a smooth transition between the section moduli of the drillstring components.

HWDP can be distinguished from standard drillpipe by an integral wear centre wear pad which acts as a stabiliser thereby increasing the overall stiffness of the drillstring. In directional and horizontal wells, HWDP is used to provide part or all of the weight on bit while drilling.

Figure 10.11 HWDP



3.8 STABILISERS

Stabilisers are tools placed above the drill bit and along the bottom hole assembly (BHA) to control hole deviation, dogleg severity and prevent differential sticking. They achieve these functions by centralising and providing extra stiffness to the BHA.Improved bit performance is another beneficiary of good stabilisation.

There are basically two type of stabilisers:

- Rotating stabilisers
- Non-rotating stabilisers

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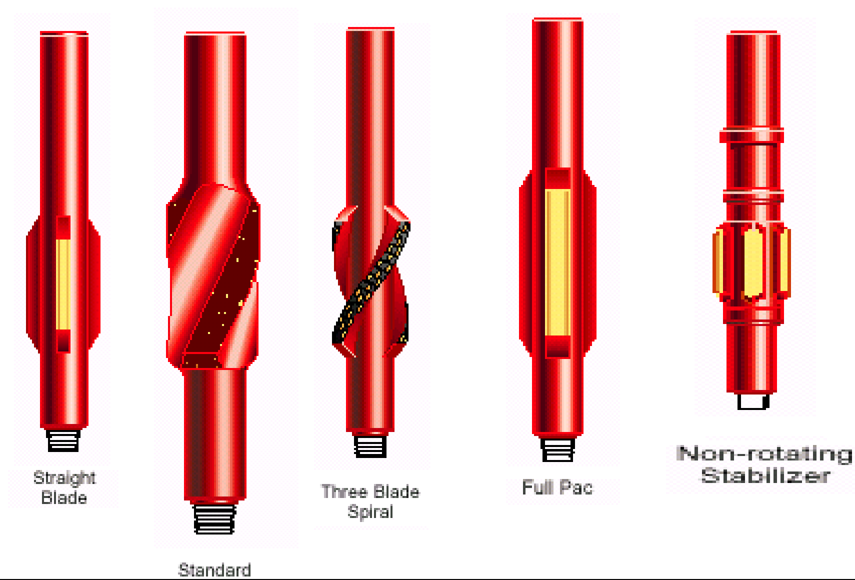
Rotating stabilisers include: integral blade stabiliser, sleeve stabiliser and welded blade stabiliser.

Integral blade stabilisers (Figure 10.12, first four pictures on left) are machined from a solid piece of high strength steel alloy. The blade faces are dressed with sintered tungsten carbide inserts. The blades can either be straight or spiral.

Figure 10.12 Types of Stabiliser,Courtesy of Weatherford



Non-rotating stabilisers comprise a rubber sleeve and a mandrel (picture on right of **Figure 10.12**). The sleeve is designed to remain stationary while the mandrel and the drillstring are rotating. This type is used to prevent reaming of the hole walls during drilling operation and to protect the drillcollars from wall contact wear.

4.0 STANDARD BHA CONFIGURATIONS

The bottom hole assembly refers to the drillcollars, stabilisers and other accessories.All wells whether vertical or deviated require careful design of the bottom hole assembly (BHA) to control the direction of the well in order to achieve the target objectives. **Stabilisers** and drillcollars are the main components used to control hole direction, see **Figure 10.12**.

The main means by which directional control is maintained on a well is by the effective positioning of stabilisers within the BHA. There are five basic types of assembly which may be used to control the direction of the well, see **Chapter 11** for details of these BHA's.

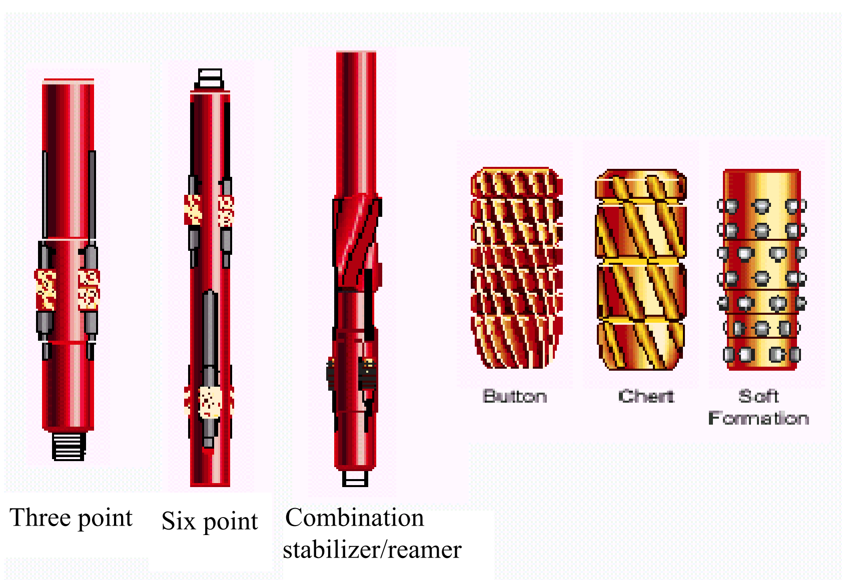
1. Pendulum assembly
2. Packed bottom hole assembly
3. Rotary build assembly
4. Steerable assembly
5. Mud Motor and bent Sub assembly

5.0 NON STANDARD BHA EQUIPMENT

5.1 ROLLER REAMERS

Roller reamers (**Figure 10.13**) are used to replace near bit and string stabilisers in bottom hole assemblies where high torque and swelling or abrasive formations are encountered.

Figure 10.13 Roller Reamers And Cutters, Courtesy of Weatherford



Roller reamers can have either 3 or 6 cutter sets. Both near bit and string reamers are available. Near bit reamers can be bored for a float valve.

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Consideration should be given to replacing the near bit and first string stabiliser with a roller reamer if high torque or severe gauge wear of stabilisers has been encountered. The standard configuration is to replace the near bit and first string stabiliser with a three point roller reamer. For severely abrasive formations or wear significant high torque is encountered a six point roller reamer may be used in place of the near bit stabiliser.

Sealed bearing roller reamers should always be used in preference to non-sealed bearing reamers. The use of sealed bearings ensures the risk of dropping a cutter block set from the reamer is minimised.

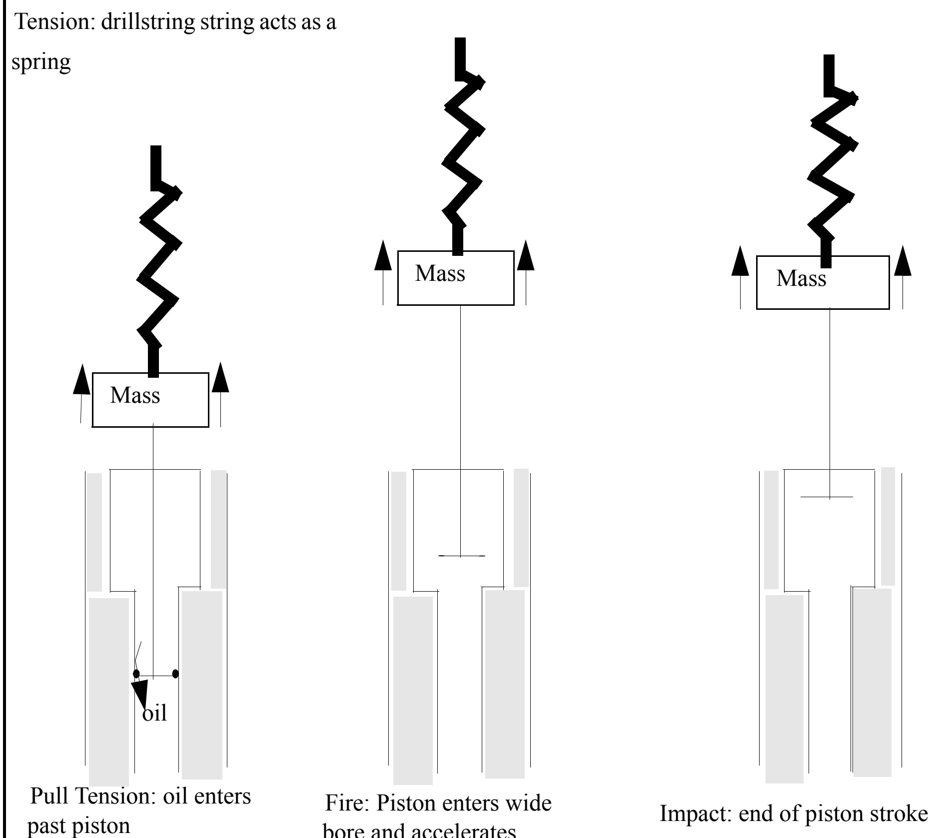
Cutter block sets are available in hardfaced steel or dressed with tungsten carbide. The selection of the appropriate block set will depend upon the formation drilled, however the block set should always be sufficiently hard to avoid wear to the gauge and thus ensure optimum directional control.

6.0 DRILLING JARS

Jars provide a means of supplying powerful upward or downward blows to the stuck drillstring.

A jar is a mandrel which slides within a sleeve. The free end of the mandrel is shaped in the form of a hammer to provide a striking action against the face of the anvil.

Figure 10.14 Principle of a hydraulic jar



Depending on the type of tripping mechanism, there are two basic types of jar: mechanical and hydraulic.

Mechanical jars have a preset load that causes the jar to trip; hammer striking the anvil. They are thus sensitive to load being used and not to time.Mechanical jars are pre-set at surface.

Hydraulic jars (see Figure 10.14) use a hydraulic fluid to control the firing of the jar until the driller can apply the appropriate load to the string to give a high impact. This controlled action (delay) is provided by hydraulic fluid which is forced through a small port or series of jets. Hydraulic jar firing delay is dependent upon the combination of load and time. Hence hydraulic jars are adjustable according to downhole overpull.

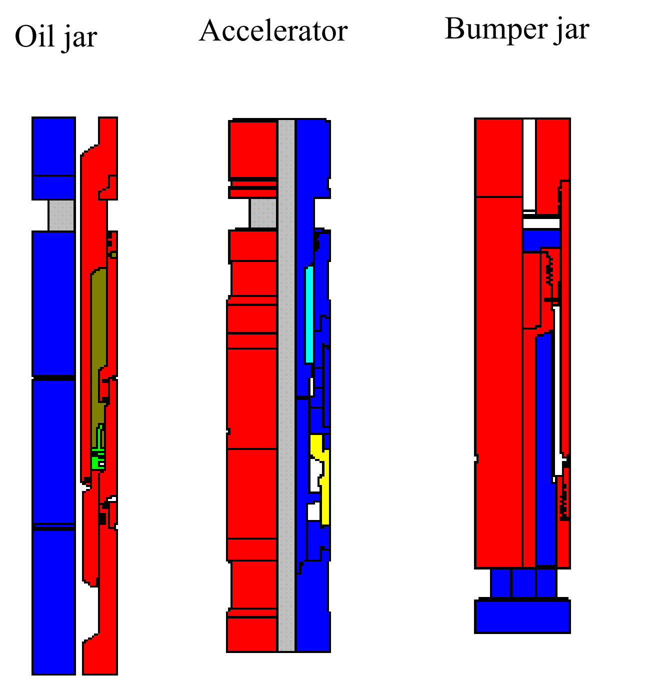
Oil jars: provide means for applying upward blows to release a stuck pipe, **Figure 10.15**.

Accelerators: store energy above the drillcollars in order to increase the impact efficiency of oil jars,**Figure 10.15**.

Bumper jars: provide free travel to assist in engaging the fish and to allow downward blows to be transmitted to the fish.and for releasing overshots downhole and at surface,Figure 10.15.

Following are a series of guidelines on the selection, positioning and use of drilling jars. The guidelines are general and therefore it is stressed that the manufacturers operating procedures and recommendations should always be followed.

Figure 10.15 Types of jars, Courtesy of Baker Oil Services



In general, an increase in jar stroke length increases the jarring effect. With these obvious advantages, a long stroke hydraulic jar is preferable to a mechanical jar.

Two phenomena have to be considered when jarring. These are the impact force and the impulse of the jarring action. The impact force must be high enough to break the binding force causing the pipe to stick. The impact force must also act long enough to move the pipe - this is what is termed the impulse. Both forces are influenced by the number of drill collars located above the jar.

The smaller the quantity of drill collars, the higher the impact force. Conversely the larger the number of drill collars the greater the impulse force. A compromise has to be reached where both impact and impulse are working together to free the pipe.

The jars should be run in tension wherever possible. This is mandatory for mechanical jars. For hydraulic manufacturers state that they can be run in compression however this is not advisable as inadvertent cocking of the jar is possible with applied WOB.

For vertical wells the amount of drill collars to be run below the jar should be the sufficient to allow the required bit weight and place the neutral point at least 30 feet away from the jar. The buoyed weight method should be used to calculate the required length and a 15% safety factor added. For directional wells an additional safety factor should be applied to the buoyed weight of the collars to account for frictional drag of the string against the low side of the hole. The hole inclination factor to be applied, as stated by jar manufacturers, is as follows:

Hole Inclination Factor=1/(Cos Inclination)

This calculated required length of drill collars should be multiplied by this factor in order to help ensure the neutral point remains below the jars.

6. The drill collars run above the jar should be the same as those run below. The jarring efficiency is significantly reduced if HWDP is run immediately on top of the jar. If differential sticking is considered a possibility, use reduced OD drill collars above the jar prior to the HWDP. i.e. if 8" collars are run beneath the jar, 6½"collars may be run above the jar prior to the HWDP. The use of DCs above increases the impulse of the jar compared to the use of HWDP.

The amount of drill collars to be run above the jar will depend upon several factors depending on the type of jar run.

For mechanical jars the weight of DC and HWDP above the jar should be sufficient to allow cocking of the jar. Mechanical jars are pre-set at surface, the required weight to cock the jar should be less than or equal to the buoyed weight of drill collars and HWDP above the jar.

For double acting hydraulic jars, the buoyed weight above the jar should be equal to or exceed the maximum anticipated down jar force. (The force of downward blows can be adjusted by increasing the down weight prior to activation of the jar).

As a general rule 3 to 4 drill collars should be run above the jar. This will ensure that sufficient weight is available to cock the jar and allow sufficient down weight to be used for effective down-jarring.

For highly deviated and horizontal wells it is recommended that the jars are not placed in the horizontal or maximum inclination section. This can be achieved by running a longer than normal string of HWDP to ensure the jars are placed in the tangent section where possible.

The frictional drag in horizontal sections severely reduced both impact and impulse of the jar. In addition the jars become difficult to cock and trip. Placement of the jars in the horizontal section is therefore considered to have minimal benefit.

7.0 Shock Subs

In its simplest form, a shock sub consists of three parts: a grooved female housing, a matching splined male housing and a set of entrapped spring elements. The spring and spline mechanisms are lubricated in hydraulic oil which is retained by seals between the housing and the mandrel. When installed above the bit, weight on bit tends to compress the springs and close the shock sub. The pressure drop through the bit nozzles below the tool tends to counteract this by acting against the internal cross section and pumping the tool open. In theory as the bit bounces and or the assembly vibrates the shock sub strokes rapidly up or down around a median point, minimising fluctuations in WOB and isolating the bit and assembly from each other.

Shock subs are used to minimise the effect of drillstring vibrations upon the bit to enhance bit performance and bit life. In addition the effects of bit bounce are reduced and isolated from the drillstring to reduce fatigue wear of the string.

7.1 Shock Sub Selection And Operating Guidelines.

- Always run the softest shock sub possible.

The softer the spring rate the wider the tools operating range and the more responsive it will be to vertical displacements. Both simple vibration theory and the technical literature suggest that the softer the spring rate the more effective the tool. Low spring rates give lower resonant vibration frequencies, in addition softer sprung tools provide more effective isolation between the bit and the drilling assembly.

- The largest shock sub recommended for the hole size should be run. The larger the tool the stiffer and more rugged it will be. The OD of the shock sub should always be equal to or greater than the OD of the drill collars.
- Careful consideration of the BHA stabilisation should be performed when running a shock sub.

Shock subs are ideally suited to pendulum drilling assemblies. Care should be taken when stiffening or packing an assembly which includes a shock sub. In particular a packed assembly with an undergauge stabiliser run immediately behind the shock sub becomes a building assembly of the near bit stabilisers is full gauge. It is preferable to run a slightly undergauge near bit stabiliser and a full gauge stabiliser immediately above the tool.

8.0 DRILLSTRING DESIGN CRITERIA

When drilling highly deviated, extended reach or horizontal wells, computer modelling of torque and drag should be used for establishing grades, size and weight of drill and coupling to be used. On such wells, calculation of the effects of deviation on predicted torque and drag are too complicated to calculate manually

The criteria used in a drill string design are:

1. Collapse
2. Tension
3. Dogleg Severity Analysis

Burst pressure is not considered in drillstring design due to the fact that burst loads and back-up loads are provided by the same fluid in the well. Therefore under normal circumstances there are no effective burst loads, except during squeeze operations where surface pressure is applied. If squeeze pressures are high, a back-up annulus pressure would normally be applied to reduce the effective burst pressure.

Collapse and tension considerations are used to select the pipe weights grades and couplings. Slip crushing affects the tension design and pipe selection. Dogleg analysis is performed to study the fatigue damage resulting from rotation in doglegs. Doglegs analysis may not affect the selection of the pipe, however it will assist in determining the maximum permissible dogleg during any section of the well.

API R7G [1] gives the following design criteria:

1. Anticipated total depth with this drillstring
2. Hole size
3. Expected mud weight
4. Desired safety factor in tension and/or margin of overpull
5. Desired safety factor in collapse
6. Length of drillcollars, OD, ID and weight per foot
7. Desired drillpipe sizes and inspection class

8.1 Collapse Design

The criteria to be used as a worst case for the collapse design of drill pipe is typically a DST. The maximum collapse pressure should be determined for an evacuated string, with mud hydrostatic pressure acting on the outside of the DP. Use of this criterion also accounts for incidence of a plugged bit or failure to fill the string when a float is used during trips into the hole.

A design factor is used in constructing the collapse design line. The design factor to be used for this full evacuation scenario is 1.0.

Collapse Calculations

1. Drill Stem Testing (DST)

The maximum differential pressure across the drillpipe which exists prior to the opening of the DST tool is given by:

$$P_c = \frac{Lx\rho_1}{19.251} - \frac{(L-Y)\times\rho_2}{19.251} \qquad (10.9)$$

where:

Pc = collapse pressure (psi)

Y = depth to fluid inside drillpipe

L = total depth of well (ft)

ρ_1 = fluid density outside the drillpipe (ppg)

ρ_2 = fluid density inside the drillpipe (ppg)

Other variations of the equation Equation () include the following:

The drillpipe is completely empty, Y = 0, ρ_2 = 0, equation Equation () becomes:

$$P_c = \frac{Lx\rho_1}{19.251} \qquad (10.10)$$

When the fluid density inside drillpipe is the same as that outside drillpipe, i.e. $\rho_1 = \rho_2 = \rho$, then equation 8.9 becomes:

$$P_c = \frac{Y\times\rho}{19.251} \qquad (10.11)$$

2. Design Factor in collapse

$$DF = \frac{collapse\,resis\tan ce\,of\;Drillpipe}{collapse\;pressure\,(Pc)}$$

A DF of 1.125 is normally used.

8.2 TENSION DESIGN

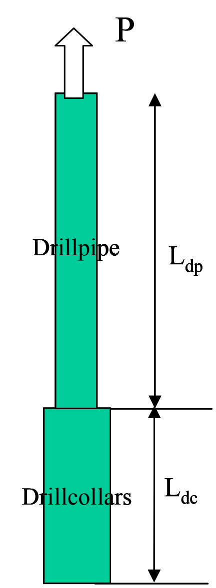
The tension load is evaluated using the maximum load concept. Buoyancy is included in the design to represent realistic drilling conditions.

The tension design is established by consideration of the following:

1. Tensile Forces: These include:
   - weight carried
   - shock loading
   - bending forces
2. Design factor
3. Slip Crushing Design

8.2.1 TENSILE FORCES

Figure 10.16 Tension Design



Weight Carried

The greatest tension (P) on the drillstring occurs at the top joint at the maximum drilled depth, see Figure 10.16. This is given by:

$$P = \left[\left(L_{dp} \times W_{dp} + L_{dc} \times W_{dc}\right)\right] \times BF \qquad (10.12)$$

where:

L_{dp} = length of drillpipe per foot

W_{dp} = weight of drillpipe per unit length

L_{dc} = weight of drillcollars

W_{dc} = weight of drillcollars per unit length

BF = buoyancy factor

Note P is the total weight of the submerged drillstring. It is highly dependent on mud weight. The higher the mud weight the less weight seen at surface on the Martin Decker weight indicator. The influence of mud weight is shown through the term BF: buoyancy factor.

The drillstring should not be designed to its maximum yield strength to prevent the drillpipe from yielding and deforming. At yield, the drillpipe will have:

- deformation made up of elastic and plastic (permanent) deformation
- permanent elongation
- permanent bend and it may be difficult to keep it straight

To prevent this, API recommends that the use of maximum allowable design load (Pa), given by:

$$P_a = 0.9 \text{ x } P_t \tag{10.13}$$

where

P_a = Max. allowable design load in tension, lb

P_t = theoretical yield strength from API tables [1], lb

0.9 = a constant relating proportional limit to yield strength

From equations Equation (10.12) and Equation (10.13), we obtain:

$$MOP = P_a - P \tag{10.14}$$

$$DF = P_a / P \tag{10.15}$$

where

MOP = Margin of overpull, lb

DF = Design factor, dimensionless

The Margin of Overpull is the minimum tension force above expected working load to account for any drag or stuck pipe. The MOP used is usually of the order of 100,000 lbs.

When deciding on the magnitude of the MOP or DF, the following should be considered:

- Overall drilling conditions

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- Hole drag
- Likelihood of getting stuck

Maximum Hole Depth

Re-arranging equations Equation (10.12),Equation (10.13),and Equation (10.14)gives the maximum length of pipe which can be used from a given grade/weight of drillpipe:

$$L_{dp} = \frac{P_t \times 0.9 - MOP}{W_{dp} \times BF} - \frac{W_{dc}}{W_{dp}} \times L_{dc} \tag{10.16}$$

8.2.2 Tension Design Procedure

1. Determine maximum design load (P_a):

Pa = 0.9 x Minimum Yield Strength

2. Calculate total load at surface using

$$P = \left[\left(L_{dp} \times W_{dp} + L_{dc} \times W_{dc}\right)\right] \times BF$$

3. Margin Of Overpull

MOP= Pa - P

4. The maximum length of drillpipe that can be used:

$$L_{dp} = \frac{P_t \times 0.9 - MOP}{W_{dp} \times BF} - \frac{W_{dc}}{W_{dp}} \times L_{dc}$$

8.2.3 Shock Loading

The additional tensile force generated by shock loading is given by:

$$Fs = 1500 \times W_{dp} \left(lbf \right) \tag{10.17}$$

where W_{dp} = weight of drillpipe per unit length, lb/ft

8.2.4 Bending

The additional tensile force generated by bending is given by:

$$Fb = 63 \times \theta \times W_{dp} \times D \left(\text{lbf} \right) \tag{10.18}$$

where

θ = dog-leg severity in °/100 ft

D = outside diameter of pipe in inches

8.3 Design Factor

A design factor of 1.6 should be applied to the tension loads calculated above if shock loading is not accounted for. If the shock loading is quantified and included in the load calculation, a design factor of 1.3 can be used.

8.4 Slip Crushing

The maximum allowable tension load must also be designed to prevent slip crushing of the pipe. Reinhold and Spini [6] proposed an equation to calculate the relationship between the hoop stress caused by the action of the slips and the tensile stress in the pipe resulting from the load of the pipe hanging in the slips. The equations used are as follows:

$$T_S = T_L \left(S_H / S_T \right) \tag{10.19}$$

where

T_S =Tension load due to slip crushing

T_L =Static load tension

S_H/S_T=Hoop stress to tension stress ratio as derived from the equation below:

$$\frac{S_H}{S_T} = \left(1 + \frac{DK}{2Ls} + \left(\frac{DK}{2Ls} \right)^2 \right)^{0.5} \tag{10.20}$$

where

S_H =Hoop stress (psi)

S_T =Tensile stress (psi)

D =OD of the pipe (ins)

K =Later load factor on slips (1/tan (y + z))

y =Slip taper (typically 9.4625 degrees)

z =Arctan μ

μ =Coefficient of friction ,typically 0.08 -0.25

Ls =Length of slips,usually 12-16 in

When all tension loads are calculated, the pipe grade selected in the collapse calculation can be assessed and modified for the tension requirements. It is usually preferable to increase the grade rather than the weight, as increasing weight usually has negative effects in terms of smaller clearance and high pressure drop.

Couplings are then selected based on the tension design. For highly deviated extended reach well or horizontal wells torque and drag modelling is performed to evaluate tension strength requirements of the pipe and couplings and the computed torque is used for determining coupling requirements.

8.4.1 ADDITIONAL DESIGN VARIABLES

1. Torsion

The drillpipe torsional strength, when subjected to pure torsion is given by:

$$Q = \frac{0.096167 \times J \times Y_m}{D} \qquad (10.21)$$

where:

Q = minimum torsional yield strength (lb-ft)

Y_m = minimum unit yield strength (psi)

J = polar moment of yield inertia = $\frac{\pi \times (D^4 - d^4)}{4}$

J = 0.098175 (D^4 - d^4)

D = outside diameter (in)

d = inside diameter (in)

When drillpipe is subjected to both torsion and tension, as is the case during drilling operations, the above equation Equation (10.21) becomes

$$Q_t = \frac{0.096167 x J \sqrt{Y_m^2 - \frac{P^2}{A^2}}}{D} \quad (10.22)$$

where

Q_T = minimum torsional yield strength under tension (lb-ft)

A = cross-sectional area (in2)

P = weight carried, (lb)

2. Pipe Stretch Of Submerged Drillstring

e_1 = stretch due to weight carried (i.e. weight of drillcollars)

$$e_1 = \frac{P \times L}{735,444 \times W_{dp}} \quad (10.23)$$

where:

P = load carried in lbf

L = length of drillpipe

e_2 = stretch due to suspended weight of drillpipe

$$= \frac{L^2}{9.625 \times 10^7} \times (65.44 - 1.44 \times \rho_m) \quad (10.24)$$

where ρ_m = mud density in ppg

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Example 10.4: Tension Design With A Single Drillpipe

A drill string consists of 600 ft of 8 ¼ in x 2.13/16 in drillcollars and the rest is a 5 in drillpipe, 19.5 lbm/ft Grade X95 drillpipe. If the required MOP is 100,000 lb and mud weight is 10 ppg, calculate the maximum depth of hole that can be drilled when (a) using new drillpipe (Pt = 501,090 lb) (b) using Class 2 drillpipe having a yield strength (Pt) of 394,000 lb.

Solution

(a) Weight of drill collar per foot can be calculated from:

$$A \times 1 \text{ ft} \times \rho_s = \frac{\pi}{4}\left((8.25)^2 - (2.8125)^2\right) \times 1 \times 489.5 \times \frac{1}{144} = 160.6 \text{ lbm/ft}$$

where

ρ_s = density of steel = 489.5 lbm/ft

A = cross-sectional area (in)

Using:

$$L_{dp} \quad \frac{P_t \times 0.9 - MOP}{W_{dp} \times BF} - \frac{W_{dc}}{W_{dp}} \times L_{dc}$$

$$BF == \left(1 - \frac{10}{65.5}\right) = 0.847$$

Pt = 501,090 lb (New Grade X95)

MOP = 100,000 lb

Therefore:

$$L_{dp} = \frac{501{,}090 \times 0.9 - 100{,}000}{19.5 \times 0.847} - \frac{(160.6) \times 600}{19.5} = 16{,}309 \text{ ft}$$

The maximum hole depth that can be drilled with a new drillpipe of Grade X95 under the given loading condition is

= length of drillpipe + length of drillcollars

= 16,309 + 600 = 16,909 ft

(b) Now P_t= 394,600 lb

$$L_{dp} = \frac{394,600 x 0.9 - 100000}{19.5 x 0.847} - \frac{160.6 x 600}{19.5} = 10,506 \text{ ft}$$

Maximum hole depth = 10,506 + 600 = 11,106 ft

Example 5: Mixed Drillpipe

An exploration rig has the following grades of drillpipe to be run in a 15,000 ft deep well:

Grade E: 5/4.276 in, 19.5 lb/ft, yield strength = 395,600 lb

Grade G: 5/4.276 in, 19.5 lb/ft, yield strength = 553,830 lb

If the total length and weight of drillcollars plus heavy-walled drillpipe is 984 ft and 157,374 lb, respectively calculate:

a. the maximum length that can be used from each grade of drillpipe if a MOP of 50,000 lb is to be maintained for the lower grade; and

b. the MOP of the heavier grade.

The maximum expected mud weight at 15,000 ft is 13.4 ppg.

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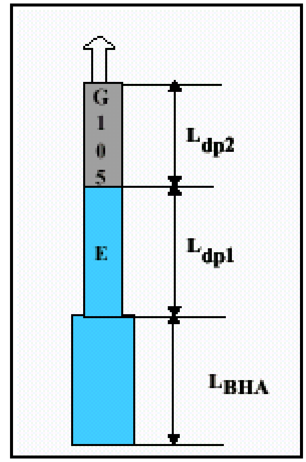
Solution

Part a

1. Bottom Section



The lightest grade (Grade E) should be used for the bottom part of the hole, while the highest grade should be used at the topmost section. Thus, Grade E will carry the weight of drillcollars and heavy-wall drillpipe.

The term W_{dc} should include the combined weight of these the items. Hence,

$$W_{dc} \times L_{dc} = weight\ of\ drillcollars + weight\ of\ HWDP \quad = 157{,}374 \text{ lb}$$

Using:

$$BF = 1 - \frac{13.4}{65.5} = 0.795$$

$$L_{dp} = \frac{P_t \times 0.9 - MOP}{W_{dp} \times BF} - \frac{W_{dc}}{W_{dp}} \times L_{dc}$$

$$L_{dp} = \frac{501{,}090 \times 0.9 - 100{,}000}{19.5 \times 0.847} - \frac{(160.6) \times 600}{19.5}$$

= 11,646 ft

Accumulated length of drill string will consist of:

Drill collar and heavy-walled drillpipe= 984 ft

Grade E drillpipe= 11,646 ft

Total= 12,630 ft

2. Top Section

The top part of the wall will consist of Grade G of length

15,000 - 12,630 = 2,370 ft

Check Grade G for suitability

This grade will carry a combined weight of Grade E (11,646 ft) + drillcollars and heavy-walled drillpipe.

= 11,646 x 19.5 + 157,374 = 384,471 lb

$$L_{dp} = \frac{553{,}830 \times 0.9 - 50{,}000}{19.5 \times 0.795} - \frac{384{,}471}{19.5}$$

= 9,175 ft

Hence, under the existing loading conditions, 9,175 ft of Grade G can be used as a top section. In our example only 2,370 ft are required.

Part b

$$\text{MOP} = \text{P}_t \times 0.9 - \text{P}$$

P = buoyant weight carried by top joint

= weight of drillpipe of Grades E and G and weight of drill collars and HWDP

$$= (2370 \times 19.5 + 11{,}646 \times 19.5 + 157{,}374) \times \text{BF}$$

= 430,686 x 0.795 = 342,395 lb

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MOP = 553,830 x 0.9 - 342,395 = 156,052 lb

Example 10.5: Drill Pipe Design Using Pressure-Area Method

Well Data

Hole size	=12¼"
Bit Depth	=11,000 ft
Collar length	=500 ft
Drill Pipe	=5"OD 4.276" ID (Available Grade X-95)
Drill Collars	=8"OD 3.0" ID
Overpull	=100,000 lbs
Mud Weight	=11.5 ppg
DST packer depth	=10,700 ft
Length of Slips	=16"

Maximum anticipated surface pressure = 5000 psi

Design Factors:

Tension = 1.3 - 1.6
Collapse = 1.0
Burst = 1.1

Solutiona suitable

A graphical method will be used to select drillpipe grade/weight, similar to the method used for casing selection.

1. Construct the collapse load line by calculating the maximum collapse pressure at the bottom of the drill pipe.

Collapse load at 10,700 ft = 0.052 x 10,700 ft x 11.5 ppg = 6399 psi.

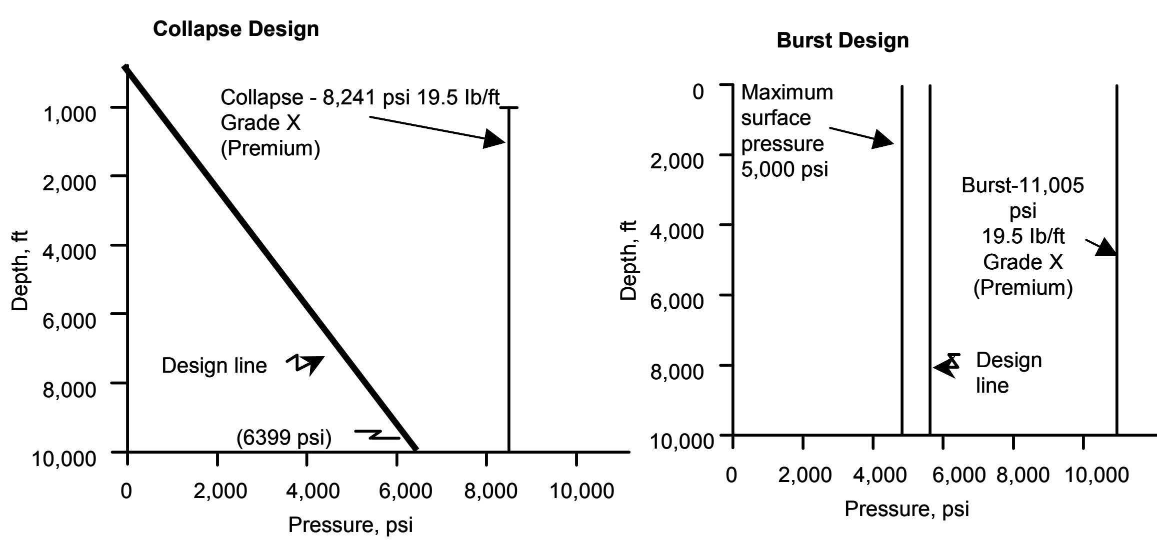
The design factor for collapse is 1.0. The design load is the calculated load multiplied by the design factor.In this case the design load is also 6399 psi.

2. Plot the load and design lines graphically (see Figure 10.17) and select an appropriate pipe grade using API tables of pipe collapse resistance data.

3. Check the burst rating of the pipe grade chosen against the maximum anticipated applied surface pressure. Plot burst load and burst design (see Figure 10.17 above)

In this instance the maximum applied surface pressure will be 5000 psi. Use of a design factor of 1.1 gives a design load of 5500 psi.

Figure 10.17 Collpase & Burst Design Loads



4. Calculate the tension load line using the following steps and plot graphically (Figure 10.18).

i. Calculate the buoyancy force (BF1) acting on the bottom of the drill collars using:

BF1= - (P x A)

$= - (0.052 \times 11{,}000 \text{ ft} \times 11.5 \text{ ppg}) \times ((\pi/4) \times (8^2 - 3^2))$
$= - (6{,}578 \text{ psi}) \times (43.197 \text{ in}^2)$
$= - 284{,}149 \text{ lb}$

ii. Calculate the buoyancy force (BF2) acting at the top of the drillcollars.

BF2= (P x A)
=(0.052 x 10,500 ft x 11.5 ppg)x [π/4 (8^2 - 5^2) + π/4 (4.276^2 -3^2)]
=(6,279 psi) x (30.631 + 7.292 sq. in) = + 238,119 lb

iii. Calculate the drill collar weight

DC Weight= 150 lb/ft x 500 ft =+ 75,000 lbs

iv. Calculate the drill pipe weight

DP Weight =19.5 lb/ft x 10,500 ft =+ 204,750 lb

v. Calculate the shock load

Shock load = 1500 x pipe weight per foot

(Note 1500 was used to represent slow running speeds. The reader can repeat the calculations with 3200 Wn as an exercise)
= 1500x 19.5 lb/ft
= 29,250 lb

vi. Now calculate the total dynamic load at surface

Total dynamic load = - 284,149 (BF1) + 238,119 (BF2) + 75,000 (drillcollar weight) + 204,750 (drill pipe weight) + 29,250 (shock load)

Total dynamic surface load =+ 262,970 lbs

Note: static load at surface = 233,720 lb ie without shock load

Static load at top of drillcollars(at 10,500 ft)= -284,149 + 75,000(DC weight in air) = -209,149 lb

Static load at bottom of drillpipe = 238,119 (BF2)+ (-209,149) = 28,970 lb

Dynamic load at bottom of drillpipe = 28,970 + 29,250 = + 58,220 lb

Plot the static and dynamic load as shown in Figure 10.18.

5. Calculate the design line for the tension load by multiplying the load on the drill pipe at surface and at the top of the collars by the 1.3 design factor (since shock loads have been included) and plot as in **Figure 10.18**.

6. Calculate the design line for the MOP by adding the 100,000 lb overpull factor to the static tension load values calculated ealier and plot as in **Figure 10.19**.

7. Calculate the design line for slip crushing using **Equation (10.20)**:

K = (1/tan (y + z))

y = 9.4625 degrees

z =Arctan μ = artan 0.08 = 0.0798

Ls =Length of slips,usually 12-16 in

$$K = \frac{1}{\tan(9.5 + 0.0798)} = 4$$

$$S_H/S_T = \left(1 + \frac{5x4}{2x16} + \left(\frac{5x4}{2x16}\right)^2\right)^{0.5} = 1.42$$

T_L = static tension at surface = 233,720 lb

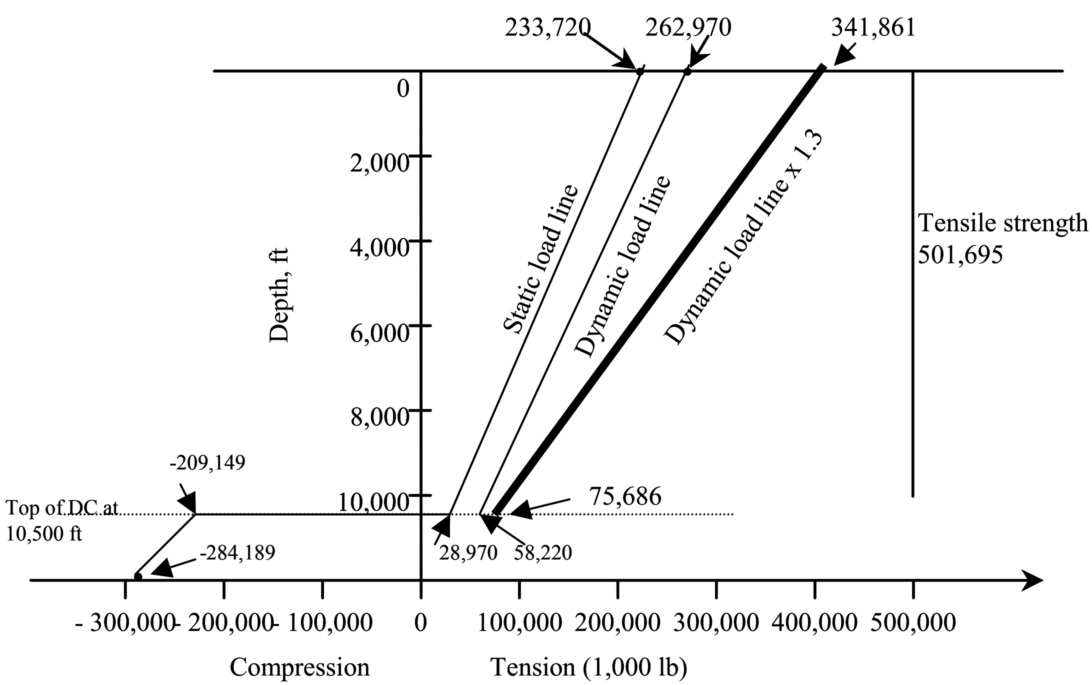
Therefore at the top of the well where the static tension load (i.e. excluding drag) is 233,720 lb, the slip crushing load:

$T_S = T_L\ (S_H/S_T)$

=233,720 X 1.42
=331,882 lb

The slip crushing value is then recalculated at the bottom of drillpipe (28,970 x 1.42) and the slip crushing design line plotted through the two points as shown in Figure 10.19.

Figure 10.18 Static & Dynamic Loads



8. The tensile rating of the pipe in lb is computed from the cross sectional area of the pipe and the yield strength as follows:

Drillpipe area $= (\pi/4)\,(5^2 - 4.276^2) = 5.281$ sq. in

Tensile strength = area x yield strength =5.281 x 95000 psi=501,695 lb

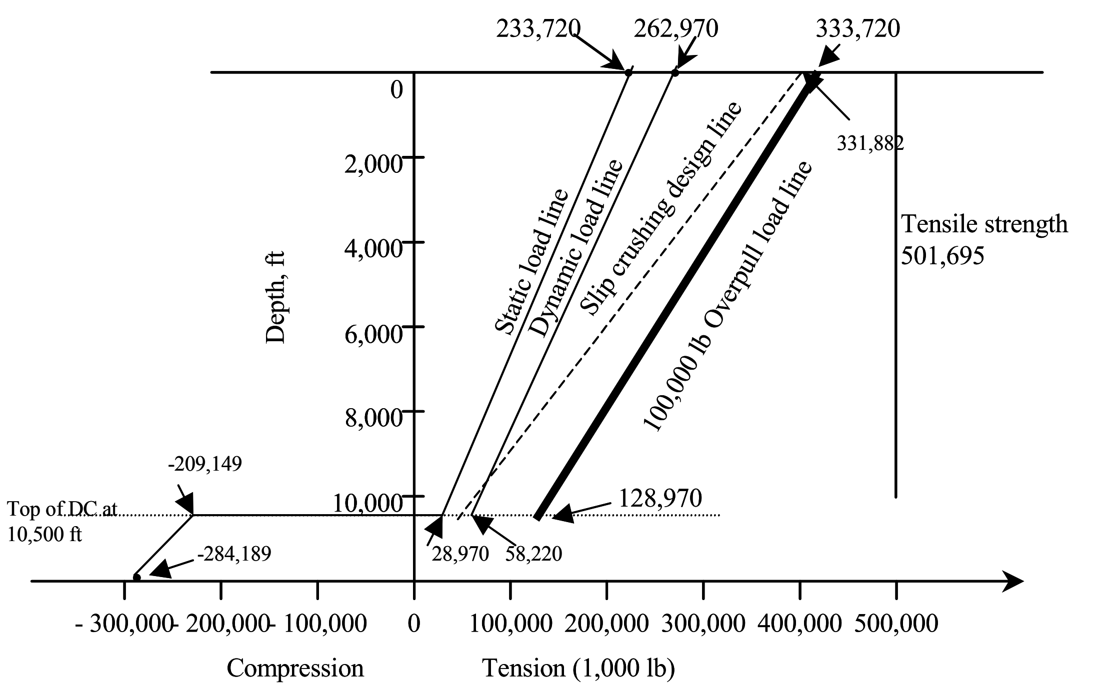
9. Calculate the tension design factors (TDF) at surface:

$$\text{Static TDF} = \frac{\text{Tensile strength}}{\text{Static Load}} = \frac{501,695}{233,720} = 2.15$$

$$\text{Dynamic TDF} = \frac{\text{Tensile strength}}{\text{Dynamic load}} = \frac{501,695}{262,970} = 1.91$$

$$\text{Overpull TDF} = \frac{\text{Tensile strength}}{\text{Overpull load}} = \frac{501,695}{233,720 + 100,000} = 1.5$$

Figure 10.19 Complete Tension Design



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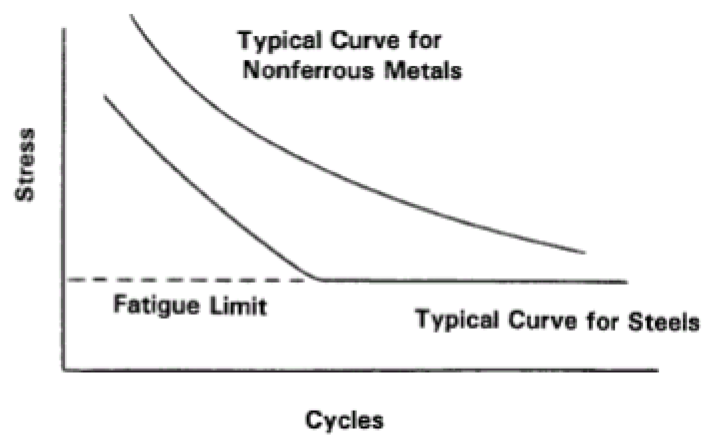
9.0 DOGLEG SEVERITY

9.1 CAUSE OF FATIGUE DAMAGE ONSIDERATIONS

Figure 10.20 S/N Curve, after reference 10



Fatigue is the tendency of a material to fracture under repeated cyclic (reversal) stresses and chemical attack. Fatigue failure usually occurs at stresses well below the static yield strength of the pipe.Cyclic stresses may be due to : vibrations, rotation in a dogleg area and thermal cycling. Fatigue failure is the most common type of failure in the drilling industry.

The bending of the pipe in a dogleg induces compression in the inner wall of the pipe and tension (strecthing) in the outer wall of the pipe.These induced stresses cause the total stress (weight carried + induced stress) on the outer wall to be significantly larger than the stress on the inner wall of the pipe.Hence as the pipe is rotated, the stress at the preiphery of the pipe is now varying between maximum and minimum values; the variation can be up to 50,000 psi.

In a material which already contains cracks, these stress reversals cause the cracks to grow and interconnect producing a larger crack that will the cause the pipe to part. In a material with no cracks, fatigue damage occurs when these stress reversals cause the microscopic grains of the material to slide over each other, eventually pulling apart and leaving small cracks in the material.Under sustained loading and rotation, these small cracks grow into a larger crack that can not support the applied load. The material will then part at the crack and is said to have suffered a fatigue failure.

Material behaviour under cyclic loading is usually presented in the form of S/N curves (**Figure 10.20**), where S is the appiled stress and N is the number of cycles to failure. Below a certain stress level, the material will no failue in fatigue regardless of the number of applied cycles. This stress level is called the Fatigue (or Endurance) Limit.

The reader should note that in the presence of corrosive agents (H_2S and CO_2) and under applied tension and rotation , fatigue damage can occur much more quickly than just under tension and rotation.In addition, steel has no fatigue limit in corrosive environments and will have a finite life.

9.2 Position of Pipe in Well

The position of drillpipe in the string will influence the amount of fatigue damage it sustains. For example, a drillpipe joint continually rotated at a severe dog-leg, such as a kick-off point will accumulate fatigue at a much higher rate than a drillpipe joint run in the upper hole section or a joint run behind the collars. With each rotation of pipe, part of its useful life is used up and permanent damage is done.

Most fatigue failures occur within 3-4 ft. from the tool joint on either end of the pipe joint because of the slip marks which help to initiate fatigue cracks. Another typical site for crack initiation is the engaged threads of the connections. Drillpipe is subjected to the same bending stresses during drilling or rotating off bottom through a dogleg.

9.3 Dogleg Severity

Lubinski [7] has published several papers that relate the magnitude of dogleg severity to pipe failure. He showed that below a given dogleg severity, rotation of the drillpipe in the dogleg area does not cause appreciable fatigue damage..

The maximum permissible dogleg severity for fatigue damage considerations can be calculated using the following formulae:

$$\text{Max Ds} = \frac{432{,}000}{\pi} x \frac{\sigma_b}{ED} x \frac{\tanh KL}{KL} \tag{10.25}$$

$$K = \sqrt{\frac{T}{EI}} \tag{10.26}$$

where:

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Max Ds = Maximum permissible dogleg severity, deg/100 ft

E =Young's Modulus of elasticity (30 x 10^6 for steel, 10.5 x 10^6 for aluminium)

D = Drill pipe OD, in

L = Half distance between tool joints, in

T = Tension load below the dogleg, lb

σ_b = Maximum permissible bending stress, psi

I = Drill pipe moment of inertia = (π/64) x (OD^4 -ID^4)

The maximum permissible bending stress (σ_b) is dependent on the the buoyed tensile stress (σt) and the grade of the pipe. The formulae for grades E and S drill pipe are included below. Additional formulae for other grades are included in API RP 7G.

Grade E drill pipe:

$$\sigma_b = 19500 - \left(\frac{10}{67}\right)\sigma_t - \left(\frac{0.6}{670^2}\right)(\sigma_t - 33500)^2 \qquad (10.27)$$

Grade S drill pipe:

$$\sigma_b = 20000\left(1 - \frac{\sigma_t}{14500}\right) \qquad (10.28)$$

The detailed procedure and example calculation of maximum permissible dogleg severity now follows, see example **Figure 10.6**

Example 10.6: Dog Leg Calculations

Determine the maximum permissible dog leg which will not result in fatigue damage in the following case:

Grade S: Drill Pipe 5" OD 4.276"ID, weight 19.5 lb/ft
Depth 5500 ft
Tension load is 180,414 lb at 5500 ft.

Solution

Procedure:

1.Calculate the tension stress at depth of interest

Tension stress (σt) = tension load /cross-sectional area

=180,414 lb / 5.275 sq in

=34,204 psi

2. calculate the maximum permissible bending stress for grade S pipe

$$\sigma_b = 20000\left(1 - \frac{\sigma_t}{14500}\right) = 20,000 \times \left(1 - \frac{34,204}{145,000}\right) = 15,282 \text{ psi}$$

3. Determine K

$$K = \sqrt{\frac{180,414}{30 \times 10^6 \times \left(\frac{\pi}{64}(5^4 - 4.276^4)\right)}} = 0.0205$$

4. Calculate the maximum permissible dog leg severity from **Equation (10.25)**.

$$\text{Max Ds} = \frac{432,000}{\pi} \text{x} \frac{15,282}{30 \text{x} 10^6 \text{x} 5} \times \frac{\tanh(0.0205 \text{x} 180)}{0.0205 \text{x} 180}$$

$$\textit{Max Ds} = 3.797 \tanh 3.69$$

$$\tanh 3.690 = = \frac{e^{3.69} - e^{-3.69}}{e^{3.69} + e^{-3.69}} = 0.9988$$

$$\textit{Max Ds} = 3.797 \text{ x } 0.9988 = 3.79 \text{ deg/100 ft}$$

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The use of drill pipe protectors greatly increases the maximum permissible dogleg. Lubinski and Williamson [8] showed that the permissible dogleg increases when using one or two drill pipe protectors per joint. Hence drillpipe protectors should be used in wells experiencing high dogleg severity.

9.4 Lateral Tool Joint Loading Considerations

It has been shown in field studies that lateral loading of drillpipe tool joints can result in significant damage to the drill pipe and casing. Lubinski suggested than an arbitrary limit of 2000 lbs be used as the maximum non-damaging lateral load. Loads above this limit are proposed as resulting in damage to the pipe and increase casing wear.The following equation can be used to calculate the maximum dog leg severity for various lateral loads:

$$\mathrm{MaxD_s} = \frac{108,000\mathrm{xF}}{\pi \mathrm{LT}} \qquad (10.29)$$

where

F =Maximum permissible lateral load (default 2000 lbs)

L =Half length of joint of drill pipe

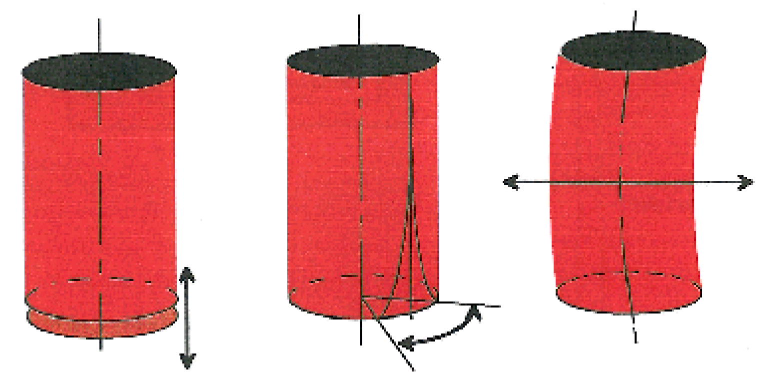
T =Buoyed tension load

10.0 Drillstring Vibration And Harmonics

The drillstring can vibrate in three different modes;

i. axial (longitudinal) vibration; vibration along the drillstring axis
ii. torsional vibration: vibration causing twist and torque
iii. transverse (lateral) vibration: side to side vibration

Figure 10.21 Types of vibrations



Axial vibrations can be recognised by topdrive vibration, Kelly bounce and whipping of the drill line. Torsional vibrations cannot be seen as the rotary table controls the motion of the drillstring at surface. Transverse motion again cannot be seen at surface.

Vibration of the drillstring occurs when the frequency of the applied force equals the natural vibration frequency of the drillstring. Rotation of the drillstring at its natural resonant frequency results in excessive and rapid wear of the drillstring and can result in premature fatigue failure.

Surface signs of destructive vibrations include:

- Tooljoint failure
- Washouts
- Twist offs
- Stabiliser and drillcollar wear
- BHA components , motor nm ccccand MWD failures
- Damaged drillbit

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- Topdrive vibrations

Field evidence has shown [12] that:

- WOB affects tricone bit vibration more than PDC bits. At higher WOB, the stability of PDC bits increases while tricone bits vivration increases.
- Hard and abrasive formations are more likely to generate vibrations than soft formations. Conglomerates , quratzite , chert, hard sanstones all produce harmful vibrations.
- Vertical holes are more prone to axial vibrations. Torsional vibration is more likely to occur in deviated wells.
- Unstabilised BHA's are more rone to vibrations than packed BHA's
- Tricone bits are more prone to bounce when drilling hard rocks at high RPM's. New anti-whirl PDC bits are more stable than conventional PDC bits , see **Chapter 9**.

10.1 VIBRATION MECHANISMS

The three modes of vibrations (axial, torsional and transverse) can result from the following mechanisms:

1. Bit Bounce: This causes an axial motion of the drillstring and results from WOB fluctations when the bit lifts off bottom and then impact the bottom of the hole again. Drilling hard and abrasive formations is another cause of bit bounce.Bit bounce usually occurs in vertical wells when using tricone bits and can be decreased by modifying the WOB/RPM combinations.

2. Stick-Slip : This mechanism cause a torsional motion of the drilstring.Stick-slip occurs in high angle welss and when using PDC bits requiring high WOB. In both cases , the increased friction between the bit and rock causes the drillbit to stop momentarily while the drillstring is still rotating and building up torque. Eventually, enough energy is builtup to spin free the bit and resume drilling.

This stick-slip mechanism creates torsional vibrations in the drillstring and uusally cause PDC bit damage , twist off , back-offs , lower ROP (when drillbit spins backward) and connection over-torquing: some drillcollars conections are torqued up beyongd the rig's capability and need to be shipped to twon to break the connections.

Stick-slip can be recognised at surface when surface torques fluctates widely. It can be reduced by increassing RPM and/or reducing WOB.

3. BHA Backward Whirl: This mechanism produces lateral vibrations in the drillstring. It results when the BHA rotates about a centre different from the wellbore centre resulting in lateral impacts between the BHA and the walls of the hole.

Backward whirl usually occurs when using pendlum and unstabilised BHA while drilling vertical holes. Bachward whirl usually cause the maximum damage to BHA compnonets, MWD and motor .Vibrations can be reduced by reducing RPM or using stabilsied BHA's.

4. Drillbit Bachward Whirl. This mechanism produces lateral motion of th edrillbit. It is caused by the drillbit rotating about a point different from its gemetric centre.Both BHA and bit whirl are difficult to be detected at the surface. It can be recognised by damage to drillbit cutting elements, overgauge holes and over-torqueing of BHA connections.Reduction of RP and re-spudding of the bit can reduce both BHA abd bit whirl.

5.Lateral Shocks: This mechanism is induced by either bit whirl or from underbalanced drillstrings. It produces a random lateral motion causing the drillstring to whirl forward and backward . Lateral shock s cause MWD and BHA components failures and usually occur when drilling hard rocks.

6. Coupled Vibration: This mechanism creates axial, lateral and torsional vibrations. Its source can be any combination of the previous mentione. It occurs while drilling hard rocks in vertiacl or near vertical wells using unstabilsied BHA's. Once again downhole compnents , bit failure, twist offs are indications ofthis mechanism.

It is the author's experience[12] that the placement of shock sub palys a major role in reducing or modifying the magnitude of drilstring vibrations. Placement of the shock sub immediately above the bit (normal practice) does not reduce drillstring vibrations. accurate positioning of the shock sub may be determined mathematically [12] .

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10.2 Methods To Reduce Drillstring Vibration

The main source of excitation of drillstring vibration is the rotation of the drillbit and the drillstring.It follows that downhole vibrations can be reduced by rotating the drillstring and bit at an RPM that is less tor more than the excitaion RPM. The actual calculation of such an RPM requires tedious mathimetics which are beyond the scope of this book, see reference 11.

Drillstring vibration can be reduced by several means.

1. Modifying the drilling operating parameters (RPM/WOB)
2. Changing the length of the collars or HWDP used in the assembly.
3. By applying mechanical damping of the string via the use of a shock sub
4. Avoiding rotating the string at the natural resonant frequency of the drillstring.

In view of the above, calculation of the critical rotary speeds for each assembly run should be performed to ensure that rotational speeds do not result in generation of harmful resonant vibrations. The methods used for the determination of critical rotary speed are quite complex and require the solution a complex set of equations which do not lend themselves easily to manual calculations. There are several computer simulators available on the market which can be used for this purpose.

11.0 Further Design Examples

Example 10.7: Torque Calculations

The following data refers to a drill string stuck at the drillcollars: Drillpipe: 10,000 ft, 5/4.276 in Grade E 19.5 lbm ft, Class 2. Drillcollars: 600 ft, total weight 80,000 lb. Make-up torque for drillpipe tool joints = 20,000 ft-lb and the free point is at 9,900 ft.

Determine the maximum torque that can be applied at the surface without exceeding the maximum torsional yield strength of drillpipe.

Solution

Using Equation (10.22)

$$Q_t = \frac{0.096167 x J \sqrt{Y_m{}^2 - \frac{P^2}{A^2}}}{D}$$

First determine the various terms in the above equation.

Since the drillpipe is 100% free at 9,900 ft, the total tensile load at surface:

$P = 9{,}900\ ft \times 19.5 = 193{,}050\, lb.$

(Note: Nominal weight of drillpipe is used).

$$J = \frac{\pi}{32}\left(D^4 - d^4\right) = \frac{\pi}{32}\left(5^4 - (4.276)^4\right)$$

$$= 28.5383 \text{ in}^4$$

$$A = \frac{\pi}{4}\left(D^4 - d^4\right) = \frac{\pi}{4}\left(5^2 - (4.276)^2\right) = 5.27 \text{ in}^2$$

Tensile strength = 311,540 lb

Minimum unit yield strength (Y_m) $= \frac{311{,}540}{A} = \frac{311{,}540}{5.27} = 59{,}116\, psi$

$$Q_t = \frac{0.096167 x 28.5383 \sqrt{59116^2 - \frac{193050^2}{5.27A^2}}}{5} = 24{,}277 \text{ ft-lb}$$

This is the maximum allowable torque for pipe body under the current loading conditions. Note API values are given for zero tension.

Since the make-up torque for the drillpipe tool joint is 20,000 ft lb, the maximum allowable torque should be based on tool joint torque and not pipe body torque.

Note: this information will be required in back-off operations.

Example 10.8: Pipe Stretch

A 3.5 in drillpipe, 13.3 lbm/ft. Grade S135 premium class, is used to run a 4.5 in OD liner to 21,000 ft. If the length of drillpipe is 175,000 ft, the mud weight is 16 ppg and the total weight of the liner is 50,000 lb, calculate the total stretch in the drillpipe.

Solution

e_1 = stretch due to weight carried:

$$= \frac{P \times L}{735{,}444 \times W_{dp}} = \frac{50{,}000 \times 17{,}500}{735{,}444 \times 13.3} = 89.5 \text{ in}$$

e_2 = stretch due to suspend weight of drillpipe

$$= \frac{L^2}{9.625 \times 10^7} \times (65.44 - 1.44\,\rho m)$$

$$= \frac{(17{,}500)^2}{9.625 \times 10^7} \times (65.44 - 1.44 \times 16) = 134.9 \text{ in}$$

Total stretch = $e_1 + e_2$

= 89.5 +134.9 =224.4 in = 18.7 ft

12.0 Learning Milestones

In this chapter, you should have learnt to:

1. List function of each component of the drillsting
2. Describe the API system of drillpipe classification
3. Explain th meaning of NC50
4. Describe how washouts develop and detected
5. Calculate approximate weight of drillpipe and tooljoint assembly
6. Calculate weight and number of Drillcollars for a given WOB
7. Describe: stabilisers, reamers, jars and shock subs
8. Calculate maximum drillable depth for a given grade and weight of drillpipe
9. Understand the effect of slip crushing on drillpipe design
10. Calculate the maximum allowable torque on drillpipe during drilling operation (**Equation (10.22)**)
11. Calculate dogleg severity
12. List sources of drillstring vibrations

13.0 REFERENCES

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14.0 EXERCISES

1. List the functions of each component of the drillsting
2. Explain th meaning of NC50
3. Describe how washouts develop and detected
4. Describe the main features of: stabilisers, reamers, jars and shock subs
5. Explain the effect of slip crushing on drillpipe design
6. List sources of drillstring vibrations
7. Determine the maximum permissible dog leg which will not result in fatigue damage in the following case:

Grade S: Drill Pipe 5" OD 4.276"ID, weight 19.5 lb/ft
Tension loads: 225 lb at 2500 ft and 233,035 lb at 2000 ft

(Ans: 31.2 and 3.04 deg/100 ft)

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11

Directional Drilling

Contents

1.0 Reasons for drilling deviated wells

Controlled directional drilling is a technique for directing a well along a predetermined course to a bottom hole target located at a certain distance and direction from a surface location.

There are many reasons for drilling a directional wells, including:

1. Side-tracking existing wells (because of hole problems or fish or reaching new targets)

2. Restricted surface locations

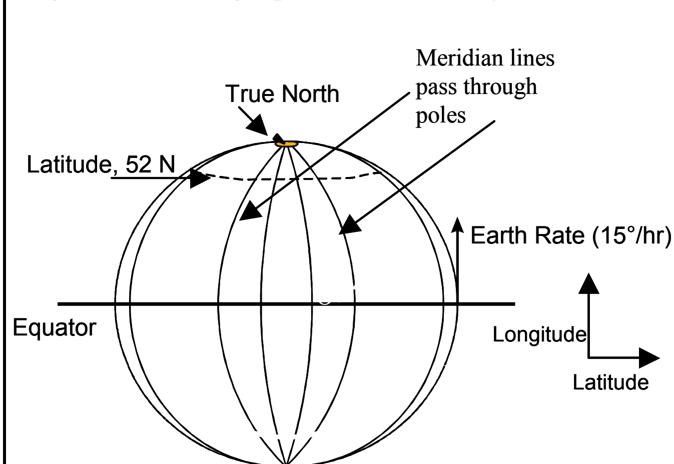
3. To reach multiple targets
4. To reduce number of offshore platforms
5. Horizontal Drilling
6. To reach thin reservoirs (using horizontal or multilateral drilling)
7. Environmental footprint
8. Salt dome drilling (direct the well away from the salt dome to avoid casing collapse problems)
9. Geological requirements
10. To avoid gas or water coning problems
11. For intersecting fractures
12. For re-entering existing wells

2.0 Coordinate Systems

2.1 Geographic Coordinates

Figure 11.1 shows the geographic coordinate system on a globe. Any position on the earth's surface can be described in terms of a value of latitude (degrees north or south of a datum) and a value for longitude (degrees east or west of a datum).

Figure 11.1 Geographic coordinate system



An imaginary network (graticule) of latitude and longitude is superimposed on the globe (earth surface). The latitude lines (or parallels) are imaginary circles running from the equator to both the north and south poles. The equator plane is half way between the two poles.The equator is at 0° latitude and the north pole at 90° N.The south pole is at a latitude of 90° S. There are ninety latitude lines between the equator and each pole, each a degree in magnitude.

Lines of longitude (or meridian lines) are imaginary lines passing through the north and south poles and crossing latitude lines at right angles. Lines of longitude are denoted by a number of degrees from 0-180 °, east or west of Greenwich in England. Greenwich has a 0° longitude or zero meridian line.In effect the earth has 360 deg of longitudes.

2.2 SPHEROIDS

In practice, it is not practical to work from a three dimensional model such as a world globe to determine relative positions on or within the earth. The world is therefore translated into a two dimensional projection using (an oblate) spheroid of reference.

To fit a general spheroid to the earth's surface is mathematically complex if not impossible. Therefore, the mathematics is simplified by imagining the land masses of the earth covered by connected canals through which the waters of the oceans can flow freely under gravity.The connected surfaces of the waters of the canals and the ocean will now form a geoid (means 'earth shaped'), assuming tidal effects of the oceans are negligible. An oblate spheroid (similar to a squashed orange) was found to be the best fit to a geoid.

Because of the irregular shape of the earth, the ideal spheroid chosen for a country or a continent may not be the ideal shape for another. As a result of this, a number of spheroids have come into use in different parts of the world. Some of these spheroids are listed in **Table 11.1**.

Once a spheroid is chosen, its shape, size and position can be adjusted so that the deviations of the spheroid surface from that of the geoid are kept to a minimum throughout the area of interest. The size and shape of a spheroid is defined by two parameters, usually the semi-major axis and the flattening factor (f):

$$1/f = a/(a-b) \qquad (11.1)$$

where (a = the equatorial radius)

b = semi-minor axis (the polar radius)

Suitable values of a and f are chosen to produce a curvature on the spheroid which most closely approximates to that of the geoid in the area of interest.

It is standard practice to use the Heyford 1910 International Spheroid Constants for the North Sea Universal Transverse Mercator Projections, based on the European Datum 1950.

Position on both the geoid and the spheroid is described in terms of latitude and longitude. Latitude and longitude on the geoid are normally determined by astronomical observations and are therefore known as astronomic latitude and longitude. Latitude and Longitude on the spheroid are termed geodetic latitude and longitude.

Table 11.1 Spheroids

Location	Spheroid Name
USA, Canada & Philippines	Clarke 1866
Europe, N.Africa & Middle East	International (1924)
UK	Airy (1849) International (1924) Heyford (1950)
Chile, Borneo & Indonesia	Bessel (1841)
Africa & France	Clarke (1880)
India, Afghanistan, Pakistan, Thailand	Everest (1830)
Malaysia	Modified Everest (1830)

2.3 MAP PROJECTIONS

The next step is to project the curved surface of the spheroid onto a flat surface to allow the engineer to work from a two dimensional surface.

The standard mercator projection, **Figure 11.2** is produced by placing a cylinder over the earth so that the contact point is round the equator. A point on the earth is projected onto the inside of the cylinder by taking a line from the centre of the earth through the point. When all the points have been projected onto the cylinder, the cylinder is unwrapped and laid flat.

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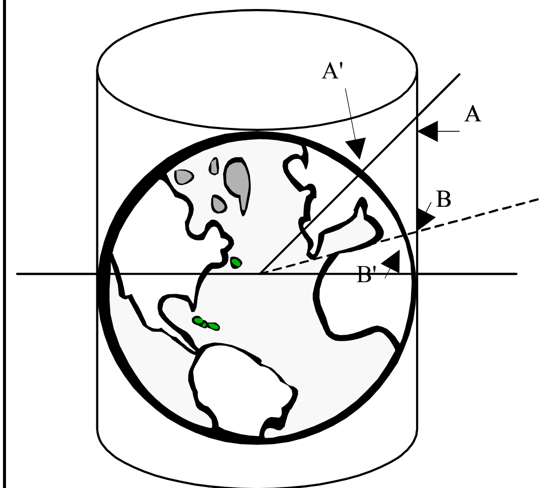
Although, the Mercator projection preserves the bearing direction, it, however, distorts distances and areas on small scale maps. For instance, with Standard Mercator, distance along the equator is represented exactly but distances at the higher latitudes are distorted. This means that Greenland appears to be the same size as South America, whereas in reality it is about one third the size.

Figure 11.2 Method of obtaining standard Mercator projection



Borehole surveying requires a map or rectangular grid system that is appropriate to the locality being surveyed. Provided that the area projected is not excessively large, it is possible to compare the calculated latitude and departure values from surveys taken on a number of wells covering a given area.

Two of the projection systems most commonly used in the Petroleum Industry are the Universal Transverse Mercator (UTM), and the Lambert conical orthomorphic, See **Figure 11.3** and **Figure 11.4**.

Figure 11.3 Universal Transverse Mercator (UTM) Projection

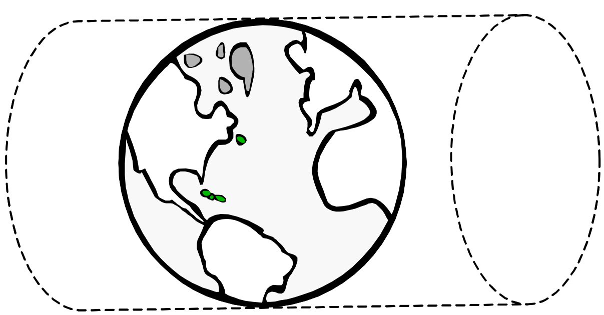
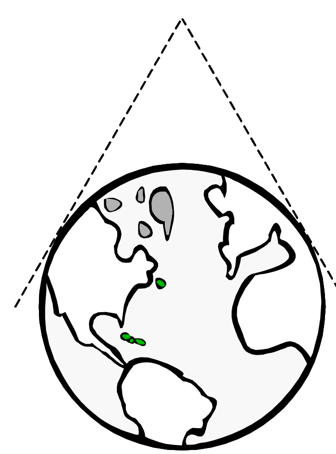


Figure 11.4 Lambert Conical Projection



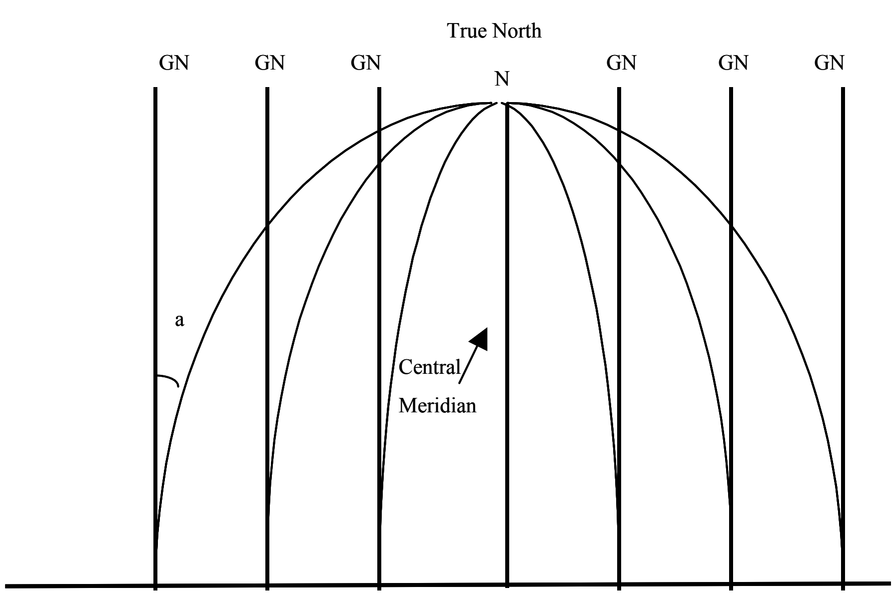
The Lambert conical projection is used in the USA as it is most suited to areas where there is a greater extent of east-west and lesser extent of north-south. The Lambert system produces a projection that has meridians as convergent lines and parallels as arcs of circles.

The UTM projection is the most commonly used projection worldwide and it uses a horizontal cylinder for projection with the earth inside the horizontal cylinder and touches the spheroid along a chosen meridian, see **Figure 11.3**.

2.4 GRIDS

The projected curved earth surface is further divided into grids.The purpose of a grid is to enable survey points to be computed and plotted in rectangular coordinates, thereby simplifying the calculations for bearings and distances.

Figure 11.5 Grid north and true north



The rectangular grid system consists of two series of parallel lines intersecting at right angles to form squares. The grid's true origin is defined in terms of latitude and longitude and one of the grid lines is aligned with a meridian line,**Figure 11.5**. The direction of this grid line is called Grid North and it is identical to True North only for this line, see **Figure 11.5**.The northerly direction of the grid is determined by the specified meridian of longitude.The grid

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norths of all other lines in the grid will be different from true north by an angle (a), called convergence angle.

The grid coordinates of any point on the earth's surface depends on the type of projection used and formulae have been prepared which convert latitude and longitude to grid coordinates and vice-versa. Since grids are chosen to cover small areas, the approximations arising from computing as if the earth' surface were flat are acceptable or can be allowed for.

3.0 Universal Transverse Mercator (UTM)

The UTM grid is a universal grid which is used to cover the world except for the polar regions. The UTM is based on 60 zones, each is 6 degrees of longitude wide and extends from 80 deg S to 84 deg N latitude, with the International metre being used as the unit of measurement (not foot). Greenwich in England is chosen as the reference meridian with 0 degrees of longitude.

Each of the 60 zones is defined by meridians; for example, zone 31 has the zero meridian on the left (Greenwich) and the 6 deg East meridian on the right, **Figure 11.6**.

For the polar regions North of 84 deg N and South of 80 deg S, a specialised projection system, called the Polar Stereographic grid, is used.

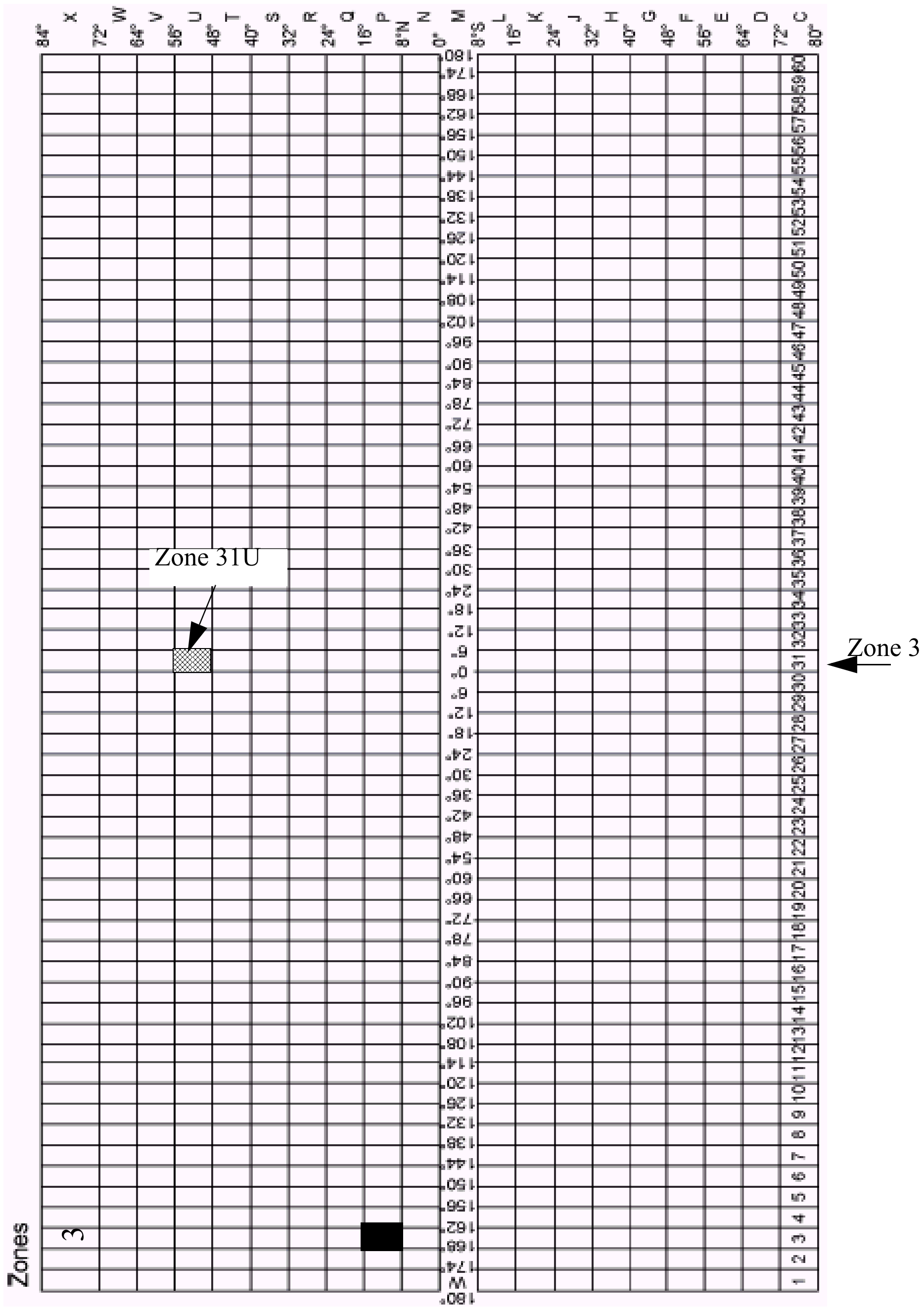

Figure 11.6 UTM grid zones with designation letters

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3.1 GRID ZONE DESIGNATION

The UTM grid is divided into areas formed by the intersection of 60 zones of longitude and 20 zones of latitude.Each zone is further subdivided into grid sectors, each grid covers 6 degrees of longitude and 8 degrees of latitude except the most northerly band which covers 12 degrees of latitude from 72 deg N to 84 deg N, see **Figure 11.6**. The longitude sectors numbers start at 180 deg meridian and proceeds easterly. The latitude sectors are lettered from C to X, omitting the letters I and 0, starting at 80 deg S and proceeding northwards to 84 deg N, **Figure 11.6**.The difference in latitude at the poles is because Antarctica is covered by the Polar Stereographic projection.

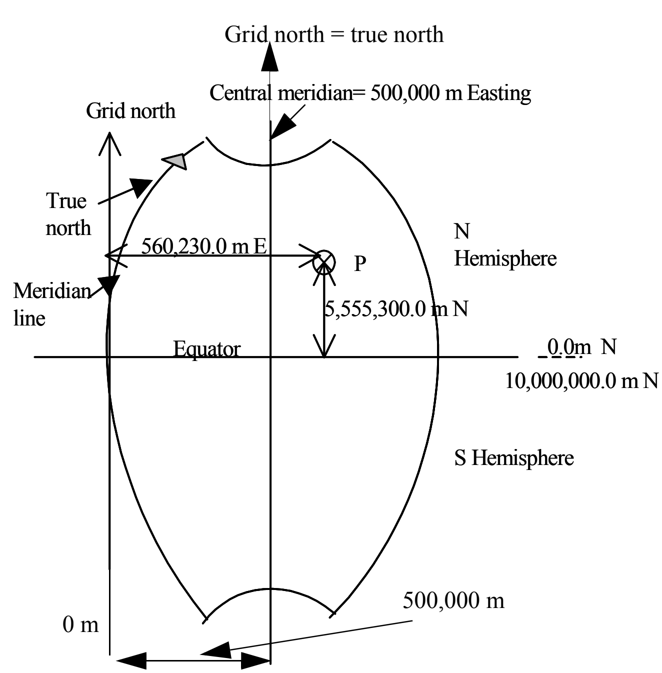
Therefore, each rectangle of the grid pattern is uniquely identified by a number from 0 to 60 and by a letter from C to X. Thus the solid rectangle in **Figure 11.6** lies between 168 deg and 162 deg and between 8 deg N and 16 deg N and is designated as 3P.

The areas east and west of the Greenwich central meridian are covered by zones 30 and 31. The Southern North Sea is designated by zone 31U, see **Figure 11.6**.

3.2 UTM COORDINATES

UTM coordinates are given as Northings and Eastings and are always positive numbers and measured in meters, **Figure 11.7**.The Northing coordinate is the distance from the equator and the easting coordinate is the distance from a line 500,000 m west of the central meridian for that sector,**Figure 11.7**.

Figure 11.7 UTM coordinates



Northings

The equator is chosen as the latitude of origin in all zones.For the northern hemisphere, false northing numbers are given to latitudes beginning with 0 metres at the equator and increasing towards the north. For the southern hemisphere, the equator is given arbitrary of northing value of 10,000,000 metres to avoid negative numbers.Northings in the southern hemisphere decrease towards the south the pole, **Figure 11.7**.

Eastings

The central meridian of each zone is given an arbitrary easting coordinate of 500,000 metres East to avoid negative numbers. False easting numbers are then given to each vertical grid line, decreasing westwards and increasing eastwards in each zone.

The coordinates of point P in **Figure 11.7** is: 560,230.0 m E and 5555,300 m N.

4.0 REFERENCE DIRECTIONS

There are three azimuth reference systems; True (Geographic North), Grid North and Magnetic North.

4.1 GEOGRAPHIC NORTH

In geographic coordinates directions are referred to true north, or a true azimuth. Geographic north points to the North Pole; this direction is indicated by the polar star. By convention, the geographic north is represented by a star on UTM grid and by the initials NG on a Lambert grid.

4.2 GRID NORTH

Grid north is an arbitrary direction and is always in the direction of the positive ordinate axis of the specific grid used for a particular survey, **Figure 11.5**.

The reader should note that the outer edges of each grid zone(**Figure 11.5**) are curved since they follow the meridian lines on the globe. Only at the central meridian, the grid north is equal to true north, **Figure 11.5**. Away from the central meridian, a convergence correction must be applied to correct grid north to true north or visa versa. The convergence is positive towards the west and negative towards the east.

Grid north is represented by the either the initials ‘GN’ (UTM) or initials ‘NL’ (Lambert).

4.3 MAGNETIC NORTH

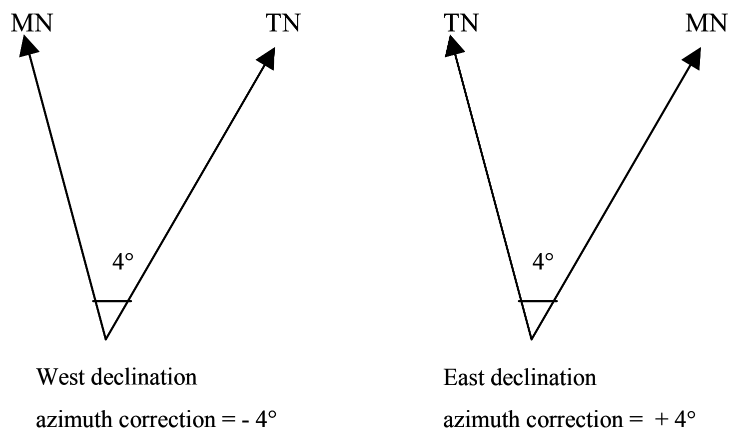
Magnetic north can be measured by a simple magnetic compass. Magnetic azimuths are not constant due to the movement of the north and south magnetic poles and hence magnetic measurements may be in error due to local magnetic field variations.

In oil wells, all surveys with ‘magnetic type’ tools are initially given an azimuth reading referenced to Magnetic North. However, the final calculated coordinates are always converted to either True North or Grid North.

By convention, the Magnetic North is represented by a semi arrow on the UTM grid and by the initials ‘MN’ on a Lambert grid.

4.4 MAGNETIC DECLINATION

Figure 11.8 Magnetic declination



Magnetic north and true north do not coincide. The divergence between true north and magnetic north is different for most points on the earth’s surface, and in addition to this the magnetic north pole changes its position very slightly each year.

The angle in degrees between true and magnetic north is called the declination angle. The declination angle is negative if magnetic north lies to the west of true north and is positive if the magnetic north lies to the east of true north, **Figure 11.8**.

In the North Sea, magnetic north lies to the west of true north and the angle varies between 6 1/2 deg and 2 deg according to location.

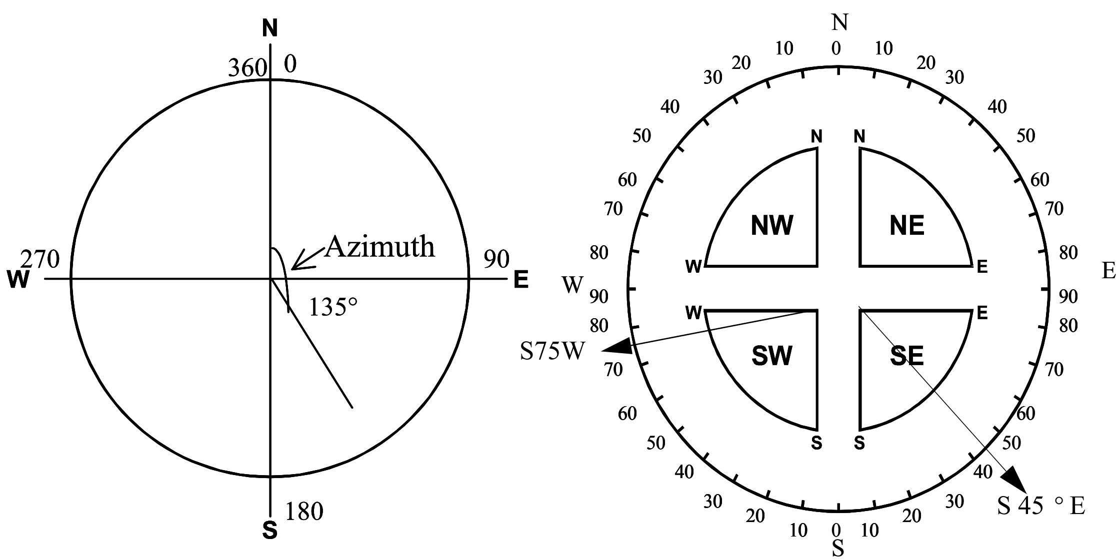
Since true north is a fixed reference point which does not change, magnetic surveys are corrected to true north. If referencing survey data to grid north is required, then a further grid correction must be applied.

Whenever a magnetic declination value is quoted, the date of calculation and model used should be quoted.A magnetic declination value should be calculated at the start of a well and the one value used for the duration of the well. A calculated declination figure is recognised as valid for 6 months.Where a well has been suspended and the original declination is no longer valid, a new magnetic declination will be calculated and applied to any further survey work performed on the well. The fact that more than one declination value has been used should be clearly documented.In a platform directional drilling project, the magnetic declination should be updated for each well drilled.

4.5 AZIMUTH

The azimuth of a wellbore at any point is defined as the direction of the wellbore on a horizontal plane measured clockwise form a north reference. Azimuths are usually expressed in angles from 0-360 °, measured from zero north,e.g. 135°, **Figure 11.9**.

Figure 11.9 Definition of azimuth



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Azimuths can also be expressed in a quadrant system from 0-90° measured from north in the northern quadrants and from south in the southern quadrants. The azimuth reading of 135° equates to S45° E in quadrant readings, see **Figure 11.9**.

Example 11.1:.Calculation of Azimuth

Determine the azimuth with respect to true north of the following wells:

Well	Observed azimuth with respect to magnetic north	Declination
1	N45^{o}E	3^o west
2	N45^{o}E	3^o east
3	S80^{o}W	5^o west

Solution

True north = magnetic north ± (declination)

Well 1

Quadrant Azimuth = N45^{o}E + (-3^o) =N42^{o}E

Azimuth with respect to true north = 42^o

(Note: Azimuth is the angle measured with respect to true north)

Well 2

Quadrant Azimuth = N45^{o}E+ (+3^o) =N 48^{o}E

Azimuth with respect to true north = N48^{o}E

Well 3

Quadrant Azimuth = S80^{o}W + (-5) = S75^{o}W

The above reading is in the third quadrant, see **Figure 11.9**, hence

Azimuth with respect to true north $= 180^o + 75^o = 255^o$

5.0 DIRECTIONAL WELL PLANNING

The planning of a directional well requires the following information:

1. Surface and Target Co-ordinates: UTM, Lambert or geographical.
2. Size of and shape target(s).
3. Local Reference Co-ordinates: For multi-well sites, these must include template, platform centre and slot location.
4. Required well inclination when entering the target horizon.
5. Prognosed Lithology: including formation types, TVD of formation tops, formation dipand direction.
6. Offset well bit and BHA data: Required for bit walk, building tendencies of BHA's.
7. Casing programme and drilling fluid types.
8. Details of all potential hole problems which may impact the directional well plan or surveying requirements.
9. A listing of definitive survey data of all near-by wells which may cause a collision risk. For offshore drilling, this listing should include all wells drilled from the same platform template or near-by platforms and all abandoned wells in the vicinity of the new wells.

5.1 BOTTOMHOLE TARGETS

The objective of an oil/gas well is to reach the target: pay zone. However, there may be other objectives in drilling a well in addition to intersecting the payzone, including:

- defining geological features such as faults or pinch-outs

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- defining reservoir structure
- intersecting another well as in relief well drilling

Irrespective of the number of objectives involved, the coordinates (in UTM, Lambert, or Geographic) must be established. For well planning purposes, it is more convenient and simpler to express the coordinates of the surface location and target in terms of local coordinates. The target given by the geologist is not a single point in space but a circle of say 150 ft in radius. The radius represents the tolerance of the target; the centre of the circle being the ideal wellbore position to the nearest foot which is virtually impossible to hit.

Rectangular coordinates of a target are usually given in feet/meters North/South and East/West of the local reference point. They can be easily derived by subtracting the grid coordinates of the surface location from those of the target.

The rectangular coordinates can be used to calculate the departure(horizontal displacement) between the surface location and the bottom hole target as follows:

$$\text{Departure} = ((\Delta E/W)^2 + (\Delta N/S^2))^{1/2} \qquad (11.2)$$

where

Δ denotes difference in coordinates between E/W or N/S

Polar coordinates can be derived from the rectangular coordinates. They are expressed as a distance (departure) and as a direction (either Quadrant or azimuth). Polar coordinates are derived from the rectangular coordinates as follows:

$$\text{Azimuth} = \tan^{-1} ((\Delta E/W \text{ Coordinates})/(\Delta N/S \text{ Coordinates})). \qquad (11.3)$$

Example 11.2: Departure &Azimuth

Given the following grid coordinates, determine the departure and azimuth of the target from the surface location

Grid Coordinates: Target	6,334,400.00 N (m)	200,600.00 E (m)
Grid Coordinates: Surface	6,335,000.00 N (m)	200,400.00 E (m)

Solution

	N/S	E/W
Grid Coordinates: Target	6,334,400.00 N	200,600.00 E
Grid Coordinates: Surface	6,335,000.00 N	200,400.00 E
Partial Coordinates	-600.00	200.00

(positive value denotes North or East, a negative value denotes South or West)

Azimuth = $\tan^{-1}(200/-600) = -18.4^o$

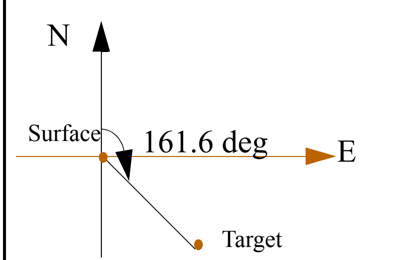
From rectangular coordinates, this angle falls in the second quadrant (south and east of surface location). Hence the azimuth of the target is:

$180 - 18.4 = 161.6^o$

Departure = $((\Delta E/W)^2 + (\Delta N/S^2))^{1/2}$

Departure = $(200^2 + (-600^2))^{1/2} = 632.5$ m

Figure 11.10



Hence in polar coordinates, the target is 632.5 m at an azimuth of 161.6^o (S18.4^{o}W).These coordinates are plotted in **Figure 11.10.**

If the N/S coordinates are equal to 0, then the polar coordinate equation will not work and the azimuth is then E or W depending on the sign of the E/W coordinate.

5.2 WELL COORDINATES

Well coordinates are usually referenced to either the wellhead for single well operations or to the central platform for offshore operations. The surface reference point is given 0.0 N and 0.0 E coordinates to eliminate the use of large numbers.

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When carrying out anti -collision analysis for a cluster of wells, it is important to refer the coordinates of the wells to a central reference point, either the surface TVD (ss) of the centre of the geological structure or the centre of the central platform.

5.3 Slots and Targets

In platform drilling, the platform may have one or two bays; each containing up to 12-15 slots. Each slot is usually assigned to a bottom hole target.

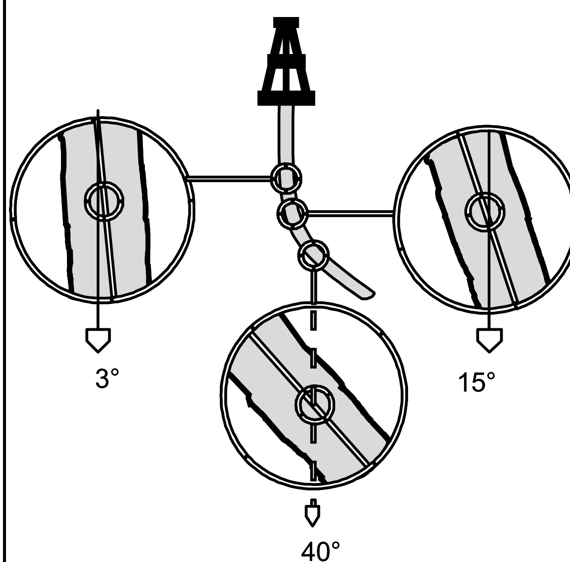
The inner slots are usually allocated to the central wells lying below the platform as these wells usually have smaller displacements from the surface. The outer slots are allocated to the outer targets which normally have larger displacements from the surface.

5.4 Well Profile: Definitions

5.4.1 Inclination Angle

The inclination angle of a well at any point is the angle the wellbore forms between its axis and the vertical, see **Figure 11.11**.

Figure 11.11 Inclination angle



5.4.2 Measured Depth

Measured depth (MD) is the distance measured along the well path from one reference point to the survey point, **Figure 11.12**. Measured depth is also known as Along Hole Depth and is measured with the pipe tally or by a wireline.

True vertical depth (TVD) is the vertical distance measured from a reference point to the survey point. TVD is usually referenced to the rotary table, but may also be referenced to mean sea level, **Figure 11.12**.

5.5 Kick-off Point

The kick off point is defined as the point below the surface location where the well is deflected from the vertical, **Figure 11.12**. The position of the kick off depends on several parameters including: geological considerations, geometry of well and proximity of other wells.

5.6 Build Up and Drop Off Rates

The maximum permissible build up /drop off rate is normally determined by one or more of the following:

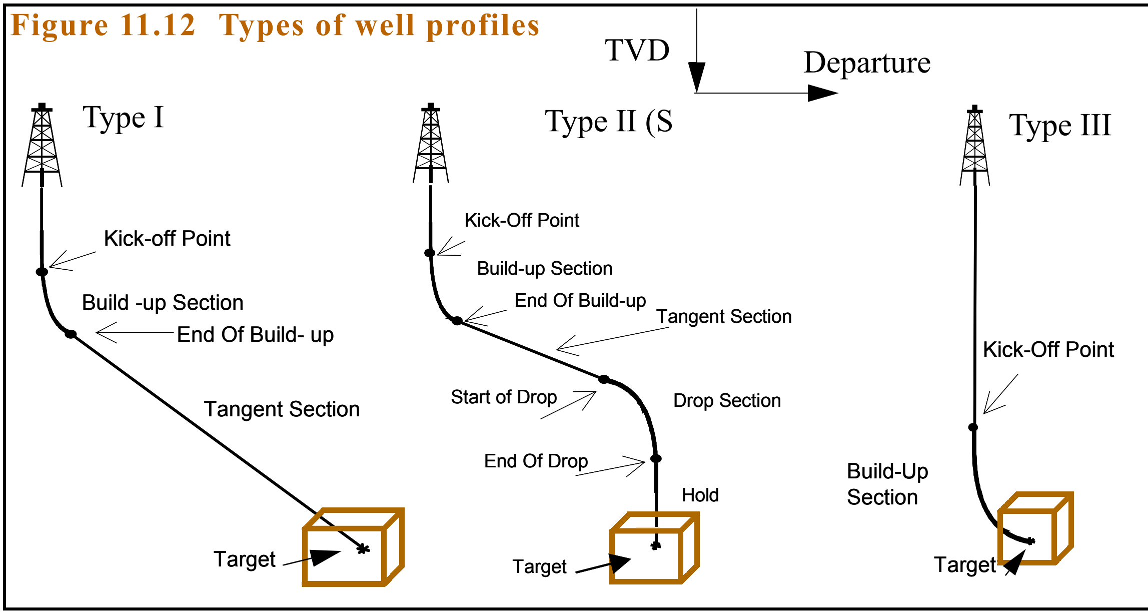
- The total depth of the well
- Maximum torque and drag limitations
- Mechanical limitations of the drill string or casing
- Mechanical limitations of logging tools and production strings.

The optimum build up and drop off rates in conventional directional wells are in the range of 1.5^0 to 3^0 per 100 ft, although much higher build up rates are used for horizontal and multilateral wells.

6.0 Types Of Well Profiles

If the position of the surface location is known and given the location of the target, its TVD and rectangular coordinates, it is possible to calculate the best well profile that fits the coordinates of the surface and the bottom hole target that fit this data.The well profile is plotted in the vertical plane as shown in **Figure 11.12**.This figure also describes the various sections of a directional well.

Figure 11.12 Types of well profiles



There are three basic well profiles which include the design of most directional wells:

1. Type one: Build and hold trajectory. This is made up of a kick off point, one build up section and a tangent section to target, see **Figure 11.12**.
2. Type two: S -Shape trajectory. This is made up of a vertical section, kick- off point, build-up section, tangent section, drop-off section and a hold section to target, see **Figure 11.12**.
3. Type three: Deep Kick off trajectory. This is made up of a vertical section, a deep kick off and a build up to target, see **Figure 11.12**.

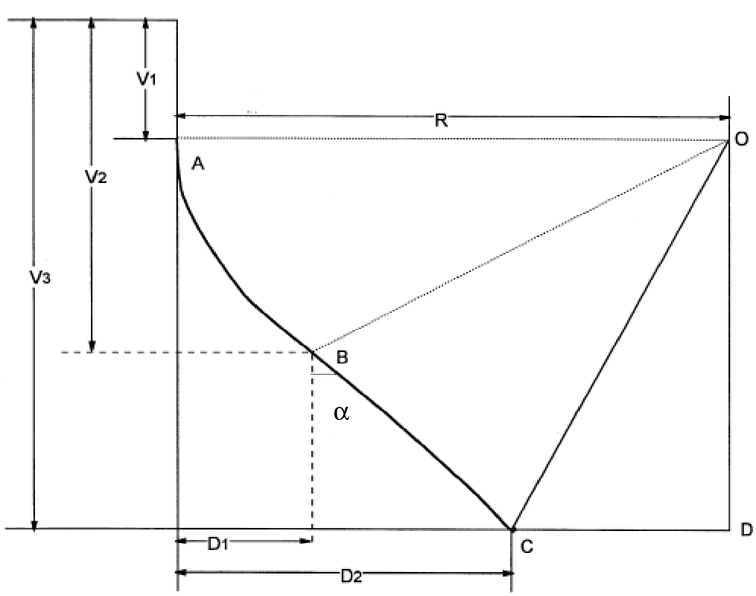
Another secondary type is horizontal wells. A horizontal well is a well which can have any one of the above profiles plus a horizontal section within the reservoir. The horizontal section is usually drilled at 90 degrees and therefore the extra maths involved is quite simple as we only need the measured length of the horizontal section to calculate the total well departure and total measured depth. The hole total TVD usually remains the same as the TVD of the well at the start of the horizontal section.However, if the horizontal section is not drilled at 90 degrees or there are dip variations within the reservoir, then the total hole TVD will be the sum of the TVD of the horizontal section and the TVD of the rest of the well.

6.1 BUILD-UP & HOLD DESIGN

To carry out the geometric planning for a Type I well, **Figure 11.13**, the following information is required:

- Surface Co-ordinates
- Target Co-ordinates
- TVD of target
- TVD to KOP
- Build-up rate

Figure 11.13 Type I profile



Using the detailed trigonometry shown in **Figure 11.13**, the maximum inclination angle α_{max} for type I trajectory can be calculated for two cases:

First Case $R > D_2$

The maximum inclination angle α_{max} for type I trajectory is given by:

$$\alpha_{max} = \arctan\left[\frac{(V_3 - V_1)}{(R - D_2)}\right] - \arccos\left(\left(\frac{R}{V_3 - V_1}\right) x \sin\left[\arctan\left(\frac{V_3 - V_1}{R - D_2}\right)\right]\right) \tag{11.4}$$

Second Case $R < D_2$

The maximum inclination angle α_{max} is given by:

$$:\alpha_{max} = 180 - \arctan\left(\frac{V_3 - V_1}{D_2 - R}\right) - \arccos\left(\left(\frac{R}{V_3 - V_1}\right) \sin\left[\arctan\left(\frac{V_3 - V_1}{D_2 - R}\right)\right]\right) \tag{11.5}$$

Build- up Section

1. Radius of curvature (R) of build-up section:

$$R = \frac{360 x 100}{2 x \pi x BUR} \tag{11.6}$$

where BUR = build-up rate, degrees/100ft

2. Measured length of build-up section:

$$MD_2 = \frac{\alpha_1 x 100}{BUR} \tag{11.7}$$

where α = maximum inclination angle at end of build up section

3. Vertical length of build-up section:

$$V_2 - V_1 = R_1 \text{ x } \sin\alpha \tag{11.8}$$

4. Horizontal displacement (departure) at end of build-up section:

$$D_1 = R_1 \text{ x } (1 - \cos\alpha) \tag{11.9}$$

Tangent Section

5. Measured length of tangent section:

$$MD_3 = \frac{V_3 - V_2}{\cos\alpha} \quad (11.10)$$

6. Vertical length of tangent section:

$$V_3 - V_2 = MD_3 \times \cos\alpha \quad (11.11)$$

7. Horizontal displacement at end of tangent section:

$$D_2 = D_1 + MD_3 \times \sin\alpha \quad (11.12)$$

6. Total measured depth for type I wells :

$$TMD = MD_1 + MD_2 + MD_3 \quad (11.13)$$

6.1.1 'S' Type Well Design

To carry out the geometric planning for a type II well the following information is required:

- Surface Co-ordinates
- Target Co-ordinates
- TVD of target
- TVD at end of drop-off (usually end of well)
- TVD to KOP
- Build-up rate
- drop-off rate
- Final angle of inclination through target

Because these wells have two curves, two radii need to be calculated and compared with the total departure D_3. These quantities are then used to calculate the maximum possible inclination angle at end of build up curve.The reader can use the detailed geometries given in **Figure 11.14** and **Figure 11.15** to calculate the maximum inclination angles for S- Type wells.

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Figure 11.14 S-type well: $D_3 > (R_1 + R_2)$

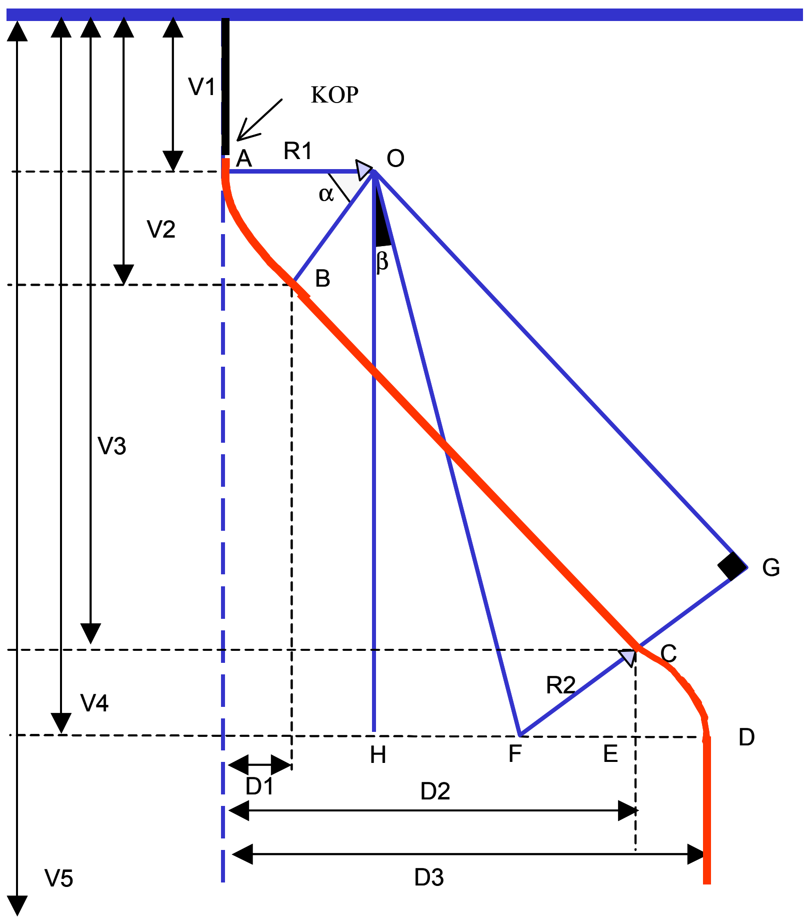
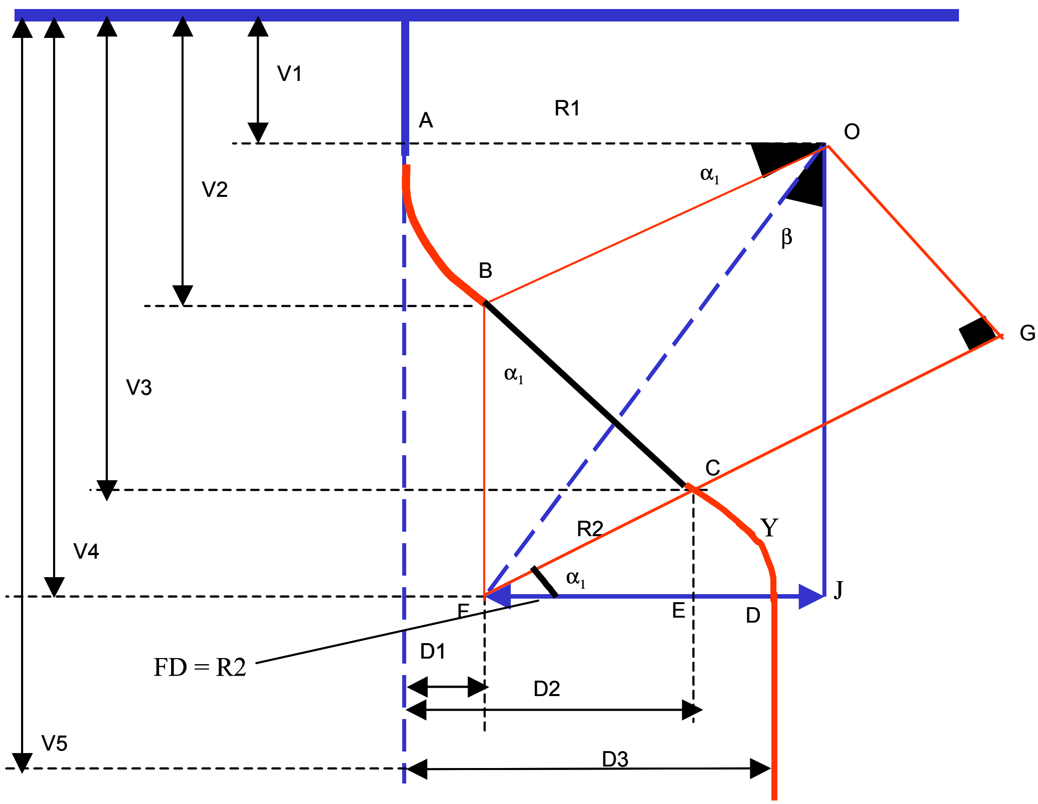


Figure 11.15 S-Type well: $D_{3<}(R_1 + R_2)$



Design Procedure for S Type Wells

1. Radius of curvature (R_1) of build-up section:

$$R_1 = \frac{360 \text{x} 100}{2 \text{x} \pi \text{x} BUR} \quad (11.14)$$

where BUR = build-up rate, degrees/100ft

2. Radius of curvature of drop-off section:

$$R_2 = \frac{360 \text{x} 100}{2 \text{x} \pi \text{x} DOR} \quad (11.15)$$

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where DOR = Drop off rate, degrees/100ft

The total departure, $\mathbf{D_3}$ (or horizontal displacement) of the target is calculated using **Equation (11.2)**.

3. First Case $D_3 > R_1 + R_2$, Figure 11.14

If the S well returns to vertical at end of drop off section at point D , **Figure 11.14**, then the maximum inclination angle is given by:

$$\alpha_{max} = 180 - \arctan\left(\frac{V_4 - V_1}{D_3 - (R_1 + R_2)}\right) - \arccos\left(\left(\frac{R_1 + R_2}{V_4 - V_1}\right) x \sin\left(\arctan\left(\frac{V_4 - V_1}{(R_1 + R_2) - D_3}\right)\right)\right) \quad (11.16)$$

4. Second Case $D_3 < R_1 + R_2$, Figure 11.16

The maximum allowable inclination angle α_{max} is determined by:

$$\alpha_{max} = \arctan\left[\frac{(V_4 - V_1)}{(R_1 + R_2) - D_3}\right] - \arccos\left(\left(\frac{R_1 + R_2}{V_4 - V_1}\right) x \sin\left(\arctan\left(\frac{V_4 - V_1}{(R_1 + R_2) - D_3}\right)\right)\right) \quad (11.17)$$

The above equation is only valid if the well returns to vertical at point D, **Figure 11.16**. If the well does not return to vertical then the following further calculations need to be made at the end of the drop off section using **Figure 11.17**.

Figure 11.16 S Well that returns to vertical

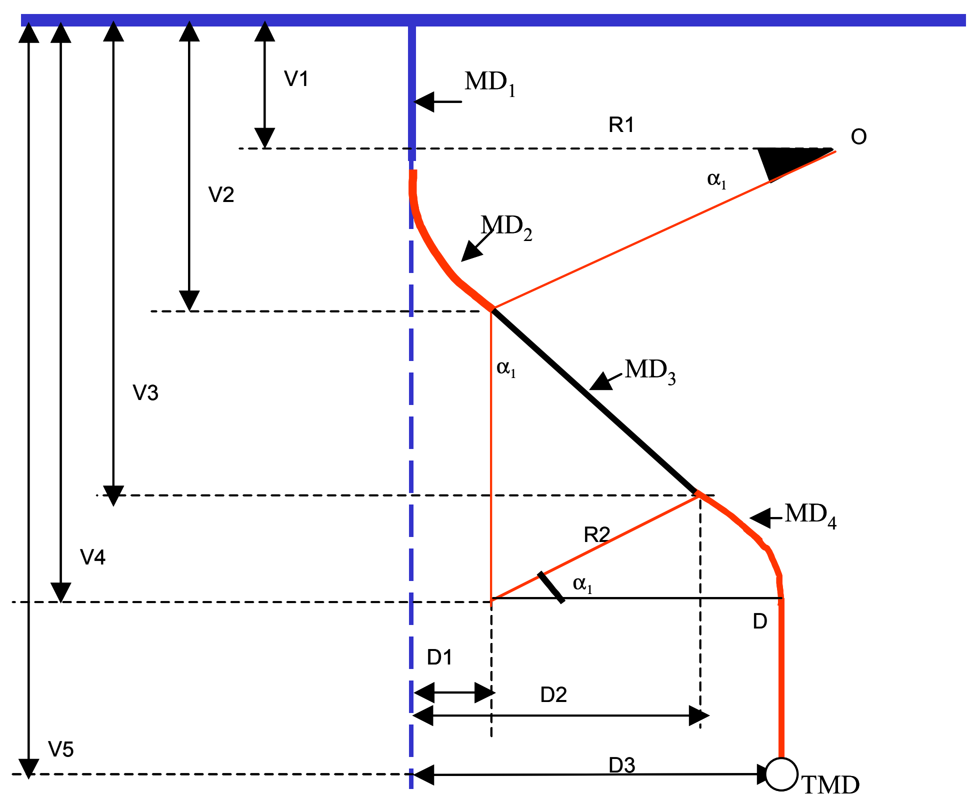

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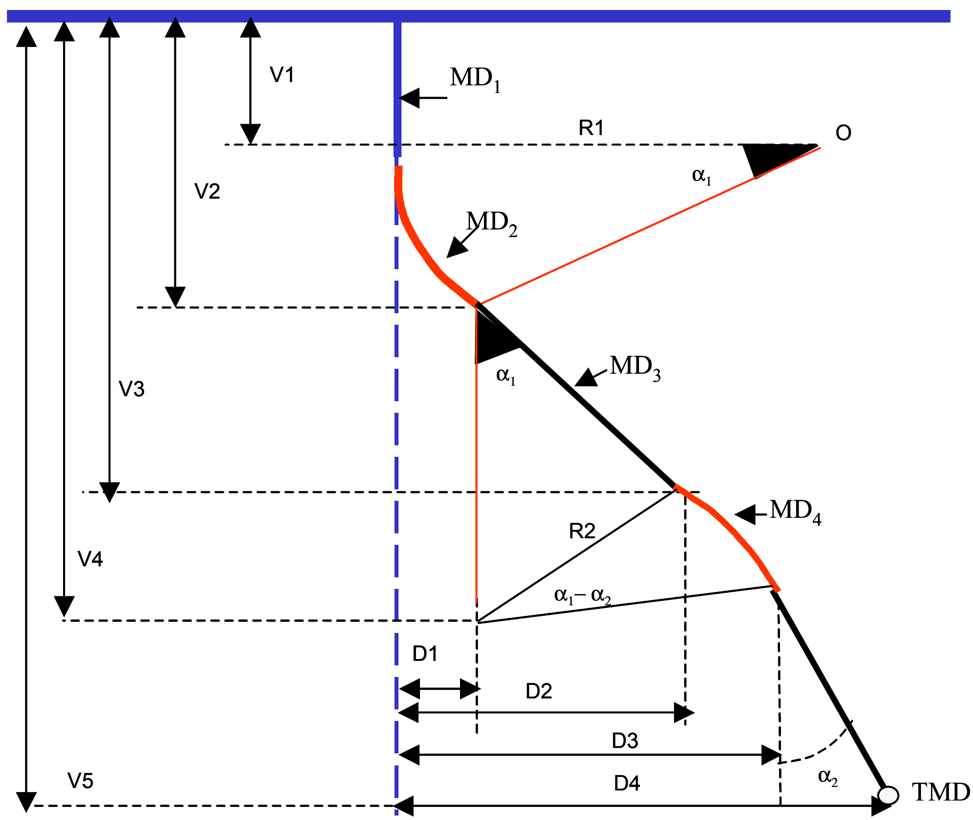
Figure 11.17 S Well that does not return to vertical



5. For S well that do not return to vertical, first calculate D_3 , Figure 11.17

$$D_3 = D_4 - (V_5 - V_4)\tan\alpha_2 \tag{11.18}$$

If $D_3 < R_1 + R_2 \cos\alpha_2$

Calculate:

$$Y = R_1 + R_2 \cos\alpha_2 + (V_5 - V_4)\tan\alpha_2 - D_4 \tag{11.19}$$

$$a = \operatorname{atan}\left(\frac{Y}{V_4 + R\sin\beta - R_1}\right) \tag{11.20}$$

$$b = \operatorname{asin}\left(\frac{(R_1 + R_2)\sin a}{Y}\right) \tag{11.21}$$

$$\alpha_1 = b - a \tag{11.22}$$

If $D_3 > R_1 + R_2 \cos\alpha_2$

Calculate:

$$Y = H_4 - R_1 - R_2 \cos\alpha_2 - (V_5 - V_4)\tan\alpha_2 - D_4 \tag{11.23}$$

$$a = \operatorname{atan}\left(\frac{Y}{V_4 + R\sin\beta - R_1}\right) \tag{11.24}$$

$$b = \operatorname{asin}\left(\frac{(R_1 + R_2)\sin a}{Y}\right) \tag{11.25}$$

$$\alpha_1 = b + a \tag{11.26}$$

Once angle α_1 is calcuated , the well geometry can be established as follows:

6. Build- up Section

Measured length of build-up section:

$$MD_2 = \frac{\alpha_1 x 100}{BUR} \tag{11.27}$$

where α_1 = maximum inclination angle at end of build up section

Vertical depth at end of build-up section:

$$V_2 = V_1 + R_1 \text{ x } \sin\alpha_1 \tag{11.28}$$

Horizontal displacement (departure) at end of build-up section:

$$D_1 = R_1 \text{ x } (1 - \cos\alpha_1) \tag{11.29}$$

7. Tangent Section

Vertical depth at end of tangent section :

For wells that return to vertical at end of drop-off section:

$$V_3 = V_4 - R_2 \sin \alpha_1 \qquad (11.30)$$

For S-wells wells that partially drop angle and maintain a certain inclination to target (**Figure 11.17**) , V_3 is give by :

$$V_3 = V_4 - R_2 (\sin \alpha_1 - \sin \alpha_2) \qquad (11.31)$$

Measured length of tangent section:

$$MD_3 = \frac{V_3 - V_2}{\cos \alpha_1} \qquad (11.32)$$

Horizontal displacement at end of tangent section:

$$D_2 = D_1 + (V_3 - V_2) \times \tan \alpha_1 \qquad (11.33)$$

8. Drop-Off Section

Measured length of drop-off section for S wells that return to vertical:

$$MD_4 = \frac{\alpha_2 x 100}{DOR} \qquad (11.34)$$

where α_2 = maximum inclination angle at end of drop off section

Total measured depth for S wells that return to vertical:

$$TMD = MD_1 + MD_2 + MD_3 + MD_4 + (V_5 - V_4) \qquad (11.35)$$

Measured depth at at end of a partial drop section where the angle of inclination is maintained to target (**Figure 11.17**) is given by:

$$MD_4 = \frac{(\alpha_1 - \alpha_2) x 100}{DOR} \qquad (11.36)$$

Total measured depth at at end of an S well where the angle of inclination is maintained to target is given by:

$$TMD = MD_1 + MD_2 + MD_3 + \frac{(\alpha_1 - \alpha_2) x 100}{DOR} + \frac{(V_5 - V_4)}{\cos \alpha_2} \qquad (11.37)$$

6.1.2 TYPE III TRAJECTORY

This type of trajectory is used for salt dome drilling and for planning appraisal wells to assess the extent of the discovered reservoir.

The following data is required:

- Surface Coordinates
- Target Coordinates
- Then one other parameter from:
    - Maximum inclination angle
    - TVD to KOP
    - Build-up rate

Final inclination angle α is give by:

$$\alpha = 2\,\mathrm{atan}\left\{\frac{D}{TVD - V_1}\right\} \tag{11.38}$$

$$R = \frac{TVD - V_1}{\sin\alpha} \tag{11.39}$$

$$BUR = \frac{18,000}{\pi R} \tag{11.40}$$

where

R = Radius of curvature

D = total required horizontal displacement

TVD = Target TVD

Example 11.3: Design of an S-type profile

Calculate the measured lengths, vertical depths and horizontal displacements of each section of the following S-shaped well designed to avoid a salt dome, using the following data and **Figure 11.16**.

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Kick-off depth = 1,200 ft

Build-up rate = 2.0 degrees/100 ft

Drop-off rate = 3.5 degrees/100 ft

TVD at end of drop-off section (V_4) = 8157 ft

Total horizontal displacement (D_3) = 2136 ft

Final inclination angle in reservoir = zero degrees

Solution, see Figure 11.16

1. Radius of curvature

Build-up section

$$R_1 = \frac{360 x 100}{2 x \pi x BUR} = \frac{360 x 100}{2 x \pi x 2} = 2,865 \text{ ft}$$

Drop-off section

$$R_2 = \frac{360 x 100}{2 x \pi x DOR} = \frac{360 x 100}{2 x \pi x 3.5} = 1,637 \text{ ft}$$

$R_1 + R_2 = 2,865 + 1,637 = 4,502$ ft

$D_3 = 2,136$ ft (given)

Since $(R_1 + R_2)$ is greater than D_3, **Equation (11.17)** must be used for determining the maximum inclination angle α_{max}:

$$\alpha_{max} = \arctan\left[\frac{(V_4 - V_1)}{(R_1 + R_2) - D_3}\right] - \arccos\left(\left(\frac{R_1 + R_2}{V_4 - V_1}\right) x \sin\left(\arctan\left(\frac{V_4 - V_1}{(R_1 + R_2) - D_3}\right)\right)\right)$$

$V_4 = 8157$ ft (given)

$V_1 = 1200$ ft (given)

$$\alpha_{max} = \arctan\left[\frac{8157-1200}{4502-2136}\right] - \arccos\left(\left(\frac{4502}{8157-1200}\right) x \sin\left(\arctan\left(\frac{8157-1200}{4502-2136}\right)\right)\right) \quad = 19 \text{ degrees}$$

2. Kick-off point

$V_1 = 1{,}200$ ft

$MD_1 = V_1 = 1{,}200$ ft

3. Build-up section

$$MD_2 = \frac{\alpha_1 x 100}{BUR} = \frac{19 x 100}{2} = 950 \text{ ft}$$

$V_2 = V_1 + R_1$ x $\sin \alpha_1 = 1{,}200 + 2{,}865$ x $\sin 19 \quad = 2{,}133$ ft

$D_1 = R_1$ x $(1 - \cos \alpha_1) = 2{,}865$ x $(1 - \cos 19) \quad = 156$ ft

4. Tangent section (see **Figure 11.16**)

$V_3 = V_4 - R_2 \sin \alpha_1$

$= 8157 - 1637 \sin 19 = 7624$ ft

$$MD_3 = \frac{V_3 - V_2}{\cos \alpha_2} = \frac{7624-2133}{\cos 19} = 5807 \text{ ft}$$

$D_2 = D_1 + (V_3 - V_2)$ x $\tan \alpha_1$

$= 156 + (7624 - 2133) \tan 19 = 2047$ ft

5. Drop-off section

$$MD_4 = \frac{\alpha_1 x 100}{DOR} = \frac{19 x 100}{3.5} = 543 \text{ ft}$$

$TMD = MD_1 + MD_2 + MD_3 + MD_4 + (V_5 - V_4)$

For this well, $V_5 = V_4$

TMD = 1200 + 950+ 5807 + 543 + (0) = 8500 ft

D_3 = 2,136 ft (given)= total hole displacement

7.0 Mud Motors

There are two types of mud motors, **Figure 11.18**:

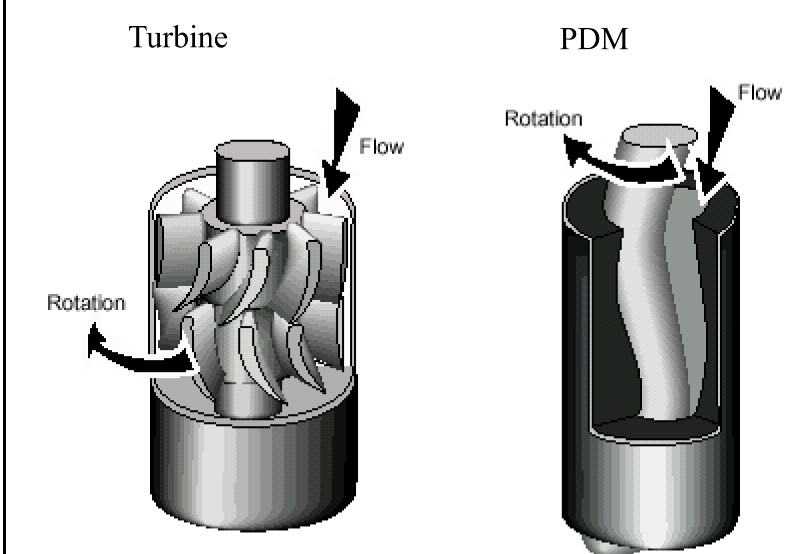
- Turbines
- Positive displacement motors (PDM)

The turbine motor consists of a multistage blade- type rotor and stator sections, a thrust bearing section and a drive shaft. The number of rotor/stator sections can vary from 25 to 50.

The rotor blades are connected to the drive shaft and are rotated by mud pumped under high pressure. The stator deflects the mud onto the rotor blades. Rotation of the rotor is transmitted to the drive shaft and drillbit.

Turbines were widely used in the past, however, recent improvements in PDM design have relegated the use the turbines to special drilling applications.

Figure 11.18 Operation principles of turbine and PDM

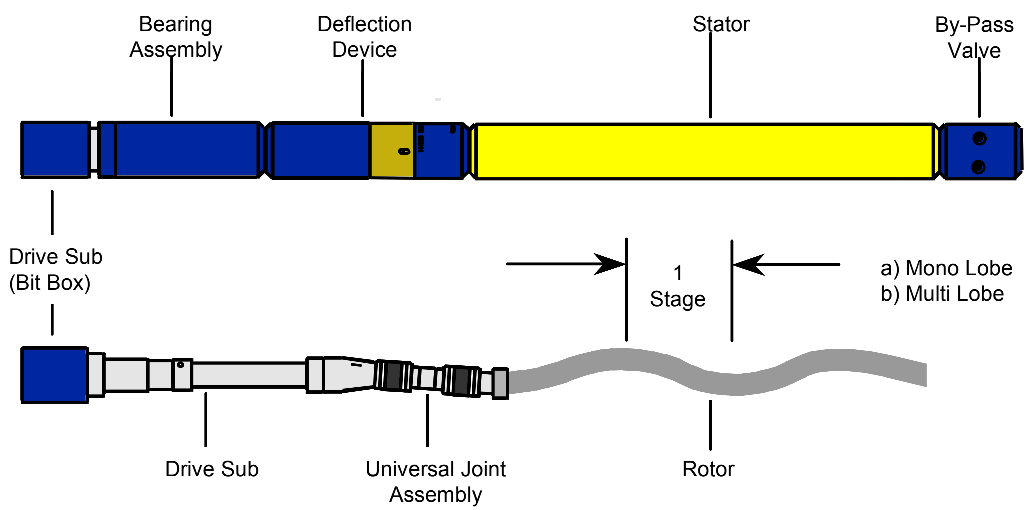


7.1 POSITIVE DISPLACEMENT MOTORS (PDM)

A positive displacement motor (PDM) consists of (Figure 11.19):

- Power section (rotor and stator)
- By-pass valve
- Universal joint
- Bearing assembly

Figure 11.19 Components of a positive displacement motor, courtesy of Baker Hughes Inteq



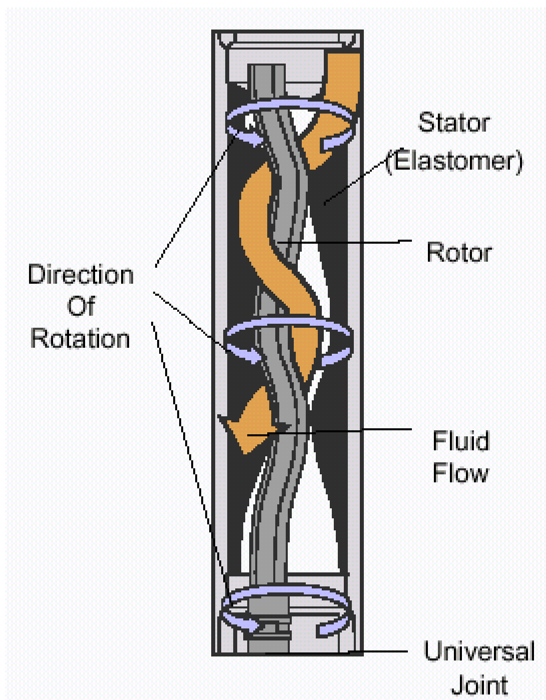
Power Section

The PDM consists of a helical steel rotor fitted inside a spirally -shaped elastomer moulded stator. Mud flowing under pressure fills the cavities between the dissimilar shapes of the rotor and stator and under the pressure of mud, the rotor is displaced and begins to rotate, **Figure 11.20**.

The rotor actually moves in an elliptical shape. This eccentric movement is converted to true circular motion by a universal joint assembly, **Figure 11.19**.

The magnitude of rotation produced is proportional to the volume of mud pumped through the motor.The torque generated by the PDM is proportional to the pressure drop across the motor and is also a function of WOB. An increase in WOB will create more torque and will in turn increase the differential pressure required across the power module, eventually stalling the motor due to lack of pressure. Hence, an increase in WOB will cause an increase in pumping pressure due to the increased differential pressure across the power section. This fact must be taken into account in drilling operations where only a limited pumping pressure is available.

Figure 11.20 Power section of a PDM, courtesy of Baker Inteq

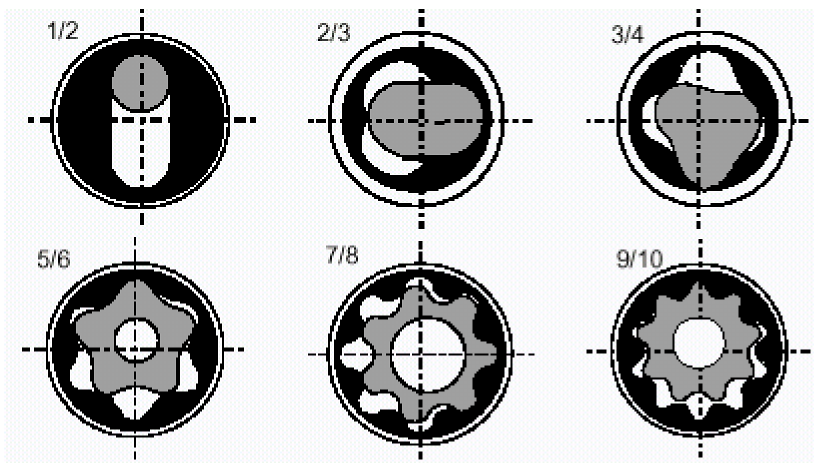


Lobes

The available rotation and torque from a PDM depend on the pitch angle and number of lobes in the stator and rotor, **Figure 11.21**. The stator always has one lobe more than the rotor.The rotor/stator configurations (or lobe ratio) currently in use are: 1/2, 3/4, 5/6, 7/8 or 9/10. Configuration 1/2 gives the highest speed and is only suitable for PDC and natural diamond bits.The greater the number of lobes, the higher the motor torque and the lower the output RPM.

Common mud motors from Baker Hughes Inteq are the Mach 1 which is a *5/6 lobe ratio* motor and is compatible with compatible with tricone bits. The Mach 2 is a 1/2 lobe ratio motor and is used with PDC or diamond bits when high rotation is required.

Figure 11.21 Lobes configuration, courtesy of Baker Inteq



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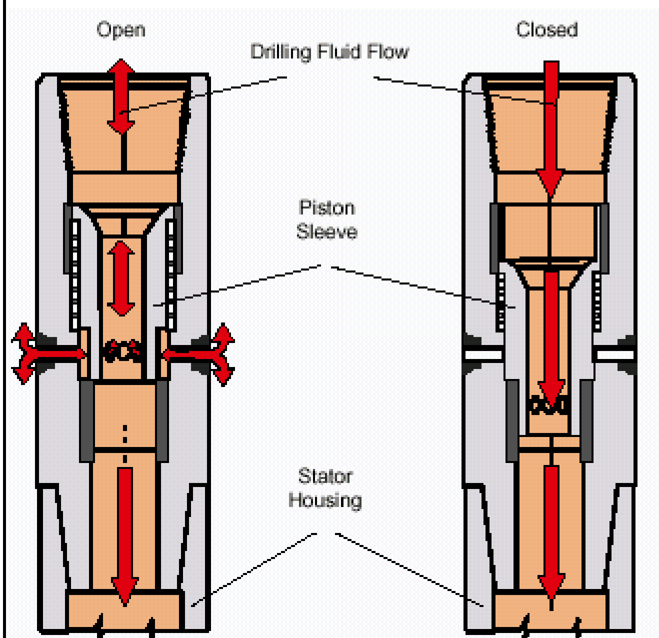
By-Pass valve

This valve (**Figure 11.22**) allows the drilling fluid to by-pass the mud motor allowing the drillstring to fill during tripping in and drain when making a connection or pulling out of hole.The valve operates by a spring which holds a piston in the upper position. In this position, ports in the by-pass valve are open allowing mud to flow in or out of the drillstring. At 30% of recommended flow rate, the piston is forced down, closing the ports and directing flow through the mud motor.

Figure 11.22 By-Pass valve, courtesy of Baker



Universal Joint: A Connecting Rod Assembly (**Figure 11.19**) is attached to the lower end of the rotor. It transmits the torque and rotational speed from the rotor to the drive shaft and bit. Universal joints convert the eccentric motion of the rotor into concentric motion at the drive shaft. These are now being replaced by titanium alloy flex shafts.

Bearing and Drive Shaft Assembly

The drive shaft is a rigidly-constructed hollow steel component. It is supported within the bearing housing by radial and axial thrust bearings (**Figure 11.19**). The bearing assembly transmits drilling thrust and rotational power to the drill bit. Most of the mud flows straight through the centre of the drive shaft to the bit.

8.0 DEFLECTION TOOLS

The wellbore can be deflected from its current position using one of the following tools:

- whipstocks

- jetting action
- downhole motors and bent sub
- steerable positive displacement motor
- rotary steerable systems

8.1 WHIPSTOCKS

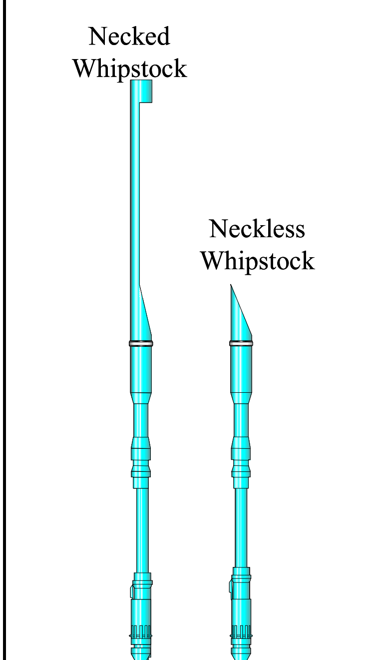
The whipstock is widely used as a deflecting medium for drilling multilateral wells.It consists of a long inverted steel wedge (shute) which is concave on one side to hold and guide a deflecting drilling or milling assembly. It is also provided with a chisel point at the bottom to prevent the tool from turning, and a heavy collar at the top to withdraw the tool from the hole, **Figure 11.23**.

Today, whipstocks are mainly used to mill casing windows for sidetracking existing wells.

There are two main types of Whipstocks:

- The standard removable Whipstock which is used to kick off wells and for sidetracking. The Whipstock is used with a drilling assembly consisting of a bit, a spiral stabilizer, and an orientation sub, rigidly attached to the Whipstock by means of a shear pin.To deflect the well, the whipstock and kick off assembly is run in hole and oriented in the required direction. Weight is then applied to shear the pin and allow the drilling bit to slide down the shute and drill in the set direction.
- The Permanent Casing Whipstock is designed to remain permanently in the well.
- Thru tubing whipstock

Figure 11.23 Whipstock



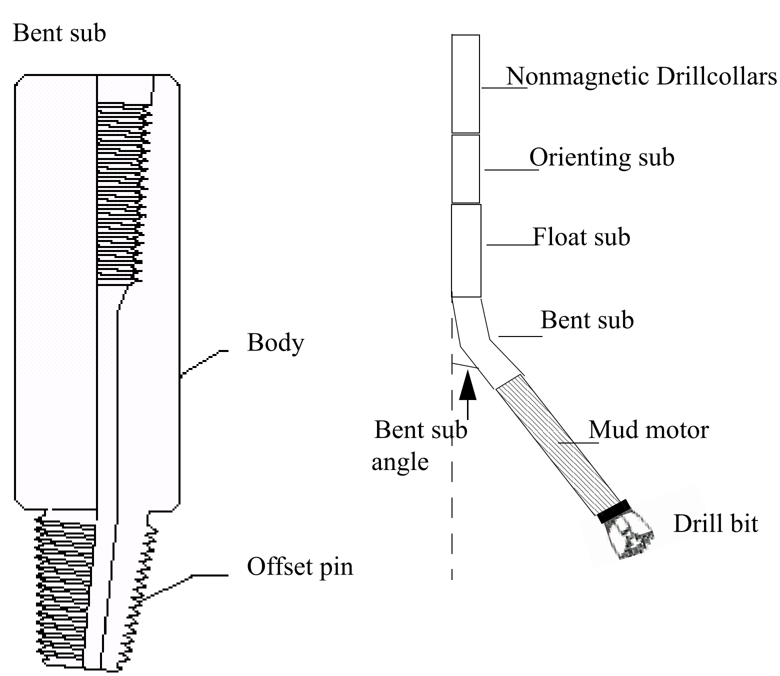
8.2 JETTING

This is an old technique which is rarely used today. It relies on hydraulics to deviate the wellbore and is therefore only effective in soft formations. A special jet bit, is often used, but it is possible to use a normal soft formation bit, using one very large nozzle and 2 small jet nozzles. The large jet nozzle is the "toolface".The fluid coming out from the large nozzle causes the maximum formation erosion and allows the well to be, effectively, deflected in the direction of the jet coming out of the big nozzle. Jetting usually causes high dogleg severities.

8.3 DOWNHOLE MOTORS WITH BENT SUBS

A downhole motor with a bent sub, **Figure 11.24**, was a common method for deflecting wells until replaced by steerable motors.The bent sub is run directly above the motor and its pin is offset at an angle of 1-3 degrees.The bent sub has a scribe line cut on its outside body (casing) above the pin offset. This scribe line is used to orient the BHA in the required direction. The orienting sub (**Figure 11.24**) allows single shot surveys to be taken to confirm the orientation of the BHA.

Figure 11.24 PDM BHA with bent sub



Deflection of the wellbore occurs when drilling is carried out with no surface rotation to the drillstring. The drillbit is forced to follow the curve of the bent sub. The degree of curvature depends largely on the bent sub offset angle and the OD of the motor. When the required angles (inclination and/or azimuth) are obtained, this BHA is tripped out and replaced with a rotary assembly.

8.4 STEERABLE POSITIVE DISPLACEMENT MOTORS

The motor is designed with an in-built bent housing below the motor section; usually the connecting rod housing. The bent housing angle is usually 0.25-1.5 degrees and is designed to tilt the axis of the bit relative to the axis of the hole.The reader should note that having only a small bit offset will create a considerable bit side force (deflecting force).

A steerable motor can be used in oriented mode (sliding) or rotary mode.In the sliding mode, the drillstring remains stationary (rotary table or top-drive is locked) while the drillbit is rotated by the motor. The course of the well is only changed when drilling in sliding mode as the drillbit will now follow the curvature of the motor bent housing. In rotary mode, the steerable motor becomes "locked" with respect to trajectory and the hole direction and inclination are maintained while drilling. The use of steerable motors with the correct drillbit and BHA reduces the number of round trips required to produce the desired inclination/azimuth.

Single shot surveys are not usually accurate in orienting steerable motors due to the high reactive torque produced by the motor. For this reason, most steerable motor assemblies are run with an MWD (measurement while drilling) tool to provide real time survey and orientation data. A steerable motor with an MWD tool is described as Steerable System.

Steerable motors are usually used to drill complete sections of a well, from current casing shoe to next casing point.

Double tilted U-joint Housing: Nortrak DTU (from Baker Hughes Inteq) is a PDM with double tilted U-joint housing.

The U-joint housing angles first in one direction, then doubles back in the opposite direction. The DTU angle is calculated as the resultant angle computed from the opposite two angles. The principle of the DTU is to obtain a high build capability while keeping the bit offset low to facilitate rotary drilling.

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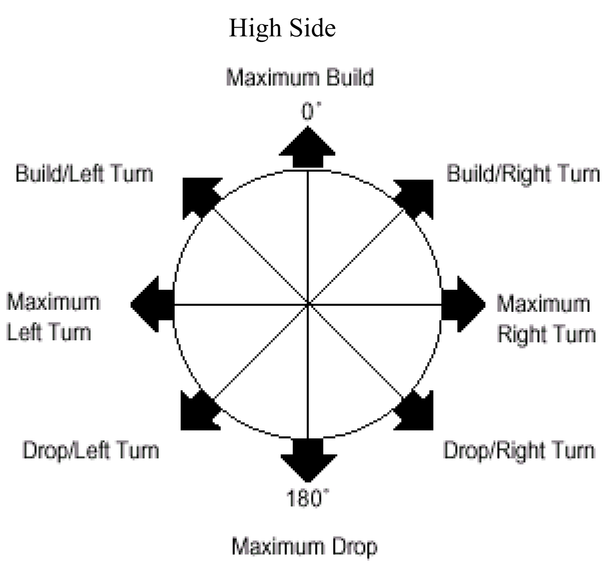
9.0 ORIENTATION OF DEFLECTION TOOLS

The toolface orientation of a deflection tool (bent sub or steerable motor) is usually marked on the outer tool casing with a scribe line. For deflection purposes the scribe line of the deflecting tool is oriented in a particular direction to produce the desired well course.

The tool face orientation is usually expressed as a high side tool face or gravity tool face. High side tool face is the tool face orientation measured from the high side of the well in a plane perpendicular to the axis of the hole. If tool face is measured as a magnetic or gyro toolface then the high side tool face can be obtained by subtracting the magnetic or gyro toolface from hole azimuth. The toolface is set relative to north (magnetic or gyro) for wells with low inclinations (5 degrees) as in these wells the effect of gravity is minimal and the wells therefore do not have a well defined high or low side

As a rule of thumb, setting the bent sub on the high side (i.e. in the same current hole direction) will build the inclination angle and keep the hole direction constant, **Figure 11.25**. However, setting the bent sub on the low side (i.e. 180 degrees from current hole direction) will give the maximum drop rate while maintaining the current hole direction. In between we obtain a combination of build and right or let turn or drop and right or left turn, **Figure 11.25**.

Figure 11.25 Tool face orientation



The Ragland vector diagram can be used to calculate the tool face orientation required to attain a given inclination and hole direction.The use of this diagram is best illustrated by an example.

Example 11.4: Toolface orientation

Using the Ragland Diagram, determine the required orientation of the deflection tool to change the hole direction from N30^{o}E to N40^{o}E, assuming that the current hole deviation is 7^o and maximum dog-leg severity is 2^o/100 ft. Also determine the new hole inclination.

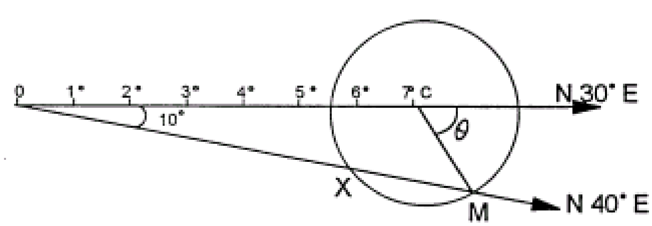
Solution (Figure 11.26)

(1) Draw a horizontal line of 7 units in length representing the current hole inclination.The direction of this line is N30^{o}E. Also, mark the ends of this line as 0 at zero, and C at 7 units.

(2) Plot a circle of 2 units in radius with its centre at C. The 2 units represent the maximum dog-leg severity.

(3) From point 0 draw a line 10^o to 0C. The 10^o represents the difference in azimuth between the present hole position and final hole position, i.e. N40^{o}E - N30^{o}E = 10^o. Mark this line as OM. Line OM represents the deviation and direction of the final hole.

Figure 11.26 Example 11.4



Ragland vector diagram θ = orientation of deflection tool with respect to hole bottom; by measurement

$\theta = 47°$

(4) Angle θ between line OC and radius CM gives the required orientation of the tool. From **Figure 11.26**, the value of angle θ is 47^o to the right of the present hole direction of N30^{o}E. Hence, the required setting of the deflection tool is N(47 + 30)^{o}E, or N77^{o}E.

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(5) The new hole inclination is represented by the length of line OM. From **Figure 11.26**, the new hole inclination is 8.5^o at N40^{o}E.

9.1 Reactive torque

Mud motors suffers from reactive torques produced by the drilling mud pushing on the stator of the motor. As the stator is e locked to the body of the motor, the resulting force acts to twist the motor and the BHA to the left or anti-clockwise causing a change in hole direction. High torque motors produce high reactive torque.

To compensate for the effects of reactive torque, the amount of left hand turn produced by the motor has to be first estimated before orienting the bent sub. The tool face is then set a number of degrees round to the right of the desired tool face. During drilling, the reactive torque will bring the hole direction back to the desired direction.

9.2 Nudging

When drilling a cluster of wells from a platform template, nudging is used to spread out conductors and surface casings to minimise the chance of collision when the wells are drilled. Nudging involves building a small angle in the surface hole or using a conductor with an angled shoe. The angle is built in a chosen direction to ensure the wells are kept as far apart as practical.

9.3 Directional Effects of Bit Type

9.3.1 Rock Bits

Tricone bits usually cause a right hand walk when using rotary drilling assemblies.Soft drillbits with grater cone offset create a greater degree of right hand walk than hard drill bits with little or zero offset. The right hand walk generated is due to the gouging and scraping actions produced by the soft tricone bits. Tricone bits are preferred for kicking off a directional well from vertical.

9.3.2 PDC Bits

Field experience shows that little walk is produced with most PDC bits used with rotary drilling assemblies.However, PDC bits used with angle drop assemblies produce a lower rate of drop than when using a rock bit. PDC bits with a flatter profile were found to work better for dropping angles using rotary assemblies.

PDC bits hold both angle and direction when used with packed hole assemblies.

10.0 Bottom Hole Assemblies (BHA)

The bottom hole assembly refers to the drillcollars, HWDP, stabilisers and other accessories used in the drillstring. All wells whether vertical or deviated require careful design of the bottom hole assembly (BHA) to control the direction of the well in order to achieve the target objectives. **Stabilisers** and drillcollars are the main components used to control hole inclination.

There are three ways in which the BHA may be used for directional control:

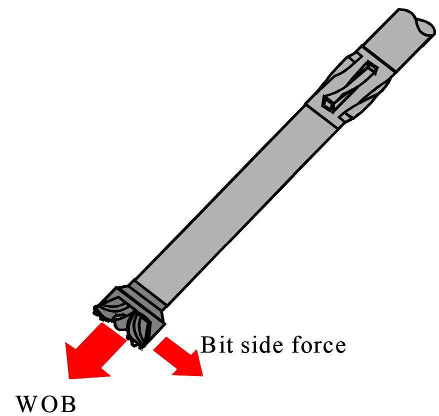
1. Pendulum Principle
2. Fulcrum principle
3. Packed hole stabilisation principle

1. Pendulum Principle

The pendulum technique (**Figure 11.27**) is used to drop angle especially on high angle wells where it is usually very easy to drop angle.The pendulum technique relies on the principle that the force of gravity can be used to deflect the hole back to vertical.The force of gravity is related to the length of drillcollars between the drill bit and the first point of tangency between the drillcollars and hole. This length is called the active length of drillcollars and can be resolved into two forces: one perpendicular to the axis of the wellbore and is called the side force and one acts along the hole.

Increasing the active length of drillcollars causes the side force to increase more rapidly then the along hole component. The side force is the force that brings about the deflection of the hole back to the vertical. Some pendulum assemblies may also use an under gauge near-bit stabilizer to moderate the drop rate.

Figure 11.27 Pendulum principle

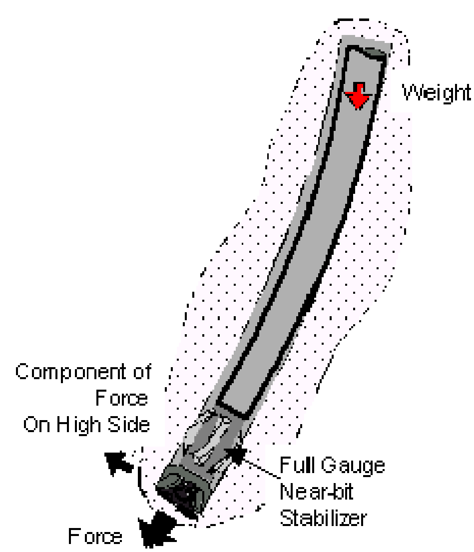


High WOB's used with a pendulum assembly may bend the BHA and cause the hole angle to build instead of drop. Also pendulum assemblies have a tendency to walk to the right depending on the type of bit used and since they are flexible they will follow the natural walk of the drill bit.

2. Fulcrum Principle

This is used to build angle (or increase hole inclination) by utilising a near bit stabiliser to act as a pivot or a fulcrum of a lever, **Figure 11.28**. The lever is the length of the drillcollars from their point of contact with the low side of the hole and top of the stabiliser.The drillbit is pressed to the high side of the hole causing angle to be built as drilling ahead progresses.Since the drillcollars bend more as more WOB is applied, the rate of angle build will also increase with WOB.

Figure 11.28 Fulcrum



The build rate also increases with:

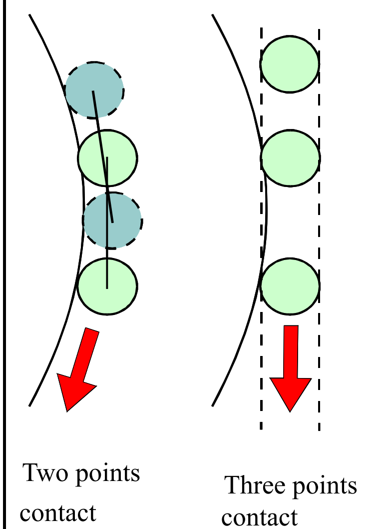
- distance from near bit stabiliser to first stabiliser in the BHA
- reduction in RPM
- increase in hole angle

- reduction in drillcollar diameter

3. Packed Hole Stabilisation Principle

This is used to hold or maintain hole inclination and direction and are typically used to drill the tangent section of a well. The packed BHA relies on the principle that two points will contact and follow a sharp curve, while three points will follow a straight line, **Figure 11.29**. Packed BHA have several full gauge stabilizers in the lowest portion of the BHA, typically three or four stabilisers. This makes the BHA stiff and hence it tends to maintain hole angle and direction.

Figure 11.29 Packed BHA principle

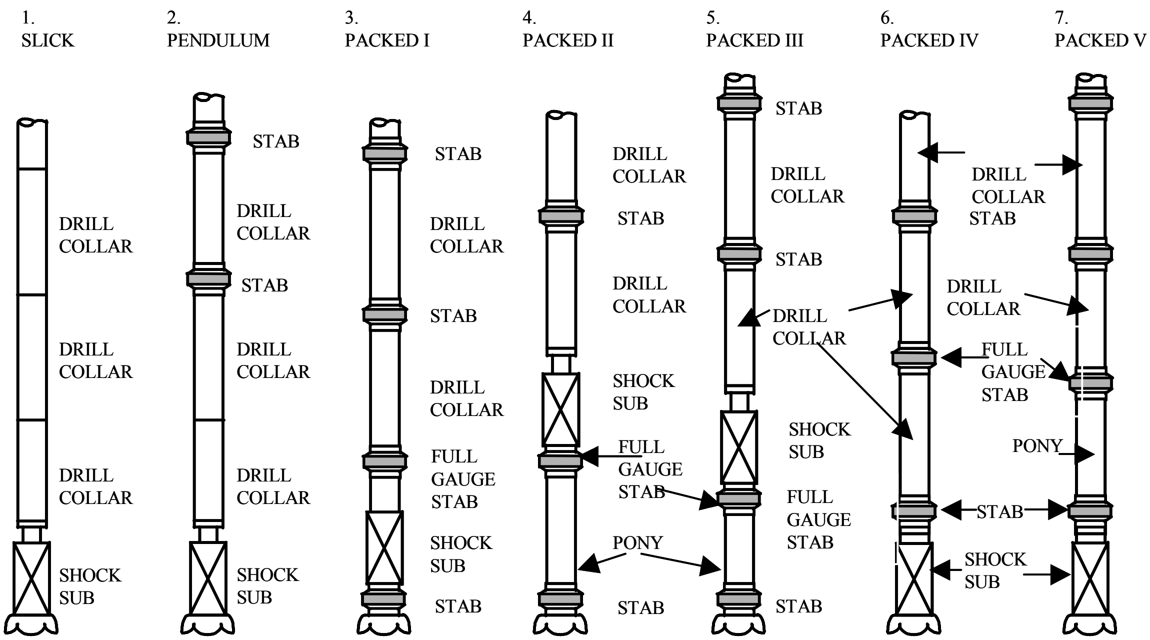


10.1 STANDARD BHA CONFIGURATIONS

Using the three principles of BHA control discussed above, there are five basic types of BHA's which may be used to control the direction of the well, see **Figure 11.30**:

1. Pendulum assembly
2. Packed bottom hole assembly
3. Rotary build assembly
4. Rotary drop assembly
5. Steerable assembly
6. Mud motor and bent sub assembly

Figure 11.30 BHA Configurations



10.2 Pendulum Assembly

The pendulum assembly makes use of the gravitational effects acting on the bit and lower portion of the BHA to maintain vertical hole or drop angle back to the vertical. In this assembly, the first string stabiliser is placed approximately 30, 40 or 60 feet above the bit. The assembly is commonly used as an angle reducing assembly on deviated wells but is difficult to control.

10.3 Packed Assembly

A packed assembly typically uses a near-bit stabiliser and string stabilisers a further 30 and 60 feet from the bit, **Figure 11.30**. A tightly packed assembly incorporates a further string stabiliser normally located 15 feet from the bit. This type of assembly is often run where formation dip cause angle building tendency and is also used to maintain vertical hole when higher weights (WOB) are used. This BHA is typically used in 12¼" and 8½" hole sections on vertical well and in tangent sections of deviated wells to maintain the hole inclination.

10.4 Rotary Build Assemblies

A rotary build assembly is based on the fulcrum principle and is used to build hole angle after initial steering runs on deviated wells. Rotary build assemblies are usually used after the initial kick-off to eliminate the need for further use of a mud motor.

The BHA consists of: near bit stabiliser, two drillcollars, a first string stabiliser located a further 60 feet from the bit, DC and a further string stabiliser 30 feet above.

During drilling operations, application of WOB causes the two drillcollars above the near bit stabiliser to be bent and consequently cause the drillbit to loaded on the high side of the hole thereby causing increases in hole angle as the hole is drilled.

10.5 Steerable Assemblies

Steerable assemblies include the use of the following:

- Bent motor housing tool and MWD tool
- Double tilted U-joint housing (DTU) and MWD tool

The above BHA's are run stabilised and can be used to drill the build and tangent sections of a hole. When used in steering mode, a steerable system can be used to correct both hole angle and direction. In rotary mode, a steerable system is used to maintain hole direction.

When using a steerable system it is essential to determine its directional characteristics in rotary mode. Where possible, once the main build has been ¾ completed, 2 stands should be drilled in rotary mode to determine the inclination and azimuth tendencies to enable the tangent section to be drilled without the need for numerous corrections.

From experience, it has been found that numerous small corrections can lead to micro doglegs and severe increases in torque when drilling deep or extended reach wells.

Downhole Adjustable Stabilisers

Steering of a drilling assembly can also be achieved by the use of a downhole adjustable stabiliser. The gauge of the stabiliser can be adjusted from surface and the behaviour of the assembly varied depending on the position of the other stabilisers in the string.

These tools were initially designed for specific use in the 12¼" tangent section of deviated wells to avoid pulling the assembly for a correction run.

Use of an adjustable stabiliser, such as the Andergauge stabiliser, means that any change in inclination can be corrected without having to pull the assembly. The stabiliser can be set at any number of gauge settings prior to running. By alternating the tool setting between activated and de-activated the assembly behaviour can be varied between build and hold or hold and drop.

The tools are generally the same length as a normal integral blade stabiliser. Activation of the gauge adjustment is either by applying weight or hydraulic pressure. Tungsten carbide studs incorporated within the tool are driven through the blade to full gauge position or retracted to undergauge position.

The Andergauge tool has a hydraulic lock feature which locks the tool at the required setting.

Surface indication of tool activation is achieved by a restrictor ring which induces a small 150-200 psi increase in pump pressure.

The tools generally have internal pump-open force which is directly related to the bit hydraulics. When this is calculated and added to the weight of the assembly below the stabiliser, the minimum drilling weight required to close the tool is known. The pump open force can be utilised to reduce the desired tripping weight where necessary, e.g. in high torque situations. By reducing the mud flow the pump open force is reduced, thereby reducing the tripping weight.

10.6 Mud Motor and Bent Sub

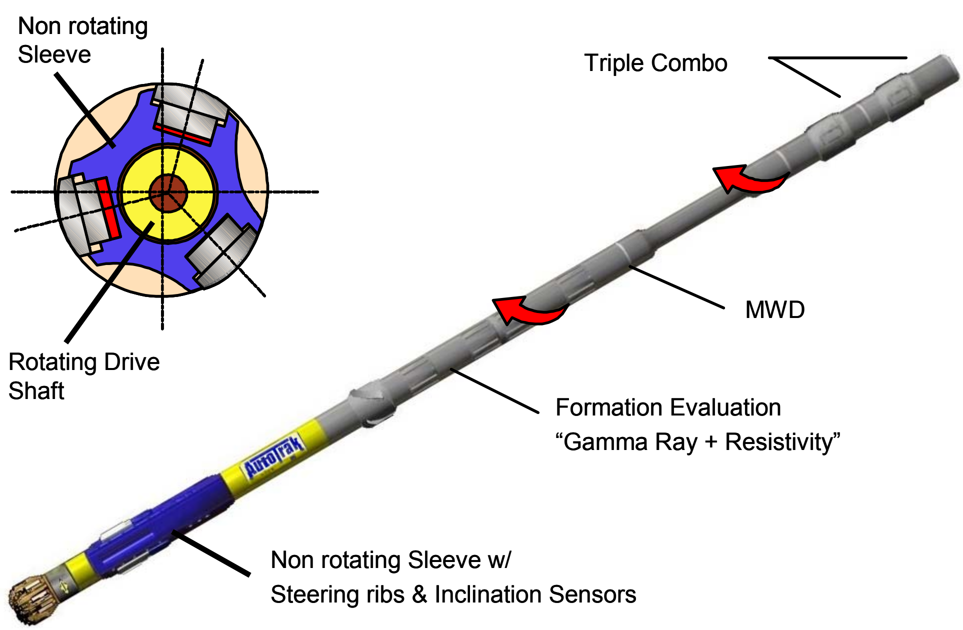
This assembly is typically run for performing the initial kick-off and build up sections of deviated wells, **Figure 11.24**. It is then pulled prior to running a packed BHA for drilling the tangent sections. This BHA may also be used for correction runs.

10.7 Rotary Steerable Systems

These systems do not use bent subs for affecting hole angles. Changes in hole angles are brought about by the action of three pads contained within a non-rotating sleeve. The pads are kept in constant contact with the formation by internal mud powered actuators. If no angle change is required, the system is put in neutral mode by pushing the pads in every direction thereby cancelling each other.

If changes in angle and direction are required, the electronics within the instruments cause each pad to extend against the side the hole opposite the intended bias direction, **Figure 11.31**. The resultant action of these forces then cause the bit to build or drop angles as required. Signals can be sent from surface to the instrument downhole as is the case with most current rotary steerable systems or the hole inclination and direction are programmed into the instrument at surface and the instrument then automatically corrects the hole trajectory without driller's intervention.

Figure 11.31 Autotrack, courtesy of Baker Hughes Inteq



Autotrak from Baker Inteq is an example of a rotary steerable system,**Figure 11.31**.

11.0 Survey Tools

Wells are surveyed for the following reasons:

- To intersect the geological targets
- To monitor the progress of the well and determine the amount of orientation required to bring the well back to its planned course
- To prevent collision between the current well and near-by wells
- To provide accurate definition of geological and reservoir data to allow for optimisation of production and for equity determination if more than one partner is involved in the well(s).
- To determine the exact location of the bottom hole to be used in the event of a blowout when a relief well is required to be drilled to kill the blowing well.
- To fulfill requirements by the regulatory authorities
- To calculate the dog-leg severity

11.1 Inclination Angle Tools

Inclination angle is normally measured by a mechanical pendulum housed in a special barrel. The instrument measures hole angle in degrees and a record of the measurement is made on a paper disc when punched by the pendulum stylus. The paper disc is divided into concentric circles, each circle representing 1 deg of deviation. The instrument is designed to produce two punches 180 deg apart. The instrument is also equipped with a timing device to control the movement of the paper disc when the survey depth is reached. This instrument is usually called, Totco, after the company who first developed it.

The following survey instruments are usually used in appraisal or development wells:

Inclination Only Tools

- TOTCO-Inclination Only Tool: mechanical
- Teledrift-Inclination Only MWD Tool (by SDC): angle measured by mud pulses

- Anderdrift-Inclination Only Tool (by Andergauge): angle measured by mud pulses

The Teledrift wireless drift indicator measures deviation angles up to 10½°. The tool generates signals in the form of pressure surges in the mud stream. These signals are received at surface by a chart recorder situated near the doghouse.

The Teledrift consists of a pendulum that moves along a series of graduated stop shoulders and a signalling plunger that traverses a series of seven annular restrictions to produce pressure pulses in the mud. A maximum of seven signals can be generated, each representing an increment of hole angle of ½°.

11.2 Magnetic Survey Tools

Magnetic survey tools are designed to measure both hole inclination and azimuth (magnetic north direction).The tool actually detects and measures the direction of the horizontal component of the earth's magnetic field.

A declination correction is required to convert magnetic north to true north, see **"Magnetic Declination" on page 453**.

The following magnetic survey tools are currently in use in the oil industry:

1. Magnetic Single shot (MSS): either photomechanical or electronic
2. Magnetic Multishot (EMS): either photomechanical or electronic
3. Measurement While Drilling (MWD)

11.3 Non-magnetic Drill Collar Requirements

Magnetic surveys suffer from the following sources of error:

- Drillstring magnetisation
- Magnetic effects from casing strings or BHA
- Geological structures containing magnetic materials
- Magnetic storm effects

- Wireline magnetization
- Magnetic declination
- Tool misalignment
- Depth measurement

Drill string magnetisation causes the largest errors in magnetic surveys. These errors can be reduced by housing the survey instrument in non-magnetic drillcollars (e.g. K-Monel).

11.4 MAGNETIC SINGLE-SHOT

This instrument measures hole inclination and magnetic north direction at a single station.The instrument consists of:

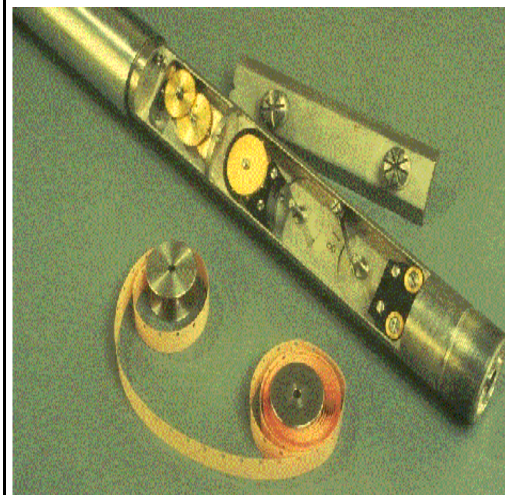
- compass card: aligns with magnetic north
- angle unit (pendulum): gives hole inclination
- camera: to capture the image of direction and inclination on film
- timing device to turn light on
- battery pack

The survey measurement is made on a disc which can be developed at surface in a few minutes.Magnetic single shots are usually run to provide a check survey at section TD, bit trips and when MWD fails.

11.5 Magnetic Multi-shots

The instrument measures both hole inclination and direction and records these measurements permanently either on a photographic film or digitally, **Figure 11.32**. The instrument can be dropped from surface (go -deviled), tripped inside the drillstring or run on wireline.

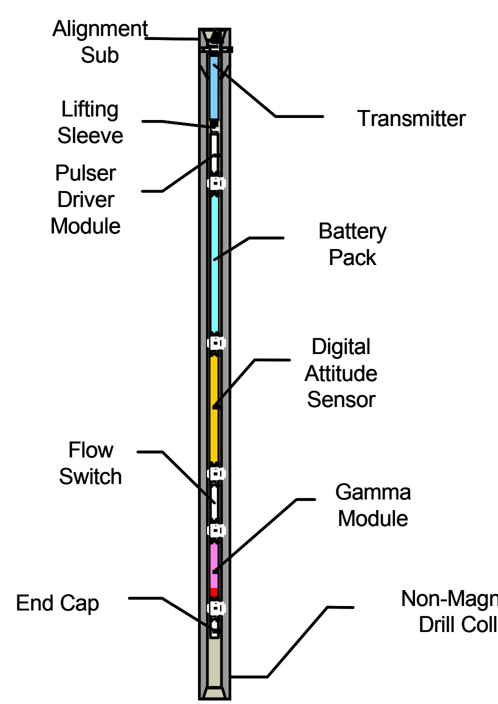
Figure 11.32 MMS, Courtesy of Baker Hughes Inteq



11.6 Measurement While Drilling

Measurement While Drilling (MWD) measures hole inclination and azimuth in real time and relays this data to the surface through the mud, **Figure 11.33**. The tool contains a plunger which sends signals through the mud inside the drillstring; this tool is called Positive Pulse MWD and is the most common in the industry. MWD tools which send signals through the annulus are called negative pulse MWD and these send signals through an aperture inside the casing of the MWD tool through the mud in the annulus to be detected at surface.

Figure 11.33 MWD components, Courtesy of Baker Hughes Inteq



The electronics of the MWD consist of a set of triaxial accelerometers and magnetometers housed in a special non-magnetic material collar. The accelerometers measure the components of the earth's gravitational field and the magnetometers measure the earth's magnetic field. The measured forces are used to give inclination, azimuth and

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tool face orientation. The MWD tool sends directional data through the mud in the form of signals which are decoded at surface.

The positive pulse MWD has a restictor valve (plunger) which is operated by hydraulic actuator contained within the body of the MWD tool. When the plunger is operated, it partially restricts the flow of mud through the tool; this is observed at surface as an increase in the standpipe pressure. When the tool is operated several times, a series of mud pulses are observed at surface which are decoded into directional data.The surface instrumentation actually detect the presence or absence of a pulse in the form of binary data (zero and one). The MWD is programmed to send directional data from downhole in a series of this binary data to be processed at surface into absolute values.

Currently MWD tools have sensors to measure a variety of downhole data including: directional, temperature, drillstring dynamics and formation evaluation data: gamma ray, resistivity and density. When formation evaluation data are measured together with directional data, the combined tool is called LWD: logging while drilling. LWD provides a real time log of downhole data, replacing the need to run wireline logs separately at the end of each hole section.

MWD tools are only constrained by high temperature and high doglegs. At high temperatures the electronic circuits become unstable and then malfunction.

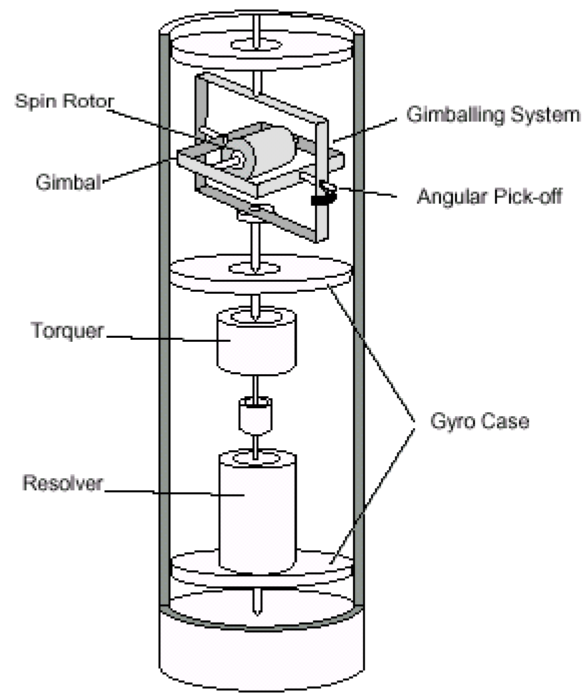
11.7 The Gyro Survey Tool

There are three types of gyros:

- Conventional
- North seeking
- Inertial

11.7.1 Conventional Gyros

Figure 11.34 Conventional gyro



The principal elements of a conventional gyro is a rapidly spinning weighted wheel (rotor) mounted on a frame and gimbals, **Figure 11.34**.

The gyro can be likened to a spinning top which can maintain its vertical direction as long as the top spins fast enough and no external forces act on it. In a gyro, the rotation of the rotor is maintained by a motor and the gyro attempts to maintain a preset direction by resisting external forces. In the real world, it is impossible to make a perfect gyro that does not drift with time or react to external forces.

A typical gyro used in the oil industry has two degrees of freedom by being supported by two frames (called gimbals) which allow free rotation of the rotor,**Figure 11.34**. Hence as the gyro moves downhole during a survey, the gimbals allow the gyro to attempt to maintain a horizontal orientation in space. The frame has ball-bearings between its base surface and outer gimbal and inner gimbal. The rotor is held in the inner gimbal by rotor bearings. Thus components are free to move and are connected by low friction bearings.

The gyro has two more basic components: a compass card aligned with the horizontal spin axis of the gyro and a plumb bob assembly over the compass for measuring hole inclination.

In a photomechanical gyro, the gyro remains stationary at each survey station to allow a picture taken of the plumb bob direction with respect to the compass card, giving readings of wellbore azimuth and inclination when the picture is processed at surface.

The rotor maintains a preset direction by resisting changes in direction due to its inertia. Thus if the wheel is made to rotate parallel the earth’s axis of rotation, then it maintain this

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direction thereby serving as a direction indicator.The gyro spin axis provides a stabilized reference line about which rotation of the base surface can be measured.

Gyros do 'drift' away from their initial reference alignment with time. This is due to imperfections in construction and friction in the bearings. Gyro drift is measured periodically

Conventional gyros must be aligned to a known fixed reference on surface before run in hole. Gyros tend to drift away from their initial settings and surveys must therefore be corrected for drift errors and misalignment errors.

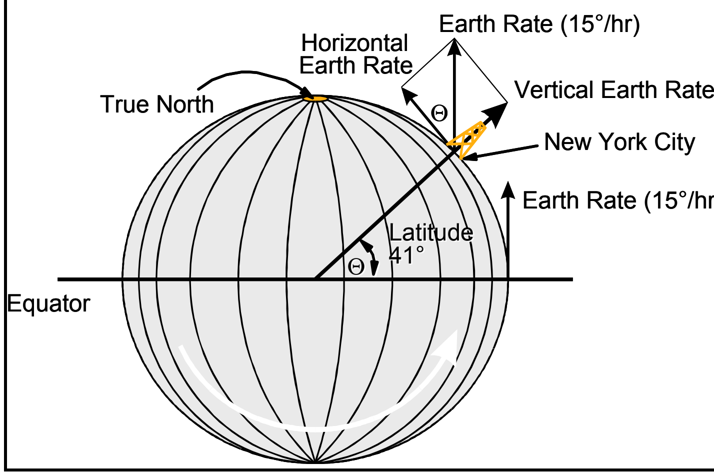
Surface Readout Gyros (SRG): These are used to provide a surface readout of the wellbore survey through a conducting wireline.The tool can be run inside either drillpipe or casing. The tool measures inclination, azimuth and tool face.They are often used in top hole, for orienting purposes, and in areas with large magnetic effects.Survey readings suffer from errors due to alignment to a fixed direction and drift.

Components:

- Two degrees of freedom conventional gyro with downhole electronics package which replaces camera angle unit and timer in a conventional gyro.
- A wire line supplies power and connects the probe with a surface computer that monitors probe performance and prints survey data as it is gathered.
- Accelerometers instead of plumb bobs are used to measure hole inclination.

11.7.2 North Seeking Gyros (NSG)

Figure 11.35 True north reference, courtesy of Baker Inteq



NSG's use sophisticated electronics to measure the rate of rotation of the earth and then determine the direction of true north. NSG's are designed to resolve and measure the horizontal component of the earth's spin vector, **Figure 11.35**. The horizontal component always points to true north and is used as the reference direction for aligning the spin axis of the gyro. As can be seen from **Figure 11.35**, the horizontal component of the earth's rotation decreases away from the equator and becomes zero at the north pole. North seeking gyros require no corrections for drift and do not need to be oriented to a fixed geographic reference point as in conventional gyros.

NSG's can be run inside drillpipe or casing. NSG's provide surface readout of the wellbore survey through a conducting wireline. They are often used for orientation purposes and can provide a section or complete wellbore survey.

The major north seeking gyros currently on the market are:

- Seeker from Baker Hughes Inteq
- Finder from Scientific Drilling Controls
- Wellbore Surveyor from Gyrodata
- Guidance Continuous Tool (GCT) from Schlumberger
- G2 from Sperry Sun

It is beyond the scope of this book to give a detailed description of each.

The following is a description of the components of G2.

The instrument has a minimum PC diameter of 2.6in and is 18ft in length. The G2 contains a two-axis dynamically tuned gyro and a tri-axial accelerometer package, mounted on a platform (gimbal), that has an axis of rotation coincident with the tool axis. One of the two gyro input axes (Z) is also coincident with the tool axis and is used to inertially stabilise the platform during a survey. The second gyro input axis (x) is perpendicular to the tool axis and gyro spin axis.One accelerometer input axis is aligned with each of the gyro axes.

During a survey, the second gyro axis (x) is used to north seek (near vertical) at the start and end of a survey and this calibration usually takes 15 minutes. After alignment the spin axis is aligned in the principal hole direction and is maintained in this direction, using the first gyro axis (z).All gyro drift compensation is performed on surface which means that spin axis orientation will change due to both hole direction changes and gyro drift. Azimuth is calculated incrementally, by measuring the change in spin axis orientation after compensation for gyro drift. Inclination is calculated from the outputs of the three accelerometers.

The instrument is stopped at each survey station for approximately 10 seconds to let sensor output stabilize. An inrun and outrun is performed and a closure calculated to correct for uncompensated platform drift.

The Guidance Continuous Tool - Schlumberger

The instrument has a standard protective case (PC) diameter of 3 $^{5}/_{8}$ in and is 40ft in length.The guidance continuous tool (GCT) contains a two-axis accelerometer. Both sensors are mounted on the inner gimbal of a two-gimbal inertial system with one accelerometer input axis (X) coincident with the spin axis of the gyro and the second accelerometer input axis (Y) coincident with the gyro input axis (Y) which is perpendicular to the spin axis and instrument axis.

During operation, an initial gyrocompass is performed in hole near vertical to minimise the effect of g-sensitive errors and the spin axis is aligned in the principal hole direction. This takes a minimum of 45 minutes. The instrument is then run continuously and the spin axis is maintained horizontal and pointing in the principal direction The heading is maintained by sensing rotation about the vertical axis with the second giro input axis (Z).

An inrun and outrun is performed and a survey closure is calculated to correct for uncompensated drift.

11.7.3 Limitations of NSG's

- Not suitable for latitude greater than 70 deg, see **Figure 11.35**
- Not suitable for hole inclination greater than 65-70 deg
- Sensitive to motion
- Require a conducting wireline

11.8 Rate Inertial Gyro System

This instrument uses a triaxial package of ring laser gyros to establish true north and a triaxial package of accelerometers to measure accelerations in three dimensions. The RIGS (Rate Inertial Gyro System) from Baker Hughes Inteq is an example of this gyro. RIGS is used in cased hole multishot surveys and for wellhead orientation.It is more expensive than conventional or north seeking gyros.

11.9 SURVEY TOOL SELECTION

Survey tool selection depends on various factors including:

- Planned well depth.
- Well type e.g. HPHT, horizontal, long reach wells.
- Maximum hole inclination.
- Target size.
- Anti-Collision requirements.
- Potential drilling problems.
- Survey tool operational limitations.

The above factors determine the required accuracy of the survey instruments and also determine the appropriate survey programme.

11.10 Minimum Survey Programme

Table 11.2 gives a suggested minimum survey programmes for development wells. For exploration wells, the requirements vary from one company to another.

Table 11.2 Survey programme for a development well

Casing	Hole Section	Survey Requirements
Conductor	Open Hole	Surface recording gyro (SRG) orientation tool to be run on wireline in drill pipe to monitor verticality (cemented conductors only)
	Cased Hole	N.S.G. definitive survey @ 30’ intervals from T.D. to seabed. (RIGS may be used if more accurate survey required).
Surface	Open Hole	Surface recording gyro (SRG) orientation tool to be run on wireline in drillpipe. If a nudge is to be done in this section then an MWD tool should also be used. Only inclination and (when over 4-5 degrees) highside toolface to be recorded until free from magnetic interference.
	Cased Hole	N.S.G. definitive survey @ 50‘intervals from T.D. back into conductor shoe. (RIGS may be used if more accurate survey required).
Intermediate	Open Hole	Build: SRG every 30’ until free from magnetic interference, if present and then MWD surveys every 30‘until trend established and it is possible to relax the survey spacings accordingly.
		Tangent: - MWD survey interval spacing 90’. If hole section is the interval immediately prior to reaching the reservoir then a tandem E.M.S. with surveys at 90ft intervals should be conducted from section T.D. back to the previous tie in point
	Cased Hole	No requirement
Production	Open Hole	M.W.D. survey interval spacing 90‘. (MSS to be used if no MWD run and section is long). At T.D. a tandem E.M.S. with surveys at 90’ intervals should be conducted from T.D. back to overlap with the previous definitive survey.
	Cased Hole	No requirement unless spurious survey readings with the E.M.S. or hole conditions preclude the taking of the E.M.S. In these instances a N.S.G. survey should be required.

12.0 TRAJECTORY CALCULATIONS

At the end of each successful survey (e.g. single-shot, multishot, steering tool, surface readout gyro, MWD) the following data is measured:

- survey measured depth
- wellbore inclination
- wellbore azimuth (corrected to relevant North).

The above data will then enable the bottom hole location at the last survey point to be calculated accurately in terms of:

- TVD
- Northing
- Easting
- Vertical section
- dog-leg severity

The calculated data is then plotted on the directional well plot (TVD vs vertical section on the vertical plot, N/S vs E/W rectangular coordinates on horizontal plot), see **Figure 11.39**.

12.1 CALCULATION TECHNIQUES

There are several methods used for survey calculations. However, only the two most widely used methods will be presented here:

- radius of curvature method
- minimum curvature method

12.1.1 RADIUS OF CURVATURE METHOD

The radius of curvature method (**Figure 11.36**) uses the top and bottom angles to generate a space curve having a spherical arc shape which passes through the two stations.Each course length is assumed to be a circular arc in both the vertical and horizontal planes.

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Increment of true vertical depth (ΔTVD):

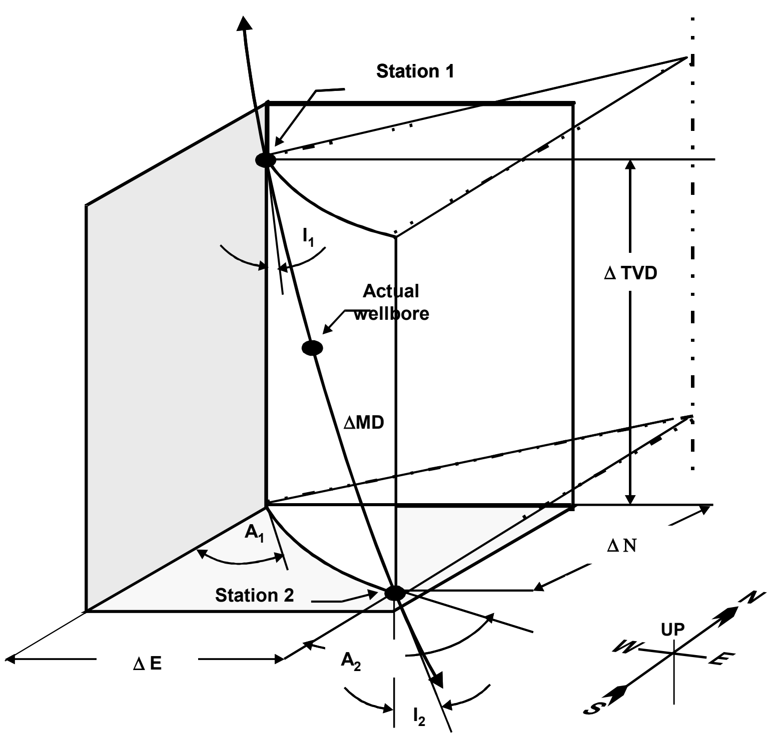
$$\Delta TVD = \frac{360x\Delta MD(\sin I_2 - \sin I_1)}{2\pi(I_2 - I_1)} \tag{11.41}$$

where

ΔMD = increment of course length

I_1, I_2 = inclination angles at stations 1 and 2 respectively

Figure 11.36 Radius of curvature



Increment of northing co-ordinate (ΔN)

$$\Delta N = \frac{(360)^2\Delta MD(\cos I_1 - \cos I_2)(\sin A_2 - \sin A_1)}{4\pi^2 (A_2 - A_1)(I_2 - I_1)} \tag{11.42}$$

Increment of easting co-ordinate (ΔE)

$$\Delta E = \frac{(360)^2 \Delta MD (\cos I_1 - \cos I_2)(\cos A_1 - \cos A_2)}{4\pi^2 (A_2 - A_1)(I_2 - I_1)} \tag{11.43}$$

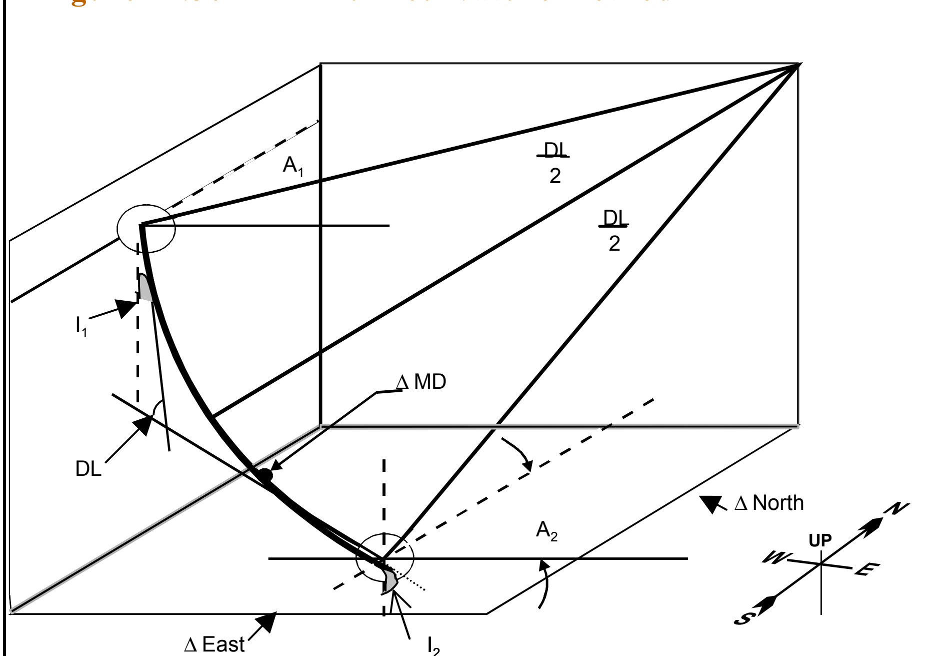
where A_1, A_2 = azimuth angles at stations 1 and 2 respectively

Note: If the azimuth and inclination angles remain unchanged between survey points then these equations are no longer applicable because of the resulting division by a zero term.

12.1.2 MINIMUM CURVATURE METHOD

The minimum curvature method (**Figure 11.37**) uses the principle of minimising the total curvature within the constraints of the wellbore in order to produce a smooth circular arc. The surveys at the two stations define vectors which are tangent to the wellbore at the survey points. A ratio factor (RF) is used to smooth the vectors on to the wellbore curve.

Figure 11.37 Minimum curvature method



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First calculate the ratio factor (RF):

$$RF = \frac{2 \times 180}{DL \times \pi} \times \tan \frac{DL}{2} \tag{11.44}$$

where

RF = Ratio Factor

DL = dog-leg angle in degrees; and

$$\cos DL = \cos(I_2 - I_1) - \sin I_1 \times \sin I_2 \times (1 - \cos(A_2 - A_1)) \tag{11.45}$$

$$\Delta TVD = \frac{\Delta MD}{2}(\cos I_1 + \cos I_2) \times RF \tag{11.46}$$

$$\Delta N = \frac{\Delta MD}{2} \times (\sin I_1 \cos A_1 + \sin I_2 \cos A_2) \times RF \tag{11.47}$$

$$\Delta E = \frac{\Delta MD}{2} \times (\sin I_1 \sin A_1 + \sin I_2 \sin A_2) \times RF \tag{11.48}$$

12.2 VERTICAL SECTION

The vertical profile of a well is defined in a plane bounded by the direction straight from the slot (surface location) to the target. This direction is described as the vertical section azimuth or target direction.The total horizontal deviation (displacement) of the well projected onto this plane is called the vertical section.

The easting and northing coordinates from the survey stations can be plotted on the horizontal plane as shown in **Figure 11.38**. The line joining these points is the actual well path in the horizontal plane. The vertical view of the well profile is obtained by projecting all points in the horizontal plane onto a plane containing the reference origin (surface= O) and bottomhole target (=T), line OT, **Figure 11.38**. Line OT is the target direction.

The survey calculations methods presented earlier calculate the eastings (E_A) and northings (N_A) of a point, e.g. point A in **Figure 11.38**. The length OA is also known as the closure of point A and is given by:

$$OA = \sqrt{\Delta N_A^2 + \Delta E_A^2} \qquad (11.49)$$

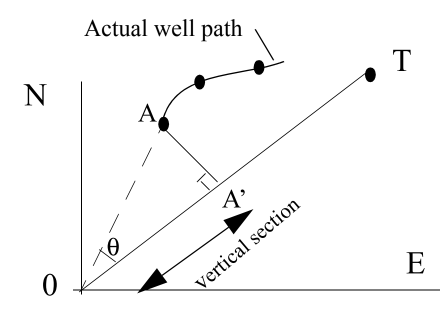
Closure of a point is the shortest horizontal distance from a particular survey point back to the reference point.

The projected length of line OA onto line OT is line OA′. The length OA′ is known as the vertical section and is given by:

$$\text{Vertical section} = OA' = OA\cos\theta \qquad (11.50)$$

$$\theta = \text{target bearing} - \text{atan}\left(\frac{\Delta E}{\Delta N}\right)$$

Figure 11.38 Horizontal plan of well path



13.0 DOGLEG SEVERITY

13.1 DEFINITION

Dogleg severity is a measure of the amount of change in inclination and / or direction of a borehole, usually expressed in degrees per 100 feet of course length. Several formulae are available to compute the total effects where there is both a change in inclination and azimuth.

The dogleg angle (DL) in degrees is given by:

$$\cos DL = \cos(I_2 - I_1) - \sin I_1 \times \sin I_2 \times (1 - \cos(A_2 - A_1)) \qquad \textbf{Equation (11.45)}$$

The dogleg severity (DLS) is given by:

$$DLS = \frac{100}{MD}\arccos[\cos(I_2 - I_1) - (\sin I_1 \sin I_2) \times (1 - \cos(A_2 - A_1))] \qquad (11.51)$$

where

DLS = Dogleg severity, degrees /100 ft

A = Azimuth direction, degrees
I = Inclination, degrees
MD = Measured distance, feet
Δ = Change between survey stations
1,2 = Subscripts to denote survey stations 1 and 2

Example 11.5:.Calculations of Well Path

The following data refer to a directionally drilled well:

TVD of station 1 = 1150 ft

Northing coordinate of station 1 = 350 ft

Easting coordinate of station 1 = 550 ft

Target bearing = 65 degree

Survey data at two stations are as follows::

Station	Measured Depth (ft)	Inclination (I)	Corrected Azimuth (A)	Vertical section (ft)
1	1200	15	45	646.3
2	1400	19	55	

Use the radius of curvature method to calculate the well path between stations 1 and 2 and dog-leg severity.

Solution

$$\Delta TVD = \frac{360 x \Delta MD(\sin I_2 - \sin I_1)}{2\pi(I_2 - I_1)}$$

$$= \frac{360\ (1{,}400 - 1{,}200)}{2\pi\ (19 - 15)}(\sin 19^o - \sin 15^o) = 191.22 \text{ ft}$$

True vertical depth at station 2 = TVD at station 1 + ΔTVD (between stations 1 and 2)

$= 1{,}150 + 191.22 = 1{,}341.22$ ft

Increment of northing co-ordinate (ΔN)

$$\Delta N = \frac{(360)^2 \Delta MD(\cos I_1 - \cos I_2)(\sin A_2 - \sin A_1)}{4\pi^2 (A_2 - A_1)(I_2 - I_1)}$$

$$= \frac{360^2 (1{,}400 - 1{,}200)(\cos 15^o - \cos 19^o)(\sin 55^o - \sin 45^o)}{4\pi^2 (55 - 45)(19 - 15)} = 37.53 \text{ ft}$$

Increment of easting co-ordinate (ΔE)

$$\Delta E = \frac{(360)^2 \Delta MD(\cos I_1 - \cos I_2)(\cos A_1 - \cos A_2)}{4\pi^2 (A_2 - A_1)(I_2 - I_1)}$$

$$= \frac{360^2 (1{,}400 - 1200)(\cos 15° - \cos 19°)(\cos 45° - \cos 55°)}{4\pi^2 (55 - 45)(19 - 15)} = 44.73 \text{ ft}$$

Northing co-ordinate at station 2 = northing of station 1+ ΔN = 350+ 37.53 = 387.53 ft

Easting co-ordinate at station 2 = easting of station 1+ ΔE = 550 +44.73 =594.73 ft

Vertical section

Station 2

$$\theta = \text{target bearing} - \text{atan}\left(\frac{\Delta E}{\Delta N}\right) = 65 - \text{atan}\left(\frac{44.73}{37.53}\right) = 65 - 50 = 15°$$

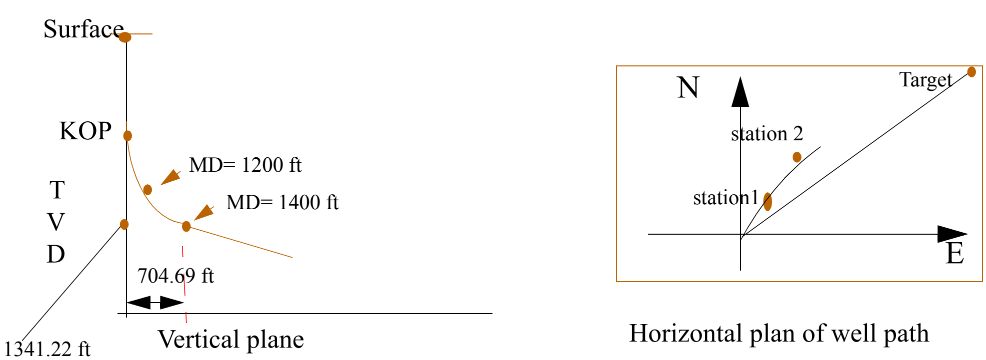
$$\text{Vertical section} = OA' = OA\cos\theta = \sqrt{N_A^2 + E_A^2}\cos\theta = \sqrt{44.73^2 + 37.53^2}\cos 15 = 58.39 \text{ ft}$$

Vertical section at station 2 = 646.3 + 58.39 = 704.69 ft

The following table summarises the calculations and the well path in both the horizontal and vertical planes can be plotted as shown in **Figure 11.39**.

Station	MD (ft)	TVD (ft)	Vertical Section (ft)	E (ft)	N(ft)
1	1200	1150	646.3	550	350
2	1400	1,341.22	704.69	594.73	387.53

Figure 11.39 Plotting of well path, Example 11.5



$$\text{Dog-leg severity} = \frac{\text{dog-leg angle}}{\text{length of interval between stations 1 and 2}}$$

$$\cos DL = \cos(I_2 - I_1) - (\sin I_1 \sin I_2 \times (1 - \cos(A_2 - A_1))$$

$$= \cos(19^o - 15^o) - (\sin 15^o \sin 19^o \times (1 - \cos(55 - 45))$$

$$\cos DL = 0.9963$$

$DL = 4.94^o$

$$\text{Dog-leg severity} = \frac{\text{dog leg angle}}{\text{interval} - \text{drilled}} \text{x}\, 100\,\text{ft}$$

$$= \frac{4.94}{(1400 - 1200)} \text{x}\, 100 = 2.47 \text{ deg/100 ft}$$

13.2 PROJECTING AHEAD

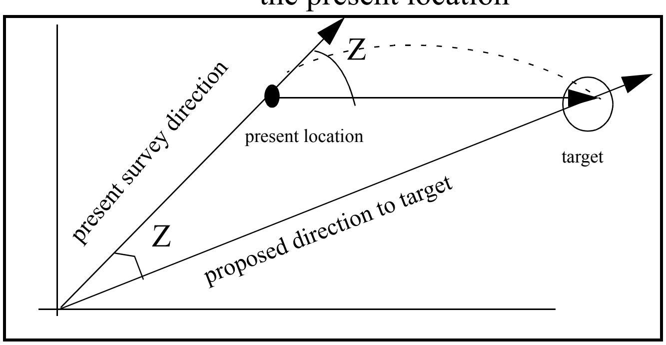
Once the location of the last survey point is calculated, it is also necessary to calculate the future course of the well to see whether the well is on course to hit the target.If the well is off course, then a correction may be required.

In the horizontal plane:

$$\text{current walk rate} = \frac{\text{total azimuth change x 100}}{\text{course length drilled}} \text{ deg/100 ft} \qquad (11.52)$$

$$\text{Total walk needed} = 2\ Z \qquad (11.53)$$

where Z= difference between the present direction and direction to target from the present location



$$\text{walk rate required} = \frac{\text{total walk needed x 100}}{\text{MD left to drill}} \qquad (11.54)$$

$$\text{Expected walk} = \frac{\text{walk rates of assembly to be used x MD left}}{100} \tag{11.55}$$

If the total walk anticipated is different from the walk rate required, the directional driller may decide to use the current rotary BHA or use a new BHA if the well is in danger of missing the target, in which case the new BHA will be used for a correction run.If a steerable assembly is in hole, then a the new interval will be drilled in steering (oriented) mode.

$$\text{Turns required in the coretion run} = Z \pm \frac{\text{expected walk}}{2} \tag{11.56}$$

In the above equation, the terms are added together if the expected walk is in the opposite direction as the required turn and are subtracted if they are in the same direction to the required turn.

One can also project in the vertical plane provided that the azimuth is constant or is changing very slightly:

$$\text{Projected inclination} = \text{atan}\{\tan(\text{actual inclination}\}\text{x}\cos\text{DD}\} \tag{11.57}$$

where DD = directional difference between hole azimuth and vertical section azimuth

$$\text{Current build/drop rate} = \frac{\text{change in inclination x 100}}{\text{course length drilled}} \text{""} \frac{°}{100\text{ ft}} \tag{11.58}$$

(a negative value indicates drop)

$$\text{Build / drop needed} = \frac{2(I_2 - I_1)}{\text{MD left to drill}} \text{""} \frac{°}{100\text{ ft}} \tag{11.59}$$

$$\text{Inclination at target} = I_1 + 2\,(I_2\text{-}I_1) \tag{11.60}$$

where

I_1 = present hole inclination

I_2= inclination to target from current BHA location

$$\text{Total expected build/drop} = \frac{\text{current build / drop x MD left to drill}}{100} \tag{11.61}$$

Example 11.6: Projecting Ahead

A packed BHA was run from 2500 to 4900 ft. The azimuth over this interval changed from 56° to 65°. The direction to the target from the present BHA location is 58°. If the well is lined up on target on the vertical section (inclination angle is constant) and the estimated MD of the target is 9500 ft, calculate:

a. current walk rate

b. total walk needed to hit the target

c. rate of walk required

d. expected walk with the packed BHA

e. turns required in the correction run

Solution

a. $$\text{current walk rate} = \frac{\text{total azimuth change x 100}}{\text{course length drilled}}\ \text{deg/100 ft}$$

$$\text{current walk rate} = \frac{(65-56)}{4900-2500} x100 = 0.38\frac{°}{100\text{ft}}\ \text{Right}$$

b. Total bit walk needed to hit target = 2 Z = 2 x(65-58) = 14 ° Left (since location is to left of target)

(Z= difference between the present direction and direction to target from the present location)

c. $$\text{walk rate required} = \frac{14x100}{(9500-4900)} = 0.30\frac{°}{100\text{ ft}}\ \text{Left}$$

d. $$\text{Expected walk} = \frac{\text{walk rates of assembly to be used x MD left}}{100}$$

$$\text{Expected walk} = \frac{0.38}{100} x(9500-4900) = 17.4°\text{right}$$

e. $$\text{Turns required in the corretion run} = Z \pm \frac{\text{expected walk}}{2}$$

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$$\text{Turns required in the correction run} = 7 + \frac{17.4}{2} = 15.7 \approx 18°\text{Left}$$

14.0 Anti-Collision Planning

In offshore operations where a number of wells are drilled from one platform there is always a risk of wells colliding with each other unless the wells are carefully planned. Planning of multiple wells from a single platform or a single pad (land operations) begins with the plotting of the surveys of the wells that are already drilled and then superimposing on the same plot the positions of the new planned wells. This plot is called the Spider Plot (**Figure 11.41**) and shows N/S and E/W coordinates of the wells. It follows that obtaining accurate surveys is essential in cluster wells to prevent disastrous problems.

If the spider plot shows there is a possibility of collision between the subject (new) well and object (existing) wells, then a number of contingencies must be implemented including changing the well profiles of the new wells, shutting producing wells in the path of the subject wells and placing plugs in the critical wells.

14.1 Positional Uncertainty Calculations

Since a directional survey is a measurement in three dimensions, it is therefore subject to measurement errors in three dimensions resulting in a volume of uncertainty.The error volume at any point within the wellbore takes the form of an ellipsoid. When the error measurement is reported on the horizontal plane only it then called the ellipse of uncertainty.

There are several errors associated with taking surveys inside a wellbore.These errors are due to:

1. Systematic errors due to magnetic or gyro compass
2. Misalignment of the survey tool within the wellbore
3. Depth error
4. Inclination error

Wolff & De Wardt[2] presented a mathematical method for calculating the likely position of a wellbore based on analysing and quantifying the errors associated with the elements of a survey measurement. They proposed an ellipsoid (a 3-D ellipse) to represent the envelope containing the likely position of the wellbore.This ellipsoid is called the volume of uncertainty and its size and shape is evaluated using maximum of six of the following error terms:

1. Magnetic compass error: Error is due to survey instrument measurement of azimuth.
2. Drillstring magnetic error: This error is applicable only to magnetic survey instruments and is caused by the magnetic effects of the drillstring which causes errors in the measurement of azimuth.
3. Gyro compass error (drift): This error is applicable only to gyro survey.
4. Misalignment error: Error is due to physical misalignment of instrument in the wellbore and this error affects both inclination and azimuth.
5. True inclination error: Error is due to survey instrument measurement of inclination.
6. Depth error: Error is due the physical measurement of along hole depth with the drillpipe or wireline.

The reader should note the volume of uncertainty is a probability volume (not absolute volume) determined from estimated errors in the survey equipment used in the wellbore.Some of theses errors are random, others are systematic. Therefore the position of the wellbore could be any where inside the ellipsoid.

Since the Wolff & De Wardt model was published, there has been several developments to estimating the position of the wellbore with the mathematics becoming more complex as more terms are added to the original six terms [2]. This book will not delve into these complex equations but will concentrate on the application of the Wolff & De Wardt model s it provides sufficient accuracy for most wells.

The applications of the ellipsoid of positional uncertainty are in:

1. Geological target constraints: The size of the ellipse is incorporated in the defined target size and in lease line constraints.
2. Relief well drilling: The smaller the size of the ellipse, the lower the cost of relief well drilling due to greater certainty in intersecting the blowing well.
3. Collision avoidance: The ellipse of uncertainty can be used a measure for planning the proximity of wells in congested platforms and is then used to take safety measures if errors in the new wells are dangerously close the planned errors.

Table 11.3 summarises the magnitude of errors in most of the survey instruments in current use.

14.2 QUANTIFICATION OF ERROR SOURCES

Table 11.3 gives typical survey errors associated with some common survey tools. A zero (0) on the end of a term represents a base error value for that term, e.g. ΔC_{20} is a base error for drillstring magnetic error.

1. Magnetic Compass Reference Errors, ΔC_1

$$\Delta C1 \text{ (rads)} = \Delta C_{10} \text{ (deg)} \times \pi/180 \tag{11.62}$$

2. Drill String Magnetic Error, ΔC_2

$$\Delta C_2 \text{ (rads)} = \Delta C_{20} \text{ (deg)} \times \text{Sin I} \times \text{Sin A } (\pi/180) \tag{11.63}$$

3. Gyro Compass Error, ΔC_3

$$\Delta C_3 \text{ (deg)} = [\Delta C_{30} \text{ (deg)} / \text{Cos I}] \times \pi/180 \tag{11.64}$$

Total Azimuth Error, ΔC

$$\Delta C = \Delta C_1 + \Delta C_2 + \Delta C_3 \tag{11.65}$$

4. Misalignment Error, ΔI_m

$$\Delta I_m = \Delta I_m \text{ (rads)} \tag{11.66}$$

5. True Inclination Error, ΔI_t

$$\Delta I_t = \Delta I_{to} \text{ x Sin I (rads)} \tag{11.67}$$

6. Relative Depth Error,ε

$$\varepsilon = \varepsilon \text{ (x } 10^{-3}\text{) (ft/1000ft)} \tag{11.68}$$

Table 11.3

	Relative Depth	Misalignment	True Inclination	Reference Error	Drillstring Magnetization	Gyro compass
	ε	ΔI_m	ΔI_{to}	ΔC_{10}	ΔC_{20}	ΔC_{30}
	(10^{-3})	(degrees)	(degrees)	(degrees)	(degrees)	(degrees)
Good Gyro	0.5	0.03	0.2	0.1		0.5
Poor Gyro	2	0.2	0.5	1		2.5
Good Mag	1	0.1	0.5	1.5	0.25	
Poor Mag	2	0.3	1	1.5	5.0 + 5.0	

14.3 Ellipsoid Descriptive Equations

The bottom of the hole is described by the following sizes of the half -axes of the ellipsoid:

(I = Inclination A = Azimuth MD = Along Hole Depth)

1. Along Hole Error

$$AHE = MD \text{ x } \varepsilon \tag{11.69}$$

2. Lateral Error

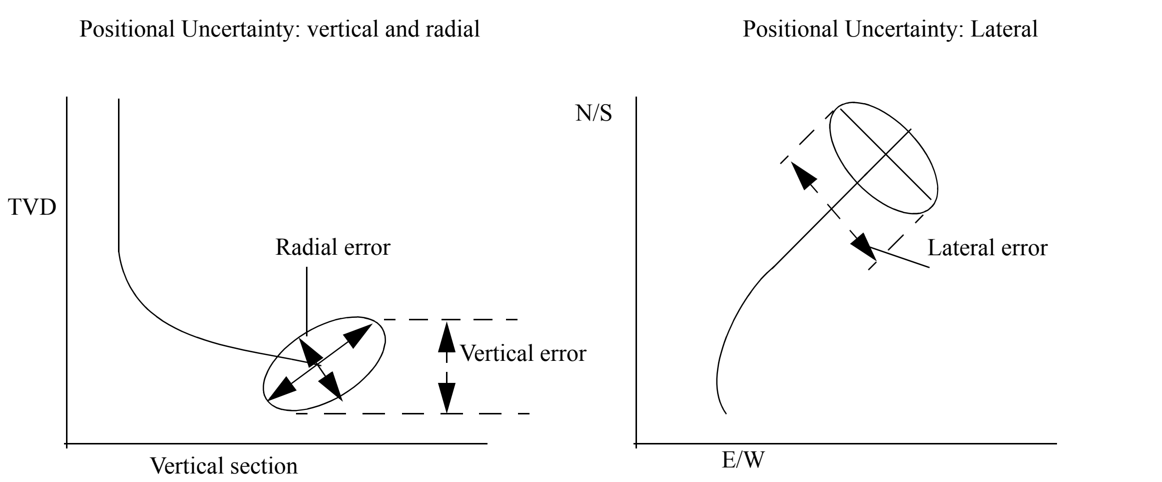
$$LE = MD\sqrt{\Delta I^2{}_m + (\Delta C \sin I)^2} \tag{11.70}$$

3. Upward Error

$$UE = MD\sqrt{\Delta I^2{}_m + \Delta I_t{}^2} \tag{11.71}$$

The above three terms can be used to describe the shape and size of the ellipsoid. The error normally utilised for error assessment in the wellbore is the largest error, which is generally the lateral error. This is because the lateral error is dependent on azimuth measurements which are subjected to greater errors than either inclination or depth measurements.The lateral error is usually the figure submitted to the regulatory authorities, see **Figure 11.40**.

Figure 11.40



Example 11.7: Calculation of positional uncertainty

An extended reach well is being drilled in the South North Sea. A good gyro is used to take a single shot survey prior to commencing the second build. Assuming this survey is not tied back to previous surveys, calculate the positional uncertainties using the following data:

Inclination = 45.15°

Azimuth = 295°

MD = 10670 ft

Solution

From Table 11.3 we will only use the data pertaining to a good gyro:

$\Delta I_m = 0.03$, $\Delta I_{to} = 0.2$, $\Delta C_{10} = 0.1$ and $\Delta C_{30} = 0.5$ (Note $\Delta C_{20} = 0$ and hence $\Delta C_2 = 0$).
Depth error = 0.5×10^{-3}.

1. Magnetic Compass Reference Errors, ΔC_1

ΔC_1 (rads) = ΔC_{10} (deg). $\pi/180 = 0.1 \times 0.0174 = 0.001745$ rads

2. Gyro Compass Error, ΔC_3

ΔC_3 (deg) = $[\Delta C_{30\,(deg)} / \text{Cos I}] \times \pi/180 = [0.5 / \text{Cos } 45.15] \times 0.0174 = 0.0123$ rads

3. Total Azimuth Error, ΔC

$\Delta C = \Delta C_1 + \Delta C_2 + \Delta C_3 = 0.001745 + 0 + 0.0123 = 0.014045$ rads

4. Misalignment Error, ΔI_m

$\Delta I_m = \Delta I_m$ (rads) $= 0.03 \times 0.0174 = 0.000523$

(note 0.0174 converts degrees to radians)

5. True Inclination Error, ΔI_t

$\Delta I_t = \Delta I_{to} \times$ Sin I (rads) $= 0.2 \times$. Sin $(45.15 \times 0.0174) = 0.00246$ rads

6. Relative Depth Error

$\varepsilon = \ (0.5 \times 10^{-3})$ ft/1000 ft from Table 11.3.

7. Along Hole Error

AHE = MD X ε

AHE = 10670 x 0.0005 = 5.33 ft

8. Lateral Error

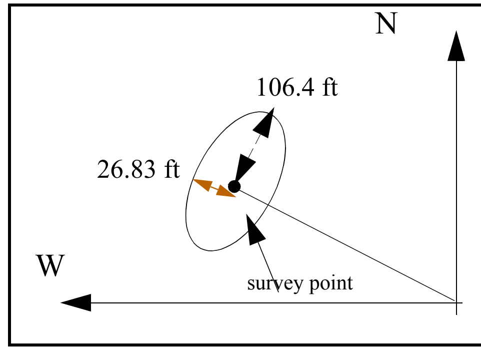
$$LE = MD\sqrt{\Delta I^2{}_m + (\Delta C \sin I)^2}$$

$$\text{LE} = 10670\text{x}\sqrt{0.000523^2 + (0.01404\text{x}\sin 45.15)^2} = 106.4 \text{ ft}$$

9. Upward Error

$$UE = MD\sqrt{\Delta I^2{}_m + \Delta I_t{}^2}$$

$$\text{UE} = 10670\sqrt{0.000523^2 + 0.00246^2} = 26.83 \text{ ft}$$



Example 11.8: Positional Uncertainty

Find the new positional uncertainties for the well given in **Example 11.5** when drilling continues for another 2000 ft using MWD surveys. The new section drilled is horizontal with the last survey point having: Inclination = 90°, Azimuth = 295°.

Solution

The last 2000 ft of the hole is horizontal, with: Inclination = 90°, Azimuth = 295°.

From Table 11.3, the errors relating to a good magnetic survey will be used as those associated with an MWD survey.

1. Magnetic Compass Reference Errors, ΔC_1

ΔC_1 (rads) = ΔC_{10} (deg) x π/180 = 1.5 x 0.0174 = 0.026 rads

2. Drill String Magnetic Error, ΔC_2

ΔC_2 (deg) = ΔC_{20} (deg) x Sin I x Sin A x π/180

= 0.25 x Sin 90 x Sin 295 x 0.0174 = -0.00395 rads

$\Delta C_3 = 0$ as this error only applies to a gyro.

3. Total Azimuth Error, ΔC

$\Delta C = \Delta C_1 + \Delta C_2 + \Delta C_3 = 0.026 - 0.00395 + 0 = 0.02205$ rads

4. Misalignment Error, ΔI_m

$\Delta I_m = \Delta I_m$ (rads) = 0.1x 0.0174 = 0.00174 rads

5. True Inclination Error, ΔI_t

$\Delta I_t = \Delta I_{to}$ x Sin I (rads) = 0.5 x Sin 90 x 0.0174 = 0.00872 rads

6. Relative Depth Error

$\varepsilon = 1x\,(10^{-3})$ (ft/1000ft) = 0.001 From Table 11.3.

7. Along hole error at last survey station:

AHE = MD X ε

AHE = 2000 x 0.001 = 2 ft

8. Lateral error at last survey station:

$$LE = 2000\sqrt{0.00174 \;\; + (0.02205 \sin 90)^2} \;\; = 44.23\,ft$$

9. Upward error at last survey station:

$$UE = 2000\sqrt{0.00174^2 + 0.00872^2} \;\; = 17.78\,ft$$

New Positional Uncertainties

Tying the MWD survey into the last survey gives the following uncertainties at MD of 12670 ft:

AHE = 5.33 + 2 = 7.33 ft

LE = 106.4 + 44.23 = 150.63 ft

UE = 26.83 + 17.78 ft = 44.61 ft

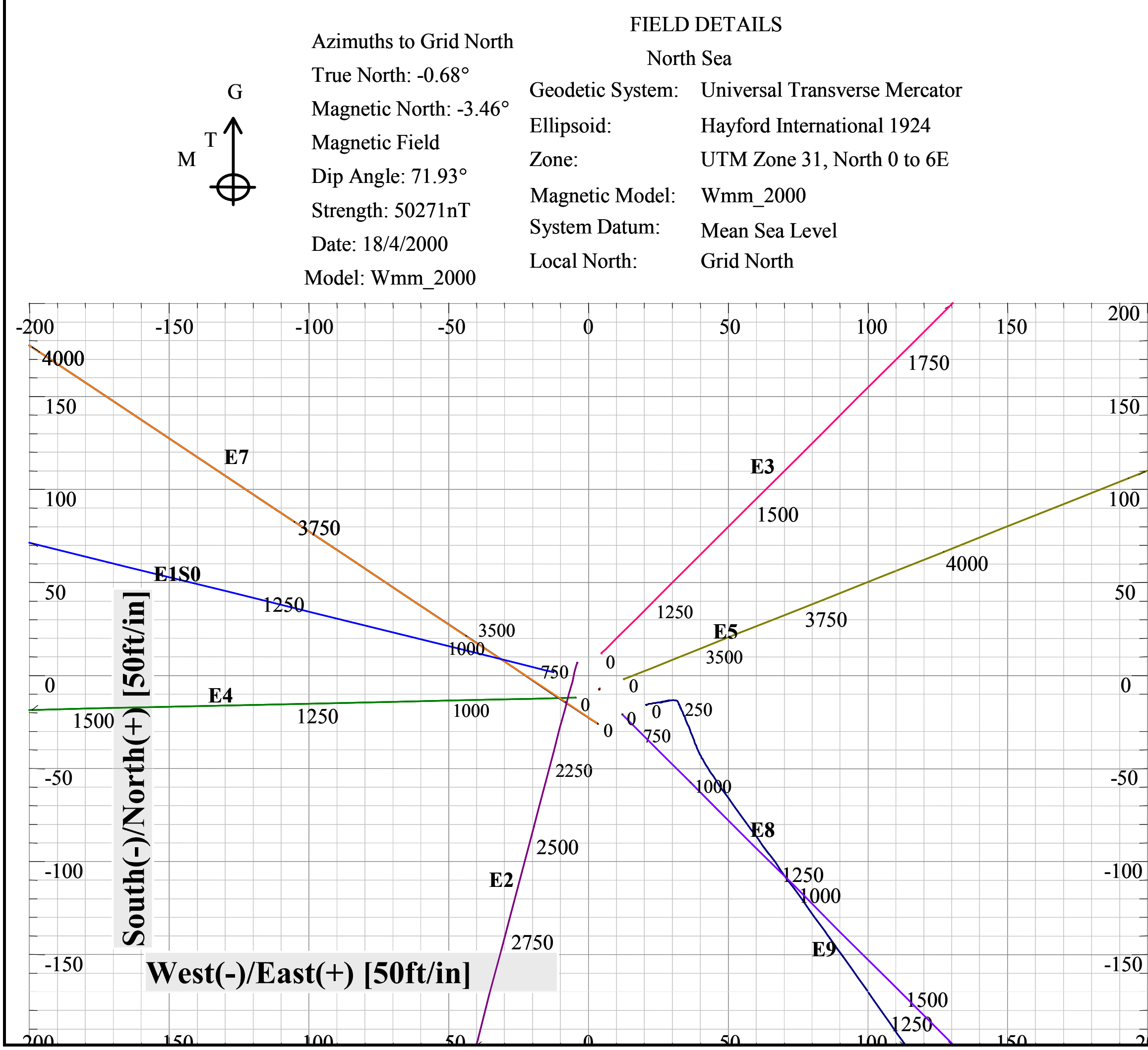
The error normally utilised for error assessment in the wellbore is the largest error, which is generally the lateral error and is usually the figure submitted to the regulatory authorities.

14.4 Spider Plots

A spider plot (**Figure 11.41**) is a scaled horizontal plan view of all wells that are considered potential collision risks to the new planned well(s). On a platform or template structure this should normally include all slots. The scales chosen for spider plots include:

- 1"/5’ scale may be required for surface casing plots,
- 1"/200‘plot may be required to show all wells drilled from a platform template to TD.

Figure 11.41 Spider plot



To aid visual inspection, a complimentary tabular listing of all proximity data is normally prepared in addition to the spider plots.

The following data is required on all spider plots:

1. Well name, field name, directional contractor name and scales

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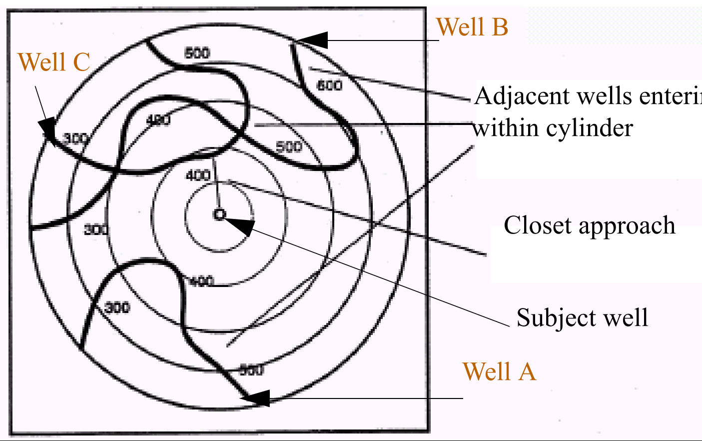
2. North reference.

3. The radius of uncertainty should be included for each wellbore at the same TVD where practical.
4. Co-ordinates of the platform template centre (if applicable) with all slots listed relative to the platform template centre.

14.5 TRAVELLING CYLINDER PLOT

The travelling cylinder plot is a popular plot relating the position of the planned wellbore relative to all other potential target wells at various depths complete with data as specified below:

Figure 11.42 Travelling cylinder plot



1. Well name, field name, directional contractor name and scale.

2. North reference or high-side reference.

3. Surveying Requirements

The travelling cylinder is a plot of how close adjacent wells are to the planned wells. The Travelling Cylinder analysis is a visualisation tool which involves imagining several concentric circles that are concentric and normal to the planned wellbore. These concentric circles form an imaginary cylinder as one travels down the planned wellbore, hence the name travelling cylinder. Adjacent wells which may cause collision problems will initially enter the outer circle (largest separation) and gradually enter the inner circles (closet separation). Then all the depths of interest are collapsed to a single flat plane (i.e. all of the travelling concentric circles are superimposed on one another) to obtain the "travelling cylinder" plot. Relevant depths are indicated on the plot as shown in **Figure 11.42**.

The travelling cylinder can therefore be used to identify the best trajectory for the planned well. The trajectory of the new well must also be monitored during the drilling process to ensure that the well is not drifting towards nearby wells.

Travelling cylinder analysis by manual calculation is not practical due to the large number of survey stations involved.

15.0 Learning Milestones

In this chapter, you should have learnt

1. The reasons for drilling deviated wells.
2. Coordinate Systems and the meaning of UTM
3. Reference Directions
4. How to carry out directional well planning
5. How to apply various well profiles
6. The various components of a PDM
7. Use of deflection tools and how to orient tools
8. Select the best BHA for given drilling conditions
9. How to carry out trajectory calculations
10. How to calculate the complete ellipse of uncertainty

16.0 References

1. Williamson H.S. (2000) "Accuracy prediction for directional measurement while drilling" SPE drilling & Completion 15 (4), December

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17.0 PROBLEMS

Exercise 1: Azimuth

Determine the azimuth with respect to true north of the following wells:

Well	Observed bearing with respect to magnetic north	Declination
1	N60^{o}E	5^{o} west
2	N45^{o}E	2^{o} east
3	S90^{o}W	1^{o} west

2. List all variables required for directional well planning.

3. What is meant by reactive torque?

4. List all components of a packed BHA required for very soft formations.

5. Why do we need to survey wells?

6. List three quantities which are measured during a survey. List variables which need to be calculated to fix a bottomhole location.

7. List errors associated with taking a survey.

8. What is meant by ellipse of uncertainty?

9. Given the following data for an S-shaped well:

KOP = 1300 ft

TVD = 10,000 ft

D = 6300 ft

BUR = 3 deg/100ft

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DOR = 2 deg /100 ft.

The end of the drop off section is to intersect the target at an inclination angle of zero degrees. Calculate:

a. Inclination angle at the tangent section

b. Horizontal displacement and TVD at end of build up section and at end of tangent section.

c. Total measured depth of well

10. Calculate true azimuth and grid azimuth for the following well:

Grid convergence = 3 ° E

Magnetic declination = 8° E

Magnetic azimuth = 77°

(Ans: 85 ° and 82°)

11. Use minimum curvature method to calculate the well position for the following data. The magnetic declination is 4.5 deg west and the programmed target azimuth is 305 deg (corrected).Plot the resulting well plans.

Station No.	**MD (ft)**	**I (deg)**	**Azimuth Actual**	**Azimuth Corrected**	**TVD (ft)**	**N (ft)**	**E (ft)**	**Vertical Section (ft)**
1	1974	20		319.5	1659.5	-11782.75	-99.96	355.35
2	2124	23	317.5					
3	2214	25.5	314					
4	2305	28.5	312					
5	2395	32	311					
6	2458	34	309					
7	2552	36.5	308					

Station No.	MD (ft)	I (deg)	Azimuth Actual	Corrected	TVD (ft)	N (ft)	E (ft)	Vertical Section (ft)
8	2677	38.5	307					
9	2801	41	307					
10	2926	42	306					
11	3082	43	305					
12	3238	42.5	305					

Wellbore Stability

12

Contents

1.0 Wellbore Stability

The successful completion of gas and oil wells involves the selection of mud weight to maintain hole stability, avoid formation fluid intrusion into the wellbore and minimise mud loss to the formation. Our concern in this section is the understanding of rock mechanical response to drilling and hydrostatic fluid support.

Borehole instability is caused by the tensile or compressive failure of the borehole wall. The borehole fails in tension when the pressure exerted by the drilling mud induces stresses in the borehole wall that exceed the tensile strength of the rock. The failure takes the form of cracks, typically starting from the borehole wall and running radially into the formation. Drilling mud may then penetrate and propagate these cracks, leading to a fall in mud level in the borehole. If this continues, the borehole stability will eventually be restored by the resulting reduction in the hydrostatic loading of the hole at depth.

The borehole fails in compression when the pressure of the drilling mud is insufficient to keep the shear stresses in the borehole wall below the shear strength of the formation. When the borehole fails in compression, broken rock falls into the borehole and the borehole diameter increases at the point of failure. Both the increase in borehole diameter and the volume of rock debris falling into the borehole sometimes make it difficult or impossible to move drilling equipment into or out of the borehole. Certain rock types, such as salt, creep rather than fail when compressed and may close around equipment in the borehole or reduce borehole diameter, again making it difficult or impossible to move drilling equipment into or out of the hole.

The implications of borehole instability to lost drilling time and equipment has prompted operators and service companies to apply rock mechanics principles to define working limits for mud weights to avoid tensile or compressive failure. This is particularly true for long reach, highly deviated and horizontal wells where the cost of downtime is very high.

The theoretical analysis involved in borehole stability is quite complex and requires a great deal of mathematical derivation. In keeping with the style of this book, only the relevant equations will be presented and will then be applied to solve practical problems. For a detailed mathematical derivation, the reader is advised to consult references 1- 10.

The quantification of wellbore instability requires the understanding and quantifying of five steps:

1. Determining magnitude and direction of in-situ earth stresses

2. Determining rock properties

3. Establishing a rock failure criterion)

4. Calculation of induced stresses around the wellbore for vertical and deviated wells.

5. Compare the induced stresses with the stresses from failure criterion to establish if the wellbore will fail

The following sections give detailed discussion of the above plus a complete wellbore stability example. Readers familiar with the equations can go straight to the worked example.

2.0 Determination Of The Magnitude And Direction Of The In-Situ Stress Field

There are three ways to determine earth stresses:

a. Fracture Tests

b. Open-Hole Calliper Surveys

c. The Application of Linear Elastic Theory

a. Fracture Tests

Formations are sometimes fractured to stimulate hydrocarbon production by increasing the formation permeability. Occasionally a formation is unintentionally fractured by using a drilling mud density that is greater than the formation breakdown pressure.

Laboratory tests have shown that fractures formed by hydraulic fracturing operations propagate perpendicular to the minor principal stress. This fact, combined with pressure data obtained from a hydraulic fracturing operation can be used to determine the magnitude of the minor principal stress.

Following the initiation and extension of a fracture, the borehole fluid pressure is reduced to allow the fracture to close. The pressure is then gradually increased by pumping fluid into the borehole and the relationship between the volume pumped and the pressure increase is monitored. When the relationship becomes non-linear the fracture is assumed to have re-opened; the pressure at this point is equal to, and counteracts, the stress perpendicular to the fracture face, shown experimentally to be the minor principal stress.

If the borehole is drilled parallel to the major principal stress it is possible to calculate the intermediate principal stress from a knowledge of the minor principal stress.

The borehole fractures when the circumferential stress at the borehole wall equals the rock tensile strength. The circumferential stress is actually an induced stress as a result of drilling the well, see equations in “Stress Distribution Around A Wellbore” on page 550.

The minimum effective compressive circumferential stress at the borehole wall is σθθ(MIN), given by:

$$\sigma_{\theta\theta(MIN)} = 3\sigma_3 - \sigma_2 - P_f \tag{12.1}$$

Fracture occurs when the tensile stress at the borehole wall on fracture equals the rock tensile strength, -T, where:

$$-T = \sigma\theta\theta(MIN) - Pw$$

Giving:

$$T = \sigma_2 - 3\sigma_3 + P_f + P_w \tag{12.2}$$

where Pw = wellbore pressure when fracture is created

If T, σ_3, P_f and Pw are known then σ_2 can be determined. In most cases σ1 is equal to the overburden stress.

In extensively explored and developed regions, the availability of large amounts of fracturing data from boreholes drilled parallel to the major principal stress can be used to establish relationships between horizontal stresses depth.

b. Open-Hole Calliper Surveys

If there are unequal stresses around a borehole, hole ovality results and this can be detected by 2, 3 or 4 arm callipers.Borehole breakouts propagate parallel to the minimum horizontal stress. If the orientation of the tool, and the ovality, is referenced to grid north, therefore the azimuth of the minimum principal stress is known.

c. The Application of Linear Elastic Theory

When no fracture and logging data are available to determine the magnitude and direction of the in-situ stress field, linear elastic theory can be applied to calculate the principal stresses, if the following assumptions are made:

- An isotropic, homogeneous rock mass,
- The principal stresses are orientated vertically and horizontally,

- No tectonic forces are acting, and therefore the horizontal principal stresses are equal,
- The vertical principal stress equals the overburden stress,
- The rock material is linear elastic

The in-situ principal stresses at any depth (H) are calculated as follows:-

$$\sigma_1 = 0.052\ \rho_b\ H \tag{12.3}$$

where ρ_b = bulk density, ppg

Taking into account the load bearing capacity and compressibility of the formation pore fluid:

$$\sigma'1 = \sigma1 - \lambda Pf \tag{12.4}$$

$$\sigma_2 = \sigma_3 = \left(\frac{\nu}{1-\nu}\right)(\sigma_1 - \lambda P_f) + Pf \tag{12.5}$$

$$\sigma'_2 = \sigma'_3 = \frac{\nu}{1-\nu}\ (\sigma_1 - \lambda P_f) \tag{12.6}$$

where $\sigma'1$, $\sigma'2$ and $\sigma'3$ = effective principal stresses

Cb = bulk compressibility

$$\lambda = (1 - \frac{Cb}{Cr})$$

Cr = rock matrix compressibility

Cb = bulk compressibility

3.0 Determination Of Rock Properties

In a borehole stability study it is necessary to define the failure surfaces of the failure criteria used. To do this the elastic properties and strength of the formation examined must be determined. There are two ways of obtaining this information:

- Laboratory Testing
- Borehole Log Analysis.

a. Laboratory Testing

Rock properties are determined by triaxially compressing rock cores. The testing is carried out over a range of axial and confining pressures with some samples being tested to failure. The rock pore pressure and temperature must also be controlled so that the test conditions match those of the rock formation studied as closely as possible.

Rock properties measured are:

- uniaxial compressive strength
- shear strength (cohesion), C
- Poisson's ratio
- tensile strength
- angle of internal friction (ϕ)

The advantage of laboratory testing is the high level of control maintained over the factors affecting rock stress-strain behaviour and failure, for example temperature, pressure and stress path. However, because of the prohibitive cost of obtaining samples of rock for testing from the in-situ formations of interest, surface outcrop rock of the formation is used. A drawback of this practice is that the mechanical properties of the outcrop formation may not be the same as the in-situ formation.

b. Borehole Log Analysis

Elastic properties of the rock can be related to the compressive and shear wave velocities through rock, as measured by the sonic log and by the gamma-ray log, Table 12.1.

The uniaxial compressive strength (Co) is calculated using the above elastic properties[11] from:-

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$$C_o = \frac{0.025\ \Delta\ E}{C_b\ x\ 10^6}\left[0.08V_{CLAY} + 0.0045\left(1 - V_{CLAY}\right)\right] \tag{12.7}$$

where,

$$\Delta = \frac{2\cos\phi}{1 - \sin\phi}$$

ϕ = internal friction angle, is taken to be 30°, when no experimentally derived value is available

Vclay = clay volume (%)

The tensile strength of rock is usually about 1/10th the compressive strength.

The advantage of using log-derived data to determine rock elastic properties and uniaxial compressive strength is that logs are available for the majority of the borehole length; usually only the top-hole is not logged before running casing. The disadvantage of using log-derived data is that the presence of drilling mud has altered the in-situ stress state, and it is known that stress state affects stress-strain behaviour and strength.

Table 12.1 Dynamic elastic properties

ν	Poisson's Ratio	$\frac{0.5(t_s x t_c)^2 - 1}{(t_s x t_c)^2 - 1}$
G	Shear Modulus	$\frac{\rho_b}{t_s} xa$
E	Young's Modulus	$2G(1+\nu)$
K_b	Bulk Modulus	$\rho_b(\frac{1}{t_c^2} - \frac{4}{3ts^2})xa$
C_b	Bulk Compressibility (with porosity)	$\frac{1}{K_b}$
C_r	Rock Matrix Compressibility (zero porosity)	$\rho_b(\frac{1}{t_{ma}^2} - \frac{4}{3tsma^2})xa$
λ	Biot Elastic Constant	$1 - \frac{C_r}{C_b}$

Where ρ_b = bulk density , t_s = shear wave arrival time , t_c = compression wave arrival time , coefficient a = 1.34 x 10^{10} if ρ_b is in gm/cm^3

4.0 ROCK FAILURE

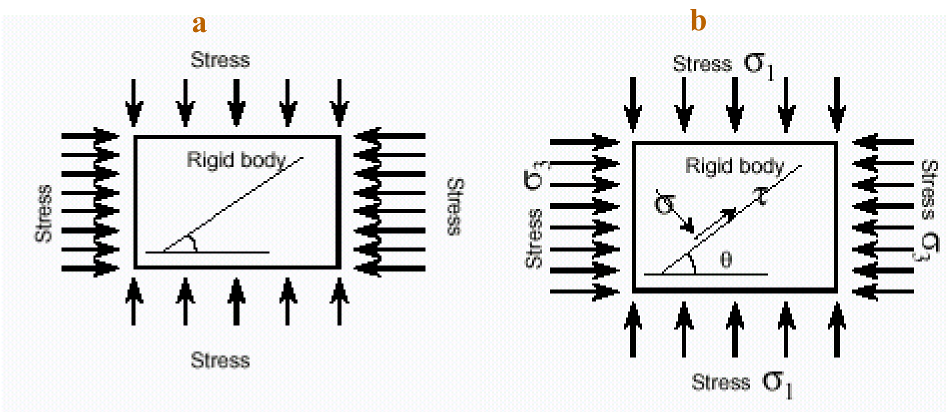
If a rigid body is subjected to normal stresses as shown in Figure 12.1 a, then these stresses will generate both shear and normal stresses within the body. In Figure 12.1 b, an imaginary plane at angle θ to stress $\sigma 1$ will have a normal stress σ and a shear stress τ acting on it. The normal stress push the surface of the plane together. The induced shear stress τ tends to cause the surfaces of this imaginary plane to slide relative to each other.

If the induced shear stress is greater than the rock's inherent shear strength then the rock will fail in shear.

Conjugate shear planes at angle θ to $\sigma 1$ can occur throughout the rock. If these failures surfaces connect then massive failure occurs, see Figure 12.1.

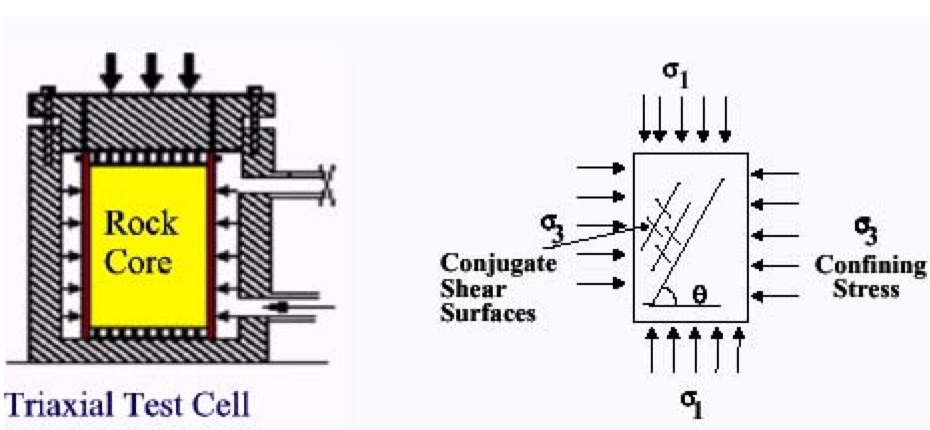
Shear failure occurs on a surface inclined at angle θ to σ1. On Mohr's circle, this angle plots as 2θ.

Figure 12.1 Stresses in a rigid body



If rock cores are tested in a triaxial testing machine (**Figure 12.2**) where axial stress (σ_1) is applied in one direction and a confining stress (σ_3), then by varying the magnitude of the confining pressure the rock will fail in shear at different values of σ_1.

Figure 12.2 Triaxial rock testing

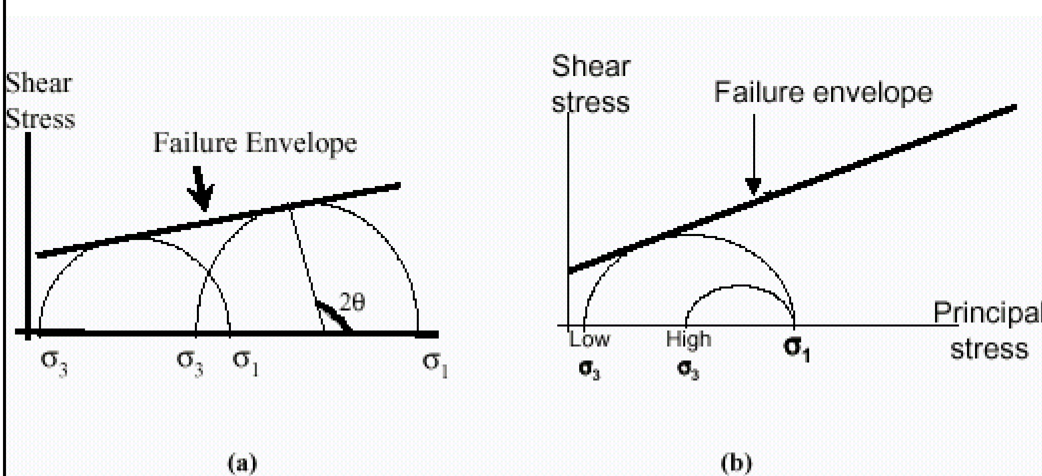


A convenient way of describing rock failure is to produce a Mohr plot where shear stress is plotted against principal stress. In practice, the shear stress is not measured, only the applied stresses σ1,σ3 are measured.

The principal stresses (σ1 and σ3) are plotted on the horizontal axis as shown in **Figure 12.3**. A circle (**Figure 12.3**) is then drawn through these values with a diameter equal to (σ1 - σ3) and centre equal to ½ (σ1 + σ3). The vertical axis becomes automatically the shear stress. The mathematical verification for this can be seen in Reference1.

A tangent to this circle is then drawn which represents the failure envelope. This tangent can be linear or a curve. The rock is stable below this envelope. The rock can not exist above this envelope as the combination of shear and principal stresses above this envelope result in rock failure.

Figure 12.3 Mohr envelope



The Mohr envelope describes shear failure in rocks. Shear failure occurs if the difference between the effective stress in one direction is much greater the effective stress acting at right angles to it. Shear failure also occurs if the pore pressure reduces by a large amount (i.e. more effective stress or if one of the acting stresses become significantly large). This can be easily seen with reference to Mohr circle.

The above results in large shear stresses developing within the rock which if exceed the rock inherent shear strength would result in shear failure.

A tangent to this circle is then drawn which represents the failure envelope. This tangent can be linear or a curve. The rock is stable below this envelope. The rock can not exist above this envelope as the combination of shear and principal stresses above this envelope result in rock failure.

4.1 Pore Pressure Effects

In the oilfields, the majority of rocks we encounter are porous and contain some pore fluid. Because of this a modified term is used to describe rock failure. This is the Effective Stress and is defined as:

Effective Stress = total stress - pore pressure

Shear failure can occur when one of the applied stresses become sufficiently large or the effective stress in one direction becomes significantly larger than the effective stress at right angles to it. This situation induces a shear stress which is greater than the inherent shear strength of the rock causing failure by sliding of rock surfaces.

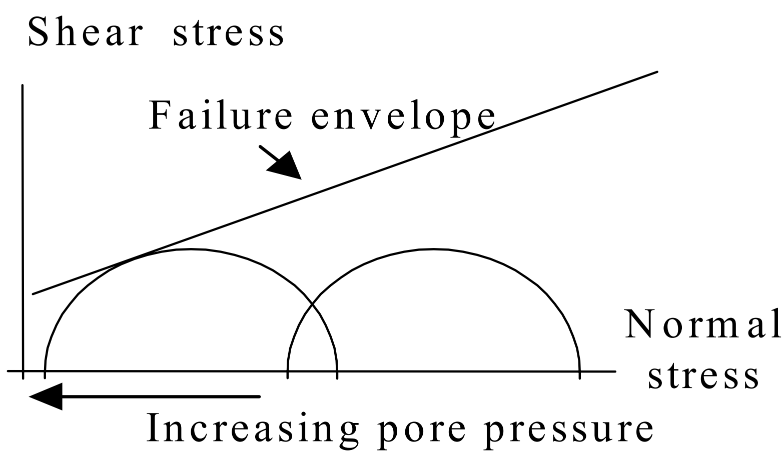
The pore pressure helps to support part of the overburden stress and also resists any lateral loading as may be seen in fracturing operations. Without the pore pressure 6, the rock matrix transmits the applied loads through grain contacts and the cementing material through out the rock which is being stressed.

In porous rocks [6], if the applied stress is sufficiently large, rock failure may occur by PORE COLLAPSE around localised areas near the wellbore due to crushing of rock grains.

Hence it is seen that rock failure will be controlled by the applied stress and by changes in pore pressure. In a depleted reservoir, therefore, the fracture pressure will be less than before depletion as there is less pore pressure to provide support against fracturing pressures.

The effect of pore pressure on the failure envelope is to move the failure circle to the left if the pore pressure increases and to the right if it decreases, as shown in Figure 12.4. A reduction in pore pressure results in an increase in the effective stress acting on grain boundaries. While shear failure may be prevented by reduction of pore pressure, the resulting effective stress may be large enough to crush the rock and cause pore collapse.

Figure 12.4 Effects of Pore Pressure on Wellbore Failure



If the rock confinement around the wellbore is increased by increasing the wellbore pressure (with pore pressure constant) then shear failure can be inhibited or prevented. This is clearly seen in **Figure 12.4** where σ3 increases towards the right. The circle height will reduce and fall below the failure envelope. This is the basis for preventing brittle shale failure by increasing the mud weight. With the exception of a few rocks, most porous rock become stronger as the confining pressure σ3 is increased.

5.0 Failure Criteria

Now that the rock properties are discussed, a rock failure criterion is required to predict whether the rock is going to fail or not depending on the applied stresses. Our aim in the oil industry is to prevent rock failure around the wellbore. The discussion below applies to shear failure.

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Failure criteria were originally developed for solid masses containing no pore pressure. Most rocks encountered in the oil industry contain pore pressure, hence for rocks with a connected system of pores, failure is controlled by the effective stress, where:

Effective stress, $\sigma' = \sigma - P_f$

We shall examine two failure criteria which are widely used in the oil industry: Mohr-Coulomb and Drager-Prager criteria.

5.1 MOHR-COULOMB CRITERION

The failure criterion states that the shear stress across a plane is resisted by the material cohesion (C) and normal stress (σ') such that: -

$$|\tau| = C + \sigma' \tan \varnothing$$

In terms of the principal effective stresses, the failure criterion is:

$$2C = \sigma'_1 \left[\left(\tan^2 \phi + 1 \right)^{1/2} - \tan \phi \right] - \sigma'_3 \left[\left(\tan^2 \phi + 1 \right)^{1/2} + \tan \phi \right] \qquad (12.8)$$

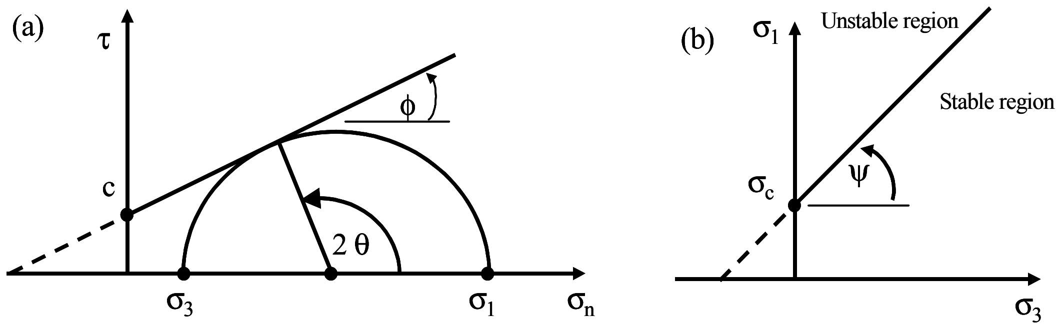
The failure envelope is determined experimentally using the Mohr construction as describe before.

Extrapolation of the failure envelope to a zero value of shear stress gives a predicted value of the uni-axial tensile strength. Experimentally determined strengths are usually less than predicted values, and a tensile cut-off is typically applied.

The criterion is shown graphically in **Figure 12.5**. The plot in Figure 12.5 b is very useful as it will be utilised later to establish wellbore stability. Simply stated, for a given rock a Mohr-Coulomb envelop is established as shown in Figure 12.5 b using rock properties from triaxial tests from offset wells. Then for the well under investigation, the wellbore stresses are compared with the envelope to establish rock stability.

All rocks to the right of the line in Figure 12.5 b are stable and those to the left are unstable. In practice, wellbore stresses are calculated for a range of mud weights to establish the minimum mud weight required to prevent hole collapse.

Figure 12.5 Coulomb Strength Envelopes In Terms Of: (a) Shear And Normal Stresses, And (b) Principal Stresses



$$\text{Tan}\,\psi = \frac{1+\sin\phi}{1-\sin\phi}$$

Although widely used in borehole stability studies, there are drawbacks to the Mohr-Coulomb criterion. These are:

- The criterion does not take into account the intermediate principal stress, which is known to affect failure.
- It implies that a major shear fracture occurs at peak strength. Experimental work suggests that this is not always the case.
- It implies a direction of shear, relative to the major and minor principal stresses, $\sigma 1$ and $\sigma 3$, that is not always seen in experimental observations.
- Experimental peak strength envelopes derived using the Mohr construction are generally non-linear. This possibly explains the poor correlation between the uni-axial tensile strength obtained by extrapolating a linear Mohr-Coulomb failure surface and that obtained by experiment.

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5.2 DRUCKER-PRAGER

An approximation to the Mohr-Coulomb law was proposed by Drucker and Prager [12,13] as a modification of the Von Mises criterion. The Drucker-Prager criterion (also known as the extended Von Mises criterion) is given by:

$$\gamma I_1 + (J_2)^{1/2} = K \qquad (12.9)$$

where

$I1$ = first invariant of stress = $\sigma x + \sigma y + \sigma z$

$J2$ = second invariant of stress deviation

$$J2 =- (SySz + SzSx + SxSy) + Syz2Szx2+ Sxy2 \qquad (12.10)$$

$$\begin{aligned} &\mathbf{S_x = \sigma_x - S,\ \ S_y = \sigma_y - S,\ \ S_z = \sigma_z - S} \\ &\mathbf{S_{yz} = \tau_{yz}\ ,\ S_{zx} = \tau_{zx},\ \ S_{xy} = \tau_{xy}} \\ &\mathbf{S = 1/3\ (\sigma_x + \sigma_y + \sigma_z)} \end{aligned} \qquad (12.11)$$

γ and K vary according to where the criterion intersects the Mohr-Coulomb failure surface. The geometrical representation of the Drucker-Prager failure surface is given in **Figure 12.6**.

In order to make the Drucker-Prager circle coincide with the outer apices of the Mohr-Coulomb criterion, it can be shown that:

$$\gamma = \frac{2\ \sin\ \phi}{\sqrt{3}\ (3 - \sin\phi)} \qquad K = \frac{6\ C\ \cos\ \phi}{\sqrt{3}\ (3 - \sin\phi)} \qquad (12.12)$$

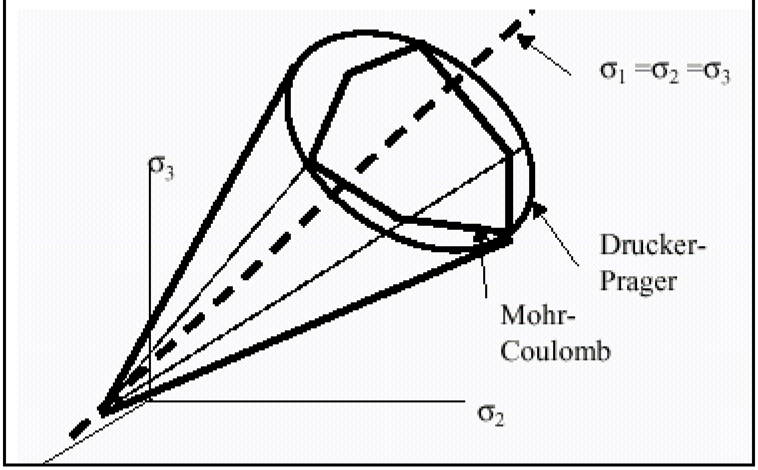
For coincidence with the inner apices it can be shown that:

$$\gamma = \frac{2\ \sin\ \phi}{\sqrt{3}\ (3 + \sin\phi)} \qquad K = \frac{6\ C\ \cos\ \phi}{\sqrt{3}\ (3 + \sin\phi)} \qquad (12.13)$$

For coincidence with the faces it can be shown that:

$$\gamma = \frac{\sin\ \phi}{\sqrt{9 + 3\sin^2\phi}} \qquad K = \frac{3\ C\ \cos\ \phi}{\sqrt{9 + 3\sin\phi}} \qquad (12.14)$$

Figure 12.6 Drucker-Prager criterion of rock failure



The Drucker-Prager failure criterion is sometimes expressed in terms of the octahedral shear stress, τoct, and the octahedral normal stress, σoct, where:-

$$\tau_{oct} = \frac{2J_2}{3} \tag{12.15}$$

$$\sigma_{oct} = \frac{I_1}{3} \tag{12.16}$$

Hence we have four failure criteria which we can use to assess wellbore stability. These are:

1. The Mohr-Coulomb failure criterion, where:

$$\sigma_1 - P_f = \frac{1 + \sin\phi}{1 - \sin\phi}\left(\sigma_3 - P_f\right) + \frac{2\,C\,\cos\phi}{1 - \sin\phi} \tag{12.17}$$

2. The Drucker-Prager failure criterion circumscribing the outer apices of the Mohr-Coulomb plot. Giving:-

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$$\tau_{oct} = \frac{2\sqrt{2}\ C\ \cos\ \phi}{3 - \sin\ \phi} + \frac{2\ \sqrt{2}\ \sin\ \phi}{3 - \sin\ \phi}\left(\sigma_{oct} - Pf\right) \qquad (12.18)$$

3. The Drucker-Prager failure criterion circumscribing the inner apices of the Mohr-Coulomb plot. Giving:

$$\tau_{oct} = \frac{2\ \sqrt{2}\ C\ \cos\ \phi}{3 + \sin\ \phi} + \frac{2\ \sqrt{2}\ \sin\ \phi}{3 + \sin\ \phi}\left(\sigma_{oct} - Pf\right) \qquad (12.19)$$

4. The Drucker-Prager failure criterion inscribing the Mohr-Coulomb Criterion. Giving:-

$$\tau_{oct} = \frac{\sqrt{6}\ C\ \cos\ \phi}{\sqrt{9 + 3\ \sin^2\ \phi}} + \frac{\sqrt{6}\ \sin\ \phi}{\sqrt{9 + 3\ \sin^2\ \phi}}\left(\sigma_{oct} - Pf\right) \qquad (12.20)$$

A study carried out by McLean and Addis[13] examined the effect of the choice of failure criterion, Mohr-Coulomb and Drucker-Prager, on safe mud weight recommendations, using a linear elastic stress-strain relationship.

The formation studied was the Cyrus sandstone reservoir in the Southern North Sea. Sandstone cores from the reservoir were tri-axially tested and gave the following results:

Cohesion, C = 6 MPa

Internal friction angle, ϕ = 43.8°

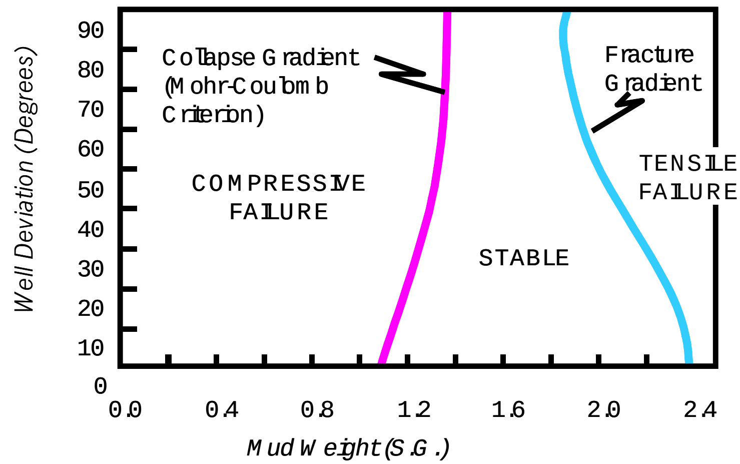
Poisson's Ratio = 0.2

The major principal stress, σ_1, is considered to be vertical and equal the overburden stress. The overburden stress gradient is 1 psi/ft and the reservoir depth is 8530 ft.

The intermediate and minor principal stresses are considered horizontal and equal to each other. No direct measurements of the horizontal stress are available therefore an arbitrary value of 0.75 psi/ft was assumed.

The tensile strength is considered negligible and tensile failure is assumed to occur when the effective compressive stress at the borehole wall is zero.

Figure 12.7 safe mud weight as predicted by Mohr - Coulomb criterion



The comparison was presented in the form of hole inclination vs. safe mud weight for the four criteria examined. The Mohr-Coulomb plot is shown in Figure 12.7. The actual mud weight used to drill the horizontal section of the Cyrus reservoir was 1.17 SG.

The Mohr-Coulomb criterion, the extended Von Mises Criterion circumscribing the inner apices of the Mohr-Coulomb plot and that inscribing the Mohr-Coulomb plot all recommend minimum mud weights significantly higher than this. The extended Von Mises Criterion circumscribing the outer apices of the Mohr-Coulomb plot predicts that 1.17 sg is within a safe mud weight range (**Figure 12.8**), implying it is the best criterion to use. However, this criterion gives unrealistic minimum mud weight recommendations for lower borehole inclinations.

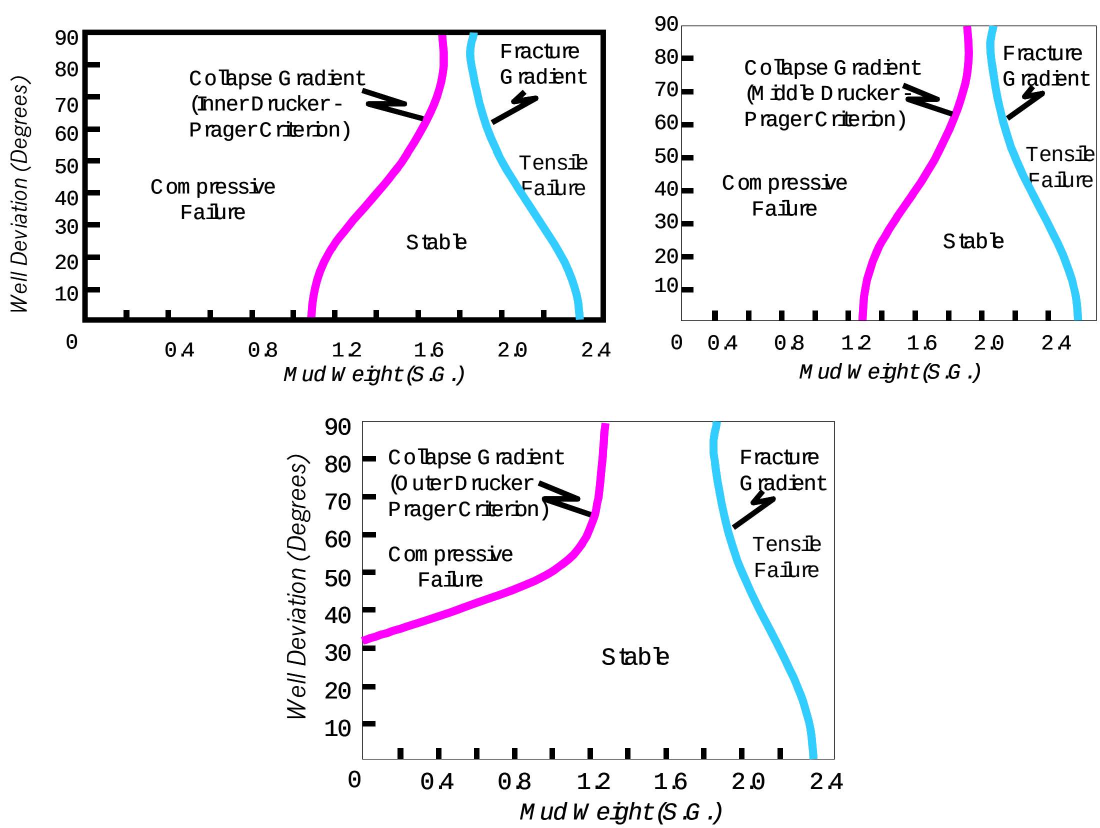
McLean and Addis concluded that:

- When using a linear elastic analysis, the failure criteria give extreme differences in predicted minimum mud weights.
- The criteria do not give consistently realistic minimum mud weight predictions as conditions, e.g. borehole inclination, change.
- None of the criteria studied should be used as a quantitative assessment of stability.

The Mohr-Coulomb criterion is recommended as the most realistic due to its good fit to experimental data. However, it is recognised that a Mohr-Coulomb failure criterion, coupled with linear elasticity, does not always give reliable predictions of minimum mud weights used in practice.

Linear Elastic Analysis coupled with any of the failure criteria studied is considered a useful qualitative tool for studying borehole instability problems.

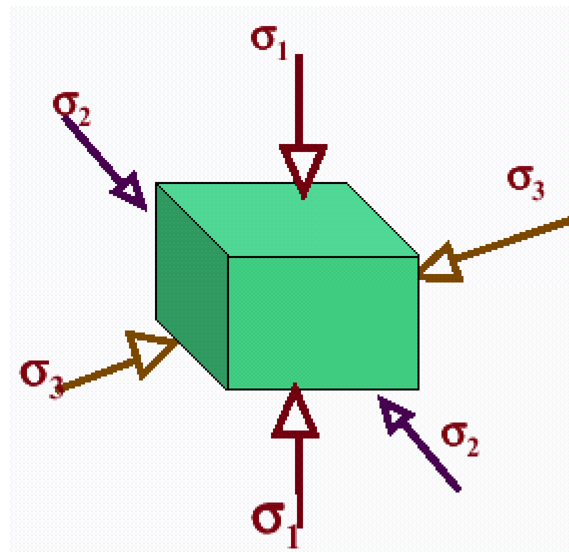
Figure 12.8 Envelope of safe mud weights as predicted by Drucker-Prager criteria[13]



The example at the end of this chapter will show how to construct the plots in **Figure 12.7** and **Figure 12.8**.

6.0 STRESS DISTRIBUTION AROUND A WELLBORE

Figure 12.9 Earth stresses



The in-situ stresses in an undisturbed rock mass are shown in Figure 12.9. It is usually assumed that the major principal stress, σ1, is vertical and the intermediate and minor principal stresses, σ2 and σ3 respectively are horizontal. However, in tectonically active areas the principal stresses may be inclined to the vertical and horizontal.

When a borehole is drilled into a rock mass, drilling fluid of a different density replaces the excavated rock, and the natural stress field redistributes locally around the borehole. The stress distribution in the borehole wall depends on the magnitude of the in-situ principal stresses and the stress-strain response of the rock material. Borehole stability studies have assumed, a homogeneous, isotropic, linear elastic rock, with no fluid flow through the

Hence the drilling of a hole in the ground disturbs the in-situ stresses around the wellbore and induces additional stresses. In particular, hoop or circumferential stresses σθθ are induced which act around the wellbore. The mud pressure creates radial stresses σrr which provide support for the walls of the wellbore. As σrr increases, the induced hoop stresses decrease and may become negative resulting in rock failure in tension, i.e. wellbore burst.

A third stress σzz, longitudinal stress acts along the axis of the wellbore.

Hence at any point near the wellbore there will be three induced stresses:

σθθ,σrr and σzz. Theses stresses are mutually perpendicular to each other at any point.

The redistributed (or induced) stresses around a vertical hole are given by the equation in Table 12.2. Note in this table the terms $\sigma x,\sigma y,\sigma z$ are used instead of $\sigma 1,\sigma 2,\sigma 3$ for the in-situ earth stresses to enable the equations to be applied to both vertical and deviated wells. The equations for $\sigma x,\sigma y,\sigma z$ are given in Table 12.3 and they are expressed in terms of $\sigma 1,\sigma 2,\sigma 3$. For a vertical well, $\sigma x,\sigma y,\sigma z$ reduce to $\sigma 1,\sigma 2,\sigma 3$.

Furthermore the magnitude of the hoop, radial and longitudinal stress vary at different positions around the wellbore, Figure 12.10. The magnitude of the induced stresses depend on:

- angle of wellbore with respect to principal stresses
- distance from the wellbore
- type of rock
- magnitude of in-situ stresses
- geometry of hole, i.e. circular or elliptical

Table 12.2 Redistributed Earth Stresses Around A Wellbore

$$\sigma_{rr} = \frac{\sigma_x + \sigma_y}{2}\left(1 - \frac{a^2}{r^2}\right) + P_w \frac{a^2}{r^2} - \frac{\sigma_x - \sigma_y}{2}\left(1 + 3\frac{a^4}{r^4} - 4\frac{a^2}{r^2}\right)\cos 2\theta + \tau_{xy}\left(1 + 3\frac{a^4}{r^4} - 4\frac{a^2}{r^2}\right)\sin 2\theta$$

$$\sigma_{\theta\theta} = \frac{\sigma_x + \sigma_y}{2}\left(1 + \frac{a^2}{r^2}\right) - P_w \frac{a^2}{r^2} - \frac{\sigma_x - \sigma_y}{2}\left(1 + 3\frac{a^4}{r^4}\right)\cos 2\theta - \tau_{xy}\left(1 + 3\frac{a^4}{r^4}\right)\sin 2\theta$$

$$\sigma_{zz} = -\nu\left[2\left(\sigma_x - \sigma_y\right)\frac{a^2}{r^2}\cos 2\theta + 4\tau_{xy}\frac{a^2}{r^2}\sin 2\theta\right] + \sigma_z$$

$$\tau_{r\theta} = \frac{\sigma_x - \sigma_y}{2}\left[1 - 3\frac{a^4}{r^4} + 2\frac{a^2}{r^2}\right]\sin 2\theta + \tau_{xy}\left[1 - 3\frac{a^4}{r^4} + 2\frac{a^2}{r^2}\right]\cos 2\theta$$

$$\tau_{\theta z} = \left(-\tau_{zx}\sin\theta + \tau_{yz}\cos\theta\right)\left[1 + \frac{a^2}{r^2}\right]$$

$$\tau_{zr} = \left(\tau_{zx}\cos\theta + \tau_{yz}\sin\theta\right)\left[1 - \frac{a^2}{{}^2}\right.$$

Hence within the vicinity of the wellbore[6] (Figure 12.10), we have a rock core subjected to:

1. A high axial stress $\sigma_{\theta\theta}$

2. A confining pressure provided by the longitudinal stress, σ_z

3. A second confining pressure provided by wellbore pressure, σ_r

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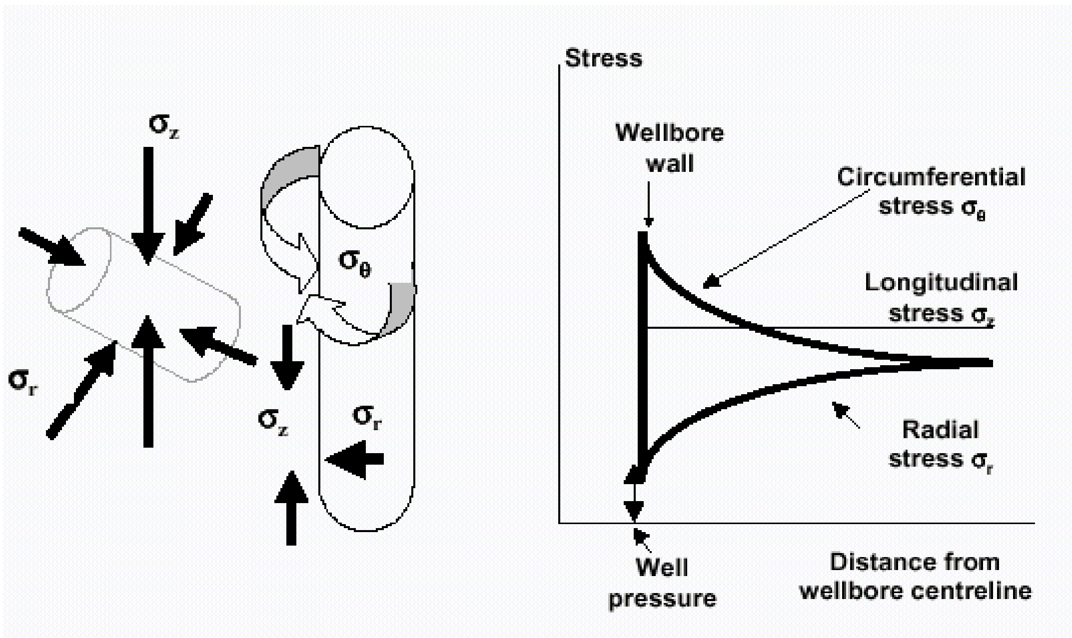
Figure 12.10 Stress Distribution Around the Wellbore



As we move away from the wellbore, the induced stresses will revert back to the in situ stresses. In drilling, wellbore stability is influenced by the stresses around and near the wellbore.

The equations in Table 12.2 can be used to explain both tensile failure and shear failure. As can be seen from Table 12.2, the expression for $\sigma_{\theta\theta}$ (hoop stress) depends on the wellbore pressure (Pw).

At high wellbore pressure, the tangential stresses goes into tension resulting in axial fractures. In fact if the minimum effective $\sigma_{\theta\theta}$ (at angle = 180 deg) was set to zero, then equation Equation (12.2) for tensile failure will be obtained.

At low wellbore pressure, the tangential stress is high and if the difference between $\sigma\theta$ and σr (i.e. deviatoric stress $\sigma 1$ - $\sigma 3$) in some areas around the wellbore is large enough then shear failure will occur. This failure is known as borehole collapse. The zone surrounding the wellbore which undergoes collapse failure is known as the yield zone or plastic zone. The plastic zone will not be circular, but may be ellipse or may be limited to small failure zone on each side of the well due to the variation of wellbore stresses around the wellbore.

The type of wellbore collapse[6] depends on the type of rock being drilled. For elastic rocks such as soft shale, the failed material remain intact and would extend slightly into the wellbore (partial closure causing tight hole) or in some cases complete closure.

For brittle rocks such as brittle shales, wellbore collapse manifest itself in the form of wellbore enlargement where rocks break away from the walls of the hole. In some soft sandstones, rock failure occurs as sand production and the individual sand grains are effectively being produced into the wellbore.

6.1 Stress Transformation For Deviated Wells

The stability of the wellbore depends on the magnitude of the induced stresses due to the creation of the borehole. For a vertical well, the induced stresses can be easily calculated using the equation presented in Table 12.2. The stresses induced are transformed into principal stresses and are compared with a failure criterion to determine the minimum mud weight required to prevent hole collapse.

However, for inclined and horizontal wells, the in-situ earth stresses must first be transformed into axes aligned with the wellbore before one can calculate the induced stresses. The in-situ principal stresses are first transposed relative to a co-ordinate system with one of the axes parallel to the borehole axis, and one in the horizontal plane. The process of transforming stresses is as follows:

1. Transform the in-situ stresses to stresses aligned with the wellbore using the equations in Table 12.3 and Figure 12.11. This process transforms the stresses from a global system to wellbore coordinates. The stresses $\sigma 1, \sigma 2, \sigma 3$ in Table 12.3 are the in-situ earth principal stresses. Angle α is the hole inclination of the well from the vertical. The angle β is the horizontal angle (azimuth) between the wellbore and $\sigma 3$.

2. Calculate the induced stresses due to the creation of the wellbore using the equations in Table 12.2. **Figure 12.11** shows the angle where these stresses are measured from. The stresses $\sigma\theta\theta$, σrr, σzz vary with the position around the wellbore. The angle θ takes any value from 0-90°, corresponding to different points

on the well circumference, **Figure 12.11**. Hence the equations in Table 12.2 do not provide a unique solution as they vary with angle θ and distance from the wellbore wall.

3. At the wellbore walls, the equations in Table 12.2 are reduced to the equation in Table 12.4. Note that $\sigma x,\sigma y,\sigma z$ depend on hole inclination and azimuth and on the magnitude of $\sigma 1,\sigma 2,\sigma 3$.

Table 12.3 Stresses Around an Inclined Well

$$
\begin{aligned}
\sigma_x &= \sigma_2 \sin^2 \beta + \sigma_3 \cos^2 \beta \\
\sigma_y &= \cos^2 \alpha \left(\sigma_2 \cos^2 \beta + \sigma_3 \sin^2 \beta\right) + \sigma_1 \sin^2 \alpha \\
\sigma_z &= \sin^2 \alpha \left(\sigma_2 \cos^2 \beta + \sigma_3 \sin^2 \beta\right) + \sigma_1 \cos^2 \alpha \\
\tau_{xy} &= \cos \alpha \sin \beta \cos \beta \left(\sigma_2 - \sigma_3\right) \\
\tau_{xy} &= \sin \alpha \cos \alpha \left(\sigma_1 - \sigma_2 \cos^2 \beta - \sigma_3 \sin^2 \beta\right) \\
\tau_{zx} &= \sin \alpha \sin \cos \beta \left(\sigma_3 - \sigma_2\right)
\end{aligned}
$$

Table 12.4 Stresses At the Wellbore Walls

$$\sigma_{rr} = P_w$$

$$\sigma_{\theta\theta} = (\sigma_x + \sigma_y) - P_w - 2(\sigma_x - \sigma_y)\cos 2\theta$$

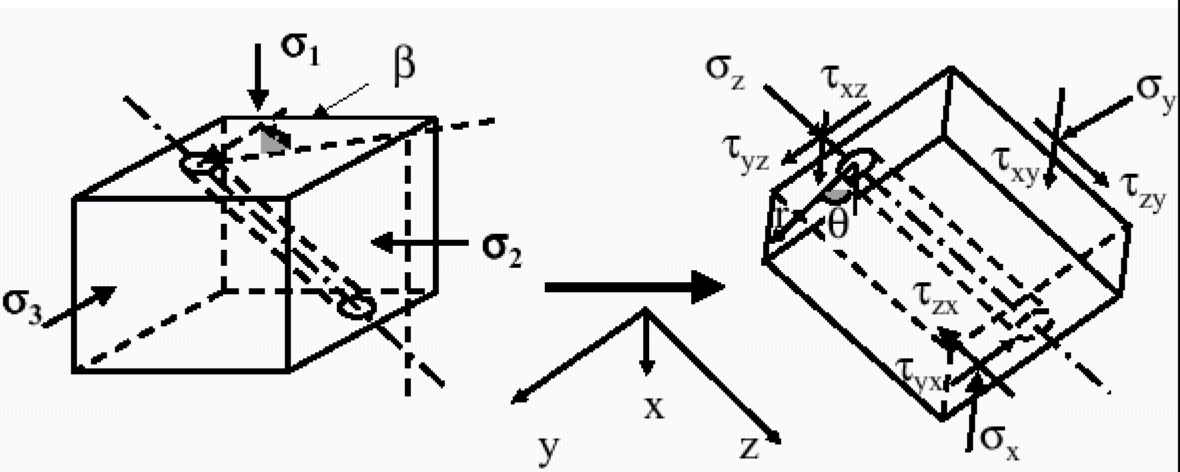
$$\sigma_{zz} = \sigma_z - \nu\{2(\sigma_x - \sigma_y)\}\cos 2\theta$$

$$\tau_{r\theta} = 0$$

$$\tau_{\theta z} = \tau_{yz}\cos\theta$$

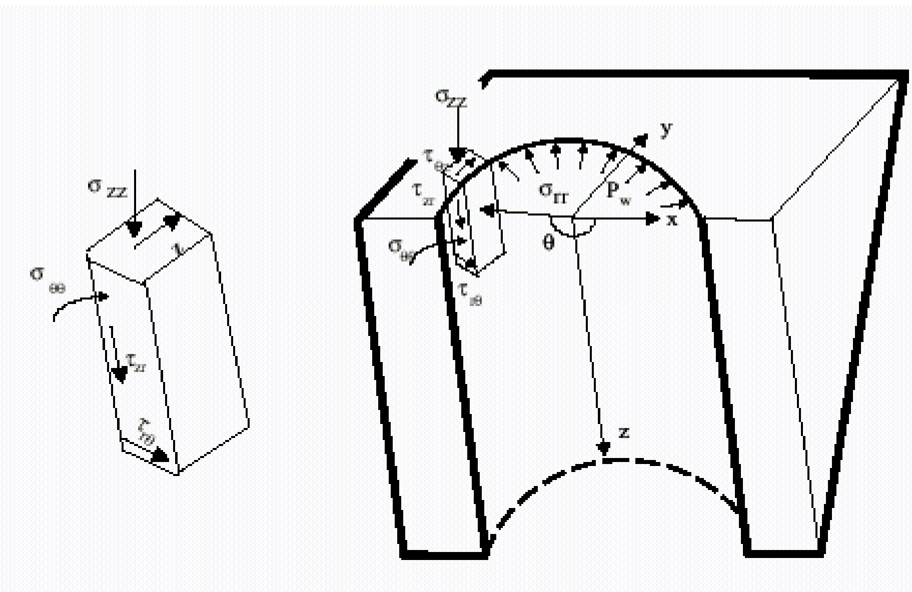
$$\tau_{zr} = 0$$

Figure 12.11 Stress Transformation



(x - axis lies in the horizontal plane)

Figure 12.12 Stresses Around The Wellbore



4.The equations in Table 12.4 give maximum stresses when cos 2θ = 1, or when θ = 0.

5. In Table 12.4, only σrr is a principal stress since τrz and τrθ are zero. Both σθθ and σzz have shear stresses (τθz) associated with them. Hence we need to find the principal stresses associated with σθθ and σzz. This is done as follows:

The two principal stresses can be calculated by referring to Mohr's circle, centred at

½ (σθθ + σzz) and with a radius of $\left\{\left[\frac{\sigma_{\theta\theta} - \sigma_{zz}}{2}\right]^2 + \tau_{\theta z}{}^2\right\}$.

Hence the three principal stresses are given by equation Equation (12.21):

$$\left\{ \begin{array}{l} \dfrac{\sigma_{\theta\theta} + \sigma_{zz}}{2} + \left\{ \left[\dfrac{\sigma_{\theta\theta} - \sigma_{zz}}{2} \right]^2 + \tau_{\theta z}{}^2 \right\}^{0.5} \\ \dfrac{\sigma_{\theta\theta} + \sigma_{zz}}{2} - \left\{ \left[\dfrac{\sigma_{\theta\theta} - \sigma_{zz}}{2} \right]^2 + \tau_{\theta z}{}^2 \right\}^{0.5} \\ P_w \\ \end{array} \right\} \tag{12.21}$$

The above transformation to principal stresses is necessary before theses stresses are used in the failure criteria, see "Failure Criteria" on page 542.

The induced principal stresses in equations Equation (12.21) at the walls of the borehole should then be arranged in ranking order:

σ1 (maximum) = psi

σ2 (intermediate)= psi

σ3 (minimum)= psi

As will be seen in the example, the induced stresses σ1 and σ3 are plotted on the same graph as the failure criterion. The intersection point gives the minimum mud weight required to prevent hole collapse.

7.0 Procedure For Determining Safe Mud Weights To Prevent Hole Collapse

1. Determine the three in-situ stresses σ1, σ2 and σ3.

2. Determine which failure criterion to use

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(a)The Mohr-Coulomb failure criterion, where: -

$$\sigma_1 - P_f = \frac{1 + \sin\phi}{1 - \sin\phi}(\sigma_3 - P_f) + \frac{2C\cos\phi}{1 - \sin\phi}$$

(b)The Drucker-Prager failure criterion circumscribing the outer apices of the Mohr-Coulomb plot. Giving:

$$\tau_{oct} = \frac{2\sqrt{2}\,C\cos\phi}{3 - \sin\phi} + \frac{2\sqrt{2}\sin\phi}{3 - \sin\phi}(\sigma_{oct} - P_f)$$

It should be noted that the Mohr-Coulomb criterion does not give consistent realistic minimum mud weights to prevent hole collapse in highly inclined wells.

The Drucker-Prager compressive failure criterion gives most accurate minimum mud weights to prevent hole collapse in highly inclined wells. However, predictions for low angle wells are not realistic.

3. Determine the cohesion and angle of internal friction from laboratory testing (triaxial testing) of cores from offset wells

4. Calculate the failure surface from either equations Equation (12.17) or Equation (12.18) to Equation (12.20) and plot σ1 vs. σ3 for a given formation pressure.

5. Calculate stresses at the borehole wall as follows:

   a. transpose the in-situ principal stresses relative to a coordinate system with one axis parallel the wellbore axis and a second axis in the horizontal plane, using equations in Table 12.3.

   b. calculate the axial, radial and tangential stresses at the wellbore wall using equations in Table 12.2 and Table 12.4.

c. convert the stresses in (b) to principal stresses so that they can be used in the failure criteria. Remember the principal stresses in (c) are not the same as the in-situ principal stresses. They are the induced stresses due the drilling of the well and due to the presence of the mud. The equations are given in Table 12.4.

The calculated principal stresses at the wellbore wall are dependent on both wellbore inclination and mud weight.

6. Asses the borehole stability by plotting the failure surface of the chosen failure criterion as a function of the appropriate stresses. The stability of the wellbore can be deduced by noting the intersection point of the existing stresses calculated in step (5 c) with the failure envelope.

7.1 Tensile Failure

The wellbore pressure required to fracture (burst) the wellbore walls for any given hole angle may be derived from the equation given for $\sigma\theta\theta$ by setting the effective stress to zero. Remember the effective stress is the total stress minus the pore pressure. We shall call this wellbore pressure as the formation breakdown gradient (FBG) to distinguish it from the fracture gradient which is related to overcoming the earth horizontal stress component.

The failure envelope for any given mud weight may be determined for a series of hole angles.

Example 12.1: Wellbore Stability Assessment

Given the following well data for a sandstone reservoir, determine the minimum mud weights required to prevent hole collapse if a horizontal well is be drilled.

Cohesion (C) = 1182 psi

Angle of internal friction is 42.4 deg

Depth is 9452 ft

Angle = 90 degrees

Azimuth = 10 deg

σ1 = 1 psi/ft

σ3 = 6143 psi at 9452 ft

Pore pressure = 3500 psi

Poisson' ratio = 0.35

Solution

Step 1

σ1 = 1 psi /ft x 9452 ft = 9452 psi

σ3 = 6143 psi at 9452 ft

Step 2

Determine the failure envelope using

(i) Mohr- Coulomb Criterion

$$\sigma_1 - P_f = \frac{1 + \sin\phi}{1 - \sin\phi}\left(\sigma_3 - P_f\right) + \frac{2\,C\cos\phi}{1 - \sin\phi}$$

$$\sigma_1 - P_f = \frac{1 + \sin 42.4}{1 - \sin 42.4}\left(\sigma_3 - P_f\right) + \frac{2\,x1182\cos 42.4}{1 - \sin 42.4}$$

$$\sigma_1 - P_f = 5.13\left(\sigma_3 - P_f\right) + 5360$$

$$\sigma_1 = 5.13\sigma_3 - 4.13P_f + 5360 \tag{12.22}$$

The reader should note that equation Equation (12.22) represents a failure envelope for a rock sample under laboratory triaxial testing where confining stress (σ3) and axial stress (σ1) are applied. Assume values of (σ3) of 2000 to 6000 psi to solve equation 2.28, using a formation pressure of 3500 psi. The results are shown in Table 2.5.

Table 12.5

Pore Pressure = 3500 psi	
Applied Stress, psi	
σ_3	σ_1
2000	1148
3000	6278
4000	11408
5000	16538
6000	21668

Plot the above values as shown in Figure 12.13 to obtain the Mohr- Coulomb failure envelope

(ii) The Drucker-Prager failure criterion circumscribing the outer apices of the Mohr-Coulomb plot, gives:

$$\tau_{oct} = \frac{2\sqrt{2}\ x1182\cos 42.4}{3-\sin 42.4} + \frac{2\ \sqrt{2}\ \sin 42.4}{3-\sin\ 42.4}\left(\sigma_{oct} - P_f\right)$$

Simplifying, gives:

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$$\tau_{oct} = 1062 + 0.82\ \sigma_{oct} - 0.82\ P_f \qquad (12.23)$$

The failure envelope is plotted as τ_{oct} vs. σ_{oct}.

The use of Drucker-Prager criterion will be left as an exercise for the reader.

Step 3

Transpose the in-situ principal stresses σ1 (9452 psi) and σ3 (6143 psi) using the equations given in Table 2.3.

Here we shall assume σ2 = σ3

Hence the equations in Table 12.2, reduce to:

(Note sin2α +cos2 α = 1 and σ2 = σ3)

$$\boxed{\begin{aligned}
\sigma_x &= \sigma_2\ \sin^2\ \beta + \sigma_3\ \cos^2\ \beta = \sigma_3 \\
\sigma_y &= \cos^2\alpha\left(\sigma_2\ \cos^2\ \beta + \sigma_3\ \sin^2\ \beta\right) + \sigma_1\ \sin^2\alpha = \sigma_3 \cos^2\alpha + \sigma_1\ \sin^2\alpha \\
\sigma_z &= \sin^2\alpha\left(\sigma_2\ \cos^2\ \beta + \sigma_3\ \sin^2\ \beta\right) + \sigma_1\ \cos^2\alpha = \sigma_3 \sin^2\alpha + \sigma_1\ \cos^2\alpha \\
\tau_{xy} &= \cos\ \alpha\ \sin\ \beta\ \cos\ \beta\left(\sigma_2 - \sigma_3\right) = 0 \\
\tau_{xy} &= \sin\alpha\cos\ \alpha\left(\sigma_1 - \sigma_2\ \cos^2\beta - \sigma_3\ \sin^2\ \beta\right) = \sin\alpha\cos\alpha(\sigma_1 - \sigma_3) \\
\tau_{zx} &= \sin\ \alpha \sin\ \cos\ \beta\left(\sigma_3 - \sigma_2\right) = 0
\end{aligned}}$$

For an inclination angle of (α) of 90 degrees and σ_1 = 9452 psi and σ_3 = 6143 psi , the above equations become:

$$\sigma_x = \sigma_3 = 6143 psi$$

$$\sigma_y = \sigma_3 \cos^2\alpha + \sigma_1 \sin^2\alpha = 6143\cos^2 90 + 9452 \sin^2 90 = 9452 ps$$

$$\sigma_z = \sigma_3 \sin^2\alpha + \sigma_1 \cos^2\alpha = 6143\sin^2 90 + 9452 \cos^2 90 = 6143 ps.$$

$$\tau_{xy} = 0$$

$$\tau_{xy} = \sin\alpha\cos\alpha(\sigma_1 - \sigma_3) = \sin 90 \cos 90 (9452 - 6143) = 0$$

$$\tau_{zx} = 0$$

Table 12.6 summarises the calculations for angles 30, 50, 70 and 90 degrees.

Table 12.6

		Wellbore Inclination , degrees				
Stress, psi		0	30	50	70	90
	σ_x	6143	6143	6143	6143	6143
	σ_y	6143	6191	7656	8943	9452
	σ_z	9452	8365	6900	5613	6143
	τ_{xy}	0	0	0	0	0
	τ_{yz}	0	1183	2141	1397	0
	τ_{zx}	0	0	0	0	0

Step 4

Calculate the induced stresses at the borehole wall

The stresses will be calculated at a point a= r, where r is the radius of the borehole.

The equations in Table 12.2 reduce to the equations in Table 12.4.

The equations in Table 12.4 give maximum stresses when cos 2θ = 1, or when θ = 0. Hence using an inclination angle of (α) of 90 degrees and σ_1 = 9452 psi and σ3 = 6143 psi, Pw = 0.052 x 9 (ppg) x 9452 ft = 4424 psi, the equations in Table 12.4 become :

$$\sigma_{rr} = P_w = 4424\,psi$$

$$\sigma_{\theta\theta} = (\sigma_x + \sigma_y) - P_w - 2(\sigma_x - \sigma_y)\ \cos 2\theta = 6143 + 9452 - 4424 - 2(6143 - 9452)$$
$$= 17{,}789\,psi$$

$$\sigma_{zz} = \sigma_z - v\{2\,(\sigma_x - \sigma_y)\}\ \cos 2\theta = 6143 - 0.35\{2[6143 - 9452]\}$$
$$= 8459\,psi$$

For hole angles 0,30,50 and 70 the results are summarised in Table 12.7.

Table 12.7

Stress, psi											
	Hole Angle	0		30		50		70		90	
	Mud Weight , ppg										
		9	12	9	12	9	12	9	12	9	12
	σ_{rr}	4424	5898	4424	5898	4424	5898	4424	5898	4424	5898
	$\sigma_{\theta\theta}$	5784	4310	9045	7571	13440	11966	17301	15827	17,789	17354
	σ_{zz}	9452	9452	9126	9126	8686	8686	8300	8300	8459	8148
	$\tau_{\theta z}$	0	0	2366	2366	4282	4282	2794	2794	0	0

Step 5 Express the wellbore stresses as Principal Stresses using equations Equation (12.21)

$$\left\{ \begin{array}{l} \dfrac{\sigma_{\theta\theta} + \sigma_{zz}}{2} + \left\{ \left[\dfrac{\sigma_{\theta\theta} - \sigma_{zz}}{2} \right]^2 + \tau_{\theta z}{}^2 \right\}^{0.5} \\ \dfrac{\sigma_{\theta\theta} + \sigma_{zz}}{2} - \left\{ \left[\dfrac{\sigma_{\theta\theta} - \sigma_{zz}}{2} \right]^2 + \tau_{\theta z}{}^2 \right\}^{0.5} \\ P_w \end{array} \right\}$$

Pw= 4424 psi (wellbore pressure for 9ppg mud)

$$\frac{\sigma_{\theta\theta}+\sigma_{zz}}{2}+\left\{\left[\frac{\sigma_{\theta\theta}-\sigma_{zz}}{2}\right]^2+\tau_{\theta z}^2\right\}^{0.5}=\frac{18828+8148}{2}+\left\{\left[\frac{18828-8148}{2}\right]^2+0\right\}^{0.5}=18828\ psi$$

$$\frac{\sigma_{\theta\theta}+\sigma_{zz}}{2}-\left\{\left[\frac{\sigma_{\theta\theta}-\sigma_{zz}}{2}\right]^2+\tau_{\theta z}^2\right\}^{0.5}$$

$$\frac{18828+8148}{2}-\left\{\left[\frac{18828-8148}{2}\right]^2+0\right\}^{0.5}=8148\,psi$$

Hence the induced principal stresses at 90 degrees at the walls of the borehole in ranking order:

$\sigma 1$ = 18828 psi

$\sigma 2$ = 8148 psi

$\sigma 3$ = 4424 psi

Table 12.8 summarises the calculations for angles 30, 50, 70 and 90 degrees and mud weights of 9 and 12 ppg. Two mud weight are required to develop a relationship between mud weight and wellbore stresses. Plot the stresses in Table 12.8 for each hole angle as shown in Figure 12.13.

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Table 12.8

Wellbore Principal Stress, psi	Wellbore Inclination , degrees										
		0		30		50		70		90	
	Mud Weight , ppg										
		9	12	9	12	9	12	9	12	9	12
	σ_1	7618	9452	11451	10838	15960	14911	18097	16750	18828	17354
	σ_2	5784	5898	6719	5858	6166	5741	7504	7376	8148	81484
	σ_3	4424	4310	4424	5898	4424	5898	4424	5898	4424	5898

Step 6

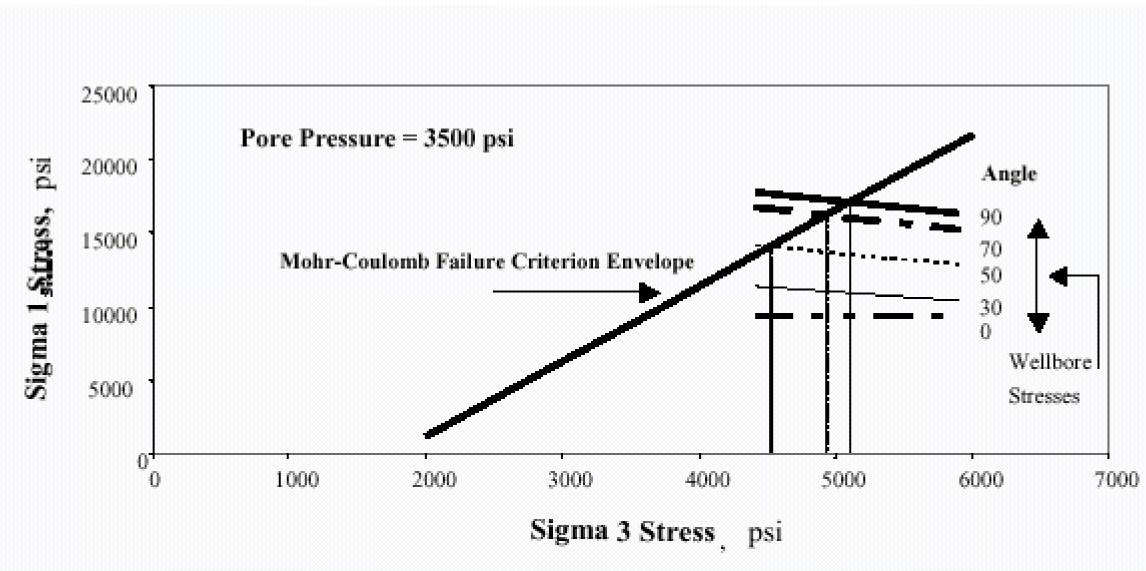
Plot the stresses in Table 12.8 for each hole angle as shown in Figure 12.13.The intersection point between the failure envelope and the principal stresses at the wellbore gives the minimum mud weight required to prevent hole collapse.

Table 12.9 gives a summary of these intersection point for hole angles 0 to 90 degrees. This data is plotted in Figure 12.14 as a stability curve.

Table 12.9

Hole Angle , deg	Mud Pressure To Prevent Hole Collapse (psi)	Mud Weight To Prevent Hole Collapse (ppg)
0	3620	7.4
30	4400	8.99
50	4800	9.8
70	5150	10.5
90	5300	10.8

Figure 12.13 Wellbore Stresses And Mohr-Coulomb Failure Envelope



Step 7

Use equation Equation (12.24) to calculate the safe mud weight for various hole angles so prevent hole fracturing by tension. The results are summarised in Table 12.10 and plotted in Figure 12.14.

$$FBP = \sigma_3 \left(3 - \cos^2 \alpha\right) - \sigma_1 \sin^2 \alpha + T - P_f \tag{12.24}$$

Figure 12.14 is the stability curve giving minimum mud weights required to prevent hole collapse and maximum mud weights which cause tensile failure. The mud weights inside the envelope represent the safe working mud weights and must be, of course, below the fracture gradient.

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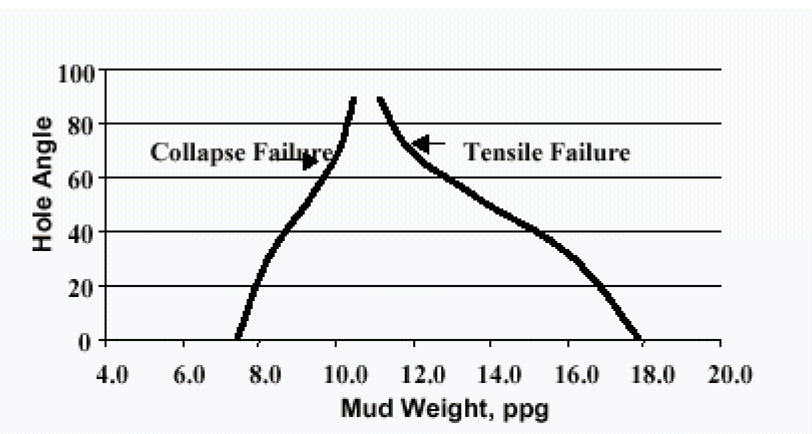
Table 12.10

Hole Angle ,deg	Mud Weight To Prevent Hole Collapse (ppg)	Mud Weight To Prevent Hole Fracturing (ppg)
0	7.4	17.9
30	8.2	16.2
50	9.2	13.9
70	10.1	11.9
90	10.5	11.1

Figure 12.14 Safe Mud Weights To Prevent Wellbore Instability



8.0 Preventing Borehole Instability

Borehole collapse while drilling can be minimised by supporting the wellbore by increasing the drilling fluid weight and/or optimising the direction of the borehole relative to the in-situ principal stresses. When increasing the mud weight it is necessary to know the size of the minimum in-situ principal stress to avoid accidentally fracturing the formation. When optimising the orientation of the well the orientation and relative sizes of the in-situ principal stresses must be known.

As a reservoir depletes the pore pressure drops and so the proportion of the overburden supported by the rock matrix increases. Therefore, reservoir depletion affects the mechanical stability of wells [19]. Generally, the fracture pressure of the reservoir formation decreases as the pore pressure drops. The upper limit of the pressure exerted by the drilling fluid is the formation fracture closure pressure (which is equal to the minimum principal in-situ stress). Exceeding this pressure will not necessarily fracture the formation (the drilling fluid pressure must be greater than the formation fracture extension pressure to do this), but existing fractures will open and drilling fluid may be lost. Using leak-off or mini-frac data to calculate the formation fracture gradient is more reliable than the commonly used alternatives based on overburden and pore pressures.

Borehole collapse is commonly defined using the Mohr-Coulomb theory Assuming that the rock mechanical properties remain constant during depletion, for a given wellbore pressure, as the pore pressure falls the wellbore is less likely to collapse.

8.1 Reservoir Compaction and Depletion Effects

The pore pressure drop associated with hydrocarbon production may lead to reservoir compaction. Most reservoirs undergo only a small amount of compaction. Occasionally, however, reservoirs may compact considerably. Recent examples of reservoir compaction are the Groningen and Ekofisk fields. For offshore fields the implications of reservoir compaction are significant as it may affect the overlying platform structure. In addition, reservoir compaction may cause the casing to collapse and increase solids production.

The compressibility of hydrocarbon formations significantly affects the estimate of recoverable reserves. The reduction of pore pressure causes the horizontal stress to increase according to:

$$\Delta\sigma_3 = \Delta P f \frac{(1-2\nu)}{(1-\nu)} \tag{12.25}$$

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8.2 Sand Production

There are two main mechanisms of sand production – shear failure or tensile failure. Shear failure is usually initiated by pore pressure reduction below a critical value. Tensile failure is usually initiated by a production rate above a critical value. Sand production caused by tensile failure at high production rates is not as prolific as that owing to shear failure. Increasing the effective stress increases the likelihood of shear failure of the formation at the borehole wall but reduces the likelihood of tensile failure.

Accurate knowledge of the size and directions of the in-situ principal stresses aids more accurate calculation of the effective stresses and so better predictions of the onset of sand production.

9.0 SYMBOLS

σv	Vertical stress
σ_H and σ_h	two horizontal stresses
σ_1	maximum principal stress
σ_2	Intermediate principal stress
σ_3	minimum principal stress
$\sigma\theta\theta$,σrr and σzz	wellbore induced stresses
τ	shear stress
α	hole deviation angle, from vertical
β	hole azimuth
ρm	mud Density (ppg)
ν	Poisson' ratio
Cb	bulk compressibility
Cr	rock matrix compressibility
ϕ	internal friction angle
Δ	represents change in a value
C	cohesion
D	TVD (feet)
FG	fracture Gradient (ppg)
FIT	formation integrity test
Pf	formation pressure, psi
Pw	wellbore pressure when fracture is created
T	tensile strength
Vclay	clay volume (%)

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11.0 EXERCISE

Given the following well data for a sandstone reservoir, determine the minimum mud weights required to prevent hole collapse if a horizontal well is be drilled.

Cohesion (C) = 1182 psi

Angle of internal friction is 42.4 deg

Depth is 9452 ft

Azimuth = 10 deg

$\sigma 1$ = 1 psi/ft

$\sigma 3$ = 6143 psi at 9452 ft

Pore pressure = 3500 psi

Poisson' ratio = 0.35

Hole angle : 30 and 70 degrees

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13

Hole Problems

Contents

1.0 Identification of Hole Problems

An event which causes the drilling operation to stop is described as a Non-Productive Time (NPT) event. Pipe sticking and lost circulation are the two main events which cause NPT in the drilling industry. Well kicks, of course, require operations to stop and when they occur can result in a large NPT. At the time of writing this book, the average NPT in the drilling industry is 20%.

There are many events which cause NPT in the drilling industry: see **Chapter 17** for details.Hence rather than detail every minor hole problem that has ever been recorded, this chapter will deal with the main problems normally encountered while drilling. These problems are: differential sticking, mechanical sticking and lost circulation. There will also be a discussion of other miscellaneous problems.

1.1 Pipe Sticking

When the pipe becomes stuck, there are two key actions that will best influence the chance of freeing the pipe:

- Determination of the cause of the stuck pipe incident.
- The initial response of the Driller and subsequent actions taken.

During the earliest stages of trying to free the pipe, the Drilling Supervisor should collate all the relevant information and determine what caused the pipe to stick. This may well be obvious from the well conditions that existed before the pipe became stuck. An incorrect assessment of the cause of pipe sticking problem will reduce the chance of freeing the stuck pipe.

Table 13.1 Pipe Sticking Mechanisms and Causes

Mechanism	Differential Sticking	Mechanical Sticking	
Cause		Hole Pack Off	Formation & BHA (Wellbore Geometry)
	Differential Force	Settled Cuttings	Key Seating
		Shale Instability	Mobile Formations
		Fractured Rocks	Undergauge Hole
		Cement Blocks	Micro Doglegs and Ledges
		Junk	

There are basically two mechanisms for pipe sticking:

1. Differential Sticking
2. Mechanical Sticking

Mechanical sticking can be caused by:

- Hole pack off or bridging, or

- Formation and BHA (wellbore geometry)

Table 13.1 gives a summary of the pipe sticking mechanisms and their most common causes.

2.0 DIFFERENTIAL STICKING

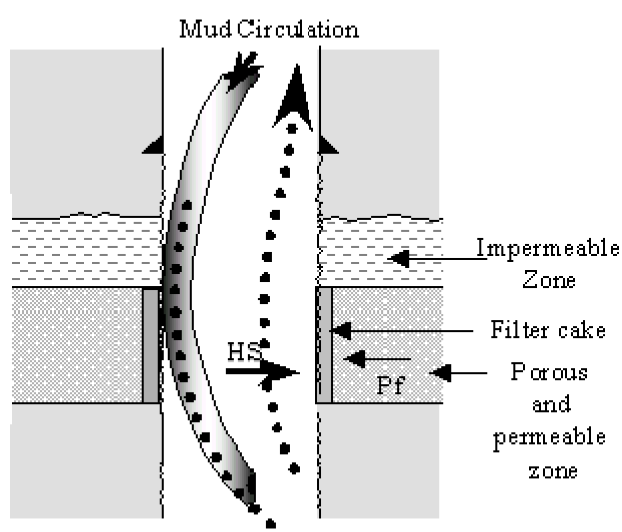
2.1 CAUSES OF DIFFERENTIAL STICKING

During all drilling operations the drilling fluid hydrostatic pressure is designed and maintained at a level which exceeds the formation pore pressure by usually 200 psi. In a permeable formation, this pressure differential (overbalance) results in the flow of drilling fluid filtrates from the well to the formation. As the filtrate enters the formation the solids in the mud are screened out and a filter cake is deposited on the walls of the hole. The pressure differential across the filter cake will be equal to the overbalance.

When the drillstring comes into contact with the filter cake, the portion of the pipe which becomes embedded in the filter cake is subjected to a lower pressure than the part which remains in contact with the drilling fluid. As a result, further embedding into the filter cake is induced.

The drillstring will become differentially stuck if the overbalance and therefore the side loading on the pipe is high enough and acts over a large area of the drillstring. This is shown diagrammatically in **Figure 13.1**.

Figure 13.1 Differential Sticking



The signs of differential sticking are the clearest in the field. A pipe is differentially stuck if:

1. drillstring can not be moved at all, i.e. up or down or rotated

2. circulation is unaffected

Mathematically, the differential sticking force depends on the magnitude of the overbalance and the area of contact between the drillpipe and the porous zone.Hence

Differential force = (mud hydrostatic – formation pressure) x area of contact

Hence for the data shown in **Figure 13.2**, and assuming the formation contacts only 4" of the drillpipe perimeter, then the differential force is given by:

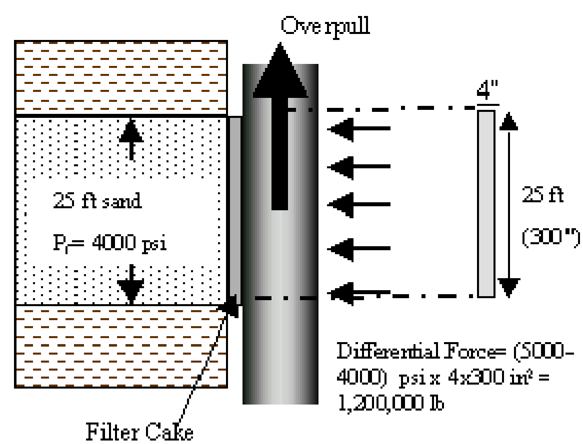
Differential Force = (5000-4000) psi x 4 x 00 = 1,200,000 lb

A more accurate form of the above equation contains a term for the friction factor between the drillstring (steel) and the filter cake is given in **Equation (13.1)**.

The force required to free a differentially stuck pipe depends upon several factors, namely:

1. The magnitude of the overbalance. This adds to any side forces which already exist due to hole deviation.
2. The coefficient of friction between the pipe and the filter cake. The coefficient of friction increases with time, resulting in increasing forces being required to free the pipe with time. Hence, when differentially stuck, procedures to free the pipe must be adopted immediately. **Figure 13.3** shows the coefficient of friction vs. time for a bentonite filter cake which shows a 10 fold increase in under 3 hours.

Figure 13.2 Magnitude of differential sticking force



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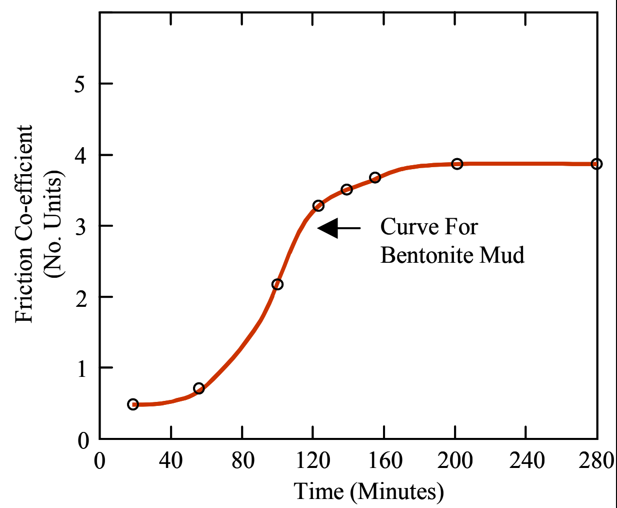
The surface area of the pipe embedded in the filter cake is another significant factor. The greater the surface area, the greater the force required to free the pipe. Thickness of filter cake and pipe diameter will obviously have a great effect on the surface area. It is for reasons of reducing available surface area that spiral drill collars (**Chapter 10**) are often specified when drilling sections which exhibit the potential for differential sticking problems.

Figure 13.3 Increase in friction factor with time



Statistically, differential sticking is found to be the major cause of stuck pipe incidents, hence great care should be taken in the planning phase to minimise the overbalance wherever possible. However, in certain circumstances, drilling with minimum overbalance is not be possible, as is the case for large gas reservoirs (e.g. the Morecambe Field in the UK) where the pressure differential across the reservoir starts at the minimum overbalance (200 psi) and increases substantially with depth to a maximum of 1300 psi. In these cases, strict adherence to precautionary drilling practices and good communication between personnel will help reduce the incidence of stuck pipe.

2.1.1 DIFFERENTIAL STICKING FORCE

The differential sticking force is given by:

$$\text{Differential sticking force (DSF)} = (H_s - P_f) \text{ x effective contact area x friction factor} \quad (13.1)$$

where H_s = hydrostatic pressure of mud

P_f = formation pressure

In Equation (13.1), the most difficult terms to determine are the effective contact area and the friction factor between the mud cake and the pipe steel. To a first approximation the effective area may be calculated as the product of the height of the exposed permeable formation times 20% of the perimeter of the drillpipe or drillcollars.

Another equation for estimating the contact area is given by [3]:

$$A = 2h\sqrt{\left(\frac{Hs}{2} - t_{mc}\right)^2 - \left(\frac{Hs}{2} - t_{mc}\left(\frac{Hs - t_{mc}}{Hs - OD_p}\right)\right)^2} \tag{13.2}$$

where

- h = thickness of permeable zone
- t_{mc} = thickness of filter cake
- Hs = hole size
- OD_p = OD of drillpipe or drillcollars

It should observed that none of the equations given for estimating the contact area are completely valid as the contact area is affected by a number of variables including the friction factor (time-dependent), the amount of bend in the drillpipe or collars, hole angle and thickness of the filter cake.

The surface estimate of the thickness of the filter cake can be very different from that occurring downhole.

Example 13.1: Differential Sticking Force

Determine the magnitude of the differential sticking force across a permeable zone of 30 ft in thickness using the following data:

Differential pressure = 500 psi

Area of contact is 20% of effective drillpipe perimeter

Filter cake = 1/2 in (12.7mm); friction factor = 0.1.

Drillpipe OD: 5"

Solution

Perimeter of drillpipe = π x OD = π x 5 = 15.71 in

DSF = $(H_s - P_f)$ x h x 20% x 15.71

= 500psi x (30ft x 12 in) x 20% x 15.71

= 565,560 lb

Example 13.2: Differential Force and MOP

A drill string consists of 15,000 ft of 21.12 lbm/ft drillpipe and 500 ft of 150 lbm/ft drill collars. It is established that the drill string can be differentially stuck at the first drill collar below the drillpipe.

Given that:

Mud weight = 13 ppg

Differential force = 108,000 lb (estimated)

Grades of drillpipe available are E, X, G and S.

Determine: (a) the buoyant weight of the drillpipe; (b) the total hook load when pulling on the differentially stuck pipe; (c) the magnitude of the margin of overpull (MOP) for the four grades, assuming the conditions of pipes to be premium.

Solution

(a) Note that only the weight of drillpipe will be considered, as the weight of drill collars is taken up by the stuck point.

Buoyant weight of drillpipe = 15,000 x 21.12 x BF

$$= 15000 \text{x} 21.12 \text{x} \left(1 - \frac{13}{65.4}\right) = 253{,}828 \text{ lb}$$

(b) Hook load including differential force

= 234,358 + 108,000

= 361,828 lbf

(c) This part can best be illustrated in tabular form, as follows:

Grade	Weight (lbm/ft)	Pipe body yield (lb)	MOP = yield strength – hook load (lb)
E	19.5	311,540	311,450 – 361,828 = -50,378
X	19.5	394,600	394,600 – 361,828 = 32,772
G	19.5	436,150	74,322
S	19.5	560,760	198,932

All drillpipe grades are assumed to be premium class and yield values are obtained from API tables.

Thus, for the existing conditions, Grade E gives a negative MOP, implying that the pipe will part if the required force of 361,828 lb is applied to free the pipe. Only Grades X, G and S can be used in this type of well, where the magnitude of the differential force is 108,000 lb.

3.0 Freeing Differentially Stuck Pipe

There are basically two ways in which a differentially stuck pipe can be released:

- reduction of hydrostatic pressure
- spotting pipe release agents

3.1 Reduction of Hydrostatic Pressure

The reduction of hydrostatic pressure is the obvious and most successful method of freeing a differentially stuck pipe. The lowering of the hydrostatic pressure reduces the side loading forces on the pipe and therefore reduces the force required to free the pipe from the filter cake. There are several methods by which this may be achieved. However prior to implementing this action the following factors should be seriously considered:

1. Are there other pressured zones in the open hole section?
2. Will these exposed zones kick if the hydrostatic pressure is reduced?
3. The confidence level in the accuracy of pore pressure estimates made while drilling and the pressure control equipment.
4. The effects of a reduction in hydrostatic pressure on the mechanical stability of all exposed formations.
5. The volumes of base oil or water required to achieve the required reduction in hydrostatic pressure. (This may well influence the method chosen).

All the above factors need to be carefully considered prior to reducing the hydrostatic pressure as the potential for inducing a well control problem or formation instability are considerably increased. The following methods for reducing hydrostatic pressure can be used:

- circulation & reducing mud weight
- displacing the choke
- the ‘U’ tube method

3.1.1 Circulation & Reducing Mud Weight

In this method, the drilling mud is circulated and its weight is gradually reduced. The minimum mud weight required to balance the highest pore pressure in open hole should be determined and the mud weight cut back in small stages. Close attention must be made to all kick indicators whilst circulating down (reducing) the mud weight, frequent flow checks should also be made. Whilst reducing the mud weight, tension should be held on the pipe.

Disadvantages of this methods are:

- It is slow, and remember the force required to free pipe is time dependent.
- The volume increase required may overload the surface pit handling capability. This may be a serious problem when OBM is used.
- The active volume will be increasing during the reduction in mud weight, making kick detection difficult.

3.1.2 Displacing The Choke

This method is applicable to floating rigs where BOPS are placed on the seabed. The hydrostatic pressure can be quickly and effectively reduced by displacing the choke line to base oil or water. The well is shut in using the annular preventer and the displaced choke line opened thereby reducing the overbalance.Note that the annular preventer isolates the wellbore from the hydrostatic head of mud in the riser from rig floor to the annular preventer.

The advantage of this method is that if any influx is taken, the well can be immediately killed by closing the choke and opening the annular. This action again exposes the well to the active hydrostatic pressure from rig floor to TD. The disadvantage of this method is that the amount of reduction in hydrostatic pressure is limited to the water depth. This may well result in a limited reduction in shallow water, or in the case of deep water, an excessive reduction in hydrostatic pressure.

3.1.3 The 'U' Tube Method

The U-tube method is used to reduce the hydrostatic pressure of mud to a level equal or slightly higher than the formation pressure of the zone across which the pipe got differentially stuck.Clearly, the objective is to free the differentially stuck pipe safely without losing control of the well by inadvertently inducing underbalanced conditions. A pipe free agent should be spotted across the permeable zone prior to adopting the 'U' tube method. The mathematics required for the full method is laborious, however, **Example 13.4** gives a simplified method of calculations.

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3.2 Spotting Pipe Release Agents

The severity of differentially stuck pipe can be reduced by the spotting of pipe release agents. Pipe release agents are basically a blend of surfactants and emulsifiers mixed with base oil or diesel oil and water to form a stable emulsion. They function by penetrating the filter cake, therefore making it easier to remove and at the same time, reduce the surface tension between the pipe and the filter cake.

Due to the time dependency of the severity of differential sticking, the pipe release agent should be spotted as soon as possible after differential sticking is diagnosed. Typically the pill will be prepared whilst initially attempting to mechanically free the pipe; ie by pulling and rotating.

Example 13.3: Reduction of Hydrostatic Pressure

Calculate the volume of oil required to reduce the hydrostatic pressure in a well by 500 psi, using the following data:

mud weight = 10 ppg
hole depth = 9,843 ft
drillpipe = OD/ID = 5 in/4.276 in
hole size = 12.25 in
specific gravity oil = 0.8 (6.7 ppg)

Solution

Initial hydrostatic pressure = 0.052 x10x 9843 = 5,118 psi

Required hydrostatic pressure = 5,118 - 500 = 4,618 psi

Thus,

New hydrostatic pressure = pressure due to (mud and oil) in drillpipe

4618 = 0.052x 10xY (mud) +0.052x (6.7) x (9843-Y) (oil) where Y = height of mud in drillpipe.

Therefore,Y = 6,927 ft

Hence,

height of oil = 9,843 - 6,927 = 2,916 ft

volume of oil = capacity of drillpipe x height $= \frac{\pi}{4} x 4.276^2 x \frac{1}{144} x (2, 916)$

$= 290.79\ ft^3$

= 51.7 bbl

Note that when the required volume of diesel oil is pumped inside the drillpipe, the hydrostatic pressure at the drillpipe shoe becomes 4,618 psi, while the hydrostatic pressure in the annulus is still 5,118 psi. This difference in the pressure of the two limbs of the well causes a back-pressure on the drillpipe which is the driving force for removing the diesel oil from the drillpipe and reducing the level of mud in the annulus. It is only when the annulus level decreases that the hydrostatic pressure against the formation is reduced and the stuck pipe may be freed.

When the formation pressure is unknown, it is customary to reduce the hydrostatic pressure of mud in small increments by the U-tube technique until the pipe is free.

A variation of the U-tube method is to pump water into both the annulus and the drillpipe to reduce hydrostatic pressure to a value equal to or just greater than the formation pressure. This method is best illustrated by an example.

Example 13.4:: Simplified U-Tube Method

The following data refer to a differentially stuck pipe at 11,400 ft:

Formation pressure	= 5,840 psi
Intermediate casing	= 9.625 in, 40# at 10,600 ft
Drillpipe	= OD /ID = 5/4.276 in

Mud density = 12.3 ppg

It is required to reduce the hydrostatic pressures in the drillpipe and the annulus so that both are equal to the formation pressure.

Calculate the volumes of water required in both the annulus and the drillpipe, assuming that the density of saltwater = 8.65 ppg.

Solution

Annulus Side

Assume the height of water in the annulus to be Y.

Required hydrostatic pressure at stuck point = 5,840 psi or

5,840 = 0.0.52x 8.65x Y + 0.052x 12.3x (11,400-Y)

Y = 7,647 ft (length of water column)

Required volume of water in annulus

= annular capacity between drillpipe and 9.625" casing x height of water

= 0.0515 (bbl/ft) x 7,6476

= 393.8 bbl

Hence, pump 393.8 bbl of water into the annulus to reduce the hydrostatic pressure in the annulus to 5,840 psi at the stuck point. When 393.8 bbl of water is pumped into the annulus, the drillpipe is still filled with the original mud of 12.3 ppg having a hydrostatic pressure at the stuck point of (0.052x12.3 x 11,400) = 7,291 psi. Thus, a back-pressure equivalent to 7,291 – 5840= 1,451 psi will be acting on the annulus and will be attempting to equalise pressures by back-flowing water from the annulus.

In order to contain the 393.8 bbl of water in the annulus, the drillpipe must also contain a column of water equal in height to that in the annulus.

Thus,

volume of water required in drillpipe to prevent back-flow from annulus

= capacity of drillpipe x height of water = 0.0178 (bbl/ft) x 7,647 ft = 136 bbl

Balancing of the columns of water in the drillpipe and in the annulus can be achieved as follows: (a) circulate 393.8 bbl of water down the annulus; (b) circulate 136 bbl of water down the annulus; (c) circulate 136 bbl of water in the drillpipe to remove 136 bbl of water from the annulus and to reduce the hydrostatic pressure in the drillpipe to 5,840 psi. At this stage the hydrostatic pressure in the well is equal to the formation pressure of 5,840 psi.

If the well should kick during the operation, reverse-circulate down the annulus using the 12.3 ppg (i.e. original density) mud to recover all the water from the drillpipe. Then circulate in the normal way through the drillpipe using 12.3 ppg mud until all the water is removed from the annulus.

4.0 MECHANICAL STICKING

4.1 CAUSES OF MECHANICAL STICKING

In mechanical sticking the pipe is usually completely stuck with little or no circulation. In differential sticking, the pipe is completely stuck but there is full circulation.Mechanical sticking can occur as result of the hole packing off (or bridging) or due to formation & BHA (wellbore geometry).

Hole pack off (bridging) can be caused by any one or a combination of the following processes:

1. Settled cuttings due to inadequate hole cleaning
2. Shale instability
3. Unconsolidated formations

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4. Fractured and faulted formations
5. Cement blocks
6. Junk falling in the well

The formation & BHA (wellbore geometry) can also cause mechanical sticking as follows:

1. Key seating
2. Mobile formations
3. Undergauge hole
4. Ledges and micro doglegs

Understanding the cause of the mechanical sticking problem is key to solving the problem. This is because the cause determines the action required to free the pipe. For example, if the pipe becomes stuck while running in an open hole, it is likely that the BHA has hit a ledge or gone into an undergauge hole. In other words, the sticking problem is due to the geometry of the wellbore. As will be seen later, the freeing action depends largely on identifying and curing the problem that caused mechanical sticking.

A discussion of each of the above processes will now follow.

4.2 Hole Pack Off Causes

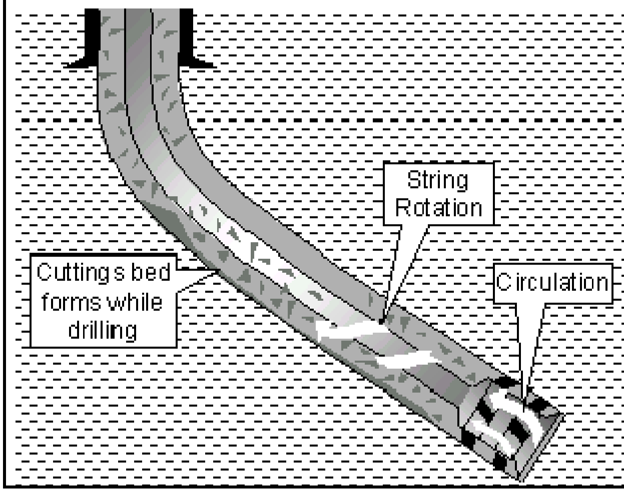
4.2.1 Settled Cuttings

Settled cuttings due to inadequate hole cleaning (**Figure 13.4)** is one of the major causes of stuck pipe. Best hole cleaning occurs around large OD pipe such as drillcollars, while cuttings beds can form higher up the hole where the pipe OD is smaller. The problem of settled cuttings is particularly severe in horizontal and high directional wells. In these wells, when the pipe is moved upwards, the cuttings may be compacted around the BHA. This can result in complete packing off of the drillstring and eventual pipe sticking.

With increasing deviation of the wellbore, drilling fluid parameters, drilling practices and hydraulics should be optimised in order to effectively clean the hole.

In vertical wells, good hole cleaning is achieved by the selection and maintenance of suitable mud parameters and ensuring that the circulation rate selected results in an annular velocity (around 100-120 ft/min) which is greater than the slip velocity of the cuttings.

Figure 13.4 Settled Cuttings Due To Poor



Highly inclined wells are particularly difficult to clean due to the tendency of drilled cuttings to fall to the low side of the hole.In a highly deviated well, the cuttings have only a small distance to fall before they settle on the low side of the hole and form a cuttings bed. Cuttings beds develop in boreholes with inclinations of 30 degrees or greater, depending on the flow rates and suspension properties of the drilling fluid.Complete removal of cuttings beds by circulation may be impossible.

Once cuttings beds have formed, there is always a risk that on pulling the pipe up the hole, the cuttings are dragged from the low side of the hole forming a cuttings pile (**Figure 13.4**). If this pile accumulates around the BHA, it may plug the hole and cause the pipe to mechanically stuck.

Besides causing stuck pipe, settled cuttings can result in:

- formation break down due to increased ECD
- slow ROP
- excessive overpull on trips
- increased torque

Hole cleaning is controlled by a number of parameters which were discussed in **Chapter 8**. These include:

1. mud rheology, in particular the YP and gel strength

2. flow rate
3. hole angle
4. mud weight
5. ROP
6. hole diameter
7. drillpipe rotation
8. presence of wash outs

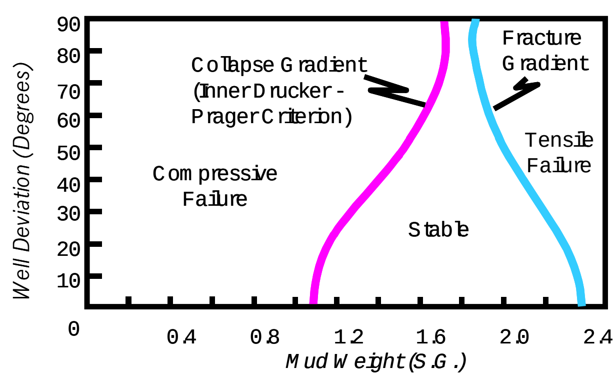
4.2.2 SHALE INSTABILITY

Shale represents 70% of the rocks encountered whilst drilling oil and gas wells. Also shale instability is by far the most common type of wellbore instability. Shales are classified as being either brittle or swelling.

Brittle Shales

Instability in brittle shales is caused mainly by tangential stresses around the wellbore which are induced as a result of the well being drilled. The induced stresses depend on the magnitude of the in-situ stresses, wellbore pressure, rock strength and hole angle and direction. Formation dip may also be a contributory factor to brittle shale failure. A safe mud envelope may be established which can be used to determine the safe mud weights to prevent either tensile failure or collpase (compressive) failure.

Figure 13.5 Safe mud weights envelope



Brittle shales tend to fail by breaking into pieces and sloughing into the hole. Rig indications of brittle shale failure include:

- large amounts of angular, splintery cavings when circulating the well
- drag on trips

- large amounts of hole fill.

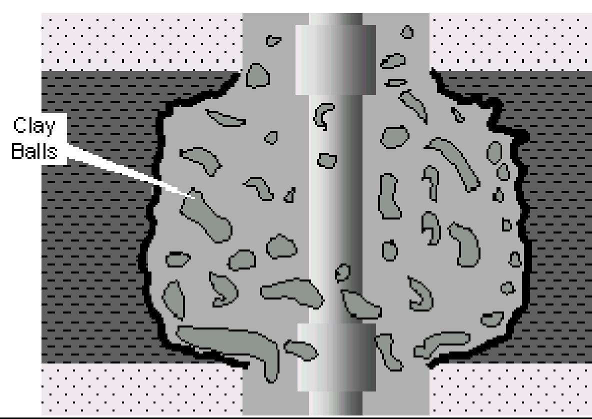
Swelling Shales

Shales swelling (**Figure 13.6**) can be caused by hydrational processes or by the osmotic potential which develops between the pore fluid of the shale and drilling fluid salinity.

The swelling of shales (**Figure 13.6**) is controlled by several complex factors including:

- Clay content
- Type of clay minerals (ie hydratable or inert)
- Pore water content and composition
- Porosity
- In-situ stresses
- Temperature

Figure 13.6 Swelling of reactive shales



The degree of clay hydration depends on the clay type and the cation exchange capacity (CEC) of the clay content. The greater the CEC, the more hydratable is the clay. In drilling operations the following clay types are encountered:

- Smectite with CEC of 80-150 meq/100g. Most of the hydratable shales (termed gumbos) belong to this group. Bentonite clays belong to the smectite group.
- Illite with CEC of 10-40 meq/100g.
- Chlorite with CEC of 10-40 meq/100g.
- Kaolinite with CEC of 3-10 meq/100g.

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To aid the understanding of shale swelling, the following points must be considered:

1. The permeability of shales is very low, typically in the range of 10^{-9} to 10^{-6} Darcy. (1 md = 10^{-13} m^2)
2. Thus, filter cakes do not form on shale surfaces.
3. However, water can still migrate into the shale (helped by the mud overbalance).
4. Water infusion into the shale will allow chemical effects to start working inside the shale and at the exposed surfaces of the wellbore.
5. The pore pressure inside the shale section will also increase, contributing to de-stabilisation.
6. The low permeability of shale means that swelling effects can take considerable time and shale instability can be a delayed effect.

Water can flow into or out of the shale through several processes; the most important ones are hydrational and osmotic forces:

1. Hydration: This is by far the most common cause of shale hydration where water flows into the shale and hydrate the clay plates. Highly hydratable shales are composed of predominantly smectite- based clays. These clays (e.g. montmorillonite) absorb water into the inner-layer space due to the high negative charge on the surface of the clay platelet. This process results in the expansion of the clay to several times its original volume.

   Hydratable shales are usually found near the surface, ±7000 ft. At grater depths, the process of diagenesis converts the clay minerals into more stable forms, see **Chapter 1**. However, hydratable shales have been found in some wells at depths greater than 7000 ft due to the inhibition of the diagenetic processes.
2. Chemical osmosis: This type of flow occurs at semi-permeable membranes which are permeable to water and impermeable to solute ions or molecules. Shale surface acts as a semi-permeable membrane allowing water to flow into or out of the shale depending on the solute concentration of the mud and pore water of the shale. Water

flows through the semi-impermeable membrane from the low concentration to high concentration solution. In terms of chemical jargon, water flows from solutions of high water activity to solutions of low water activity until the concentrations of the two solutions are equalised. (Water activity (a_w): ratio of vapour pressure of water in a solution, drilling mud or shale pore water to the vapour pressure of pure water at the same temperature.)

3. Chemical diffusion: This is caused by the flow of solutes (soluble solids) from areas of high concentration to low concentration. Hence if the concentration of certain ions or molecules in the drilling mud is greater than those in the formation water of the shale then the solute will flow into the formation provided there are no barriers to flow. Solutes can also flow out of the shale if their concentration is greater than that in the drilling mud. No flow will occur if solute concentration is the same in mud and shale.
4. Hydraulic diffusion; water flows in the direction of decreasing hydraulic pressure gradient (Darcy's Law). This flow can only occur if the rock has permeability.

Shale hydration – Rig Site Indications

- Soft, hydrated or mushy cuttings
- Clay balls in the flowline
- torque and drag fluctuations
- Shale shaker screens blind off
- Increase in LGS, filter cake thickness, PV, YP and MBT (Methlyene blue test)
- Increase or fluctuations in pump pressure
- Circulation is restricted or sometimes impossible
- Bit and stabiliser balling when POH
- Generally occurs while POH (Tight hole) and problems while logging
- Problems increase with time.

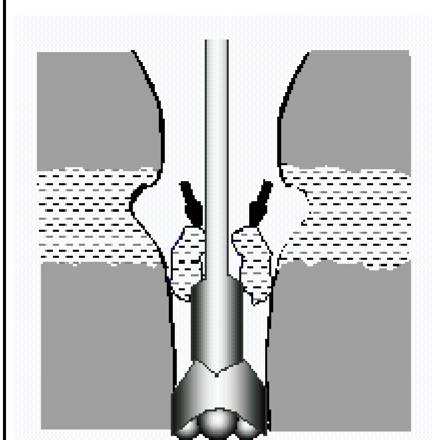
Shale hydration – Prevention and Cure

- Use Inhibited mud system or displace to OBM system if possible
- Maintain mud properties as planned
- Addition of various salts (potassium, sodium, calcium) will reduce chemical attraction between shale & water
- Addition of encapsulating polymers to WBM
- Reduce exposure time and case off the hydrated shale as soon as possible
- Regular wiper trips
- Good hole cleaning (especially in extended reach wells, ERW)

4.2.3 UNCONSOLIDATED FORMATIONS

Unconsolidated formations are usually encountered near the surface and include: loose sands, gravel and silts. Unconsolidated formations have low cohesive strengths and will therefore collapse easily (**Figure 13.7**) and flow into the wellbore in lumps and pack off the drillstring.

Figure 13.7 Collapse of unconsolidated formations



Surface rig indications of an impending stuck pipe situation near top hole are: increasing torque, drag and pump pressure while drilling. Other signs include increased ROP and large fill on bottom.

A common remedial action is to use a mud system with an impermeable filter cake to reduce fluid invasion into the rock. Reduction of flow rate, and in turn annular velocity, will reduce erosion of the hole and removal of the filter cake.

4.2.4 Fractured and Faulted Formations

This is a common problem in limestone and chalk formations. Several symptoms can be observed on surface including:

- large and irregular rock fragments on shakers
- increased torque, drag and ROP
- small lost circulation

These fractured and faulted formations may fall into the Wellbore as soon as they are drilled as the stresses which originally held them together are relieved by the drilling of the hole. In addition, excessive drillstring vibrations cause the pipe to whip downhole and break and dislodge the exposed fractured/faulted rocks. Therefore it is important to reduce drillstring whipping to prevent dislodging of rock fragments when drilling fractured and faulted rocks. In all cases, it is imperative to keep the hole clean in order to reduce the chances of hole packing off.

If the drillstring is stuck in limestone or chalk formations and cannot be freed by jarring, an inhibited hydrochloric acid pill may be spotted around the stuck zone.The acid will react with the chalk/limestones, dissolving the rock around the pipe.If the pill is successful the pipe will be freed quickly.

4.2.5 Cement Blocks

Stuck pipe can be caused by cement blocks falling from the rat hole beneath the casing shoe or from cement plugs.Cement plugs were discussed in detail in **Chapter 6.**

This problem may be prevented by minimising the rat hole to a maximum of 5 ft and also by ensuring a good tail cement is placed around the shoe, see also **Chapter 6**.

The drillstring can also be stuck in green cement which has not set properly. This usually occurs after setting a cement plug inside the casing or open hole. If the drillstring is run too fast into the top of the cement and if the cement is still green then the cement can flash set around the pipe and cause the pipe to be permanently stuck.

The author has come across several situations where the top of the cement is soft when tagged, but literally within seconds of tagging the cement, the cement flash sets around the BHA causing mechanical sticking. One possible explanation for this sudden flash setting is that the energy release while circulating and rotating is enough to cause flash setting. It is recommended that circulation is started two to three stands above the expected top of cement and that WOB should be kept to absolute minimum.

4.2.6 Junk

Several recorded incidents of pipe sticking occurred as a result of junk falling into the hole. This include junk falling into the wellbore from the surface or from upper parts of the hole.

Typical junks dropped from surface include pipe wrenches, spanners, broken metal, hard hats etc. This problem can be minimised by keeping the hole covered when no tools are run in the hole.

Junks can also fall from within the well including broken packer elements, liner hanger slips and metal swarf from milling operation.

4.3 Formation And BHA (Well Geometry) Causes

4.3.1 Key Seating

Key seating (**Figure 13.8**) is caused by the rotating drillstring coming into contact with soft, easily drillable formations. The rotational action causes the tooljoint to erode a narrow groove in the formation which is approximately equal to the diameter of the drill pipe tool joint. The created groove or slot is smaller in size than the larger BHA components below.When pulling out of hole (POH), the BHA may be pulled into the narrow -sized key seat resulting in BHA being stuck.

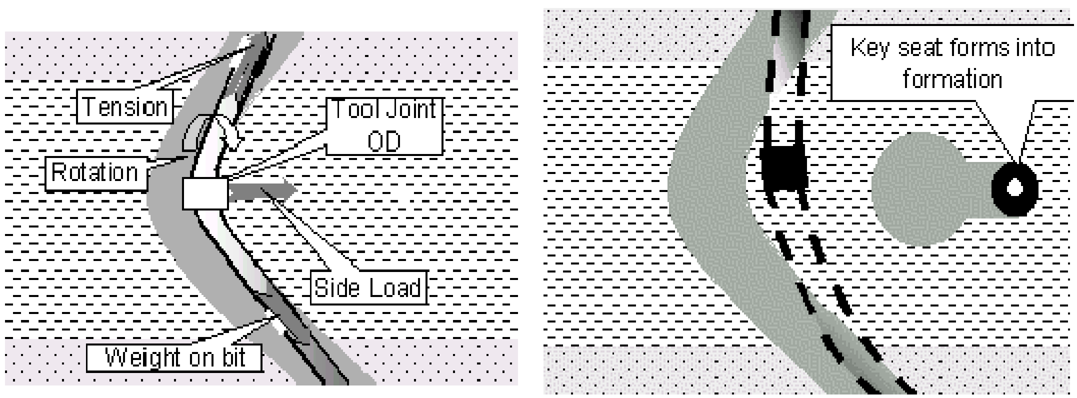
Key seats are often seen in soft formations or in wells with ledges and doglegs.The doglegs and ledges allow the drillstring to bend and provide points of contact between the tooljoint and the walls of the hole. Key seats may also develop in casing shoes in highly deviated wells.

Pipe stuck in a key seat can be recognised by the following symptoms;

1. Circulation is free when the pipe is stuck
2. Hole is tight on tripping out only.
3. Tight hole position can be correlated with the positions of large OD members of the BHA.
4. Tight hole will occur at the same depth on trips.

Figure 13.8 Key Seating

a. Mechanism **b.Formation of keyseat**



Pipe stuck in a key seat must be worked and jarred downwards (and only downwards) until free movement and rotation is established. Once the drillstring is free in a downwards direction, the string should be slowly pulled past the key seat using minimum tension and slow rotation.

4.3.2 MOBILE FORMATIONS

The term mobile or plastic formations usually refer to halites and claystones. These formations posses plastic properties enabling them to deform and flow under applied stress. The majority of problems encountered in mobile formations have been across halite (salt) sections. This discussion will therefore be restricted to problems caused by halites, **Figure 13.9**.

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Salt is encountered in drilling operations from pure sodium chloride to very complex blends of mixed chloride salts. The main salt types are [13]:

1. Halite ($NaCl$)
2. Sylvite (KCl)
3. Bischofite ($MgCl_2 \cdot 6H_2O$)
4. Carnalite ($KMgCl_3 \cdot 6H_2O$)
5. Polyhalite ($K_2MgCa_2(SO_4)_4 \cdot 2H_2O$)
6. Tachydrite ($CaCl_2 \cdot MgCl_2 \cdot 12H_2O$)

Salts are usually underlained by either sulphates or carbonates and can be a perfect seal for reservoirs. A typical example of mobile salts is in the Southern North Sea and in central Europe, the Zechstein group. The Zechstein group was formed during the late Permian and is a sequence of evaporites and carbonates.

The Zechstein Group is characterised by five main cycles (Z 1 - Z 5). Each cycle corresponds to a change in sea level that allows a major influx of seawater into a large costal basin. Precipitation of salts during evaporation resulted in the deposition of the Zechstein group.

Order of Precipitation

1. Carbonates: calcites and dolomites. Some dolomite reservoirs formed

2. Sulphates: anhydrite and gypsum. These rocks have poor porosity and permeability and therefore act as perfect seals.

3. Chlorides: Halites

4. Mixed Salts: carnalite, bischofite, sylvite and kieserite

Salt problems

The main problems from salt sections are:

- Salt washout
- Salt movement & casing collapse

4.3.3 Salt Washout

When water-based muds (WBM) are used used to drill salt sections the water phase of the WBM dissolves the salt causing a large washout in the hole, **Figure 13.9**. Factors affecting salt washout are summarised as follows:

- Salts generally have a high solubility in water
- Bischofite is ten times more soluble in hot water than halite
- Large washouts are usually found across complex (Bischofite) salt sections
- Washouts beyond current calliper logs limit (22") have been observed [14]
- Washouts usually lead to poor cement jobs and then casing collapse
- Sodium chloride saturated drilling fluid will dissolve potassium, magnesium and calcium salts. When Mg, K and Ca ions in the mud increase, the rate of solution will decrease and no further washing out of the salt occurs (probably too late by then)
- Mixed salt mud systems were used as drilling fluids, but have largely failed to become standard. This is because these systems rae designed to be saturated for particular ions at surface conditions. At bottom hole conditions, the temperature is high and further dissolution of salt occurs. Mixed salt systems are also costly and difficult to maintain.
- OBM is usually the best drilling fluid for preventing salt washout.

4.3.4 Salt Movement

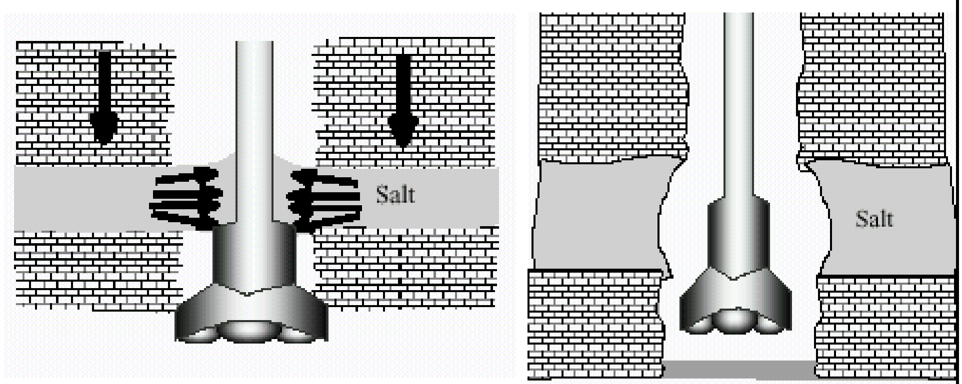
Salt movement (or creep) is a very complex process and is controlled by several factors relating to depth, temperature, earth stresses and water content.The following points summarise the current knowledge regarding salt movement around oilwells:

1. Salt behaves like a super-viscous fluid

2. Rate of movement of the salt section depends on depth, temperature, composition, water content and impurities

3. Halites are relatively slow moving

Figure 13.9 Salt Plastic Deformation (left) And Washout (right)



4. Movement rate can be as high as 1" per hour (pipe gets stuck while drilling)

5. More complex salts (carnalite and bischofite) containing more water content give more movement than pure halites.

6. Flow of salt can be into or out of the well depending on mud hydrostatic pressure. Mud weights should always be designed to hold back salt movements into the wellbore.

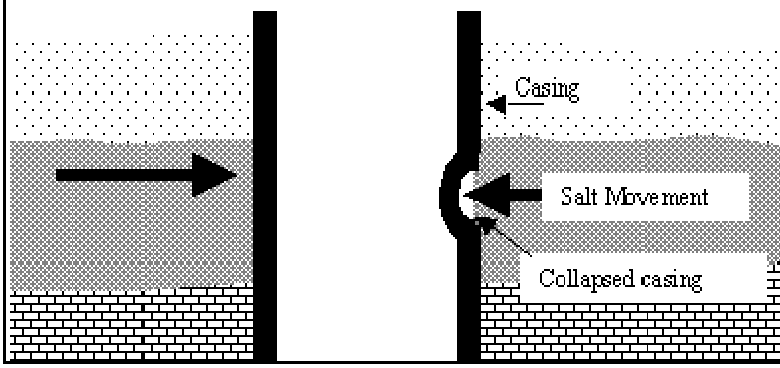
7. Anhydrites and carbonates underneath salt sections are immobile

The main problems caused by salt movement are **casing collapse** and **stuck pipe** while drilling. Drillstring stuck in salt sections while drilling can be easily freed by spotting a water pill around the stuck zone to dissolve the salt and free the pipe. Large washouts and poor cement jobs usually result when water pills are used to free stuck pipe in salt sections.

4.3.5 Salt- Induced Casing Collapse

If the movement of the salt is into the wellbore, it will cause the drillstring or any pipe in hole to be stuck. If the salt movement occurs after the well is drilled, it is likely that the salt will, in time, contact the casing and subject it to extremely high forces. These forces can, in some recorded cases, be greater than the collpase strength of casing resulting in casing failure by collapse.

Figure 13.10 Salt induced casing collapse



The actual problem results when mobile salt is washed out during drilling leaving a hard ledge of carbonate or sulphates as the only rock in the washed out section. When casing is run and cemented, it is likely that the washed out section will be poorly cemented or not cemented at all. Salt movement starts as soon as drilling and cementing operations stop. This movement causes the ledges in the washed out section to move, contact and subject the casing to point loadings. These point loads can be extremely high and often exceed the collapse strength of casing, causing it to fail in collapse.It has been reported that [14] the magnitude of these point load forces can be as high as 19,000 psi. Casing collpase by salt is called Salt-Induced Casing Collapse (SICC), **Figure 13.10**. Several wells in the Southern North Sea and Gulf of Sues have suffered SICC.

Salt-induced casing collapse across mobile salt sections is the most common type of casing collpase observed in the oil industry. Other types of casing collpase have been observed in the following situations:

1. during cementing when using high cement weights
2. when casing is run partially or totally empty
3. due to fluid heating in the annulus, see **Chapter 15**.This is caused by collapsing pressures from excess pressure produced due to temperature effects.
4. during inflow testing of liner laps

In all situations where SICC was recorded, the wells had to be sidetracked as either the internal diameter of the casing is greatly reduced or the casing is physically damaged beyond repair. There are recorded incidents [14] where casing collpase occurred during drilling operations causing the drillstring to be collapsed as well.

The most common method of resisting SICC is to use heavy-walled casings rather than high collapse strength casings. Tests have shown that high tensile strength steels are more brittle and less effective across salt sections than thick-walled casings. Under the action of point loads, a heavy-walled casing with low tensile strength bends more easily than high tensile strength steels; ultimately failing but after a considerable long time compared with high tensile strength steels. It has been established that the casing creep resistance increases linearly with casing strength and to power two (square) with wall thickness.

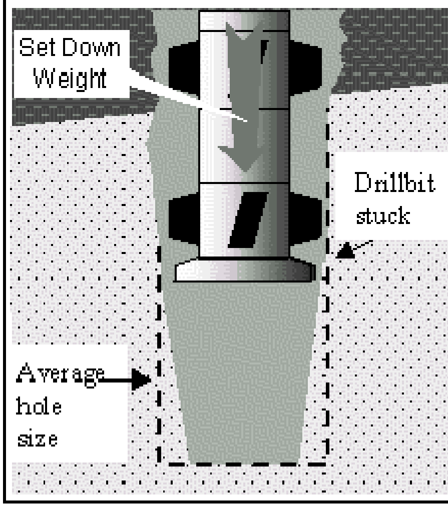
Another widely used solution in the Gulf of Suez (Egypt) is the use of concentric cemented casings across mobile salts. Practical tests showed that the combined collapse strength of the concentric casings is greater than the combined collapse strengths of the individual casings. This solution practically eliminated all problems relating to casing collpase across mobile salts but, of course, limited the size of the production casing.

The author’s recommendation is to always use heavy walled casings across mobile salt sections.

4.3.6 Undergauge Hole

The drilling of abrasive formations such as sandstones can result in bit and stabiliser gauge wear. This loss of gauge (diameter) causes an undergauged hole to be drilled. Development of undergauge hole is to be avoided as it results in costly reaming operations on the subsequent bit run. In addition, incidence of stuck pipe have occurred as a result of running full gauge bits and stabilisers into the undergauge section, **Figure 13.11**. Extra caution should always be exercised when tripping in the hole after pulling an undergauge bit.

Figure 13.11 Undergauge hole



4.3.7 Micro doglegs and Ledges

Micro doglegs and ledges develop when drilling formations of varying strengths or dipping formations. A gauge hole is drilled in the harder zone and an oversized hole, caused by fluid erosion, is drilled in the softer zone. This oversized hole causes the bit and the BHA to be deflected to the low side of the hole causing a small dogleg when the next hard section is drilled. The drilling of several successive layers of varying strengths result in both hole ledges and micro -doglegs to develop.

5.0 Other Hole Problems

This section briefly considers other hole problems which may not cause the pipe to stick but will nevertheless result in downtime.

5.1 Bit Balling

Recall from Chapters One and Seven, when water comes into contact with soft shales containing montmorillonite, the shale plates (clay minerals) hydrate, swell and disperse into

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the water system. Hydration and swelling of shales is prevented by the use of inhibited mud systems containing additives such as salts (KCL) and polymers.

Bit balling occurs whilst drilling reactive shales which exhibit plastic properties. The problem occurs in poorly inhibited water-based muds when drilled shale particles adhere to the face of the drillbit, stabilisers and drillcollars.

In practice bit balling can be recognised by:

- Reduced ROP as the bit cutting face is completely covered with a cake
- Increased pump pressure due to reduced annular diameter
- Blocked shaker screens with soft clays
- Overpull on trips

Bit balling can be prevented by using inhibited mud systems which prevent the dispersion of the clay plates. If bit balling is observed while drilling, a detergent is usually added to disperse the balled clays. The use of a small percentage of glycol also helps to reduce bit balling.

Bit balling rarely occurs in oil-based muds, but when it occurs, the cure is achieved by increasing the mud salinity in order to draw moisture from the shale and increase its hardness.

5.2 TIGHT HOLE

A hole is said to be tight when the upward pulling force is greater than the buoyant weight of the drillstring. The extra force above the buoyant weight is called the drag force. Increased drag while drilling or pulling out of hole is a clear indication that the hole is becoming tight.

Tight hole is usually observed across sections containing reactive clays or salt. The swelling of the clays results in a reduced wellbore diameter eventually causing increased drag when pulling out of hole.

Other symptoms of tight hole include:

- increased torque and

- higher pump pressures

Tight hole is more of a problem in deviated wells and in long reach wells than vertical wells.

The following methods are usually applied to cure tight hole:

- Increase mud weight to force the wellbore from moving in
- Increase mud salinity, especially in oil-based muds, to draw moisture out of the clay sections and increase their hardness
- Add lubricant to the mud

The reader should note that tight hole can also be observed across salt sections. The cure is straight forward and it involves spotting a fresh water pill across the salt to washout it and free the pipe.

5.3 Hole Washout and Erosion

A hole washout occurs when the diameter of the hole drilled is greater than the bit size used to drill the hole. Hole erosion and washout occur across weak and soft formations as a result of using large flow rates resulting in excessive mud annular velocities. Washouts also occur across reactive shales which slough into the hole when contacting uninhibited water-based mud.

Signs of washouts at surface include:

- Increased volume of cuttings on shale shakers
- Large cuttings
- Difficulty in running into the hole
- Bottoms up time increase

Hole washouts cause several problems including difficulty in cleaning the hole, poor directional control, difficulty in running into the hole and most importantly result in very poor cement jobs. A number of casing buckling problems have been observed across severely washed-out holes which could not be cemented to the critical height required to prevent buckling, see **Chapter 15**.

Preventing washouts should be planned ahead of drilling the well. In the field, if washouts are suspected then mud inhibition should be increased, lifting capacity of mud improved by increasing the mud yield point (YP) and annular velocities reduced to the absolute minimum consistent with effective hole cleaning.

5.4 Hole Collapse and Hole Fracture

The mechanisms and calculations for hole collapse (compressive failure) and hole fracture (tensile failure) were discussed in detail in **Chapter 12**.

It is important to note that the required mud weight should not just be based on the value required to balance the formation to prevent well kicks. Some formations require overbalance in excess of the usual 200 psi value in order to prevent hole collapse. This is particularly true for shale/mudstone section which could collapse if insufficient mud weight was used.

For sections containing sandstones and carbonates, high mud weights usually result in fractures which could lead to severe lost circulation.

For hole sections containing both sandstones/carbonates and shales/mudstones, the mud weight chosen should be a balance between that required to prevent hole fracturing (maximum value) and the mud weight required to prevent hole collapse. This is the mud envelope exercise presented in **Chapter 12** for various hole angles.

If a balance can not be reached, then an extra casing string should be considered. If the well plan does not allow for an extra casing string, then hole instability problems must be tolerated.

5.4.1 Borehole Orientation and Inclination

A further cause of formation instability is exhibited when drilling boreholes of varying directions and inclinations from multi-well drilling sites. Shales tend to be weaker and will fail along planes of fissility and along bedding planes. The degree of failure will depend on the angle and direction of the hole with respect to formation dip and planes of fissility.

6.0 Free Point Determination And Back-Off Operations

6.1 Free Point Determination

If the drillstring can not be recovered by pulling or spotting pipe release agents, then the next stage is to find where in the hole the drillstring is stuck. This is the start of sidetracking or fishing operations.

The free point of the drillstring can be found by either of the following methods:

1. Stretch Test
2. Free Point Indicator Tool

6.1.1 Stretch Test

The stretch test is a simple, quick and inaccurate method of determining the approximate depth where the drillstring is stuck. The method is highly inaccurate in deviated wells where hole friction impedes or restricts pipe stretch. It should also be noted that the stretch measurements do not account for drillcollars or heavy weight drill pipe response to pull.The method should therefore never be used for determining the point at which the string is to be backed-off.

The accuracy range of this method is around ± 200 ft.

Procedure:

i. Pull the string until the hook value is equal to the weight of the string in air. Mark the string at the rotary table, point A.

ii. Pull additional 40 klbs above the original hook load and mark the string at the rotary table, point B.

(Ensure that the minimum yield strength of the weakest member of the drillstring is not exceeded.)

iii. Lower the string to the original hook load and mark the string at the rotary table, point C.

iv. Again pull 40 klbs above the original hook load and mark the string at the rotary table, point D.

v.Measure the distance between the mid point of marks A and C to the mid point of marks B and D. This is the stretch of the drill pipe, denoted as e.

vi. The relationship between the stretch (e) and the length of free pipe is expressed as:

$$L = \frac{(735, 294eW_{dp})}{F} \tag{13.3}$$

where

L = the free length of drill string

F = Differential pull (lbs.)

e = pipe extension

W_{dp} = weight of drillpipe (lb/ft)

6.1.2 Free Point Indicator Tool

The free point indicator tool (FPI) is designed to determine where the drillstring is free by measuring the points in the drillstring where tension and/or torque are zero. The tool has a series of axial strain gauges that measure the tension and torque in the string. Surface pull and torque are applied as the tool is positioned at various connections to determine the points where the string is free. If none of the applied surface torque or tension can be recorded at a point downhole, the string is assumed to be stuck at that point. There will of course be various degrees of stuck pipe ranging from totally stuck (0% free) to totally free (100% free), depending on the tool measurements down hole. Torque and overpull measurements are of course complicated in deviated wells and in wells with doglegs due to friction between the pipe and the walls of the hole. Therefore, the neutral point in deviated wells is less precise compared to vertical wells.

Back off attempts are usually be made where torque and tension readings are 80-90% of free pipe. For practical purposes, the back off point may be chosen to be the next connection above the free connection (from FPI) which was broken on the last trip.

6.1.3 Backing-Off The String

The term back-off refers to separating the free pipe from the stuck pipe at a threaded connection at or just above the free point. It is accomplished by placing an explosive charge (**string shot**) across the connection. The string shot consists of the explosive assembly and equipment necessary to reach the point of detonation downhole. The major parts include: safety sub, shooting head, shot bar assembly, electric blasting cap and the detonating cord.

The free threaded connection is located by means of a casing collar locator (CCL); the latter tool distinguishes between the body of the casing and the thicker coupling (tooljoints) sections. Once the free point is determined, the FPI tool is pulled out of hole.

The backing off operation is performed by running the explosive charge on wireline to ± 3000 feet above the connection to be freed. Left hand torque is then applied and some overpull is maintained until the explosive charge is run to the back off point. **Table 13.2** give suggested values for torque values to be used.When the charge is in position, the surface weight is slacked off to the desired value and the charge is fired.

After the charge has been fired the tool is pulled to determine if the operation has succeeded. If the pipe is free, the Martin Decker (weight indicator) will register a lower weight than before the drillstring was stuck due to loss of the weight of lower portion left in hole.

If the chosen connection has not backed-off completely, it may be that further left hand torque is required to fully unscrew the thread. A larger explosive charge may be used if the first backing off attempt has failed.

Table 13.2 API make Up Torque Values

Size	Grade	Connection	Make-Up Torque (ft-lb)
5” 19.5 lb/ft Drillpipe	E	NC50 (X.H.)	15,800
	X	NC50 (X.H.)	20,200
	G	NC50 (X.H.)	21,900
	S	NC50 (X.H.)	28,400
3.5” 13.3 lb/ft Drillpipe	E	NC(38) (I.F.)	7,300
	X	NC(38) (I.F.)	8,800
	G	NC(38) (I.F.)	9,900
	S	NC(38) (I.F.)	12,600

There are three factors which ensure a successful back-off:

1. The explosive charge must be large enough to break the connection

It should be noted that the explosive charge must not damage the pin and box of the connection to be freed as this makes reconnection with a fishing assembly difficult. The whole objective here is to remove the stuck pipe and recover the drilled hole where a large investment has been spent.

2. Sufficient left hand torque at the connection has to be applied.

3. The connection to be backed off should be at neutral point, with preferably a small overpull.

7.0 FISHING OPERATIONS

Once the pipe is backed off or severed as outlined in the previous section, the remaining portion of the drillstring is called the "fish". Oilwell fishing is defined as the process of retrieving a stuck pipe which is left in hole after back-off or twist off operations. Fishing involves running a set of equipment to the top of the fish, engaging it and then retrieving it.

7.1 FISHING EQUIPMENT

The standard fishing assembly should comprise the following elements:

Fishing Tool - Bumper Sub - Jar - DCs - Accelerator - HWDP – Circulating sub - DP.

The actual assembly chosen will depend upon tool availability and the specific situation encountered. There are a numerous types of fishing tools, only a few will be mentioned here. The interested reader is advised to read manufacturers literatures [1,2].

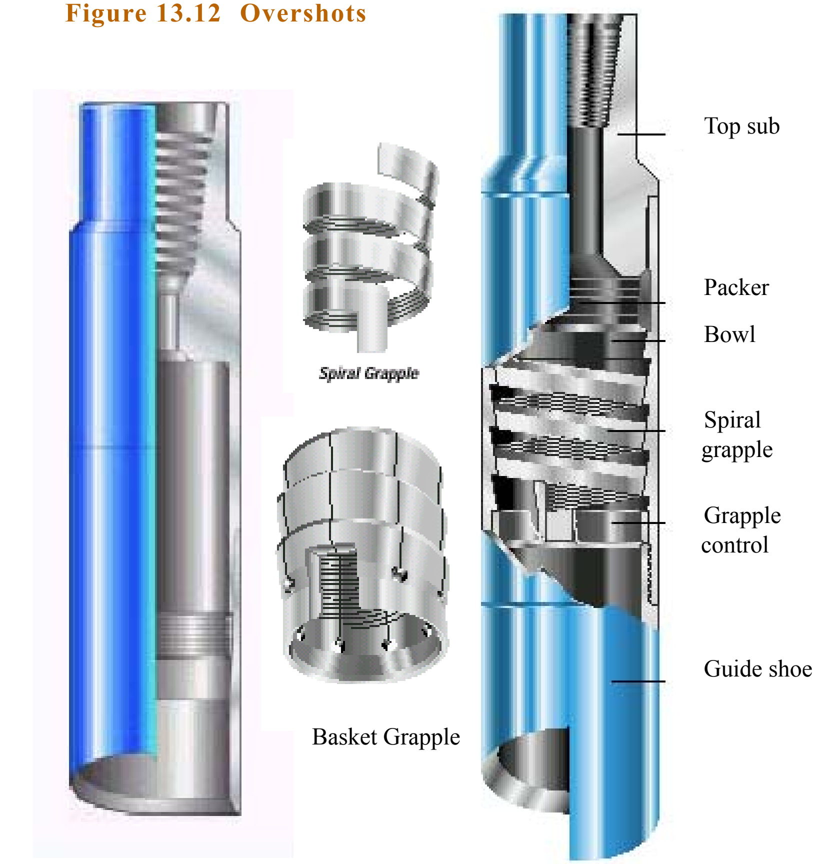
7.2 FISHING TOOLS

7.2.1 OVERSHOTS

An overshot (**Figure 13.12**) is used for engaging, packing off and retrieving a tubular fish.

A basic overshot consists of three parts: top sub, bowl and guide, **Figure 13.12**.The overshot can be dressed with a spiral grapple if the fish OD is close to the maximum catch of the overshot or a basket grapple if the fish diameter is around 1/2" below maximum catch size.
The bowl of the overshot is designed with

Figure 13.12 Overshots



Bulldog Overshot (Baker)

Overshot with spiral grapple

helically tapered spiral section in its inside diameter where the gripping member (spiral grapple or basket grapple) is fitted. The spiral grapple is a helical spring(**Figure 13.12**); the basket grapple is a segmented, expandable cylinder. The grapple is held inside the bowl by a grapple control and a guide shoe.The inside surface of the grapple has a whickered surface (**Figure 13.12**) and has a slightly smaller circumference than the fish it is designed to catch.

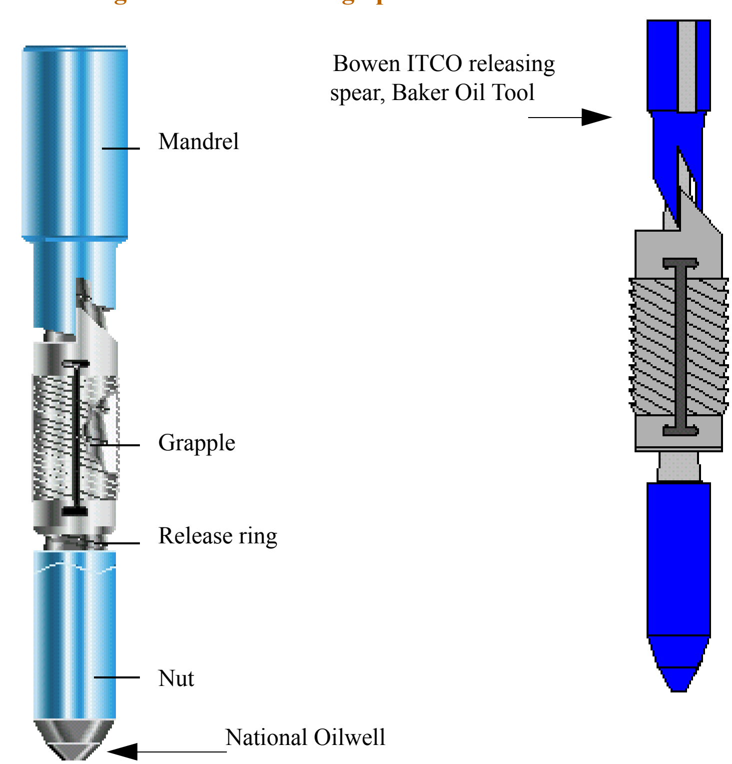
To engage the fish, the overshot is rotated to the right and lowered onto the top of the fish. The grapple will expand when the fish is engaged, allowing the fish to enter the grapple.Rotation is then stopped and an upward pull exerted to allow the grapple to be contacted by the tapers in the bowl and its deep wickers to grip the fish firmly. The fish is released by a sharp downward bump, rotation to the right and slowly elevating the overshot.

7.2.2 Spears

Spears are used to catch and engage the fish internally.

A fishing spear typically consists of: a mandrel, grapple or slip segments, release ring, and a nut, **Figure 13.13**. A spear containing slip segments has its body machined into several stages of identical cone sections, this surface is matched by tapered surfaces on the slip segments. This design allows the slip segments to expand when moved downwards relative to the body of the tool.

Figure 13.13 Fishing spears



Both the grapple and slips type designs are run in hole in the retracted position by the use of J slots or appropriate mechanisms. When the spear enters the fish, the spear is rotated to the right to release the slips or grapple placing them in the engaging position.A straight pull will then wedge the grapple or slips into positive engagement with the fish. Release of the spear is achieved by bumping downwards and rotating the string two to three turns to the right.

7.2.3 Bumper Subs

Bumper Subs are used to provide upwards or downwards blows to the stuck drillstring. The main component of the bumper sub is a hexagon-shaped mandrel which slides in a similar shaped mandrel body to provide continuous torque capability. Most tools have a standard 20" stroke but longer strokes designs are also available. Bumper Subs are designed to bump down, jar up, or help disengage a fish after retrieval.

If used, the bumper sub should be installed immediately above the fishing tool for maximum effect. Bumper subs are most effective at shallow depths and in vertical wells drilled from floating rigs.

7.2.4 Jars

Jars provide a means of supplying powerful upward or downward blows to the drillstring. There are two types of jar, mechanical and hydraulic, see **Chapter 10** for details.

7.2.5 Jar Accelerators

An accelerator (see **Chapter 10**) concentrates the jarring action within the drill collars above the jar, preventing the jarring force from dissipating up the string. This results in a higher hammer velocity which increases both impact and impulse of the jarring action.

7.3 Miscellaneous fishing Equipment

7.3.1 Washover Strings

A washover string (**Figure 13.14**) is run if an overshot and jarring assembly fails to remove the fish.Washover strings are generally used to remove debris that is surrounding a fish. It may be required in any of the following instances:

- Where the formation has bridged and stuck the string.

- Where the string has become cemented.
- To dress the top of OD of a fish in preparation for running a fishing tool.
- Where casing has collapsed on the pipe and mud solids are accumulating on the stuck point.

The washover string is a pipe with an ID larger than the OD of the fish and is run with a rotary shoe, **Figure 13.15**.

Figure 13.14 Washover operation, Courtesy of Baker Oil Tools

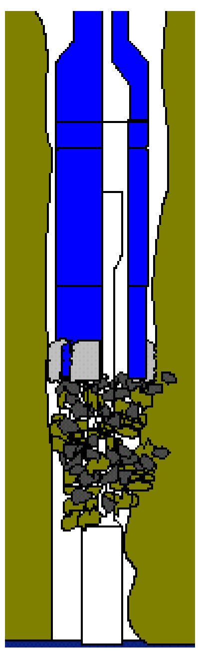
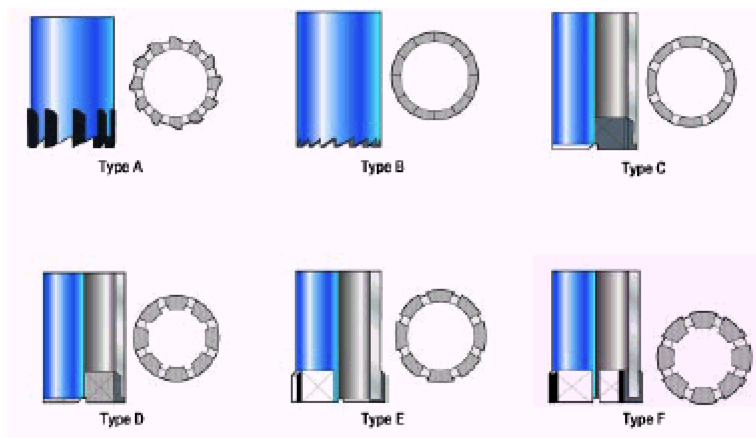


Figure 13.15 Rotary shoes, Courtesy of Baker Oil Tools



7.3.2 Impression Blocks

An impression block (**Figure 13.16**) is a short sub with a flat bottom covered with a soft layer of lead. An impression block is run into the hole to ascertain the shape of the fish inside the hole in order to determine the appropriate fishing tool to run.

Figure 13.16 Impression block, Courtesy of National Oilwell

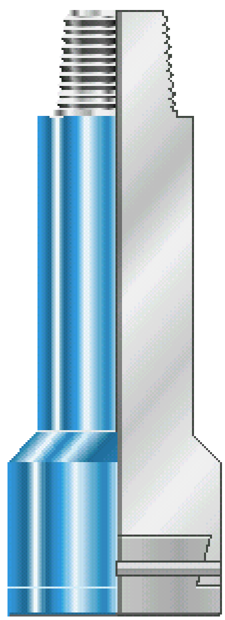
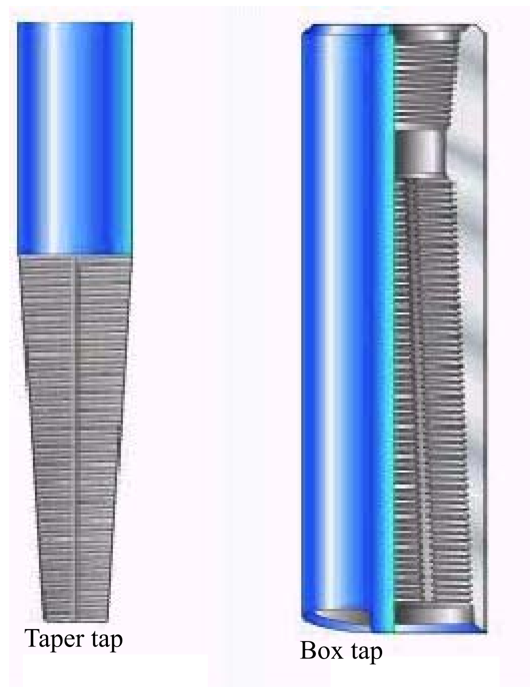


Figure 13.17 Taper tap and box tap, Courtesy of Baker Oil Tools



7.3.3 Taper Taps And Box Taps

Taper taps (**Figure 13.17**) are used to engage the inside of a fish when the use of a conventional releasing spear is not feasible. It is designed to cut threads into the steel so that the fish can be retrieved or the fishing job continued.

A box tap functions the same way as a taper tap, except it is designed to engage the outside diameter of the fish.

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7.4 Fishing Economics

The option of abandoning fishing operations and sidetracking the well should be taken on economic grounds unless there are exceptional logistical, legislative or safety grounds. Before giving up on a fishing job the cost of sidetracking operations together with re-drilling to the original depth needs to be calculated. This cost when converted to equivalent rig day rate days can be used to assess the amount of time that it is economic to pursue fishing operations. The procedure is as follows:

a. Calculate the total cost of the fish to be left in hole.

b. Calculate the cost of backing-off and setting of a cement plug prior to sidetracking. This should include all rental and consumable items, including personnel.

c. Calculate the cost of the sidetrack including directional equipment and casing milling equipment (if applicable).

d. Calculate the cost of drilling to the original depth. This should be based on the time to drill the original section plus an additional 10% to account for the directional aspects.

Total cost is therefore = a + b + c + d.

This should be converted to rig days by dividing the total cost by the rig day rate.

Abandonment of fishing operations should be considered when the fishing time has reached ½ the above number of days, and the probability of completing the fishing operation is gradually becoming small.

8.0 Lost Circulation

8.1 Causes Of Lost Circulation

Lost circulation is the loss of mud or cement to the formation during drilling operations. Lost circulation causes:

- increased well costs, due to lost rig time and loss of expensive drilling fluid

- loss of accurate hole monitoring
- well control problems.

Mud losses can be experienced as a result of either natural losses, induced fractures during drilling operations or due to excessive overbalance.

8.1.1 Natural Losses

Natural losses occur in rocks containing porosity and permeability or with natural fractures. Three types of formations can be recognised:

i. Coarse Sands and Gravel Beds

Usually occur near the surface where the formation is both porous and highly permeable: permeability in excess of 10 to 25 Darcy.

ii. Natural Fissures or Fractures

Natural fissures and fractures usually occur in limestones and chalks which have been subjected to tectonic activities or to leaching by acids. Losses in the formations is usually severe.

iii. Cavernous Formations

Caverns develop in limestone and dolomite formations ranging in size from fraction of an inch to large tunnels. They form as a result of ground water percolating through the formation and subsequent dissolving of the calcium. Total losses are usually experienced when drilling cavernous formations, resulting in the use of a special drilling technique called blind drilling. In blind drilling, drilling is carried out without returns to surface, usually using sea water.

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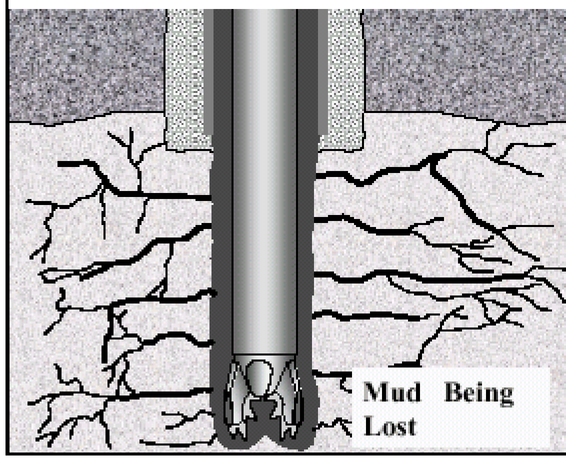
8.1.2 Induced Fractures

In formations where the difference between pore pressure and formation fracture pressure is low, fractures may be induced by either the drilling ECD or surge pressures, **Figure 13.18**. Mud losses will occur through the induced fractures.

Figure 13.18 Induced fractures



The increased volume of cuttings in the annulus can increase the ECD to beyond the formation fracture pressure. This is especially true in surface holes, see **"Volume of Drillcuttings in The Annulus" on page 620**.

8.1.3 Classes of Lost Circulation

Lost circulation can be grouped into four classes:

1. Seepage losses: From 1-10 bbl/hr and lost while circulating at the normal drilling circulating rate
2. Partial losses: From 10-50 bbl/hr and lost while circulating at the normal drilling circulating rate
3. Severe losses: Greater than 50 bbl/hr and lost while circulating at the normal drilling circulating rate. In some cases, no losses may be seen if pumping stops indicating that the ECD is the cause of lost circulation.
4. Total losses: When the mud level in the annulus can not be seen or the hole can not be filled through the annulus. Total losses usually occur in cavernous formations.

8.2 Prevention Of Lost Circulation

The following is a list of measures which must be considered to prevent lost circulation:

- Volume of drillcuttings in the annulus

- Controlling viscosity and gel strength
- Controlling surge pressure

8.2.1 VOLUME OF DRILLCUTTINGS IN THE ANNULUS

Increases in annular mud weight due to drilled cuttings loading can result in formation breakdown, particularly in surface holes. The increase in annular mud weight due to drillcuttings must be calculated and taken into account. It may be necessary to reduce the ROP in order to keep the annular mud density to an acceptable value.

Example 13.5: Effective Annular Density Due To Drill Cuttings

Given the following well information, calculate the actual annular mud weight:

ROP	= 100 ft/hr
Circulation Rate	= 1200 gpm
Hole Size	= 17½ inches
Input Mud Weight	= 9.0 ppg
Formation Density	= 2.30 sg

Solution

$$\rho_{eff} = \frac{\text{mass of mud + mass of cuttings (lbm/min)}}{\text{volume of mud + volume of cuttings (gal/min)}} \quad \text{lbm/gal}$$

In symbol form:

$$\rho_{eff} = \frac{\rho_m \text{ x } Q + 141.4296 \text{ x } 10^{-4} \text{ ROP x } d_b^2}{Q + 6.7995 \text{ x } 10^{-4} \text{ ROP x } d_b^2} \tag{13.4}$$

where

ρ_{eff} = effective mud density in hole, ppg

ρ_m = density of mud at surface, ppg

Q = mud flow rate, gpm

ROP = penetration rate, ft/hr

d_b = drillbit size (= hole size), in

$$\rho_{eff} = \frac{9 \times 1200 + 141.4296 \times 10^{-4} \times 100 \times 17.5^2}{1200 + 6.7995 \times 10^{-4} \times 100 \times 17.5^2}$$

Resultant mud weight (MW)= 9.2 ppg

Hence, the increased volume of drill cuttings will increase the effective density by 0.2 ppg. There is also the additional increase in density due to mud circulation.

Hence

Effective circulating mud density (ECD) = static mud density + drillcuttings contribution + annular pressure loss contribution

8.2.2 Controlling Viscosity And Gel Strength

The viscosity and gel strengths of the mud affect the equivalent circulating density (ECD) and therefore should be maintained within the programmed specification. If the yield point of the mud is too high, breaking circulation will induce high ECD before the mud shears and flows. To prevent this, break circulation slowly and increase the pump speed only after returns are obtained.

If viscosities are very high, circulation should be broken at stages whilst running through the open hole. This will help shear the mud reducing the high surge pressures when running in and ECD when initially circulating.

8.2.3 Controlling Surge Pressures

Fast running of pipe in hole induces surge pressures which when added to the mud hydrostatic pressure can fracture exposed formations. Typically, the weakest formations are near the casing shoe and these usually fracture when the pipe is run too fast resulting in lost circulation.Surge pressure is applied on the formation as soon as the string is run in the hole. However, the maximum permissible speed will be greater when the bit is near surface and will decrease with depth.

In areas of potential lost circulation, surge pressure calculations should be performed and the driller instructed as to the maximum allowable speed for running pipe. Running speeds can be monitored and alarmed in the mud logging unit to assist the driller in maintaining a safe tripping speed.

8.3 Curing Lost Circulation

Lost circulation can be cured by either reducing mud weight, using loss circulation material (LCM) or a combination of both. For severe losses, special plugs may be used to plug off the loss zone.

8.3.1 Reducing Mud Weight or ECD

Reduction of mud weight is the obvious measure for curing lost circulation. Mud weight can only be reduced to a level where it is still greater than the formation pressure of any exposed formation. Otherwise a kick will result and can lead to an extremely difficult well control situation.

An estimate of the maximum mud weight the formation can stand can be obtained using the methods described below.

i. If there are mud returns whilst circulating, fill the annulus with a measured volume of water or base oil, depending upon mud system, and calculate the new mud weight, see **Example 13.6**.

ii. If there are no returns whilst circulating: Compare the circulating pressure prior to the losses occurring (Pressure A) with the pressure at the same circulating rate after the losses have occurred (pressure B). The height of empty hole can then be deduced from:

$$\frac{\text{Pressure A - Pressure B}}{\text{Mud weight (psi/ft)}} = \text{height of empty hole (ft)}$$

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Example 13.6: Lost Circulation

During drilling of an 8.5 in hole at 8,000 ft, a complete loss of circulation was observed. Drilling was stopped and the mud level in the annulus was observed to fall rapidly. The well was filled with water of 8.3 ppg density until the annular level remained stationary. If the volume of water used was 65.7 bbl and mud density was 10 ppg, determine the formation pressure and the new mud weight required to balance the formation pressure. Assume the intermediate casing to be 9.625 in, 40# set at 6,000 ft. Drillpipe is Grade E, 5 in OD.

Solution

Capacity of annulus between 5 in drillpipe and 9.625 "casing = 0.0515 bbl ft

$$\text{Height of water column} = \frac{67.5 \text{ bbl}}{0.0515 \text{ (bbl/ft)}} = 1{,}276 \text{ ft}$$

When the well is balanced, the following equation applies:

Formation pressure = pressure due to mud column + pressure due to water column

$$= 0.52 \times 10 \times (8{,}000 - 1{,}276) + 0.052 \times 8.3 \times 1{,}276 = 4{,}0\,47 \text{ psi}$$

(Note: hole depth = 8,000 ft, of which 1,276 ft is filled with water and 6,724 ft with mud).

$$\text{Required mud weight} = \frac{4{,}047}{0.052 \times 8{,}000} = 9.7 \text{ ppg}$$

Example 13.7: Lost Circulation and Effective Circulating Density (ECD)

Given:

Hole size = 8½ in

Hole depth = 12,000 ft

Intermediate casing = 9 5/8 in set at 10,400 ft

Casing ID = 8.765 in

Drill string = Drillpipe 5/4.276 in, 11,400 ft

Drillcollars = 6/3 in, 600 ft

Mud weight = 12.7 ppg

Density of fresh water =8.3 ppg

While drilling at 12,000 ft depth, circulation was lost and a 110 bbls of fresh water was used to fill the annulus.

Determine:

1) The formation pressure at 12,000 ft, if the annulus level remains static.

2) The equivalent density in the annulus and the density of mud required to balance the formation.

3) The hydrostatic pressure at the casing seat.

4) Assume that the mud level continued to drop and that a cement plug was considered necessary. Calculate the volume of cement required to fill 1,000 ft of open hole.

5) The dynamic pressure while circulating the new mud assuming:

Flow rate = 250 gpm

Yield point = 20 lb/ft^2

Viscosity = 25 cp

Solution

1)Capacity of annulus between 9 5/8" casing and 5" drillpipe = 0.0515 bbls/ft

$$\text{Height of water column} = \frac{110 \text{ bbls}}{0.0515 \text{ bbl/ft}} = 2136 \text{ ft}$$

When the well is in balance, we have

Formation pressure = pressure due to mud column + pressure due to water column

= 0.052 x 12.7(12000 - 1236) + 0.052 x 8.3 x 2136 = 7436 psi

2) Equivalent density = $\frac{7436}{12000 \times 0.052}$ = 11.9 ppg

This is the density of the new mud required to just balance the formation.

3) Hydrostatic head at casing shoe = 0.052 x 10,400 x 11.9 = 6436 psi

4) Volume of cement = volume of open hole x 1,000 ft $= \frac{\pi}{4}(8.5)^2(\frac{1}{144})x1000$

= 394.1 ft^3 = 70 bbls

5) Annular Pressure Losses

a. DP/Casing

Length of section (L) = 10400 ft

$$P = \frac{L \times PV \times V'}{60,000 \times D_e^2} + \frac{L \times YP}{225 \times D_e}$$

$$V' = \frac{24.5x250}{8.765^2 - 5^2} = 118.2 \text{ ft/min}$$

$$P_1 = \frac{10,400 \times 25 \times 118.2}{60,000 \times (8.765 - 5)^2} + \frac{10,400 \times 20}{225 \times (8.765 - 5)} = 281.7 \text{ psi}$$

b. DP/Open hole

L = 11400 - 10400 = 1000 ft, V' = 129.6 ft/min

$$P_2 = \frac{1000 \times 25 \times 129.6}{60,000 \times (8.5 - 5)^2} + \frac{1000 \times 20}{225 \times (8.5 - 5)} = 29.8 \text{ psi}$$

c. DC/Open hole

L = 600 ft, V' = 168.7 fpm, De = 8.5 – 6 = 2.5 "

$$P_3 = \frac{600 \times 25 \times 168.7}{60,000 \times (8.5-6)^2} + \frac{600 \times 20}{225 \times (8.5-6)} = 28.1 \text{ psi}$$

Total annular pressure = 339.6 = 340 psi

Dynamic pressure = 7436 + 340 = 7,776 psi

$$\text{Equivalent circulating density} = \frac{7,776}{0.052 \times 12000} = 12.5 \text{ ppg}$$

8.3.2 Lost Circulation Material

There are numerous types of lost circulation material (LCM) available which can be used according to the type of losses experienced. Typical LCM materials used are:

a. Conventional LCM

These include:

1. Flakes: includes mica and cellophane
2. Granular: includes nutshells, calcium carbonate and salt
3. Fibrous: includes glass fibre, wood fibre and animal fibre

b. Reinforcing Plugs and Cement

These are specialised plugs and are only used as a last resort if every thing else fails.

Two types of reinforcing plugs are in common use:

- Oil bentonite plug (water based muds)
- Water organophilic clay plug (oil based muds)

Oil/Bentonite Plug

The use of this plug is based on the fact that bentonite does not hydrate in oil but when spotted downhole it will contact water, hydrate and with oil forms a strong plug. The pill is pumped to the loss zone with spacers ahead and behind to prevent it from contacting the water based mud en route to the loss zone. When the pill is finally spotted, it will contact water and will hydrate and seal the loss zone.

Water/Organophilic Clay Plug

For oil based mud, the reverse of the above is used. An organophilic clay, which yields (disperse) in oil based mud but not in water, is mixed with water and is pumped as a pill to the loss zone.On contact with the oil mud downhole it will form a strong solid material. The pill must be pumped with a spacer ahead and behind to prevent it from contacting the oil based mud en route to the loss zone.

9.0 Learning Milestones

In this chapter, you should have learnt to:

1. List pipe sticking mechanisms
2. List causes of differential sticking and calculate differential sticking force
3. Describe methods for freeing differentially stuck pipe
4. Describe mechanical sticking methods and their avoidance
5. Describe shale hydration mechanisms
6. Describe problems relating to shale hydration
7. Describe salt problems and casing collapse caused by salt
8. Describe causes of lost circulation and curing methods

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11.0 EXERCISES

Exercise 1

Determine the magnitude of the differential sticking force across a permeable zone of 30 ft in thickness using the following data:

Differential pressure = 1500 psi

Area of contact is 25% of effective drillpipe perimeter

Filter cake = 1/2 in (12.7mm); friction factor = 0.1

Drillpipe is known to be stuck, size 5" OD

Exercise 2: Reduction of Hydrostatic Pressure

Calculate the volume of oil required to reduce the hydrostatic pressure in a well by 450 psi, using the following data:

mud weight= 10 ppg

hole depth= 11000 ft

drillpipe= OD/ID = 5 in/4.276 in

hole size= 12.25 in

specific gravity oil= 0.8

3. List pipe sticking mechanisms.

4. List causes of differential sticking and calculate differential sticking force.

5. Describe methods for freeing differentially stuck pipe.

6. Describe mechanical sticking methods and their avoidance.

7. Describe shale hydration mechanisms.

8. Describe problems relating to shale hydration.

9. Describe salt problems and casing collapse caused by salt.

10. How dose bit balling occur?

10. Describe causes of lost circulation and curing methods.

11. How does an oil/bentonite plug cure lost circulation?

12. What is meant by blind drilling?

14

Horizontal & Multilateral Wells

Content

1.0 Introduction

The aim of this chapter is to introduce some of the design principles required in planning horizontal and multilateral wells, sometimes described as "designer wells". The term designer wells was introduced in this industry primarily to emphasis the complex directional profiles that can be implemented with today's technology.

It is not intended to detail all the equipment and procedures in current use as this subject is developing rapidly. Indeed, some of the equipment which were invented in the early 1990's are now regarded as old technology. The emphasis will be placed on the more general procedures and equipment which will are in current use.

2.0 Horizontal Wells

By oilfield convention, a horizontal well is defined as a well with an inclination angle of 90 degrees from the vertical. A vertical well is one with zero inclination angle.

There is a misconception in some quarters within the industry that horizontal wells were introduced during the mid to late 1980's. In fact as the list below shows horizontal drilling dates back to the 1950's.

2.1 Milestones in the Development of Horizontal Drilling

1950s	Russians drilled 43 horizontals
1978	Esso, modern horizontal, Alberta
1979	Arco drilled to overcome high GOR's and gas coning
1979-83	Elf test 3 onshore horizontals; Elf and Agip drill first Offshore horizontal (Ropso Mane, Adriatic)
1986	50 horizontals worldwide. Cost 1.5-2 times greater than vertical wells
1987-88	Horizontal well test theory and productivity assessment Guidelines. Number of horizontals increased dramatically
1989	265 horizontals drilled worldwide.
1990	1000 horizontals drilled.
1991	First Australian horizontal drilled
1992	Over 2,500 horizontals drilled worldwide - 75% in North America (mostly low permeability, gas/water coning regions) Developments in hydraulic fracturing, perforating, computer models and screen completion failures in unconsolidated formations
1993-2000	Horizontal wells are drilled world-wide and become routine wells

2.2 Types of Horizontal Wells

There are three types of horizontal wells:

1. Short radius
2. Medium radius; and
3. Long radius

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Table 14.1 gives a summary of the features and tools for each type.

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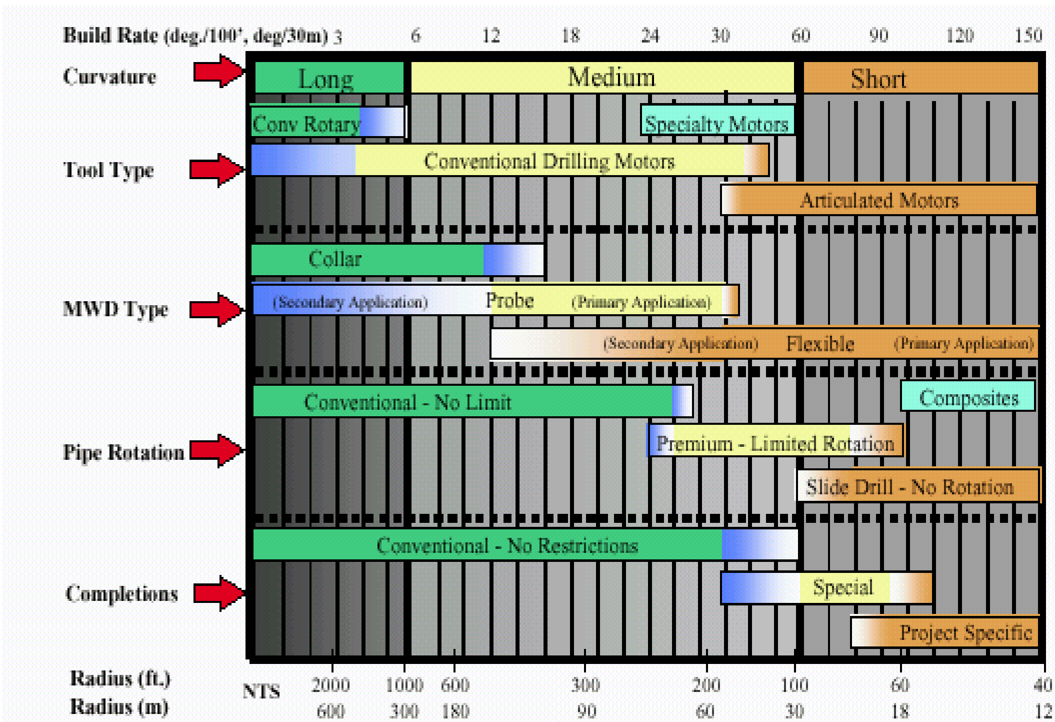
Table 14.1 Types and features of horizontal wells, Courtesy of Baker Hughes Inteq



2.2.1 Short Radius Wells (SRW)

The main features of this type is the very high build-up rate of 60 – 150 degrees /100 ft with a radius range of 40-100 ft. This type requires specialised articulated motors to affect the high build angles, see table Table 14.1 for further details.

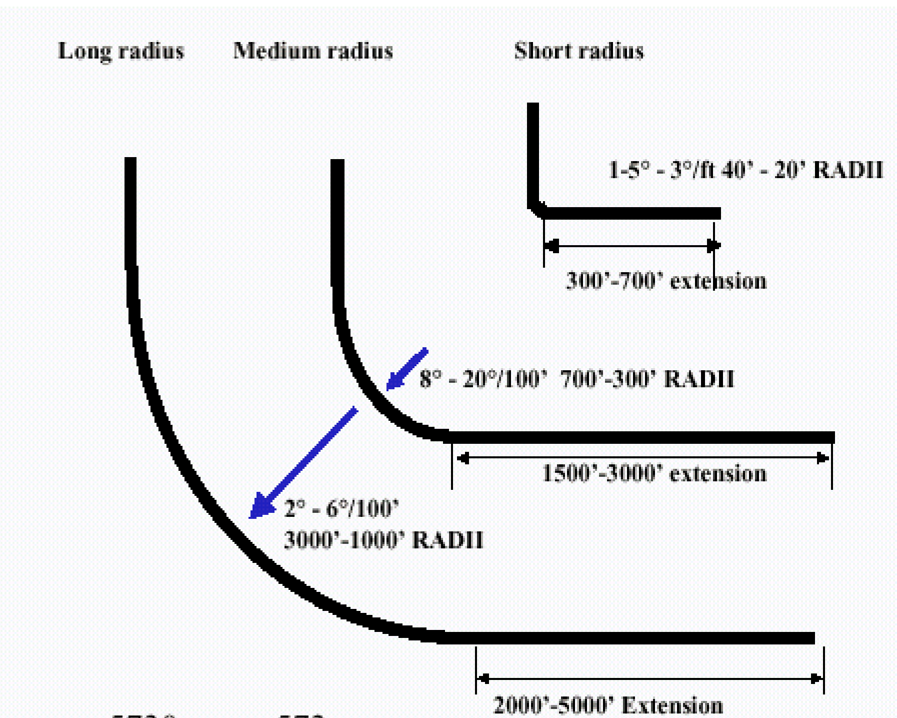
Advantages

1. Enables sharp turns into thin reservoirs
2. Both motor driven and drill pipe driven
3. Laterals can be completed and tied back using special liners

Disadvantages

1. Limited extension possible - Record = 1200’
2. Poor directional control, must snake left then right to
3. Special tools and equipment required

Figure 14.1 Types of horizontal wells



$$R = \frac{5730}{°/100'} \text{ or } \frac{573}{°/10m}$$

2.2.2 Medium Radius Wells (MRW)

The build-up rate for this type is usually 8-30 degrees/100ft with a radius range of 200 to 700 ft. The horizontal drain is usually between 1000 – 3500 ft.

A typical well profile consists of build-tangent section and a build-horizontal section. Two different BHA's will therefore be required for this type of well.

The second build-up section should ideally start at the top of the "**marker zone**" and should reach a maximum of 85-100 degrees on entry into the reservoir. An angle hold assembly should be used to drill the horizontal section.

2.2.3 Long Radius Wells (LRW)

This is the most common type of horizontal wells especially offshore. The build-up rate is usually from 2 to 6 degrees/100ft. The most common BHA used is a steerable system containing a single bent sub with a downhole motor.

Two profiles are in common use:

- A single build-up section terminating in the horizontal section
- A build-tangent and then a higher build-lateral section.

3.0 Well Profile Design Considerations

The following factors should be considered when designing a horizontal well:

- Target definition
- Single curve Design
- Double curve design

3.1 Target Definition

A horizontal well is usually a development well with well-defined geological and reservoir objectives.

The following information is required to define the horizontal target accurately:

1. target co-ordinates
2. entry point into the reservoir
3. length of horizontal drain
4. azimuth range of target
5. vertical depth range of target
6. tolerance in vertical depth and displacement
7. dip of target

It should be observed that the entry point into the reservoir may have different co-ordinates from that of the reservoir. Usually most reservoirs have marker zones which can be used as the starting point for the final build up section before entering the reservoir. The marker zones are usually thin shale section which can be easily identified with gamma ray logging tools.

In new areas, a pilot vertical hole is usually drilled through the reservoir to ascertain the exact depth of the marker and the reservoir, thickness of reservoir and the crooked hole tendency of the formations in the well. The pilot hole is then plugged back to a convenient depth from which the horizontal hole section is sidetracked.

In wells where the objective is to avoid water or gas coning, the inclination of the horizontal section is usually kept constant at 90 degrees in order to maintain the distance with the gas or water contact.

If the reservoir has a significant dip angle, then the horizontal section must be designed to follow the dip to maintain a constant separation above the gas or water contact. In this case the hole is not truly horizontal but may be above or below 90 degrees.

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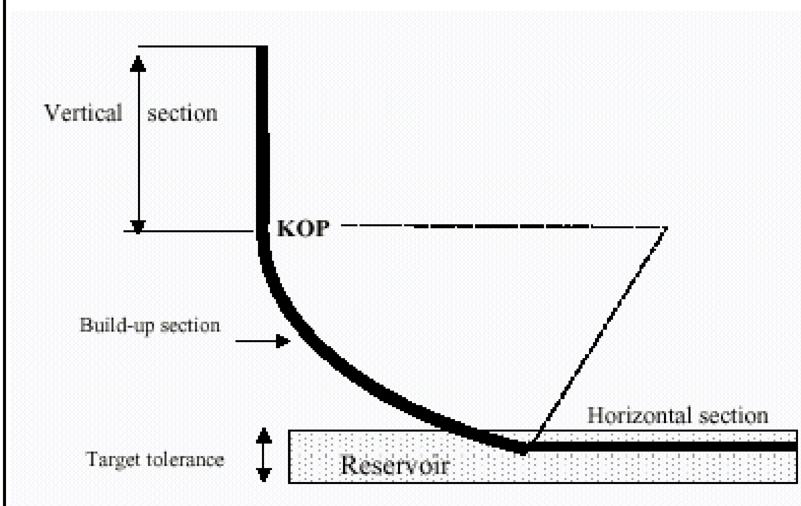
3.2 SINGLE CURVE DESIGN

In this design, the hole angle is built up from zero at the KOP to 90 degrees at the entry point into the reservoir. If this design is used the build up tendencies of both the formation and the rotary or steerable BHA should be known in order to avoid missing the target due to excessive or insufficient build up rates.

Also the build-up rate (BUR) should be selected to land exactly on the target. If the BUR is too low the well path will fall below the target and if the BUR is too high the well path falls above the target. In both cases, expensive well correction is required.

Figure 14.2 Single Curve Design



3.2.1 DESIGN EQUATIONS

$$R = \frac{5730}{BUR} \tag{14.1}$$

$$V1 = R.(SinI_2 - SinI_1) \tag{14.2}$$

$$H1 = R.(CosI_1 - CosI_2) \tag{14.3}$$

$$L1 = \frac{100.(I2 - I1)}{BUR} \tag{14.4}$$

where

R = radius of curvature, ft

BUR = build-up rate, deg/100 ft

V1 = vertical height of build up section, ft

H1 = horizontal displacement of build section, ft

L_1 = length of build-up section, ft

I_1 = initial inclination angle, deg

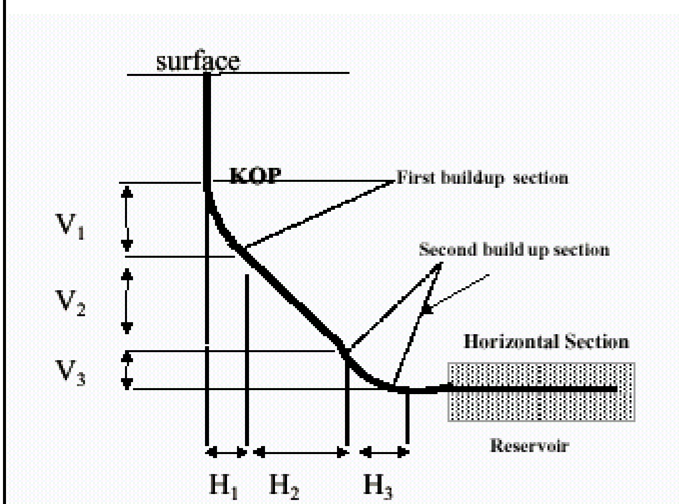
I_2 = final inclination angle, deg

3.3 Double Build Curve design

If the build up rate is too high the well path will be above the reservoir and the well will require redrilling. Similarly, if the build-up rate is too low, the well path will be below the reservoir and the drilling objectives will not be met.

The above problems can be solved by having a tangent section below the initial build up curve and then build up to the required angle when reaching a reservoir marker, see Figure 14.3. In some cases the final angle is actually built up inside the reservoir.

Figure 14.3 Double Curve Design



If a tangent section is included, the equations for the tangent section of a double build curve are:

$$V2 = L2.Cos_2 \qquad (14.5)$$

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$$H2 = L2.SinI_2 \tag{14.6}$$

where

V2 = vertical height of tangent, ft

L2 = length of tangent section, ft

H2 = horizontal displacement of tangent section, ft

The final build up section has the following design equations:

$$R3 = \frac{5730}{BUR2} \tag{14.7}$$

$$V3 = R3.(SinI3 - SinI2) \tag{14.8}$$

$$H3 = R3.(CosI2 - CosI3) \tag{14.9}$$

$$L3 = \frac{100.(I3 - I2)}{BUR2} \tag{14.10}$$

where

I3	= final build angle, usually 90 degrees
R3	= radius of second build-up section
V3	= vertical height of second build-up section, ft

Example 14.1: Double Curve Design

Design a well with two build up sections and a tangent section to land at the target at 90 degrees given:

BUR first section = 5.5 deg

BUR second section = 10 deg

Target = 10000 ft TVD

Tangent angle = 50 deg

Tangent length = 500 ft

Calculate

1. First and second KOP depths
2. Total horizontal displacement
3. Measured depth at point of entry to reservoir (at target)

Solution

First Build up

$$R1 = \frac{5730}{5.58} = 1042\ ft$$

$$V1 = R1.(SinI_2 - SinI_1) = 1042(Sin50 - Sin0) = 798\ ft$$

$$H1 = R1(CosI_1 - CosI_2) = 1042(Cos0 - Cos50) = 372\ ft$$

$$L1 = \frac{100.(I2 - I1)}{BUR} = \frac{100(50-0)}{5.5} = 909\ ft$$

Tangent Section

L2 = 500 ft (given)

$$V2 = L2.Cos_2 = 500\ Cos\ 50 = 321\ ft$$

$$H2 = L2.SinI_2 = 500\ .Sin\ 50 = 383\ ft$$

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Second Build Up Section

$$R3 = \frac{5730}{10} = 573\,ft$$

$$V3 = R3.(SinI_2 - SinI_1) = 573(Sin90 - Sin50) = 134\,ft$$

$$H3 = R3.(CosI_1 - CosI_2) = 573(Cos50 - Cos90) = 368\,ft$$

$$L3 = \frac{100.(I2 - I1)}{BUR} = \frac{100(90-50)}{10} = 400\,ft$$

Kick Off Points

First KOP = 10000 –V1- V2-V3

= 10000- 798-321-134 = 8747 ft

Second KOP = KOP1 +V1 + V2

= 8747+798+321 = 9866 ft

Total Displacement

H = H1+H2+H3 = 372+ 383+ 368 = 1123 ft

Total Measured Depth

At end of first build up = Depth of first KOP + L1 = 8747 + 909 = 9656 ft

At end of tangent = 9656 + L2= 9656 + 500 = 10156 ft

At target (end of second build-up) = 10156+ L3 = 10156 + 400 = 10556 ft

Azimuth Change

$$Az = BUR2 \times (I_2 - I_1) / (BUR1) \qquad (14.11)$$

$$= \frac{10\,(90-50)}{5.5} = 72.27 \text{ deg}$$

The azimuth change if all turn is in the same direction

$$Az = arcCos\left[\frac{CosDL - CosI1.\cos I2}{SinI1.SinI2}\right] \qquad (14.12)$$

$$Az = arcCos\left[\frac{Cos72.27 - Cos50.\cos 90}{Sin50.Sin90}\right] = 66.6 \text{ deg}$$

4.0 Torque and Drag

In a directional well, the friction between the drillstring and the walls of the well produces drag and torque. Drag is produced when the drillstring is moving and torque is produced when the drillstring is rotating.

Knowledge of torque and drag will enable the selection of an optimum well profile and optimum size and weight of the drillstring and its components.

In horizontal wells, it is usual to run the heavy-walled Drillpipe (HWDP) along the curved section of the wellbore to counteract the forces caused by bending and drag. The drillcollars

The following predictions must be made when designing a horizontal well:

1. Torque and drag while drilling with surface rotation
2. Torque and drag while steering a downhole motor
3. Drag forces while tripping
4. Buckling forces on the drillstring

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There are currently several propriety software packages which can do the above. All these packages use essentially the same equations for calculating torque, drag and buckling forces. The following equations may be used to carry out the above calculations {Reference 1].

4.1 TORQUE

1. Horizontal Section

The torque on the pipe (Th) in the horizontal section is given by [1]:

$$T_h = \frac{ODWmL}{72} ....ft - lb. \tag{14.13}$$

where

OD = outside diameter of tool joint, in

Wm = average buoyant weight of pipe, lb/ft

L = length of hole or pipe section, ft

2. Final Build-Up Section

For WOB < 0.33 x Wm x R, use [1]

$$T_h = \frac{ODWmR}{72} ....ft - lb \tag{14.14}$$

For WOB > 0.33 x Wm x R, use

$$T_h = \frac{ODWmR}{144} + \frac{ODWOB}{46} ....ft - lb \tag{14.15}$$

where

R= buildup radius, ft

4.2 DRAG FORCES

Drag forces or drag develops when during tripping operations. Running in drag is the main limiting factor in drilling horizontal and long reach wells since a point can be reached where the drillstring can no longer fall into the hole under its own weight as would happen in vertical wells.

The following equations apply to tripping operations or steering with a downhole motor:

1. Horizontal Section [1]

$$D_h = 0.33\ W_m L \tag{14.16}$$

where D_h = drag force in horizontal section

2. Build-Up Curve

The drag force in the build-up section is a function of the axial compression force (F_o) at the end of the build curve. Assuming a single build- up curve, then the axial compression force at the end of the build-up curve is the sum of the weight-on –bit (WOB) and drag force in the horizontal section [1]:

$$F_o = D_h + WOB \tag{14.17}$$

If $F_o < 0.25$ Wm R, then drag force (D_b) in the build curve is given by:

$$D_b = 0.4\ W_m\ R \tag{14.18}$$

If $F_o > 0.25$ Wm R, then drag force (D_b) in the build curve is given by:

$$D_b = 0.25\ W_m\ R + 0.69\ F_o \tag{14.19}$$

Example 14.2:: Torque and Drag

Given the following well data:

Build curve radius (R) = 1042 ft

Horizontal section = 1500 ft

WOB = 30,000 lbf

Mud weight = 9.2 ppg

BHA is made up mostly of HWDP

HWDP = 5", 50 lb/ft, OD of tool joint is 6.5"

Calculate a) Torque while rotating off bottom

b) Torque and drag while drilling

Solution

Buoyancy factor (BF) = 0.86 (based on 9.2 ppg)

Buoyant weight = 50 x 0.86 = 43 lb/ft

(a) Torque while rotating off bottom

Horizontal section

$$T_h = \frac{ODWmL}{72} .... ft - lb$$

$$T_h = \frac{6.5x43x1500}{72} = 5829\, ft - lb$$

Build-up curve

While rotating off bottom, WOB = 0, hence equation Equation (14.14) applies:

$$T_h = \frac{ODWmR}{72} .... ft - lb$$

$$T_h = \frac{6.5x43x1042}{72} = 4045\, ft - lb$$

Total torque while rotating off bottom = 5829 + 4045 = 9874 ft-lb

(b) Torque and drag while drilling

Torque in horizontal section = 5829 ft-lb

Torque in Build-up curve:

First calculate 0.33 W_m R = 0.33 x 43 x 1042 = 14,786

Hence WOB > 0.33 W_m R and equation Equation (14.15) must be used to calculate torque in the build –up curve:

$$T_h = \frac{6.5x43x1042}{144} + \frac{6.5x30{,}000}{46} = 6262\, ft - lb$$

$$T_h = \frac{ODWmR}{144} + \frac{ODWOB}{46} \ldots. ft - lb$$

Total torque while drilling = 5829 + 6262 = 12090 ft-lb

Drag Force

Horizontal Section

D_h = 0.33 W_m L = 0.33 x 43 x 1500 = 21, 285 lbf

Build-up curve

F_o = D_h + WOB = 21, 285 + 30,000 = 51,285 lbf

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And $\mathbf{0.25\ W_m\ R} = 0.25 \times 43 \times 1042 = 11{,}202$ lbf

Since $F_o > 0.25\ W_m\ R$, equation Equation (14.19) applies:

$D_b = 0.25\ W_m\ R + 0.69\ F_o$

$= 0.25 \times 43 \times 1042 + 0.69 \times 51{,}285 \quad = 46{,}588$ lbf

Total drag force while drilling in the steering mode $= D_h + D_b$

$= 21{,}285 + 46{,}588 = 67{,}873$ lbf

Hence to drill this hole with WOB = 30,000 *lbf,* it is necessary to slack off

= 30,000 + 67,873 = 97,873 lbf

5.0 Horizontal Borehole Stability

When a well is drilled, the column of rock which initially supported the (three) virgin stresses is now replaced by a column of mud. The stress within the mud column is hydrostatic and is equal in all directions, ie, the principal stresses within the mud column are equal. The action of drilling a wellbore results in stress concentration in the vicinity of the well and more importantly at the wellbore wall. When the induced stresses at the wellbore exceed either the tensile or shear strength of the formation, failure of the wellbore occurs. The magnitude of the mud weight, in-situ stresses and the orientation of the wellbore to the in-situ stresses determine whether the wellbore fails in tension or in compression (shear).

In sand/shales, the failure properties of the rock depend on the clay content which can be inferred from Gamma Ray logs.

A wellbore can fail by either fracturing or shearing. Failure by fracturing occurs when the tensile strength of the rock is exceeded and failure by shearing occurs when the rock shear strength is overcome. The changes in stresses around the wellbore is brought about by the physical action o drilling and by the effects of mud hydrostatic pressure. These changes in stresses are the causes of wellbore failure.

In shales, excessive mud weights usually cause shear failure while insufficient mud weights cause sloughing.

(i)Shear Failure

Shear or compressive failure occurs when the local stresses at the wall of the wellbore exceed a threshold value which depends on the intrinsic shear strength of the rock and the frictional forces acting along that shear failure plane.

Shear failure is manifested by the collapse of the wall hole and by material falling into the hole. Hole collapse can also be caused by chemical effects and by the action of stabilisers.

Compressive or shear failure can occur at both high and low mud weights.

Shear failure occurs when the difference between the maximum principal stress and the minimum principal stress is large enough. Shear failure initially manifest itself by the formation of shear cracks which when they combine result in a large crack. The location of the failed zone around the wellbore depends on the magnitude of the principal stresses, see Chapter Two for details.

(ii)Tensile Failure

Extremely high mud weights can cause the wellbore to burst. Depending on the local earth stresses, the fractures generated usually align with the maximum principle in-situ stress or may break out of the wellbore with a different orientation.

Tensile failure occurs when the maximum (tensile) tangential stress exceeds the tensile strength of the rock. The tensile strength of rock is usually between 1/10 to 1/12 of the rock uniaxial strength.

(iii)Wellbore Orientation

The magnitude of the earth stresses at the wall of the wellbore depend on the orientation of the well to the original earth principal stresses.

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In a vertical well, the axial stress at the wellbore lines up with the vertical stress, the overburden stress. The radial and tangential stresses at the wellbore wall can be determined from the earth horizontal and intermediate principal stresses.

In a horizontal well, the earth vertical principal stress acts along a radial axis of the well. The local stress field generated at the walls of the wellbore is in this case very sensitive to the direction of the horizontal wellbore. The wellbore may be stable if drilled in the direction of one of the horizontal principal stresses and unstable if drilled in the other direction.

(iv)Signs of Wellbore Instability

- Washouts
- Tight hole or formation creep
- Cavings and sloughing shale
- Lost circulation

Washouts are identified by:

- Excessive cuttings at shale shakers
- Large size or angular cuttings
- Excessive hole fill after tripping
- Mud volumes in excess of calculated amount
- Excessive drillstring vibration
- Oversized hole from calliper logs

6.0 EXTENDED REACH WELLS

Extended Reach Wells (ERW) are defined as wells where the ratio of measured depth (MD) to true vertical depth (TVD) is greater than two. In other words for a LRW with a ration of two we require to drill twice the TVD to reach the reservoir. Hence, if the reservoir is at 10,000 ft TVD, the MD is 20,000 ft.

At the time of writing this book, a well drilled by BP AMOCO at Wytch Farm, England had a ratio of MD/TVD approaching 8. Well M16 in Wytch Farm had a total measured depth of 11 287 m, with a departure of 10 728 m. Close attention to every aspect of the well design is essential if the drilling costs are to be kept to a minimum. In some ERW round trip times can be up to 48 hours, bit selection becomes critical.

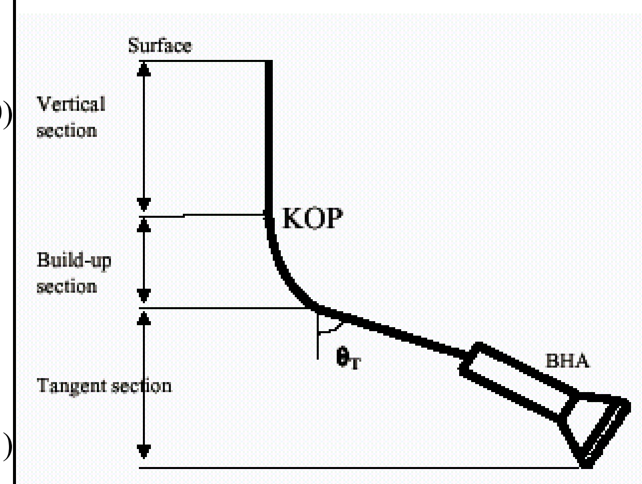
Field experience has shown that beyond 8500 m (27,887 ft), axial drag is too high to allow an oriented steerable motor and drillbit to slide. Beyond this critical depth, rotary steerable systems was found to provide both good performance and the ability to steer.

There are many aspects which must be considered in the design of ERW which will require an entire book. Hence only some design aspects of ERW will be presented here: these include buckling and weight calculations. It is predicted that in a in a few years time, most wells drilled will be those resembling extended reach wells.

6.1 WEIGHT CALCULATIONS IN EXTENDED REACH WELLS

Reference to **Figure 14.4**, the following equations can be derived:

Figure 14.4 Geometry Of An Extended Reach Well



1. Vertical Section

$$W_1 = V_1 \times W_{dp} \times BF \tag{14.20}$$

2. Build-up Section

$$Weight = length \times W_{dp} \times BF$$

$$= Sin\theta_T \left(\frac{5729.6}{BU}\right)\left(W_{dp} \times BF\right) \tag{14.21}$$

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where W_{dp} = weight of drillpipe (lb/ft)

BU = build-up rate in degrees / 100 ft

BF = buoyancy factor

θ_T = angle below tangent point

If the well is not built up from vertical, then the weight in the build up section is given by:

$$BFW_{dp}\left(\frac{5729.6}{BU}\right)\times\left(Sin\theta_T - Sin\alpha\right) \qquad (14.22)$$

where θ_T = angle below tangent point

α = angle above build up

3. Weight of pipe in tangent section

$$= BFxCos\theta_T \times (W_{dp}xL_{dp} + W_{BHA}xL_{BHA}) \qquad (14.23)$$

6.2 Buckling Of Drillpipe And BHA

Buckling of BHA's while rotating is the main cause of fatigue in BHA connections. Buckling in vertical and near vertical wells can not be avoided except at very low WOB's. As the hole angle increases, the BHA becomes more stable as it lies on the lower side of the well enabling the BHA to be supported by the walls of the hole.

The following are general points regarding buckling in drillstrings in compression which are useful before embarking on well planning:

- Light drillstrings are more prone to buckling at small inclination angles than at higher angles
- Buckling is not a problem until critical buckling is reached
- In horizontal and long reach wells, all parts of the drillstring which have been subjected to critical buckling should be inspected

- Rotating drillstrings which are under critical buckling loads are prone to failures
- Drillstring may be subjected to critical buckling if the drillstring is not rotating, ie whilst sliding when building angle

6.3 Critical Buckling Force

Buckling of drillpipe occurs when the applied compressive force exceeds the pipe's critical buckling load. The critical buckling force is the minimum compressive force which results in the pipe buckling. The **critical buckling force** is given by:

$$Fc = 550\left[\frac{I\,W_{dp}(65.5 - MW)\,Sin\,\theta}{D_H - D_{TJ}}\right]^{1/2} \tag{14.24}$$

where

F_c = Critical buckling force, lb

I = Moment of inertia of pipe, in^4 $= \frac{A_s}{16}\left(OD^2 + ID^2\right)$

A_s = cross sectional area of pipe, in^2

$= 0.7854\left(OD^2 - ID^2\right)$

OD = outside diameter pipe body, in

ID = inside diameter pipe body, in

Wdp = weight of drillpipe of pipe in air, lb/ft

MW = mud density, ppg

D_H = hole diameter, in

D_{TJ} = diameter of tool Joint, in

θ = hole angle, degrees

For a give drillstring, the engineer should determine the compressive (buckling) force on the pipe and then compare this force to the critical buckling force from equation Equation (). The pipe will only buckle if the existing compressive force is greater than the critical buckling force.

6.4 Buckling Determination In Extended Reach and Horizontal Wells

For a horizontal or extended reach well, the following sections can be identified:

1. Vertical
2. Build-up section
3. Tangent section
4. Drop off section
5. Horizontal section

It is imperative that drillpipe buckling is prevented or kept to the absolute minimum. Buckling in each hole section is evaluated as follows:

6.4.1 Buckling Above KOP

Buckling in this section occurs if

WOB $\geq F_{crit}$ + buoyed weight of drill string below

This is virtually an impossible situation as it implies that drilling is carried out with WOB equal to the entire weight of the drill string plus additional compression.

6.4.2 Buckling In the Build-Up Section

The critical load required to buckle drillpipe increases as the hole angle increases [2,4]. For a positive build up (ie hole angle increases with depth), the critical buckling load in the build up section is greater than that in a straight hole of the same angle. In general, buckling at the KOP will occur in the straight section above the KOP point.

6.4.3 BUCKLING IN THE TANGENT SECTION

In the tangent section, buckling occurs first in the straight section just below the tangent point [4]. If the angle of inclination is less than 90 degrees, the highest compression in the drillstring will be in its bottom joints, close to the top of the BHA.

Hence buckling of drillpipe will be predicted at this point if the WOB is greater than the critical buckling force + buoyed weight of drilling assembly below the bottom (last) joint of the drillpipe.

Mathematically buckling will occur when:

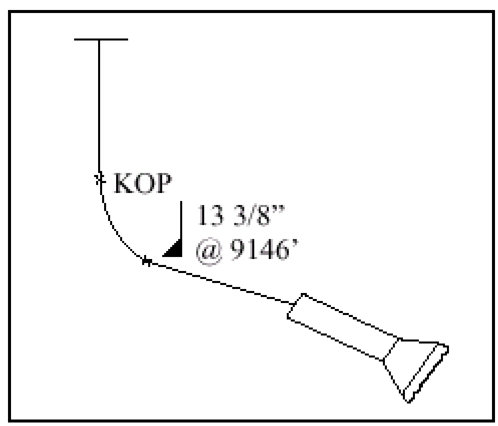
$$WOB \geq F_{crit} + BF\cos\theta\left(W_{BHA} \times L_{BHA}\right) \tag{14.25}$$

In a horizontal well, $\theta = 90$, hence $WOB \geq F_{crit}$

and buckling will occur in the tangent section.

Example 14.3: Extended Reach Well Design

Given the following extended reach well:



KOP = 8000 ft

Final well angle = 80 degrees

13 3/8" casing set at top of tangent section at 9146 ft

Average build up rate = 7 °/100 ft

BHA = 180 ft of 100 lb/ft including tools (Bit/Subs/PDM/MWD)

Target TD = 17000 ft

Drillpipe = 5", 19.5 lb/ft, NC 50 grade S, adjusted weight is 22.6 lb/ft

Hole Size = 12 ¼"

Mud weight = 12.5 ppg, SOBM

The drillbit is currently at 2000 ft below the 13 3/8" casing.

Investigate the possibility of buckling at the current depth and when reaching target TD of 17000 ft.

Solution

1. First calculate the critical buckling force for 5" drillpipe

$$Fc = 550\left[\frac{14.27 \times 22.6 \times (65.5 - 12.5)\ \text{Sin}\,80}{12.25 - 6.375}\right]^{0.5}$$

=29.4 Klb

(where I = 14.27 in ^{4}, Wdp = 22.6 lb/ft, D_H = 12.25", D_{TJ} = 6.375", MW = 12.5 ppg)

This buckling force of 29.4 K lb affects the drillstring from the KOP to TD.

For the vertical section, assume θ = 3. The buckling equation gives: Fc = 6.8 K lbs. This buckling force affects the drillstring from surface to KOP.

To prevent buckling, the compressive force should not exceed 6.8 K lb from surface to KOP and 29.4 K lb from KOP to TD.

2. Now calculate the weight of each section and then cumulative weights

Current depth = 9146 + 2000 = 11,146 ft

BF = 0.809

Wdp = 22.6 lb/ft

Weights

BHA = 180 ft x 100 lb/ft x 0.809 cos 80 = 2.52 K lb

Tangent section= (2000-180)x22.6x0.809 x cos 80 = 5.78 K lb

Build-up section $= \left(\dfrac{5729.6 \times \sin 80}{7}\right) \times 22.6 \times 0.809$ =14.74 K lb

Vertical section= 8000 x 22.6x 0.809 =146.3 K lb

The points of interest in terms of buckling are at: bit, top of BHA, tangent point and above KOP. The following table gives the weights at each point of interest corresponding to a given weight on bit (WOB).

Point of Interest and its weight	Cumulative Tension at Top section (K lb)	WOB (K lb)				Critical Buckling Load (K lb)
		0	20	32	35	
		Weight at point of interest (K lb)				
Bit (0)	0	0	-20 (0-20)	-32	-35	
BHA (2.53)	2.53	2.53	-17.5 (2.53-20)	-29.5 (Buckling occurs here)	-32.5 (Buckling)	-29.4
Tangent section (5.78)	8.31 (2.53+5.78)	8.31	-11.72	-23.7	-26.7	
KOP (14.74)	23.05 (8.31 +14.74)	23.05	3.1	-8.9 (Buckling)	-11.9 (Buckling)	-6.8
Surface (146.3)	169.35 (23.05+146.3)	169.35	149.4	137.4	134.4	

From the above, it was shown that that at weight on bit of less than 31 K lb, no buckling occurs any where within the BHA or drillpipe. When the WOB is equal to 32 K lb, the compressive force at the top of the BHA becomes -29.4 K lb. This is equal to the critical buckling force of 29.4 K lb, corresponding to a hole angle of 80 degrees. At WOB of 32 K lb, there will be buckling at the KOP and at the top of the BHA.

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At WOB of 35 K lb, critical buckling occurs at the BHA and at the KOP.

3. AT target TD = 17000 ft

Weights

BHA = 180 ft x 100 lb/ft x 0.809 cos 80 = 2.53 K lb

Tangent section= (17000- 180- 9146) x22.6x0.809 x cos 80= 24.26 K lb

Build-up section= $\left(\frac{5729.6 \times \sin 80}{7}\right)$ x 22.6x 0.809= 14.74 K lb

Vertical section= 8000 x 22.6x 0.809=146.3 K lb

The points of interest in terms of buckling are at: bit, top of BHA, tangent point and above KOP. The following table gives the weights at each point of interest corresponding to a given weight on bit (WOB).

Point of Interest and its weight	Cumulative Tension at Top section (K lb)	WOB (K lb)				
		0	20	32	54	Critical Buckling Load (K lb)
		Weight at point of interest (K lb)				
Bit (0)	0	0	-20	-32	-54	
BHA (2.53)	2.53	2.53	-17.5	-29.5 (Buckling occurs here)	-51.5 (Buckling)	-29.4
Tangent section (24.26)	26.79	26.79	6.8	-5.2	-27.4	
KOP (14.74)	41.53	41.53	21.5	9.5	-12.4 (Buckling)	-6.8
Surface (146.3)	187.83	187.83	167.8	155.8	133.8	

The buckling points are shown in the table above for three values of WOB.

At TD, the WOB required to buckle the drillstring in the vertical section is 54 K lb; which is substantially greater than that when the bit was at 11,146 ft.

6.5 Reduction of Fatigue Failure

Fatigue failure occurs by either repeated cyclic stresses or by vibrations. Most washouts are caused by fatigue cracks except those caused by connection leaks.

Fatigue cracks are smooth and planar and oriented perpendicular to the axis of pipe or connection. Fatigue cracks occur at stress concentrators such as: internal upsets, slip cuts, corrosion pits on tubes and thread roots of connections. The last engaged pin or box threads are usually the starting points for connection fatigue.

Prevention of Fatigue Failure

1. Lower cyclic stress is achieved by having:
   - Minimum dogleg severity
   - Stabilized BHA's
   - Neutral point in top of BHA
   - Keeping drillpipe compression to below critical buckling load in high angle wells
   - Avoiding rotating at critical vibrations
2. Stress relief features
3. Protect pipe against corrosion: Use corrosion coupons in the upper connection of the Kelly or top drive saver sub and one in the connection at the top of the BHA. Coupons should be removed periodically and weighed to determine corrosion rate.
4. Use lowest pH possible and oxygen scavengers.

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6.6 FLOATING CASING

In order to reduce the effective weight of the casing and therefore drag, it is now a standard procedure in most ERW to run the casing (usually 9 5/8") either empty or partially empty. This practice is described as Floating Casing.

If extra weight is required, then drill collars are run inside the vertical section of the casing. The drillcollars are suspended from a retrievable packer which set inside the 9 5/8" casing. The packer may have to repositioned higher in the casing as the casing is run deeper to provide maximum weight advantage.

The practice of using drillcollars is preferred to filling the casing in case the casing needs to be pulled out of hole.

If casing is to be floated, then accurate collapse calculation must be carried out to ensure that the casing will not collapse.

The disadvantages of floating casing include: limitations on running speeds, inability to circulate the hole while running casing, and the need for high-torque connections if pipe rotation is required.

7.0 MULTILATERAL WELLS

7.1 DEFINITIONS

A multilateral well is a well that has two or more drainage holes (or secondary laterals or branches or arms or legs) drilled from a primary well bore (or trunk or main bore or mother bore or backbore), see **Figure 14.5**. Both trunk or branches can be horizontal, vertical or deviated.

Lateral: A lateral can be a horizontal portion of a well drilled from the top of the reservoir or an entire well deviated from a given point above the top of the reservoir.

Multi-laterals: Multiple boreholes drilled from a single wellbore. These can be horizontal or deviated.

Branch: A lateral drilled from a horizontal lateral in the horizontal plane.

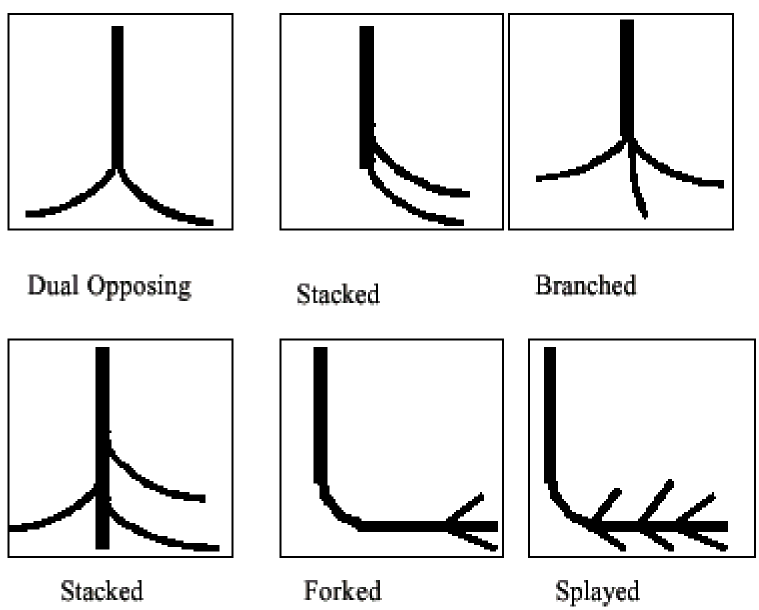
Dual-lateral: A multi-lateral well with two laterals, usually the two laterals are opposed at 180 degrees emerging from the same wellbore.

Stacked-lateral: Two or more laterals departing from the same wellbore at different depths.

Branched: Two or more laterals emanating from a single point

Figure 14.5 shows other types of laterals.

Figure 14.5 Types of Multilateral Wells



7.2 Historical Background

1928 USA Multi-lateral patents filed.

1953 The first Russian multi-lateral well was recorded. Longest lateral was 528 ft from mother bore. Several laterals were drilled.

1979	Earliest applications for multilateral drilling in Delaware Basin, Anadarko Basin, Texas Panhandle
1988	Multilateral world record set by Gardes Directional drilling for 10 Laterals from a single horizontal well bore in North Louisiana
1991	Petro-Hunt Corp. drilled an opposed bore dual lateral well in the Austin Chalk, Texas
1993	Shell Canada drilled nine re-entry dual laterals in the Midale field
	Sperry-Sun co-invented with CS Resources the Lateral Tie-Back System
1994	Novel downhole technique developed for drilling and lining laterals, tying the well bores back to the surface
1995	Texaco drilled eight multilaterals in the Greater Aneth field in Utah (five dual laterals, one quad lateral). Later drilled wells with six laterals each
1996	Sperry-Sun installed 50th multilateral window casing tie-back system
	Baker Hughes completed the first isolated trilateral well in the Bokar field offshore Malaysia
2000	Multi-lateral wells are drilled routinely

7.3 Advantages of Multi-Laterals

- Increased production from a single well due to increased reservoir exposure
- Accelerated production
- Reduction of surface well equipment and surface facility costs

- Multi-laterals provide flexible selectivity and easy monitoring of oil and gas wells
- Future plugbacks are layed out now avoiding expensive future re-drills.

7.4 Main Applications of Multi-lateral Wells

- Tight reservoirs
- EOR tools
- Slot recovery
- Injection/Production from same well
- Complex drainage reservoirs
- Structural delineation from first few wells
- Exploration wells keepers, if main well was dry

7.5 Multilateral Well Planning Considerations

The following is a partial list of some of the most important considerations in planning a multilateral well:

1. Drilling methods
2. Junction design
3. Well control issues
4. Drilling issues
5. Milling problems
6. Completion requirements
7. Multi-lateral requirements
8. Abandonment

7.6 DRILLING PLANNING ISSUES

There are three main drilling techniques:

- Long radius
- Medium radius
- Short radius

The drilling assemblies (BHA's) used are typically build-up or drop angle assemblies, as described in Chapter 10. Figure 14.1 gives the geometries of each of the above three profiles.

The planning issues to consider when drilling a lateral are:

1.Hole size

2.Hole angle

3.Kick off methods

4.Flow control and isolation

5.Formation damage and clean up of the lateral

6.Drainage patterns for optimum production

It will be assumed that factors 1,4 and 6 will be decided by the reservoir engineer for maximum productivity. Current typical hole sizes are 8 ½" and 6" and hole angles of 80-90 degrees.

7.7 KICK OFF METHODS

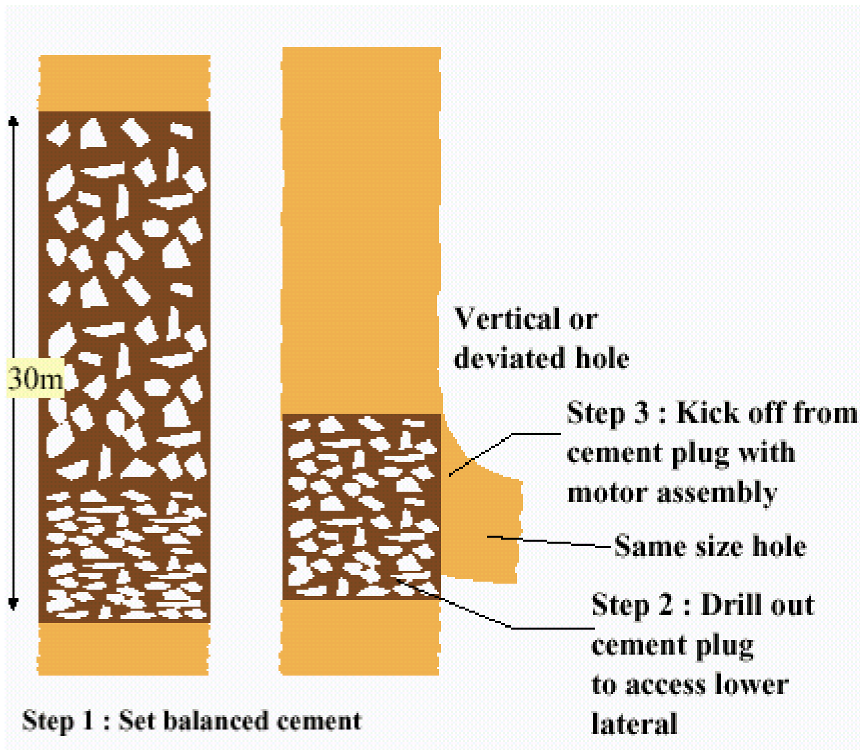
A lateral can be kicked off using one of three methods:

1. Open hole
2. Cased hole
3. Composite casing

7.7.1 Open Hole Kick Offs

In open hole kick off (Figure 14.6), a cement plug is first placed in the open hole where the kick off window is desired. Once the cement plug is set, a kick off assembly is to build up angle away from the mother bore. Further build up assemblies or a hold up assembly are then run to drill to final total depth.

Figure 14.6 Open Hole Kick Off



Advantages of Open Hole Kick Offs

- Simple and relatively cheap
- No whipstocks (they are unreliable in open hole)
- Suitable for vertical or deviated wells
- Lateral can be same size as parent hole
- Plug can be drilled out to access lower zone
- No need for extra equipment or personnel

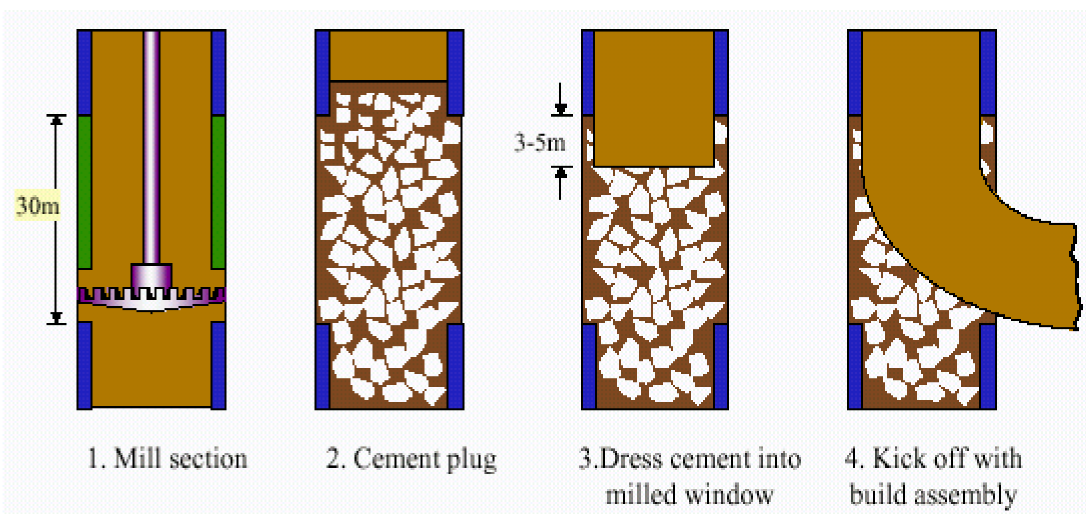
Disadvantages

- Have to wait on cement to set approx. 24 hours
- Possible contamination of drilling fluid
- Must have a good cement job to enable kick off

7.7.2 CASED HOLE KICK OFFS

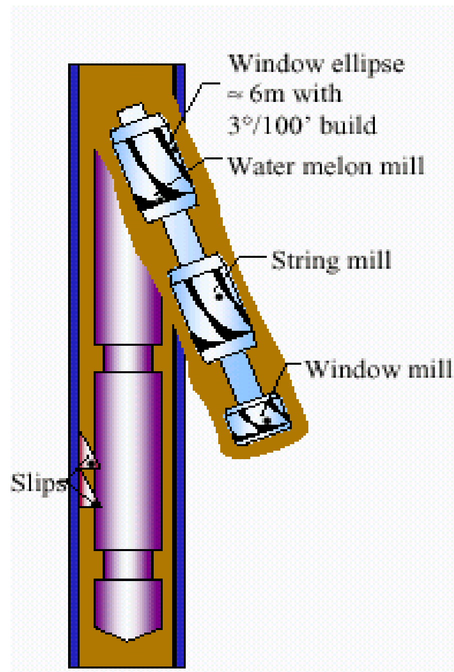
In cased hole kick offs, see Figure 14.7, a window is first cut at the position where kick off is desired. Thereafter, the same procedure as for open hole kick offs.

Figure 14.7 Cased hole kick off



7.7.3 Whipstock Kick Off

Figure 14.8 Whipstock



In cased holes, a kick off may be made by using a whipstock. A whipstock is basically a metal shut which when set inside the casing will allow the drilling or milling assembly to drill in the direction of the shute, Figure 14.8.

Advantages Of Whipstock

- Accurate orientation and positive kickoff at the desired depth in cased or open hole
- Systems are being developed to allow removal and replacement for re-entry of laterals
- Whipstocks set in composite casing may reduce total operation time and prevent problems with metal cuttings
- Recent improvements on setting and retrieval methods have improved reliability (Retrievable whipstocks using hook or screwed collet method)

Disadvantages

- Additional costs of equipment and personnel to run and set whipstock - packers etc.
- Additional time - due to multiple trips required - survey, packer etc.
- Possible difficulties retrieving whipstock
- Precautions required to ensure complete removal of milled steel from hole which can cause failure of downhole equipment (7"csg produces around 200lbs steel).
- Must mill 15'-30' of rat hole into formation to allow running of survey tool.
- Whipstock can only be used once.

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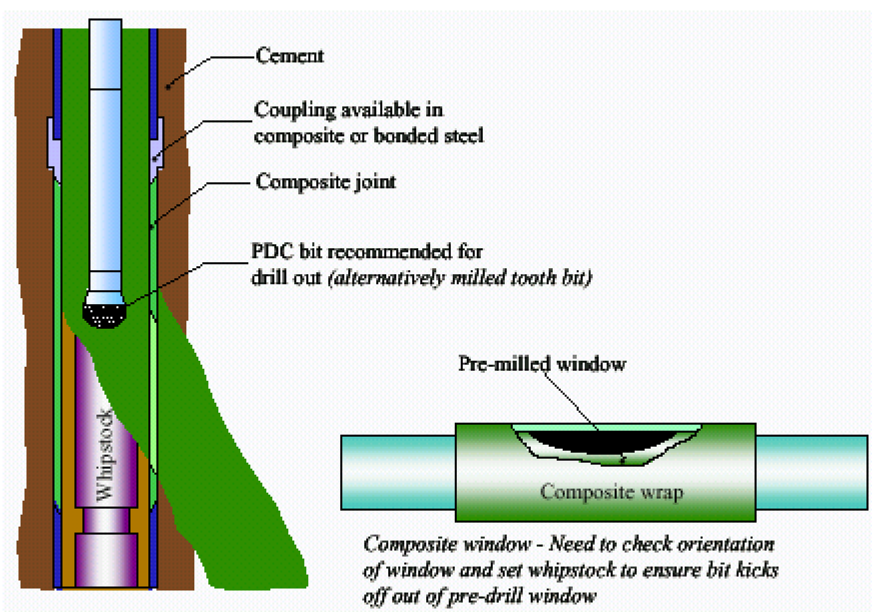
7.7.4 COMPOSITE CASING (FIGURE 14.9)

In composite casing, a sacrificial casing joint is run as part of the intermediate string (say 9 5/8 "). The casing joint is then milled and a kick off assembly is run to start the multilateral section.

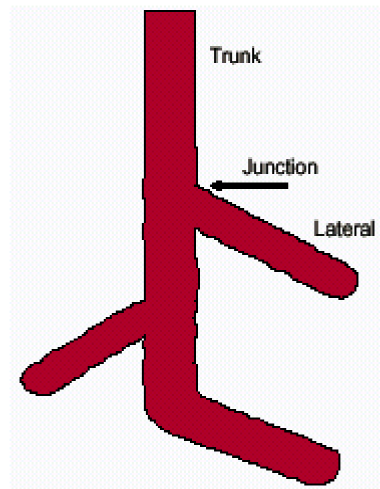
Figure 14.9 Kick off composite casing



7.8 FACTORS AFFECTING JUNCTION DESIGN

A junction is the point where the lateral meets the main bore, see Figure 14.10.

Figure 14.10 Multilateral junction



A junction in a multi-lateral well provides:

1.Isolation of lateral and main bore from surrounding formations; and

2.Allows re-entry into the lateral

When designing a junction, one must think of all the factors that affect well stability, performance and completion design.

Briefly, the junction design should consider:

- junction stability
- location of target (s) below junction
- laterals placed in zone of similar pressure and fluid properties
- production plans: commingled flow or separate flow
- casing size
- completion design
- surface location and access
- lifecycle well requirements

The **junction stability** depends on

- Fracture gradient at junction
- Pore pressure
- Mechanical properties of the material making up the junction
- Reactive formations around the junction

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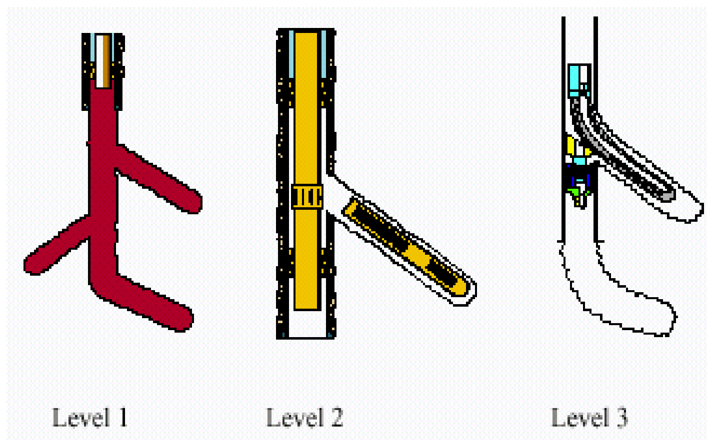
7.9 TECHNOLOGY ADVANCEMENT OF MULTILATERALS (TAML)

The industry has agreed on a classification for the complexity of junction construction. The classification is given the name: Technology Advancement of Multilaterals (TAML) Levels and has values from 1 to 6; with one having the simplest design and six the most complex.

The six classes e are:

Figure 14.11 TAML 1,2 and 3, Courtesy of Baker Hughes Inteq



Level 1, Figure 14.11

Both the main bore and lateral (s) are open and the junction is unsupported. The lateral is usually constructed in a consolidated formation from the low side of the well, Figure 14.11.

Level 2

The main bore is cased and cemented and the lateral is open or possibly a liner dropped in the lateral, Figure 14.11.

The junction integrity and stability depends on the type of formation. The Junction is constructed with either downhole milling or by installing a pre-milled window joint.

Level 3

The main bore is cased and cemented; the lateral is cased but not cemented, Figure 14.11.

In this system, mechanical integrity at the junction is required but not hydraulic integrity. Intervention and sand control are usually the main design considerations. The junction is constructed by mechanically attaching a liner to the main bore casing.

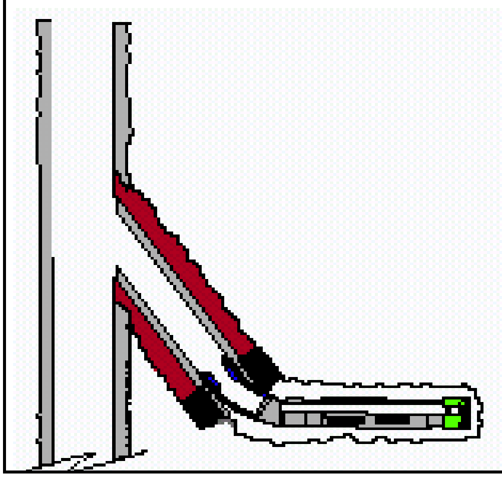
Level 4

The main bore and lateral are both cased and cemented, Figure 14.13.

The junction is constructed by one of three methods;

- Performing a washover operation that removes the lateral extension and whipstock from the wellbore thereby allowing access to the lower lateral.
- After the liner is placed in the lateral and across the junction, a hole is milled through the liner and whipstock to expose the lower main bore.
- Low-side perforations of the lateral liner and whipstock

Figure 14.13 TAML 4, Courtesy of Baker Hughes Inteq



Level 5

Pressure integrity at the junction is achieved by using the completion equipment (cement is not acceptable), Figure 14.14

The junction construction here is similar to that in level 4 with the added use of completion equipment to achieve hydraulic integrity at the junction.

In addition, packers are placed above and below the junction and in the lateral to provide complete pressure integrity at the junction. In all at least three packers: lateral isolation packer, main bore completion packer below the junction and a main bore production packer above the junction are required.

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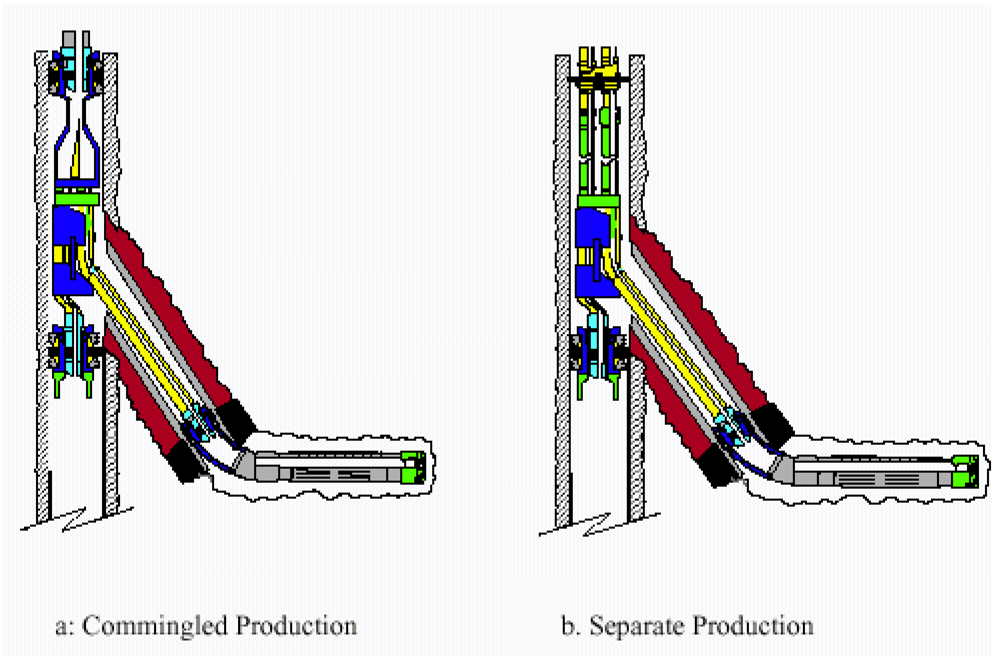
Figure 14.14 TAML 5, Courtesy of Baker Hughes In*teq*



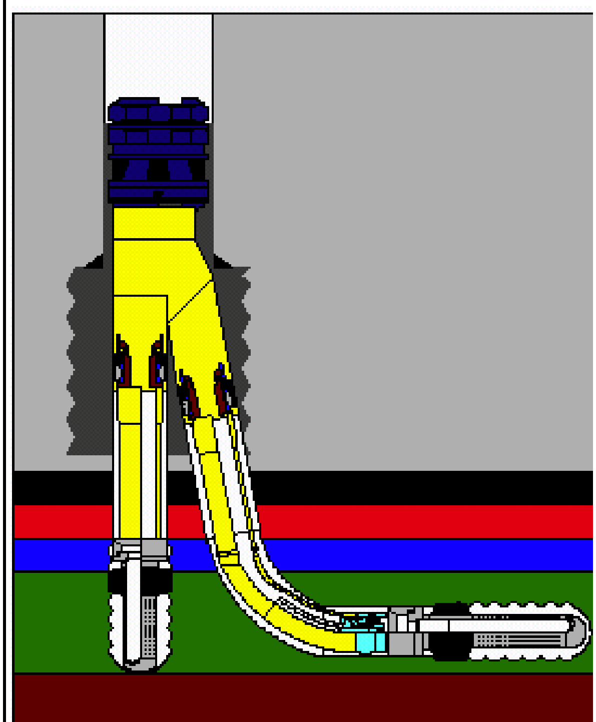
Level 6

Pressure integrity at the junction is achieved with casing. The mechanical and hydraulic integrity are achieved when the ML system is installed.

Level 6 s: Downhole splitter. Large main bore with two (smaller) lateral bores of equal size coming out of a mechanical splitter, Figure 14.15.

Levels I and II were the earliest form of ML completion and have achieved standardisation and popularity in the industry, but are only effective in hard competent formations. The technical complexity for levels 3-6 is far greater.

Figure 14.15 TAML 5, Courtesy of Baker Hughes Inteq



7.10 Workover Requirements of Junction

- Ease of pulling of completion equipment
- Through- tubing operations
- Can junction be milled if required.

7.11 Well Control Considerations

Unless the junction is actually sealed both mechanically and hydraulically, it will remain as an exposed shoe. The magnitude of its fracture gradient will then affect how the well is control led during well kill operations.

7.12 Cementation

If a junction is to be cemented, then the following factors must be considered:

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- Good centralisation
- Rotation while cementing
- Use of fibre cements
- Use of latex cementsStage cementing
- Liner top squeezes

7.13 Debris Control

The main sources of debris whilst making a junction are milling and drilling operations. Window milling is by far the major source of problems in ML operations.

Milling a window in a 9 5/8" casing typically produces 450 lb of steel swarf. This debris must be removed from the well to prevent the debris interfering with the operation of downhole tools such as packers, sealing elements, whipstock and hydraulically operated tools used to recover downhole components.

Another source of debris is the milling of the lateral liner stub (Level 4 ML wells) in order to have the lateral ID flush with the main bore. The debris from this source usually affects the completion equipment.

Debris caused by the accumulation of drill cuttings can be reduced by optimising the lifting and suspension properties of the drilling mud.

Other sources of debris: broken pieces of downhole tools such as drillbit inserts, broken centralisers, packer elements, excess cement, corroded products and dropped objects.

7.14 Flow Control and Isolation of Lateral

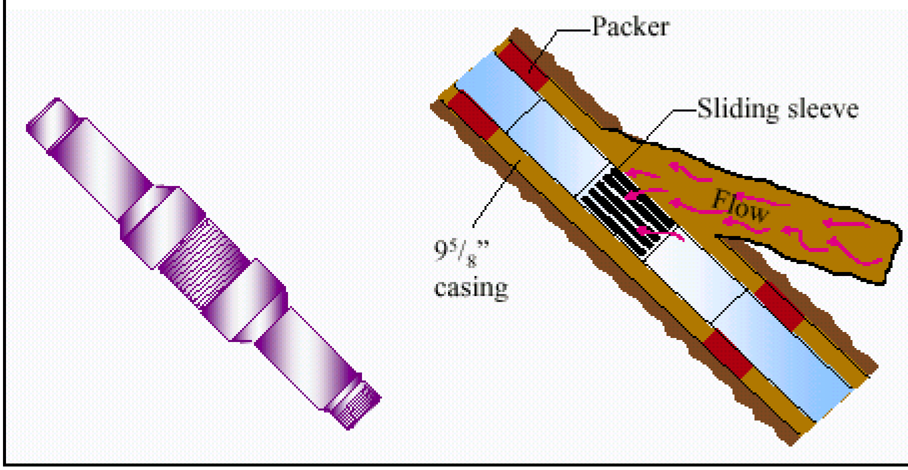
The flow from the lateral can be isolated from flow in the main bore using (**Figure 14.17**):

1. Sliding sleeves
2. External Casing Packer (ECP)
3. Hydraulically sealing lateral

7.14.1 SLIDING SLEEVE

This is a mechanical device (Figure 14.17) with hole or slot which can be covered or uncovered by mechanically or hydraulically moving a sleeve inside the sliding sleeve sub.

Figure 14.17 Sliding sleeve



Operation:

- Normally opened and closed using wireline - either up or down shift to open
- Coiled tubing used in highly deviated wells above 60°
- Pump open sleeves are available but wireline or coiled tubing is required to close ports

Advantages

- - Tried and tested technology
- - Integral landing people nipple profile for running of various tools
- - Isolation sleeves can be run to shut off production if sliding
- sleeve fails to isolate on closure
- - Flow control and sand control can be built in sizes up to 7"

Disadvantages

- - Will not allow re-entry of lateral

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- - Downward jarring is limited in highly deviated wells
- - Reliability is an issue (newer sealing materials may reduce problem)
- - Requires up to 1900 lbs to move sleeve
- - Seal failure due to sand

7.14.2 External Casing Packer

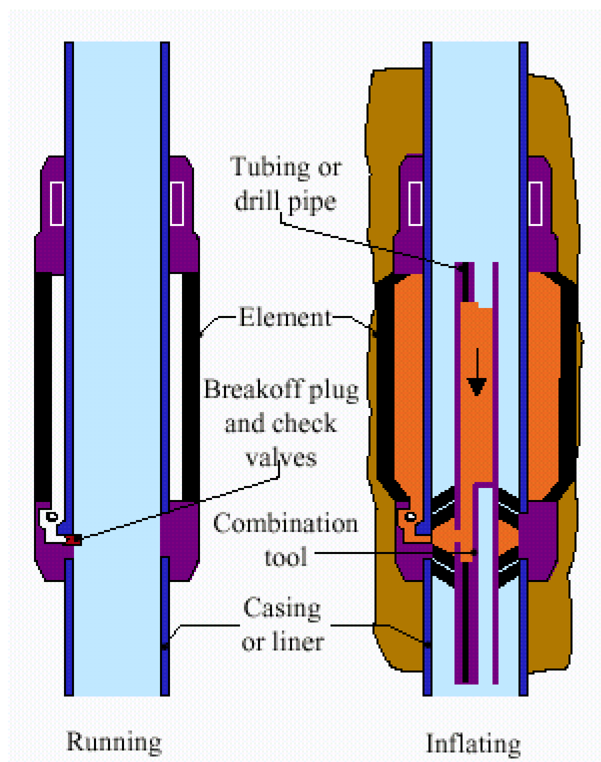
External casing packers (ECP's) (Figure 14.18) have long sealing elements (up to 40') and afford a seal in the open hole.

Inflatable external casing packers can be run on slotted pipe or wire-wrapped screen type liners. Once inside the hole, to inflate the ECP, a combination tool is located across the port, shearing the break off plug and fluid pressure is then applied. A typical inflation pressure is 1250 psi

Inflation fluids can be:

- Drilling fluids
- Completion fluid
- Cement
- Epoxy is proposed for future use

Figure 14.18 Operation of external



Advantages

Ability to seal and isolate in open hole

Disadvantages

The main disadvantage of an ECP is its reliability. Reliability depends on:

- Failure of sealing element or non return valve
- Cement if used to inflate, excess can contaminate screens or
- Can cause formation damage. Cement expands and then contracts
- On setting causing micro channeling
- ECP's can be bypassed by flow through formation

8.0 FIELD EXAMPLE

The following procedure for designing a multi-lateral well is based on actual wells drilled in Qatar, Ref. [7]: Scofield and Woodward, SPE/IADC 37675 1997.

The design procedure that follows basically applies all of the above recommendations. However, it should be noted that there are several variations of methods and tools which can be applied with equal success. The procedure is only valid for Level 2 complexity.

8.1 THE RESERVOIR

This contains four zones (A to D). Only the two top zones A and B are commercially productive. The permeability is 1-3 mD and porosity 18-22%. Each zone is approximately 80 ft in thickness. The upper zone is overlaid with thick Nahr Ummer Shale, making geosteering an excellent path finder.

It is intended to drill two laterals in zones A and B.

8.2 DIRECTIONAL PLANNING

The laterals must be designed so that the window can be existed at the optimal inclination and azimuth angles for later drilling and completion.

The best directional profile is one which allows the window to be placed at or near horizontal. This placement ensures that the maximum dogleg severity is limited to 7 deg/100 ft when drilling off a whipstock into a new formation.

The window joint is placed 10-15 ft above the depth where the lateral will be geosteered. This allows the window opening to be positioned on the high side of the hole and creating a slight uphill exit for the window opening. This will prevent assemblies run specifically into the primary wellbore from inadvertently exiting the main bore and entering the lateral.

8.3 Installation of 9 5/8" Casing in Mainbore

The window joint is run as part of the 9 5/8" casing and must be oriented and positioned correctly within the main wellbore. Open hole log analysis will determine the exact depth at the window should be positioned.

The casing is then made up and run until the window joint is required. The window joint is then carefully made up and the casing is then rotated to the correct magnetic orientation using a rough line of sight orientation to produce the required downhole orientation when the pipe is landed.

The casing is then run in hole until an inclination angle of 20 degrees is reached. At this stage a gyro check shot is taken of the orientation of the window joint to ensure that the window opening is at high side. The pipe can be rotated if the window exit is incorrectly pointing.

8.4 Cementation

The 9 5/8" casing is cemented conventionally with two spring bow centralisers on the each of the first five joints and then one centraliser per joint up to the 13 3/8" casing.

As the window joint is covered with an isolation sleeve, flexible cement wiper plugs are used to pass the 6 5/8" ID of the protection sleeve.

Once the casing is cemented and pressure tested, a retrieving tool for the isolation sleeve is run together with a directional MWD package. Once the isolation sleeve is latched, the orientation of the window opening is checked and adjustments to the directional plan are made.

8.5 Drilling Through the Window Opening

After the isolation sleeve is removed, a whipstock with a latch coupling made up on its bottom is run and set in position to provide a precise orientation to the window exit.

The window opening is usually closed with composite material. An 8.5" milled tooth bit with bearings is run on a mud motor.

The bit is run on a directional assembly utilising a bent housing motor and MWD directional package. Once the window is drilled, the hole angle is built at 5-7 deg/100 ft to push the new wellbore away form the existing 9 5/8" casing. A new hole is drilled to approximately 150 ft length prior to pulling out the drilling assembly.

A new drilling assembly with formation evaluation while drilling (FEWD) is then run and the lateral is drilled to its total depth.

The drill bit is then pulled out of hole, the lateral is logged and a short 7" liner (250 ft) is run to line the curve of the lateral and form a window joint.

8.6 The Junction

The 7" liner provides a junction with mechanical integrity but with out hydraulic isolation. The mechanical junction is required to provide long term mechanical integrity and avoid the problems of junction deterioration associated with formation collapse.

The 7" liner also provides a guide for drilling assemblies and coiled tubing tools that will be run during well servicing.

The 7" liner is run with an external casing packer (ECP) and a stage cementer. The ECP is used to prevent cement form flowing downwards and damaging the reservoir. Once the ECP is inflated the stage cementer opens allowing cement to flow around the 7" liner and up to the junction.

8.7 Washover of the Transition Joint / Drilling Whipstock

After cementing, the well is cleaned out to the top of the 7" transition joint.

A washover assembly is then run and the transition joint and the whipstock are washed over.The washover assembly contains a recovery mechanism for the whipstock. Once the whipstock is washed over, a no-go bushing is encountered which trips open a slip ring allowing the whipstock, casing remnant and latch assembly to be recovered in one go.

At this point, the second lateral into B zone can begin.

9.0 REFERENCES

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15

High Pressure & High Temperature Wells

Content

1.0 Definition

In the UK and Norway, a high pressure/high temperature (HPHT) well is defined as follows:

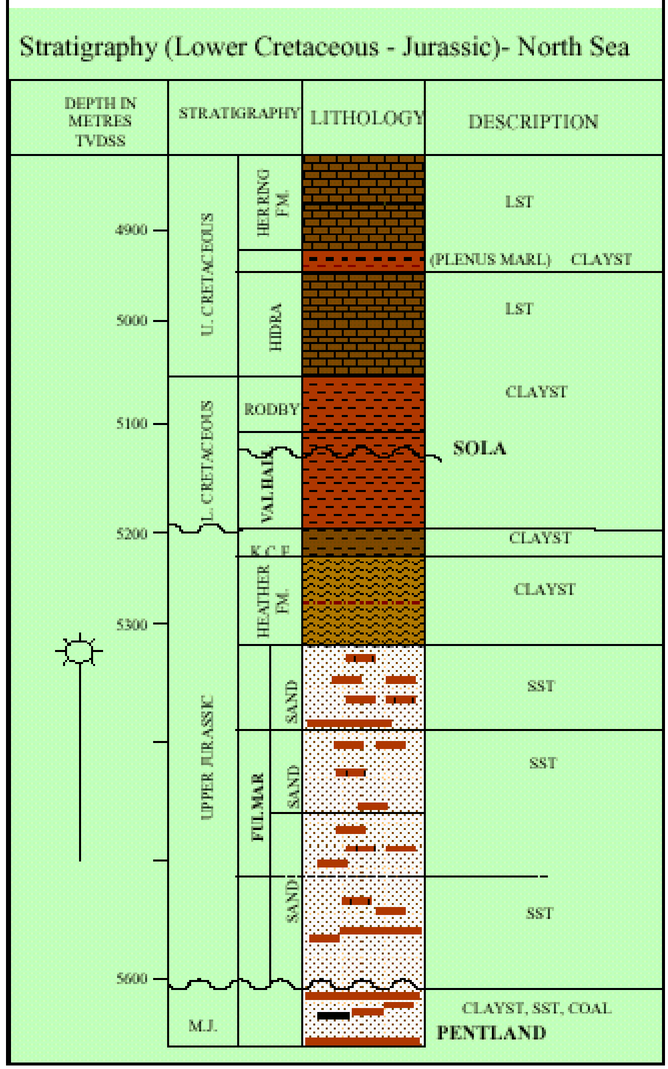
Undisturbed BHT at the prospective reservoir depth is greater than 300 deg F (149 deg C) and either the maximum anticipated pore pressure exceeds 0.8 psi/ft or pressure control equipment with a rated working pressure in excess of 10,000 psi is required, see Figure 15.1.

There are two very important points which must be considered before designing high pressure/high temperature (HPHT) well:

1. The margin between the fracture gradient and pore pressure is usually small. The difference is critical in the design of the well.

2. HPHT wells usually have high ECD's (Effective Circulating Density) leading to lost circulation problems followed by a loss/ gain cycle that becomes difficult to control.

Figure 15.1



The following sections provide general guidelines on how to design HP/HT wells. The reader should note that knowledge of the area and data from offset wells must always be used for fine tuning the well design and equipment.

2.0 Rig Selection Considerations

For offshore operations, the choice is usually between a Jack-up and a Semi-submersible rig. For a land well, a heavy duty rig is required.

2.1 Semi-Submersible

Factors to consider:

1. Weather downtime
2. Surge and swab in rough seas can delay operations
3. Deep water
4. Longer wireline tool strings
5. Lower BOP temperature rating

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2.2 Jack-Up

Factors to consider:

1. Less movement allowing simpler landing string
2. Not prone to weather problems
3. Shorter wireline tool strings
4. Requires a much larger calm weather window and lower sea state before the rig can be jacked down

3.0 Mud Selection Considerations

Accurate modelling of mud density for HPHT wells is critical due to the narrow margin between the pore pressure and the fracture gradient and because of the presence of a long cold riser in offshore operations.

Mud for HPHT wells must:

- Be stable under extreme temperatures and pressure as unstable mud leads to mud gellation and barite sag
- Have optimised rheology to minimise ECD

In most countries, the use of oil-based mud (OBM) is not allowed. The choice of drilling mud is between WBM and Pseudo-oil mud (SBM).

SBM is preferred as it gives better:

- thermal stability
- Inhibition
- Lubricity

3.1 Comparison Between Water-Based Muds And SBM

The following is a comparison between WBM and SBM:

1. SBM is more expensive
2. In a well control situation, if SBM is used the well may be shut in for days with the bottom hole mud at high temperature without deterioration. In comparison, WBM decomposition of polymeric additives can give rise to H_2S and CO_2 gasses which hinder evaluation of well conditions
3. SBM is more tolerant to influxes of acidic gases and hydrocarbons. Also, as long as the lime content of the mud is maintained, CO_2 intrusion will not adversely affect the mud.
4. At high mud weights, the Plastic Viscosity (PV) for SBM will be double that of a WBM with a similar mud weight. This high PV causes:
   - increased risk of losses
   - reduces hole cleaning
   - poor pressure transmittal through the mud
   - Gas solubility is higher in SBM making kick detection more difficult with SBM

3.2 Well Control Issues

For well control, WBM has several advantages:

- Less compressibility. It gives better formation integrity/leak off tests. Under kill situations, one can monitor pumped volumes more accurately.
- Less gas solubility. WBM gives better kick detection without the masking effects of gas solubility.
- Rapid make up time. Volumes can be built up quickly without the need to adjust oil/water ratios.
- Elastomer compatibility. WBM will not affect seals, but it is more abrasive.

Despite the above advantages, the majority of HPHT wells use pseudo-oil based mud (SBM) as the drilling fluid. The SBM is used normally when drilling the critical HPHT reservoir sections. The top of the reservoir is cased off (usually with 9 5/8") and the reservoir section is drilled in 8.5" hole.

3.3 FIT Considerations

An FIT is usually carried at the 9 5/8" casing shoe before drilling the HPHT reservoir. The 12.25" hole (for 9 5/8" casing) is usually drilled with water-based mud (WBM).

The FIT should ideally be carried with the WBM prior to changing to the more stable SBM. If a fracture is unintentionally created then the fracture is more likely to heal with WBM than SBM. It is highly recommended that the FIT is never taken to leak off due to the very narrow margin between mud weight (ECD) and fracture gradient.

Prior to drilling and after the hole is displaced to SBM, the behaviour of the rat hole should be analysed for breathing and ballooning, see below.

When drilling ahead, every time a connection is made, downhole pressure data must be recorded and analysed. The volume and rate of fluid gained or lost should be recorded. This is essential in determining accurate pit gain values in the event of a kick.

3.4 Thermal Effects on Fracture Gradient

In HPHT wells, the effect of high temperature can have considerable influence on the stability of the wellbore. Cooling or heating by 1° F induces between 3-8 psi tensile or compressive stress around the wellbore depending on the rigidity of the rock.

Cooling or heating by 100-120 ° F is possible in HPHT wells giving a stress change of more than 1000 psi.

In view of the above, thermal stresses must be considered in HPHT wells when calculating a safe margin between ECD and fracture gradient

3.5 Pressure to Break Gel

Breaking mud circulation too quickly can induce high pressures which lead to loss circulation especially in deep wells. When drilling HPHT wells, it is essential to record and monitor the pressure required to break the gel strength of mud as this pressure is additive to the mud hydrostatic pressure. In practice the drillstring should be first rotated and the pump speed increased to maximum over a period of 1-2 minutes.

Recent experience in the North Sea showed that high RPM's can increase the mud ECD.

3.6 Pipe Speed

RIH and POH can induce surge and swab pressures. For critical HPHT wells, Pressure while Drilling (PWD) MWD can be used to asses the maximum pipe speeds to avoid critical swabbing (kicks) and surge pressures (fracture pressure).

3.7 Breathing and/or Ballooning

Referring to Figure 15.2, if the well is behaving normally, and a PWD MWD was used in the BHA then during drilling operations an ECD1 will be recorded. When the mud pumps are shut off then an equivalent static density (ESD) will be read, Figure 15.2 a. Figure 15.2 b shows a sharp kick from ECD1 to ESD when the pumps are shut off. When the pump is turned on again, an ECD2 equal to ECD1 will be recorded,.

If the wellbore was breathing, then on pump shut off, ECD1 would gradually decrease to ESD and would gradually increase to ECD2 when the pump is turned on again, Figure 15.2 b. Again ECD1 would be equal to ECD2. Ballooning refers to the ability of the open hole section to stretch and expand under the effect of ECD. When the pumps are shut off the effects of ECD will be lost and only the mud hydrostatic pressure is acting on the open hole. The well returns back to its original shape giving in the process a volume of mud which is sometimes mistaken as a small kick.

Figure 15.2 c demonstrates a situation where the ECD1 is high enough to control formation fluid but the static mud weight is not. When the pump is cutoff, ECD1 decreases to ESD (now lower than Pf) and an influx is taken. The influx causes a further reduction in ESD.

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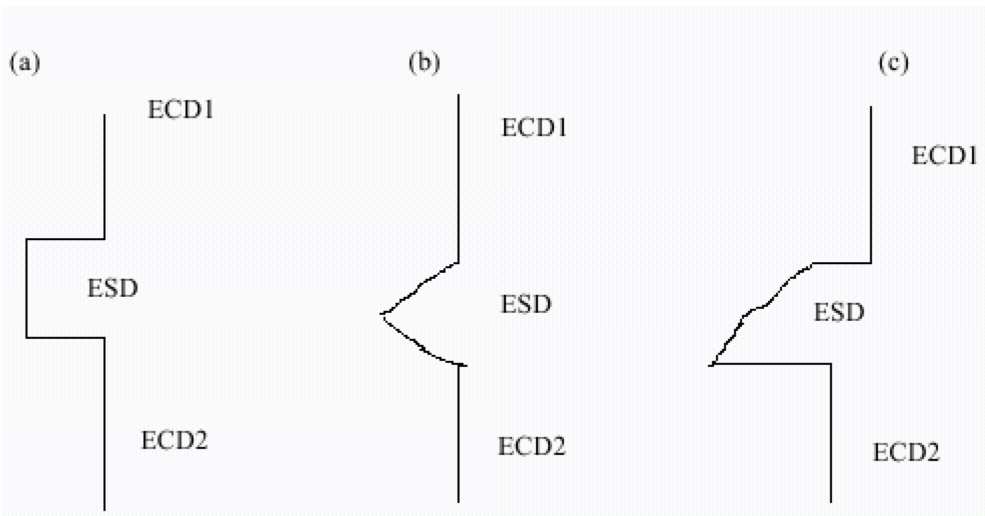
When the pump is started ECD2 will be observed to be lower than ECD1 indicating that a kick is developing.

Figure 15.2 ECD variation in an HPHT Well [1]



3.8 Barite Sag in HPHT Wells

Sag is defined as the settling of barite or other heavy weighting materials towards the low side of the wellbore causing significant variations in mud density.

Barite sag results in a number of problems including:

- lost circulation
- well control problems
- ECD fluctuations
- torque and drag
- logging problems
- poor cement job

The following conditions [1] give rise to barite sag in Invert Emulsions which are usually used to drill HPHT wells:

- Hole Angle: sagging of barite becomes a problem in hole angles above 30 degrees with slumping off at angles 45-60 deg. Above 75 deg, beds are stable.
- Static Time: sagging occurs if the mud in hole is left static for more than 30 hours.
- Flow Rate: sagging is promoted at low flow rates with annular velocities of less than 100 ft/min.
- Drillpipe Rotation: sagging is reduced with pipe rotation.
- Eccentricity: eccentric pipe also encourages sagging. Eccentricity causes a reduction in annular velocities which in turn increase the tendency towards sagging.

4.0 Well Testing Considerations

The main objectives of a well test are to:

- Determine formation deliverabilities
- Determine minimum reservoir pressure
- Obtain well fluid samples

One of the main considerations in an HPHT well test is deciding whether to use WBM, Sea water or POBM as the test fluid.

4.1 Mud as a Test Fluid

Factors to consider are:

- Strength of casing (burst)
- Barites sag
- Gelation problems

- High break circulation pressures
- TCP guns must be run armed
- High surface firing pressures
- Wireline problems
- Poor pressure transmission
- Solids interfering with the operation of downhole tools

4.2 Kill Weight Brine as a Test Fluid

Factors to consider:

- Strength of casing
- Safety and environmental hazard
- High cost of system
- Upper saturation limit (sg = 2.3)
- Hostile to elastomers and metals as brines are usually corrosive.
- Logistical problems
- Zinc bromide (s g = 2.2) has been used before but it represents a safety hazard and is environmentally pollutant.

4.3 Sea Water as a Test Fluid

Advantages

- Clean and solids free
- Excellent pressure transmissibility
- Increased tool (DST and TCP) reliability
- No requirement to run a tie back string (usually 7" tie back casing to surface)
- TCP firing head can be wirelined into place
- Ability to pressure test below packer

- No cushion needed
- Lower surface temperature

Disadvantages

- High differential pressure over liner
- Less response time if leak occurs
- More time consuming

4.4 Consequences For Testing With Sub Kill or Kill Weight Fluid

4.4.1 Testing With Sub Kill Weight Fluid

- No requirement to run a tie back string
- Retains option for nominal 9 5/8" production and 7" liner
- Ability to run 4 ½" completion designs
- Cost effective

4.4.2 Testing With Kill Weight Fluid Using either Mud or Brine

- A nominal 7" tie back string to surface
- Precludes 4 1/2" completion designs
- Creates tubing restrained production
- A costly and sub-optimal well

4.5 Typical Test String Design

The main equipment required in depth order are:

1. An upper Tubing Tester valve (TTV). The TTV is used purely for pressure testing the tubing above the BHA. Once it is used, it is locked open.

2. An annulus pressure operated single use circulating valve. This serves two functions;

   - it relieves pressure on the annulus in the event of a tubing leak
   - it provides a circulation path for the well kill operation

   The shear pressure must be designed to:

   - be sufficiently low to allow it to shear with a relatively small gas influx
   - be sufficiently high to provide adequate safety margin above the downhole tester valve hold open pressure to avoid accidental shearing

   The shear pressure of this valve is generally set at between 3000 and 4000 psi applied surface pressure.

3. An annulus pressure operated single use safety valve (pump through)

   This valve serves two functions;

   - it is the main downhole safety valve and should shear closed in the event of gas leak to the annulus
   - it allows the well to be circulated to kill mud with the reservoir safely closed in

4. An annulus pressure operated multi use downhole shut in valve. Its main functions are:

   - it closes in the well in the event of a loss of annulus pressure
   - it shuts the well in as low as possible to avoid wellbore storage effects in the pressure build-up
   - it can be used to test the tubing against if the upper TTV fails
   - it can be used as a safety valve in the event of an emergency/weather disconnect

5. A lower Tubing Tester Valve

   This is used to test the BHA. After testing the lower TTV is locked open.

5.0 CASING DESIGN CONSIDERATIONS

Since the majority of HPHT reservoirs contain either condensate or gas at extremely high pressures and high temperatures, extra care must be taken when selecting casing grades/weights. The following design considerations are usually made for HPHT wells:

1. Both the 9 5/8" (intermediate/production) and 7 "(production) casings are designed for tubing leak using either gas gradient or the condensate gradient whichever is relevant to the reservoir.
2. The 13 3/8" casing is designed for possible annulus heating effects, especially for subsea wells where the annulus can not be monitored.
3. The 9 5/8" casing is designed for buckling effects caused by high temperature.
4. Both the 9 5/8" and 7 "casings properties are derated because of the high temperature.
5. Both the 9 5/8" and 7 "casings are designed to withstand H_2S and CO_2 effects.

The above factors will be considered in the following examples and a later section of this chapter.

Example 15.1: 9 5/8" Casing Design For HPHT Wells

Relevant Data

RKB- Subsea	= 240 ft
13 3/8" set at	= 10200 ft
9 5/8" set at	= 12880 ft
Max pore pressure in 12¼" hole	= 13.2 ppg
Mud weight to drill 12¼" hole	= 13.6 ppg
Fracture gradient below 9 5/8" shoe	= 0.90 psi/ft

TD of 8½" section	= 16750 ft
Mud weight to drill 8½" hole	= 15.3 ppg
Max pore pressure in 8½" section	= at 15715 ft SS 12100 psi = 0.770 psi/ft
Gas gradient	= 0.15 psi/ft
Seawater	= 0.465 psi/ft
Bottom hole temperature	= 365 °F at 18200 ft

12 ppm H_2S prognosed

The 9 5/8" casing shoe will be set 200 ft above the high pressure, high temperature reservoir.

Check the suitability of:

10¾" 79.2 lbs/ft C95 as a top section and 9 5/8" 53.5 lbs/ft P110 as a bottom section.

Solution

(a) Burst Loading

(i) Kick Tolerance

The reader needs to refer to Chapter 3 for fundamental details on kick tolerance.

Fracture pressure at 9 5/8" shoe = 0.9 psi/ft x 12880 ft = 11592 psi

Applying a safety factor of 100 psi reduces the formation fracture at the shoe to 11492 psi or 17.16 ppg. This safety factor is particularly important in HPHT wells as the pore pressure and FG are very close.In some cases the pore pressure and FG are literally the same that if this reduction (safety factor) is applied, the well can not be drilled. For this well, the margin between pore pressure and FG is just large enough to allow this reduction.

The height of a tolerable kick (H) is given by:

$$H = \frac{0.052 \text{ x Pm (TD - CSD) + (FG x CSD x 0.052) - Pf}}{(0.052 \text{ x Pm) - G}}$$

where:

FG = the fracture gradient at the casing shoe in ppg= 17.16 ppg

Pf = formation pressure at next TD, psi = 16750 x 0.77= 12897.5 psi, (assumed a swabbed gas kick)

H = height of gas bubble at casing shoe, ft

G = gradient of gas = 0.15 psi/ft

TD = next hole total depth = 16750 ft

CSD = casing setting depth = 12880 ft

ρ_m = maximum mud weight for next hole section = 15.3 ppg

$$H = \frac{0.052 \text{ x } 15.3 \text{ x } (16750\text{-}12880) + (17.16 \text{ x } 12880 \text{ x } 0.052) - 12897}{(0.052 \text{ x } 15.3) - 0.15}$$

=2592.1 ft

Hole capacity between 5" DP and 8½" hole= 0.0459 bbl/ft

Hole capacity between 6½" DC and 8½" hole= 0.0291 bbls/ft

V1=volume of kick at shoe = 0.0459 x 2592.1 =119.0 bbls

At bottom hole conditions, using $P_1V_1 = P_2V_2$, we obtain:

$$V_2 = \frac{119.0 \text{ x } 11492}{12897.5} = 106.0 \text{ bbls}$$

Hence the circulating kick tolerance in terms of maximum kick size = 106 bbls.

(The effects of Z & T would increase the tolerance from 106 bbls to 131 bbls)

(ii) Burst Based on Gas to surface

Using a gradient of 0.770 psi/ft extended to TD, then

Pressure at surface = Pore pressure at 8½" TD - gas to surface - sea water backup to mudline

= 0.77 x 16750 - 0.15 x (16750 - 240) - 0.465 x 240

Pressure at surface (i.e. at subsea wellhead) = 10308.8 psi

Fracture gradient

Gas pressure at 9 5/8" shoe = Pore pressure - gas gradient to shoe

= 0.77 x 16750 - 0.15 (16750 - 12880) = 12317.0 psi

Fracture gradient at 9 5/8" shoe = 0.85 x 12880 = 10948.0 psi

The formation does not have sufficient competence to support gas to surface without breaking down.

Hence the maximum surface pressure at the wellhead prior to the shoe breaking down with the well evacuated to gas and a seawater backup.

= Frac. gradient at shoe - gas gradient - seawater backup to mudline

= 0.90 x 12880 - 0.15 x (12880 - 240) - 0.465 x 240 = 9584.4 psi

Well head pressure to breakdown shoe (gas) = 9584.4 psi

Burst pressure t 9 5/8" shoe = Pore pressure - gas gradient in open hole - hydrostatic behind casing:

= 0.77 x 16750 - 0.15 x (16750 - 12880) - 0.465 x 12880 = 6327.8 psi

(iii) Burst based on circulating out a 100 bbl gas kick

Industry design calls for a 50 bbls kick while drilling an 8.5" hole, however a 100 bbls kick has been used to reflect a worst case scenario and as the actual kick tolerance for this well is slightly in excess of 100 bbls.

Formation pressure at the 8½" TD of 16750 ft = 0.770 x 16750 = 12897.5 psi

The burst design is based on the ability to circulate a 100 bbl kick from 16750 ft. The Drillers method has been used to establish the annular pressures associated with this kick while circulating with the original mud weight (15.3 ppg).

The annulus pressure at the casing shoe is given by (see chapter 3 for details of equation):

$$Pshoe = \tfrac{1}{2}[A + (A^2 + 4.Pf.M.N.y_f.\,\rho_m)^{0.5}] \qquad (15.1)$$

where

$$A = Pf - \rho_m\,(TD - CSD) - Pg \qquad (15.2)$$

And the pressure at the surface is given by:

$$P_{surf} = \frac{1}{2}((P_f - TDx\rho_f - P_g) + \sqrt{(P_f - TDx\rho_m - P_g)^2 + 4P_fMNy_f\rho_m})) \qquad (15.3)$$

Pf =0.77 x 16750= 12897.5 psi

TD = 16750 ft

CSD= 12880 ft

ρ_m =15.3 x 0.052= 0.7956 psi/ft

$$M = \frac{8.5\text{" x 5" ann vol}}{9\ 5/8\text{" x 5" ann vol}} = \frac{0.1194}{0.1364} = 0.938$$

Assume Zs = Zb

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$$N = \frac{Z_s x T_s}{Z_b x T_b} = \frac{T_s}{T_b} = \frac{(60+460)}{(60+0.01x16750)+460} = 0.756$$

$$y_f = \frac{V1}{V2} = \frac{100 \text{ x } 5.6146}{(\pi/4)(8.5^2-5^2)/144} = 2178.66 \text{ ft}$$

Pg = Pressure in the gas bubble = $\rho g.y_f$ = 0.15 x 2178.66 = 326.8 psi

A = 12897.5 - 0.796 x (16750 - 12880) - 326.8 = 9491.73

$4.Pf.M.N.y_f \rho_m$ = 4x12897.5x0.938x0.756x2178.66x0.796 = 63459807

Pshoe= ½[9491.73 + (9491.73^2 + 63459807)$^{0.5}$] = 10941.68 psi

$$P_{surf} = \frac{1}{2}((12897.5 - 16750x0.7956 - 326.8) + \sqrt{(12897.5 - 16750x0.796 - 326.8)^2 + 63459807}))$$

P(surface) = 3623.2 psi

Hence the surface pressure for a 100 bbl kick = 3623.2 psi

and the kick pressure at the 9 5/8" shoe = 10941.7 psi

Fracture pressure at the 9 5/8" shoe = 0.85 x 12880 = 10948 psi

Therefore the formation will not break down when taking a 100 bbl kick.

Effective burst at the surface with a 100 bbls kick = 3623.2 psi

Effective burst at the 9 5/8" shoe is 10941.7 - 0.465 x 12880 = 4952.5 psi

(iv) Pressure testing

The 9 5/8" casing will be tested to 80% of the casing burst strength. An RTTS packer will be run in order to test the casing above the top of cement (TOC) to the maximum pressure. It has been assumed that the well will have been displaced to 15.3 ppg mud for the 8½" section.

With the top of cement (TOC) at 11200 ft, 80% of 53.5 lbs/ft P-110 = 10900 x 0.8 = 8720 psi

Test pressure = 8720 psi - (Hydrostatic from mud - Hydrostatic behind the casing)

= 8720 - [(15.3 x 0.052 x 11200) - (13.6 x 0.052 x (11200 - 240)) + (0.465 x 240)]

Surface test pressure will be = 7672 psi

Note: This pressure will test the casing to 80% of burst strength at the TOC. Later DST and production tests will assume that the mud behind the casing will have regressed to seawater, lowering the pressure to 4885 psi, see part (v)).

Current practices in the North Sea is to test the casing on bumping the plug to the maximum expected surface pressure in the vent of a kick or tubing leak.

(v) DST

The design is based on the maximum burst pressure from gas to surface during a DST caused by a tubing leak in the test string. With an assumed reservoir depth of 15715 ft, top of liner at 12380 ft (500 ft liner lap) and a packer set in the 7" liner below 15000 ft, the maximum surface pressure would be:

= Pore pressure at reservoir - gas gradient to BOP's

= (15715 x 0.77) - 0.15 x (15715 - 240) - 240 x 0.465

Maximum surface pressure = 9667.7 psi

Assuming a tubing leak during testing with the mud in the 13 3/8" x 9 5/8" having regressed to 0.465 psi/ft and the TOC 1000 ft below the 13 3/8" shoe. Maximum burst pressure down hole will occur at the TOC at 11200 ft. Kill weight brine of 15.1 ppg is assumed.

Maximum burst (at 11200 ft)= Max. surface pressure + Testing fluid hydrostatic - normal gradient backup

= 9667.7 + 15.1 x 0.052 x 11200 - 0.465 x 11200

Maximum burst (at 11200 ft) = 13253.9 psi

The following factors should be also be considered regarding the DST calculations:

- This pressure is very high, and therefore should long term testing be considered, a 7" production string will be run and tied into the 7" liner.
- This scenario cannot happen during short term testing as the annulus operated tools will shear shut the test string close to the packer.

Using Annulus Operated Tools

Assuming that the mud behind the casing has regressed to seawater. The pressure cannot exceed 80% of the burst of the 9 5/8" casing, or

= 10900 * 0.8 = 8720 psi

The maximum surface pressure required to apply 8720 psi at the top of liner (TOL) is:

= Burst pressure - (Hydrostatic pressure at TOL - formation backup)

= 8720 - ((15.1 x 0.052 x 12380) - 0.465 x 12380) = 4755.9 psi

Therefore the maximum pressure allowed for cycling annulus operated tools

= 4756 psi (equivalent to 8720 psi at the TOL)

Note:This assumes that the mud behind the 9 5/8" has regressed to a seawater gradient.

(c) Collapse Loading

(i) Partial evacuation

If lost circulation occurs while drilling the 8½" hole with 15.3 ppg mud to a 0.465 psi/ft loss zone then the minimum mud level inside the 9 5/8" casing is given by L:

Casing depth x 0.465 = Mud weight (8½") x 0.052 x L

$$L = \frac{0.465 \times 12880}{0.052 \times 15.3} = 7527.9 \text{ ft}$$

Depth to top of mud column from surface =12880 - 7527.9 = 5352.1 ft

Collapse pressure at 5352.1 ft, assuming mud behind the casing as 13.5 ppg

= Seawater gradient to wellhead (WH) + fluid level x mud gradient outside casing

= 240 x 0.465 + 5352.1 x 13.5 x 0.052 = 3868.8 psi

Collapse pressure at 9 5/8" shoe= Seawater gradient to WH + mud gradient outside casing - mud gradient from 5352.1 ft to TD

= 240 x 0.465 + (12880-240) x 13.5 x 0.052 – 15.3 x 0.052 x (12880 - 5352.1)

Collapse at 9 5/8" shoe = 2995.7 psi

Collapse pressure at 10¾" x 9 5/8" cross over point

= Seawater gradient to WH + mud gradient outside casing - mud gradient from 5352.1 ft to 7000 ft

= 240 x 0.465 + (7000-240) x 13.5 x 0.052 - 15.3 x 0.052 x (7000 – 5352.1) = 3546.1 psi

(ii) During Cementation

There is no danger of collapse from the cement. A single 16.0 ppg slurry will be used and it will extend to 1000 ft below the 13 3/8" shoe.

= Seawater gradient to mudline + Hydrostatic due to mud + hydrostatic due to cement - mud gradient inside the casing

= (240 x 0.465) + [13.6 x 0.052 x (11200 - 240)] + [16.0 x 0.052 x (12880 - 11200)] - (16 x 0.052 x 80) - [13.6 x 0.052 x (12880 - 80)]

Collapse pressure during cementation = 151.1 psi

Summary of Design Loads

Case	Loading	Pressure
Burst	Gas to surface	10308.8 psi- shoe will breakdown at 9584.4* psi
	100 bbl gas kick	3623.2 psi
	Kick Tolerance	106 bbl
	Pressure Test	7672 psi to TOC at 11200 ft
	DST	8720 psi at top of liner at 12380 ft
		13253.9 psi - Long term testing or production
Collapse	Partial evacuation	3868.8* psi at 5352.1 ft
	Partial evacuation	3546.1* psi at 7000 ft
	During cementation	151.1 psi
*: worst case used in casing selection for HPHT wells		

(e) Casing Selection

If the partial pressure of H_2S is greater than 0.05 psia then sour service casing must be used.Since 12 ppm H_2S is prognosed, H_2S rated casing may be required in this well. This can be checked as follows:

H_2S partial pressure= Formation pressure x ppm = 12000 x 12 x 10^{-6} = 0.144 psia

Since the partial pressure of H_2S is greater than 0.05 psia (see Chapter four for details), sour service casing is required from surface to 6500 ft. At 6500 ft, the static temperature rises over 150° F, where the H_2S will remain in solution.

Hence the top section from zero to 7000 ft must be a sour service casing: 10¾" 79.2 lbs/ft C95.This is the casing available to us. Other grades may also be used.

Design Factors

Top Section

Min D.F. in burst $= \frac{11350}{10309} = 1.10$ (for the case of gas to surface)

Min D.F. in collapse$= \frac{10790}{3869} = 2.78$ (for partial evacuation)

Bottom Section

From 7000 ft to TD, 9 5/8" 53.5 lbs/ft P110 can be used with the following design factors:

Min D.F. in burst $= \frac{10900}{8720} = 1.25$ (at TOL)

This is the case for operating DST tools

Min D.F. in collapse$= \frac{7950}{3546} = 2.24$ (at 7000 ft for partial evacuation)

(f) Biaxial Effects

Maximum collapse loading occurs at 5352 ft (refer to (c) above).

$P_{collapse}$ at 5352 ft (ref. c above) = 3868.8 psi

Tensile load = 5352 ft x casing wt. x buoyancy factor for 13.6 ppg mud

= 5352 x 79.2 x 0.792 = 334711.7 lbs

From Chapter 4 (API BUL 5C3 equations), the collapse resistance under axial tension should be calculated for 10¾" C-95, 79.2 lbs/ft.

At axial load of 0 lbs, the collapse resistance is 10717.70 psi.

At axial load of334712 lbs, the collapse resistance is 10086.91 psi

Reduced collapse design factor for C-95 = $\frac{10089}{3869} = 2.61$

(g) Casing Wear

The well is vertical and with a programmed 8½" section of 3870 ft, hence minimal wear is expected during drilling operations. However casing wear will be minimised by monitoring dog legs and side load forces. A record of metal in the cuttings should also be kept and if wear is thought to have commenced callipers should be run to determine the wall thickness. The casing will be de-rated accordingly. A base line calliper should be run prior to drilling out the 9 5/8" shoe.

(h) Tensile loading

Dynamic Loading= Buoyant weight of casing (in mud) + shock load

$= (79.2 \times (7000 - 240) + 53.5 \times (12880 - 7000)) \times 0.792 + (3200 \times 79.2)$

$= 673{,}178 + 233{,}280 = 906{,}458$ lbs

Pressure testing= Buoyant weight of casing + pressure test force (= πr^2 x pressure test)

$= (79.2 \times (7000 - 240) + 53.5 \times (12880 - 7000)) \times 0.792 + (\pi(8.535/2)^2 \times 7672)$

$= 673{,}178 + 438{,}940 = 1{,}112{,}118$ lbs

Hence pressure testing creates the maximum tensile load at surface.

Design Factor in Tension

For 10¾" 79.2 lbs/ft

$= \frac{2{,}190{,}000}{1{,}112{,}118} = 1.97$

For 9 5/8" 53.5 lbs/ft

$$= \frac{1,710,000}{1,112,118} = 1.54$$

6.0 Temperature Effects on Casing Strength

In high temperature wells, casing undergoes substantial thermal expansion unless cemented to the surface. High temperatures have the effect of reducing the modulus of elasticity and in turn the yield strength of casing. Different grades of casing are affected differently by the effects of high temperature. The higher the grade, the greater the reduction in yield strength due to high temperatures.

One of the major risks occurs in high temperature wells where the intermediate casing and/or upper production casing is set above the transition zone containing the high temperature. During production, these casings are heated up as a result of the hot produced fluids and their properties may alter as a result of the high temperatures.

Burst strength is directly proportional to yield strength and a reduction in the latter causes a reduction in burst strength as given by:

$$\text{Burst strength (B)} = 0.875 \times 2 \times \text{yield strength} \times \text{wall thickness/ OD} \qquad (15.4)$$

The following table shows the effects of temperature on the yield strength of casing.

Grade	Yield Strength (psi)	Ambient Temperature		
		212 °F (100 °C)	392 °F (200 °C)	482 °F (250 °C)

C75 (No longer an API grade)	75,000	70,800	69,600	69,600
L80	80,000	70,600	65,000	62,900
C90	90,000	80,100	75,000	74,300
C95	95,000	85,100	80,400	75,600

Example 15.2: Reduced Burst Strength Due to High Temperature

Calculate the burst strength of 10 ¾", C 95 casing, t = 0.922 in, at ambient temperature, 100 °C and 250 °C.

Solution

At ambient temperature

B = 0.875 x2 x 95,000x 0.922 / 10.75 = 14,258 psi

At 100 °C

B = 0.875 x2 x 85,100,0.922 / 10.75 = 12,772 psi

At 250 °C

B = 11,347 psi

As a rough figure, the reduction in burst strength is approximately 3% for every degree F above the ambient temperature of 60 F.

7.0 Cementing Considerations

The following factors must be considered:

1. Cement slurries must be designed to withstand the high temperatures
2. Strength retrogression of cement at high temperatures
3. Retardation to allow placement of cement without premature setting
4. Slurry density
5. Low fluid loss
6. Zero free water
7. Possible H_2S
8. Potential gas flow
9. Right angle set slurry
10. Maximum top of cement to prevent buckling and annulus heating problems

8.0 Trapped Annulus Pressure

8.1 Cause

Field results from several parts of the world have shown that in certain wells the production casing(s) can deform or collapse after the well is put on production due to heating effects. The produced fluids in the production casing heat the trapped fluids in the annulus between the production casing (s) and the intermediate casing. The heating effect leads to thermal expansion of the trapped fluids and in turn an increase in the annulus pressure between the production/intermediate casings.

If part of the fluid can not be vented off or if the pressure can not be bled off (as in subsea wells), then the trapped pressure may cause collapse or deformation of the casing if these pressures exceed the collapse strength of the production casing.

Damaged casings from trapped annulus pressure almost always occur when the production casing is cemented above the shoe of the intermediate casing. In the North Sea, in high pressure/high temperature applications, it is the practice to cement the production casing

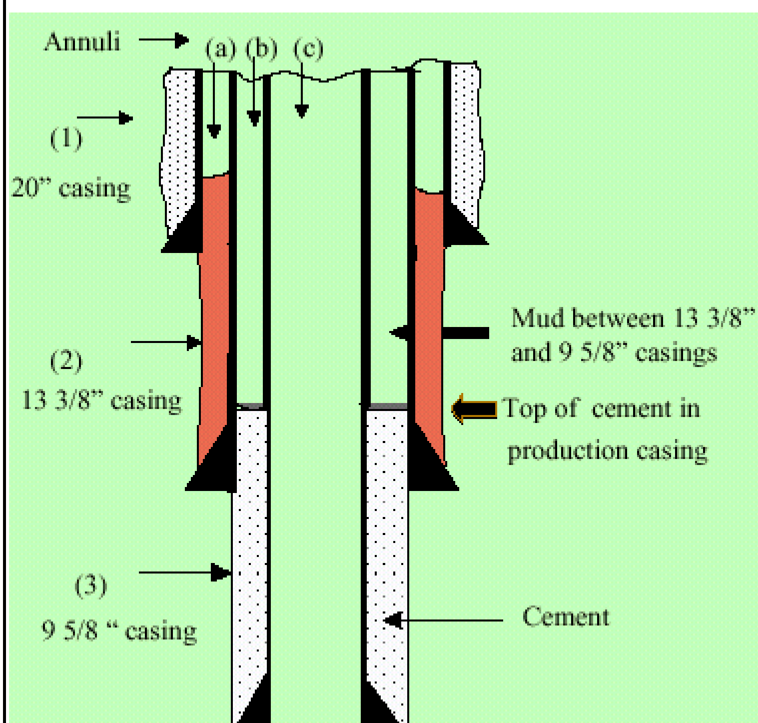
(9 7/8" or 10 ¾") 300-500 ft below the shoe of the intermediate casing (13 3/8"). If during production operations, annulus pressures develop then these will first fracture the 13 3/8" shoe and then cause a localised loss circulation thereby relieving the annular pressure.

In land and platform wells, it is the practice to install pressure gauges/relief valves that indicate the pressure inside the annulus. If the pressure exceeds a certain preset value the valve can be manually or automatically opened to relieve the trapped pressure. In these wells, therefore it is possible to cement the production casing above the intermediate casing. This would be a calculated risk and great confidence will be placed on the integrity of the pressure monitoring gauges on the wellhead.

In subsea wells, no access is possible to the annuli between the casings and the cementing height outside the production casing must be set below the shoe of the intermediate casing.

The author has come across one failure during a short DST where the 10 ¾" casing collapsed near the wellhead. The well was designed with the cement height below the intermediate casing shoe. Subsequent analysis showed that the trapped pressure was greater than the collapse strength of the casing. The casing collapsed because he cement volume requirements were overestimated and, in turn, inadvertently cementing the production casing 200 ft inside the intermediate casing.

Figure 15.3 Well Schematic For Trapped Annulu Pressure Considerations



8.2 MATHEMATICAL ANALYSIS

During testing and production operations, the produced fluids being hotter than its surroundings, start heating up the tubing, the casings and the fluids in between. This heating up will cause a volumetric thermal expansion of fluids in the annular volumes between casings with a subsequent pressure rise if the annuli are sealed. Sealing would be by the seal assembly in the wellhead and the cement top in the annulus.

Full derivation of the equations can be found in a paper by Adams [2]. The method of estimating trapped pressures will be presented in a simplified form for ease of application. The full method requires application of matrix algebra and long computation which requires a computer to speed up calculations.

Reference to **Figure 15.3**, the pressure increase (P) in the 13 3/8" x 9 5/8" annulus (b) is given by:

$$P = \frac{\text{sum of unconstrained volume changes}}{\text{Sum of system flexibility}} = \frac{\Sigma \Delta V}{\Sigma f} \qquad (15.5)$$

(Note that this simplified approach assumes no pressure changes in annuli a and c, **Figure 15.3**)

$$\Sigma \Delta V = \Delta V_2 + \Delta V_b + \Delta V_3 \qquad (15.6)$$

where

Σ =refer to sum of terms (pronounced sigma)

Δ = refers to changes (pronounced delta)

f = system rigidity

V = volume

1,2, 3 = refer to 20", 13 3/8" and 9 5/8" casings respectively

b = refers to annulus between 9 5/8" and 13 3/8"

The unconstrained volume change of casing (2) is given by:

$$\Delta V_2 = \frac{\pi}{4}\left[(D + \Delta D)^2 - D^2\right].L$$

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$$\Delta V_2 = \frac{\pi}{2} L.[D.\Delta D]$$

where $\Delta D = D\,\alpha\Delta T$

Hence

$$\Delta V2 = -\frac{\pi}{2} L_2 D_2{}^2 \alpha \Delta T_2 \tag{15.7}$$

where

L2 = length of uncemented section of casing two, or depth to top of cement

D2 = average diameter of casing 2 = (OD+ID)/2

ΔT = average temperature rise for casing two

Note the above equation has a negative sign to indicate that the casing will actually go into compression due to temperature rise as it is constrained at both ends and can not expand.

For annulus fluid (b), the volume change is given by:

$\Delta V_b = V_b\ \beta\ \Delta T_b$

For uniform casings, the volume of the annulus (b) is given by:

$$V_b = \frac{\pi}{4}(ID_2^2 - OD_3^2)L_b$$

$$\Delta V_b = \frac{\pi}{4}(ID_2^2 - OD_3^2)L_b \beta \Delta T_b \tag{15.8}$$

where

ID_2 = ID of casing (2), the 13 3/8"

OD_3 = OD of casing (3), the 9 5/8"

L_b = length of uncemented annulus (b)

β = coefficient of volumetric thermal expansion

ΔT_b = average temperature rise of fluid in annulus (b)

The unconstrained volume change of casing (3) is given by:

$$\Delta V_3 = -\frac{\pi}{2} L_3 D_3^2 \alpha \Delta T_3 \qquad (15.9)$$

where

L_3 = length of uncemented section of casing three, or depth to top of cement

D_3 = average diameter of casing 3 = (OD+ID)/2

ΔT_3 = average temperature rise for casing three

Note the above equation has a negative sign to indicate that the casing will actually go into compression due to temperature rise as it is constrained at both ends.

System Flexibility (f)

$$\Sigma f = f_2 + f_b + f_3 \qquad (15.10)$$

For Casing (2)

$$f_2 = \frac{\pi L_2 D_2^3}{4 x E x t_2} \qquad (15.11)$$

where t = wall thickness of casing two

For annulus (b)

$$f_b = C_v V_b \qquad (15.12)$$

For uniform casings

$$f_b = C_v \frac{\pi}{4} (ID_2^2 - OD_3^2) L_b \qquad (15.13)$$

where C_v = fluid comprehensibility of annulus fluid (b)

For casing (3)

$$f_3 = \frac{\pi L_3 D_3^3}{4xExt} \tag{15.14}$$

For combination strings, the terms in equations **(15.6)** to **(15.14)** must be the summation of each individual weight.

Example 15.3: Trapped Annulus Pressure

Calculate the trapped annulus pressure for the following subsea well:

Mudline = 500 ft

9 5/8 "casing 53.5#, C-95 do = 9.625", ID = 8.535, thickness (to) = 0.545"

13 3/8" casing, 72#, C-95 Di = 12.347", thickness (t) = 0.514"

9 5/8" casing is cemented 500 ft inside the 13 3/8" casing. Top of cement is at 6000 ft.

Top of cement for 13 3/8" casing is 5000 ft.

$\alpha = 7 \times 10^{-6}$ 1/F°

$\beta = 306 \times 10^{-6}$ 1/F°

$E = 30 \times 10^{6}$ psi

Cv (liquid) = 0.00000316 1/psi (At 3000 psi and 150 F°)

Cv (gas) = 0.000333 1/psi

Free gas in mud = 0.1%

Average initial temperature in annulus (b) = 85 F°

Temperature rise in annulus (ΔT b) after production = 110 F°

Temperature rise in 9 5/8" casing (ΔT3) after production = 110 F°

Temperature rise in 13 3/8" casing (ΔT2) after production = 70 F°

Solution

$$C_v = \text{total fluid comprehensibility} = f_f C_{vL} + fg\, C_{vg} \qquad (15.15)$$

where

f_f = fraction of fluid in mud

C_{vL} =comprehensibility of liquid

fg = fraction of gas in mud

C_{vg} =comprehensibility of gas

If fg is zero, then $C_v = C_{vL}$

Cv = 0.00000316 x (0.999) + 0.000333x (0.001) = 0.00000349 1/psi

$\Sigma\,\Delta V = \Delta V_2 + \Delta V_b + \Delta V_3$

Casing 2 refers to the 13 3/8" casing

$$\Delta V2 = -\frac{\pi}{2} L_2 D_2{}^2 \alpha \Delta T_2$$

L_2 = 5000 – 500 (Mudline) = 4500 ft

D_2= (OD_2+ ID_2)/2 = (13.375+ 12.347)/2 = 12.861"

$$\Delta V_2 = -\frac{\pi}{2}(4500 \times 12)(12.861)^2 \times 7 \times 10^{-6} \times 70 = -6874.8 \text{ in}^3$$

L_b = 6000 – 500 = 5500 ft

$$\Delta V_b = \frac{\pi}{4}(ID_2^2 - OD_3^2) L_b \beta \Delta T_b$$

$$\Delta V_b = \frac{\pi}{4}(12.347^2 - 9.625^2)(5500 \times 12) \times 306 \times 10^{-6} \times 110 = 104{,}353 \text{ in}^3$$

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L3 = 6500 ft

D3 = (9.625+ 8.535)/2 = 9.08 in

$$\Delta V_3 = -\frac{\pi}{2}(5500x12)(9.08)^2 x7x10^{-6}x110 = 6581.5$$

$$\Sigma\,\Delta V = -\ 6{,}874.8 + \ 104{,}353 \ + 6{,}581.5 = 117{,}809\ in^3$$

System Flexibility (f)

$$\Sigma f = f_2 + f_b + f_3$$

For Casing (2)

$$f_2 = \frac{\pi L_2 D_2^3}{4xExt_2}$$

$$f_2 = \frac{\pi(4500x12)(12.861)^3}{4x30x10^6x0.514} = 5.851\ in^5/lb$$

For annulus (b)

$$f_b = C_v\frac{\pi}{4}(ID_2^2 - OD_3^2)L_b$$

$$f_b = (0.00000349)x\,\frac{\pi}{4}(12.3472 - 9.6252)\ (5500x12) = 10.82\ in^5/lb$$

For casing (3)

$$f_3 = \frac{\pi L_3 D_3^3}{4xExt}$$

$$f_3 = \frac{\pi(5500 x 12)9.08^3}{4 x 30 x 10^6 x 0.545} = 2.373\ in^5/lb$$

$$\Sigma f = 5.851 + 10.82 + 2.373 = 19.044\ in^5/lb$$

$$\text{Trapped annulus pressure } P = \frac{\Sigma \Delta V}{\Sigma f} = \frac{117,809}{19,044} = 6,186 \text{ psi}$$

8.3 Differential Pressures

If in the above example, the 9 5/8 casing was run in a13.5 ppg mud and the packer fluid inside the 9 5/8" casing was 9.5 ppg, then the following differential pressures can be calculated:

At wellhead

Trapped pressure = 6186 psi (from **Example 15.3**)

This pressure acts to collapse the 9 5/8" casing and to burst the 13 3/8" casing.

Collapse strength of 9 5/8" casing = 7,330 psi, hence this casing is safe.

Burst strength of 13 3/8" casing = 6390 psi, again this casing is safe.

At top of Cement at 6000 ft

Differential pressure = 0.052 (13.5 –9.5) x 6000 + 6186

= 7434 psi

The differential pressure is now greater than both the collapse strength of the 9 5/8" casing and the burst strength of the 13 3/8" casing. Damage to one or both is possible. However, as the 13 3/8" is supported by cement between itself and the 20" casing, its burst strength is significantly increased above its API rated value and it will most likely cope with the above value of trapped pressure. Collapse of the 9 5/8" casing is, however, of greater concern.

To reduce this damage, increase the packer fluid density so the maximum differential pressure is less than 6300 psi or instigate a mechanism for regularly bleeding off the trapped pressure.

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9.0 REFERENCES

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66th Annual Technical Conference, dallas, TX, Oct, 6-9

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16

Rig Components

Content

1.0 Fundamentals

A drilling rig is a device used to drill, case and cement oil and gas wells.

The correct procedure for selecting and sizing a drilling rig is as follows:

1. Design the well
2. Establish the various loads to be expected during drilling and testing operations and use the highest loads. This point establishes the *DEPTH RATING OF THE RIG.*
3. Compare the rating of existing rigs with the design loads
4. Select the appropriate rig and its components.

1.1 Types of Rigs

Drilling rigs are classified as

- Land rigs
- Offshore rigs

There are two types of offshore rigs:

1. Floating rigs:
   - Semisubmersible
   - Drillships
2. Bottom-supported rigs: There are three types:
   - Jack-ups
   - Platform
   - Barge

1.2 Rig Components Sizing

The major components that need to be selected and sized for the purpose of rig sizing are:

1. Hoisting
2. Rotating Equipment
3. Circulating System
4. Tubular Goods
5. Pressure Control
6. Derrick Capacity And Substructure
7. Total Power Requirements for the above

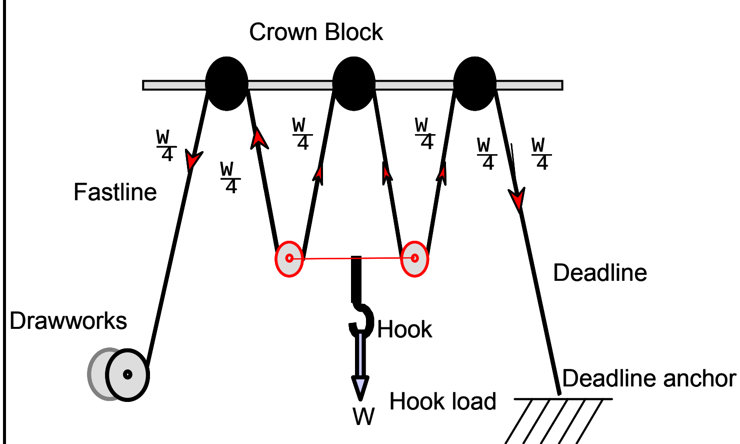
2.0 Hoisting System

The hoisting system consists of: (**Figure 16.1**)

Drawworks: this is an assembly of a rotating drum, a series of shafts, clutches, chains and gears for changing speed and for reversing, **Figure 16.2**. It also contains the main brake for stopping the drilling line. The drilling line is wound a number of times around the drum, the end of the line then passes on the crown and travelling block.

Crown Block: A block located at the top of the derrick. It contains a number of sheaves on which is wound the ***drilling line***. The crown block provides a means of taking the drilling line from the hoisting drum to the travelling block. The crown block is stationary and is firmly fastened to the top of the derrick. Each sheave inside the crown block acts as an individual pulley.

Figure 16.1 Schematic Of The Hoisting System



The drilling line is reeved round the crown block and travelling block sheaves with the end line going to an anchoring clamp called **"DEAD LINE ANCHOR", Figure 16.3.**

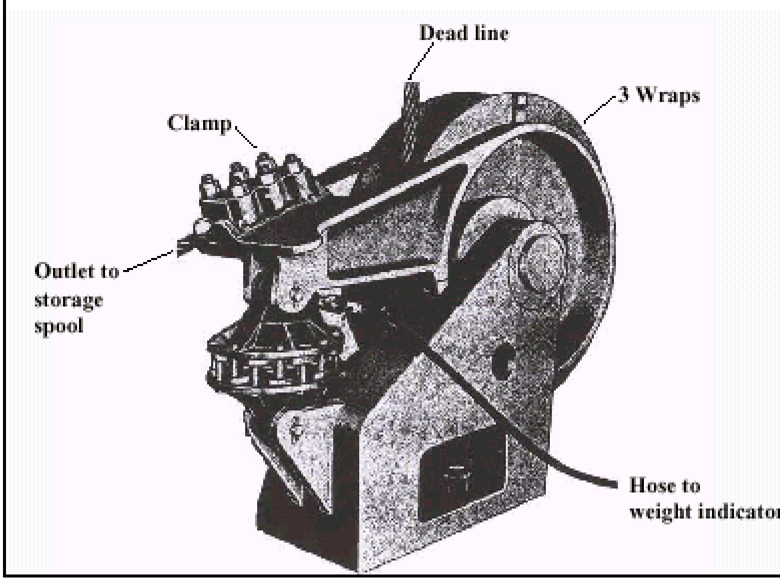
The static line is called the deadline**.** The line section connecting the drum with the crown block is called the fastline.

Figure 16.2 Drawworks, Courtesy of National Oilwell

Hence during hoisting operations, if there are 10 lines between the crown and travelling block, the fastline line travels 10 times faster than the travelling block in order to spool or unspool drilling line from the hoisting drum.

Dead Line Anchor: anchors the last line coming from the crown block and also stores drilling line on a reel. This allows new lengths of line to be fed into the system to replace the worn parts of the line that have been moving on the pulleys of the crown block or the travelling block. The worn parts are regularly cut and removed by a process called: **Slip and Cut Practice**. Slipping the line, then cutting it off helps to increase the lifetime of the drilling line.

Figure 16.3 Deadline anchor



Travelling Block: a diamond-shaped block containing a number of sheaves which is always less than those in the crown block. The drilling line is wound continuously on the crown and travelling blocks, with the two outside ends being wound on the hoisting drum and attached to the deadline anchor respectively, **Figure 16.4**.

Figure 16.4 Travelling Block, Courtesy of National Oilwell

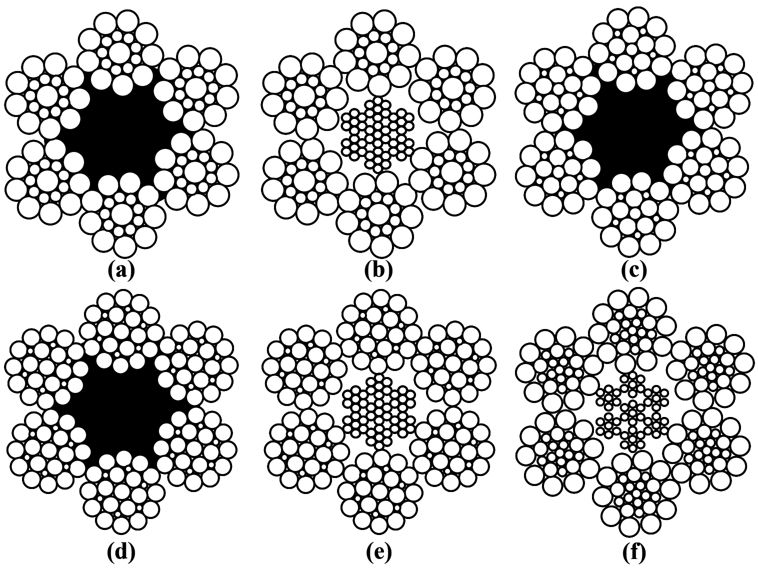
The Hook: connects the Kelly or topdrive with the travelling block. The hook carries the entire drilling load, **Figure 16.4**.

Drilling Line

The drilling is basically a wire rope made up of strands wound around a steel core. Each strand contains a number of small wires wound around a central core.

The drilling line is of the round strand type with Lang's lay. The drilling line has a 6x19 construction with Independent Wire Rope Core (IWRC). This construction implies that there are 6 strands and each strand containing 19 filler wires. The size of the drilling line varies from ½ "to 2 ".

Figure 16.6 Typical wire rope constructions: 6x 19 classification, API Spec 9A



(a) 6 x 19 Seale with fibre core;
(b) 6 x 19 Seale with independent wire rope core;
(c) 6 x 21 filler wire with fibre core;
(d) 6 x 25 filler wire with fibre core;
(e) 6 x 25 filler wire with independent wire rope core;
(f) 6 x 25 Warrington Seale with independent wire rope core.

2.1 Hoisting Design Considerations

The procedure for carrying out hoisting design calculations are as follows:

- Determine the deepest hole to be drilled
- Determine the worst drilling loads or casing loads
- Use these values the select the drilling line, the derrick capacity and in turn the derrick

2.1.1 STATIC DERRICK LOADING

Static derrick loading (SDL)= fast-line load + hook load + dead-line load (16.1)

Referring to **Figure 16.1** and for a system consisting of four lines supporting the hook load. Then under static conditions:

Fast- line load (FL) = Hook load /4

Dead-line load (DL) = Hook load /4

$$SDL = \frac{Hl}{4} + HL + \frac{HL}{4} = \frac{3}{2} HL$$

For N lines, the static derrick load is given by:

$$= \frac{(N+2)}{N} HL \qquad (16.2)$$

where

N = number of lines strung to travelling block

HL = hook load

2.1.2 EFFICIENCY OF THE HOISTING SYSTEMS (EF)

A. Hoisting Operations

Friction between the wire rope and sheaves reduce the efficiency of the hoisting system. The efficiency factor (EF) during hoisting (pulling out of hole) operations is given by:

$$EF = \frac{K \times (1 - K^N)}{N x (1 - K)} \qquad (16.3)$$

$$FL = \frac{HL}{N x EF} \qquad (16.4)$$

where

K = sheave and line efficiency per sheave

Deadline-load is given by:

$$DL = \frac{HL \times K^N}{NxEF} \tag{16.5}$$

If the breaking strength of the drilling line is known, then a design factor, DF, may be calculated as follows:

$$DF = \frac{\text{nominal strength of wire rope (lb)}}{\text{fast-line load (lb)}} \tag{16.6}$$

B. Lowering Operations

During lowering of pipe, the efficiency factor and fast-line load are given by

$$EF_{lowering} = \frac{K \times K^N(1-K)}{(1-K^N)} \tag{16.7}$$

$$FL_{lowering} = \frac{WxK^N x(1-K)}{(1-K^N)} \tag{16.8}$$

Example 16.1: Hoisting System Efficiency Factor

Calculate the efficiency factor for a hoisting system employing 8 string lines. Assume the value of K to be 0.9615.

Solution

$$EF = \frac{K \times (1-K^N)}{Nx(1-K)}$$

$$EF = \frac{0.9615 \times (1-0.9615^N)}{8x(1-0.9615)} = 0.842$$

Table 16.1 can be constructed for different numbers of lines strung between the crown and travelling blocks.

Table 16.1 Block And Tackle Efficiency Factors For K = 0.9615

Number of lines strung	Efficiency factor
6	0.874
8	0.842
10	0.811
12	0.782

2.2 Power Requirements of the Drawworks

As a rule of thumb, the drawwork should have 1 HP for every 10 ft to be drilled. Hence for a 20,000 ft well, the drawwork should have 2000 HP. A more rigorous way of calculating the horse power requirements is to carry out the following calculations:

a) Velocity of fast-line load (V_f)

$$V_f = N \times V_L \tag{16.9}$$

where

V_L = velocity of travelling block

N = number of lines strung

b)Power output at drum (P)

$$= FL \times V_f \tag{16.10}$$

$$P = \frac{HL x V_L}{EF} \tag{16.11}$$

In the Imperial system, power is quoted in horse-power and the above equation becomes:

Drum output = $\frac{HL x V_L}{EF x (33,000)}$ horse power

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Example 16.2: Hook Loads

The following data refer to a 1.5 in block line with 10 lines of extra improved plough steel wire rope strung to the travelling block.

hole depth	= 10,000 ft
drillpipe	= 5 in OD/4.276 in ID, 19.5 lb/ft
drill collars	= 500 ft, 8 in/2,825 in, 150 lb/ft
mud weight	= 10 ppg

line and sheave efficiency coefficient = 0.9615

Calculate:

(1) weight of drill string in air and in mud;

(2) hook load, assuming weight of travelling block and hook to be 23,500 lb;

(3) deadline and fast-line loads, assuming an efficiency factor of 0.81;

(4) dynamic crown load;

(5) wireline design factor during drilling if breaking strength of wire is 228,000 lb

(6) design factor when running 7 in casing of 29 lb/ft.

Solution

(1) Weight of drillstring in air

=weight of drillpipe + weight of drill collars

=(10,000 - 500) x 19.5 + 150 x 500 = 260,250 lb

(Note: Weight of string in air is also described as pipe setback load).

Weight of drillstring in mud =buoyancy factor x weight in air

$= 0.847 \times 260{,}250 = 220{,}432$ lb

(2) Hook load

= weight of string in mud + weight of travelling block, etc.

$= 220{,}432 + 23{,}500 = 243{,}932$ lb

(3) Deadline load

$$= \frac{HL \quad K^{10}}{N \quad EF} = \frac{243{,}932 \times 0.9615^{10}}{10 \times 0.81} = 20{,}336 \text{ lb}$$

$$\text{Fast-line load} = \frac{HL}{N \times EF} = \frac{243{,}932}{10 \times 0.81} = 30{,}115 \text{ lb}$$

(4) Dynamic crown load

$= DL + FL + HL$

$= 20{,}336 + 30{,}115 + 243{,}932 = 294{,}383$ lb

$$\text{(5) Design factor} = \frac{\text{breaking strength}}{\text{fast-line load}}$$

$$= \frac{228{,}000}{30{,}115} = 7.6$$

(6) Weight of casing in mud

$= 10{,}000 \times 29 \times BF = 245{,}630$ lb

HL = weight of casing in mud + weight of travelling block, etc.

= 245,630 + 23,500 = 269,130 lb

$$FL = \frac{HL}{N \times EF} = \frac{269{,}130}{10 \times 0.81} = 33{,}226 \text{ lb}$$

$$DF = \frac{228{,}000}{33{,}226} = 6.9$$

Example 16.3: Power Requirements of The Drawwork

The following data refer to an oilwell block-and-tackle system:

Number of lines = 10 (with EF = 0.81)

Maximum expected hook load = 500,000 lbf

Hook load speed = 120 ft/min

Hoisting drum diameter = 32"

Mechanical efficiency of draw works = 0.88

Calculate

1. The power at the drawwork
2. The motor power required
3. The fastline
4. Motor to drum gear ratio when pulling out of hole the maximum allowable load.

Note:Use an efficiency factor of 0.81.

Solution

V_w = velocity of hook load = 120 ft/min

1. Power at drum $= \frac{HLxV_w}{EF} x(\frac{1}{33,000})$

$$= \frac{500,000 \text{ x } 120 \text{ x } 1}{0.81 \text{ x } 33000} = 2245 \text{ HP}$$

Power at drum= motor power x mechanical efficiency

2245 = Motor Power x 0.88

Motor Power = 2551 HP

Select a motor with 3000 HP rating.

Fastline speed = 10 x Hook load speed

(V_f = N x V_w)

= 10 x 120 = 1200 ft/min

Fastline speed = drum speed x drum perimeter

1200 (ft/min) = drum speed (rpm) x 2 x π x (32 in /2) x (1 ft/12 in)

Drum speed = 143 rpm

$$\text{Gear ratio} = \frac{\text{motor speed}}{\text{drum speed}}$$

$$\text{Gear ratio} = \frac{1200}{477.5} = 2.5$$

(Assuming the motor speed is 1200 rpm, which is a reasonable speed for a motor rated to 3000 HP).

3.0 DRILLING LINE DESIGN CONSIDERATIONS

3.1 TON-MILES OF A DRILLING LINE

The drilling line, like any other drilling equipment, does work at any time it is involved in moving equipment in or out of the hole. The amount of work done varies depending the operation involved. This work causes the wireline to wear and if the line is not replaced it will eventually break. The reader should note that the drilling line can only contact a maximum of 50% of the sheaves at any one time, but the damage will be done on the contact area any way.

The amount of work done need to be calculated to determine when to change the drilling line. The following gives equations for calculating the work done on the drilling line:

(a)Work done in round trip operations (T_r)

$$T_r = \frac{D(L_S+D)W_e}{10{,}560{,}000} + \frac{D(M+C/2)}{2{,}640{,}000} \quad \text{ton-miles} \tag{16.12}$$

where

M = mass of travelling assembly (lb)
L_s = length of each stand (ft)
D = hole depth (ft)
W_e = effective weight per foot (or master) of drill pipe in mud
C = $(L \times W_{dc} - L \times W_{dp}) \times BF$
W_{dc} = weight of drill collars in air
W_{dp} = weight of drill pipe in air
L = length of drill collars

(b) Work done during drilling operations: In drilling a length of section from d_1 to depth d_2 the work done is given by

$$T_d = 3(T_2 - T_1) \tag{16.13}$$

(c) Total work done (WD) in coring = 2 round trips to bottom

$$T_c = (T_2 - T_1) \tag{16.14}$$

where

T_2 = work done for 1 round trip at d_2 where drilling or coring stopped before coming out of the hole.

T_1 = work done for 1 round trip at depth d_1, where drilling or coring started

(d) Work done in setting casing (T_s)

$$T_s = \frac{1}{2}\left[\frac{D(L_s+D) \times W_{cs}}{10{,}560{,}000} + \frac{MD}{2{,}640{,}000}\right] \tag{16.15}$$

where

W_{cs} = effective weight per unit length of casing in mud
L_s = length of casing joint
M = mass of travelling assembly (lb)
D = hole depth (ft)

Example 16.4: Ton- Miles Evaluation

Using the data given in **Example 16.3**, determine; (a) round trip ton-miles at 10,000 ft; (b) casing ton-miles if one joint of casing = 40 ft; (c) design factor of the drilling line when the 7 inch casing is run to 10,000 ft; (d) the ton-miles when coring from 10,000 ft to 10.180 ft and (e) the ton-miles when drilling from 10,000 to 10,180 ft.

Solution

(a)From Equation Equation (16.12):

$$T_r = \frac{D(L_S+D)W_e}{10{,}560{,}000} + \frac{D(M+C/2)}{2{,}640{,}000} \quad \text{ton-miles}$$

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M= 23.500 lb

$C= (L \times W_{dc} - L \times W_{dp})\ BF = (500 \times 150 - 500 \times 19.5) \times 0.847 = 55,267$

$D = 10,000$ ft, $L_s = 93$ ft

$W_e = 19.5 \times BF = 167.52$ lb/ft

Therefore,

$$T_r = \frac{10,000 \times (93 + 10,000) \times 16.52}{10,560,000} + \frac{10,000 \times (23,500 + 55,267/2)}{2,640,000}$$

$= 157.9 + 193.7 = 351.6$ ton-miles

(b) Casing operations

$$T_s = \frac{1}{2}\left[\frac{D \times (L_s + D) \times W_{cs}}{10,560,000} + \frac{D \times M}{2,640,000}\right]$$

W_{cs} = Weight of casing in air x BF = 29 x 0.847 = 24.56 lb/ft

$L_s = 40$ ft

$$T_s = \frac{1}{2}\left[\frac{10,000 \times (40 + 10,000)}{10,560,000} + \frac{10,000 \times 23,500}{2,640,000}\right]$$

$= \frac{1}{2}\ (233.5 + 89.0) = 161.3$ ton-miles

(c) DF = 5.6 (see **Example 16.3**)

(d) $T_c = 2\ (T_2 - T_1)$

where

T_2 = round trip time at 10,180 ft, where coring stopped, and

T_1 = round trip time at 10,000 ft, where coring started.

Therefore,

$$T_2 = \frac{10{,}180 \times (93 + 10{,}180) \times 16.52}{10{,}560{,}000} + \frac{10{,}180\times(23{,}500 + 55{,}267/2)}{2{,}640{,}000}$$

= 163.6 + 197.2 = 360.8 ton-miles

T_1 = 351.6 (from Part a)

Therefore,

T_c = 2 x (360.8 - 351.6) = 18.4 ton-miles

(e) $T_d = 3 \times (T_2 - T_1)$ = 3 x (360.8 - 351.6) = 27.6 ton-miles

3.2 Evaluation Of Total Service And Cut-Off Practice

Portions of the drilling line on the crown and travelling blocks sheaves and on the hoisting drum carry the greatest amount of work and are subjected to a great deal of wear and tear. These parts must be cut and removed at regular times other wise the drilling line will fail by fatigue. The process is called "slip and cut practice". The length of line to be cut is calculated as follows:

Length of drum laps = number of laps x drum circumference

= number of laps x π x D

where D = drum diameter

Table 16.2 give the recommended cut-off lengths in terms of drum laps and derrick height.

Example 16.5: Length of drilling line to cut

Calculate cut-off length in feet for:

Drilling line = 1 ½"

Drum diameter = 30"

Derrick height = 147 ft

DF = 5

Answer

Ton-miles for 1 ½" drilling line = 2600 TM for DF =5 (API) BETWEEN CUTS

From **Table 16.2**, Number of drum laps = 11.5 for a drum diameter of 30 in

Length to be cut = number of laps X (π x Drum Dia)

$$= 11.5 \times \pi \times 30\,(\text{in})/(12) = 90.3\ \text{ft}$$

Table 16.2 Recommended cut-off lengths in terms of drum laps and derrick height for a design factor = 5, Courtesy of API

Derrick height, ft	Drum Diameter, in		
	28	30	32
	Number od drum laps per cut-off		
187	15.5	14.5	13.5
142,143,147	11.5	11.5	11.5
133,136,138	11.5	10.5	9.5

4.0 ROTATING EQUIPMENT

The main components are:

1. Rotary table (Figure 16.7)

2. Kelly

3. Top Drive (this is equivalent to the Kelly and rotary table, i.e. either top drive or Kelly/rotary table

4. Swivel

5. Rotary hose

Also **Chapter 10** see for details of the above equipment.

Figure 16.7 Rotary Table, Courtesy Of National Oilwell

The rotary horse power requirement is usually between 1.5 to 2 times the rotary speed, depending on hole depth. Hence for rotary speed of 200 rpm, the power requirement is about 400 HP.

5.0 CIRCULATING SYSTEM

The heart of the circulating system is the mud pumps. There are two types of pumps used in the oil industry: Duplex and Triplex.

A basic pump consists of a piston (the liner) reciprocating inside a cylinder. A pump is described as single acting if it pumps fluid on the forward stroke (Triplex pumps) and double acting if it pumps fluid on both the forward and backward stokes (Duplex). **Figure 16.8** shows a triplex mud pump.

Figure 16.8 Triplex Mud Pump, Courtesy of National Oilwell

5.1 Pump Liners

Pump liners fit inside the pump cavity. These affect the pressure rating and flow rate from the pump. For a given pump, a liner has the same OD but with different internal; diameters. The smaller liner (small ID) is used in the deeper part of the well where low flow rate is required but at much higher operating pressure.

The horse power requirements of the pump depends on the flow rate and the pressure. The operating pressure depends on flow rate, depth and size of hole, size of drillpipe and drillcollars, mud properties and size of nozzles used. A full hydraulics program needs to be calculated to determine the pressure requirement of the pump.

The size of the pump is determined by the length of its stroke and the size of the liner.

5.2 Volumetric Efficiency

Drilling mud usually contain little air and is slightly compressible. Hence the piston moves through a shorter stroke than theoretically possible before reaching discharge pressure. As a result the volumetric efficiency is always less than one; typically 95% for triplex and 90% for duplex. In addition due to power losses in drives, the mechanical efficiency of most pumps is about 85%.

5.3 Horsepower

The following equations can be used to calculate the power output of a mud pump:

$$\text{Hydraulic horsepower} = \frac{\text{flow rate (gal/min) x pressure (psi)}}{1713.6} \tag{16.16}$$

$$\text{Hydraulic horsepower} = 0.000584 \text{ (gal/min) x pressure (psi)} \tag{16.17}$$

$$\text{Hydraulic horsepower} = \text{(bbl/min) x pressure (psi) / 40.8} \tag{16.18}$$

$$\text{Hydraulic horsepower} = 0.02448 \text{ (bbl/min) x pressure (psi)} \tag{16.19}$$

Hydraulic horsepower = brake horsepower x efficiency of power train to pump

x pump efficiency (16.20)

5.4 Pump Output

Double acting duplex pump

$$\text{gal/min} = 0.00679 \text{ x L x } (2D^2 - d^2) \text{ x spm x volumetric efficiency} \tag{16.21}$$

$$\text{bbl/min} = 0.000162 \text{ x L x } (2D^2 - d^2) \text{ x spm x volumetric efficiency} \tag{16.22}$$

Single acting triplex pump

$$\text{gal/min} = 0.010199 \text{ x L x } D^2 \text{ x spm x volumetric efficiency} \tag{16.23}$$

$$\text{bbl/min} = 0.000243 \text{ x L x } D^2 \text{ x spm x volumetric efficiency} \tag{16.24}$$

5.5 Pump Factors

In practice, it convenient to express the pump output in terms of how many gallons or barrels for every stroke of the pump. The equations for the two types of pumps are:

For duplex

$$F_p = \frac{N_c \times 1_s \times (2 \times d_l^2 - d_r^2) \times E_v}{42 \times 294} \qquad (16.25)$$

For triplex

$$F_p = \frac{N_c \times 1_s \times (2 \times d_l^2 - d_r^2) \times E_v}{42 \times 294} \qquad (16.26)$$

where

N_c = number of cylinders

1_s = length of stroke, inch

d_l = liner diameter, inch

d_r = rod diameter, inch=

E_v = volumetric efficiency, fraction

F_p = pump factor, bbl/stroke

Example 16.6: Horse Power Requirement of a Mud Pump

Calculate the power requirement for the following pump:

Flow rate = 1200 gpm
Pressure = 2000 psi
Mechanical Efficiency = 0.85

Solution

$$\text{Hydraulic horsepower} = \frac{\text{flow rate(gal/min)} \times \text{pressure (psi)}}{1713.6}$$

$$\text{Hydraulic horsepower} = \frac{1200 \times 2000}{1713.6} = 1400.6 \text{ HP}$$

Power required from motor = 1400.6 / 0.85 = 1648 HP

5.6 Centrifugal Pumps

This type uses an impeller for the movement of fluid rather than a piston reciprocating inside a cylinder. Centrifugal pumps are used to supercharge mud pumps and providing fluid to solids control equipment and mud mixing equipment.

5.7 Mud Handling Equipment

Rig sizing must incorporate mud handling equipment as these equipment form the heart of the circulation system and determine the speed of drilling and the quality of hole drilled.

The equipment includes:

1. Shale Shakers: size, number of type (see **Chapter 7**)

The type of mud (i.e. oil-based or water-based) determines the type of the shaker required and the motion of the shaker. Deep holes require more than the customary three shakers.

2. Mud Pits

The number and size of pits is determined by the size and depth of hole. Other factors include: size of rig and space available, especially on offshore rigs. The size of a mud pit is usually 8-12 ft wide, 20-40 ft long and 6-12 ft high.

3. Mud degasser

4. Centrifuges and mud cleaners

5. Desanders and desilters

6.0 Tubular Goods

Tubular goods were discussed in details in Chapter 10.

The components of the drillstring are:

1. Drillpipe

2. Drillcollars

2. Accessories including:

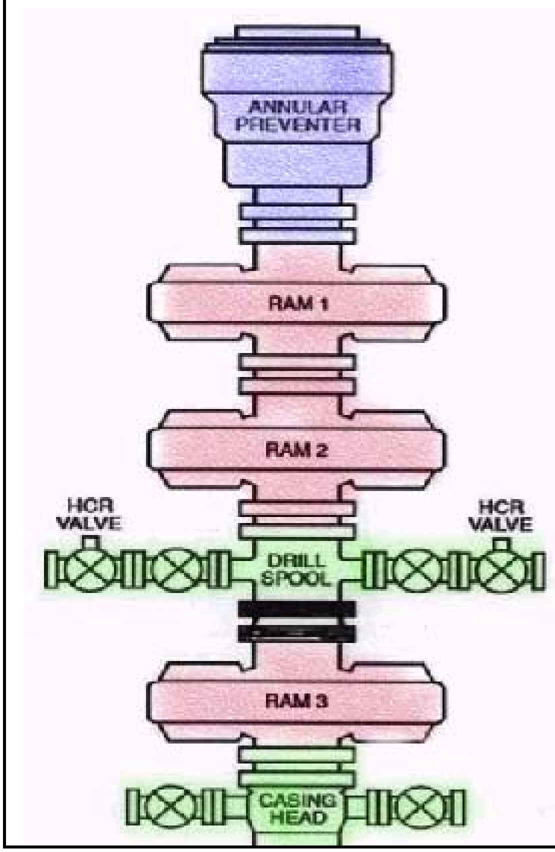
- Heavy-walled drillpipe
- Stabilisers
- Reamers
- Directional control equipment

The selection of the above equipment determines the loading on the derrick.

7.0 PRESSURE CONTROL EQUIPMENT

BOPs equipment are selected based on the maximum expected wellbore pressures. The pressure rating, size and number of BOP components must be determined by the Drilling Engineer prior to drilling the well. This is the sizing exercise, **Figure 16.9**.

Figure 16.9 A Basic BOP Configuration



Select:

1. Diverter if required, usually for offshore operations during the drilling of top or surface hole. Make sure the diverter discharge line is 12" or above.
2. Annular preventer
3. Ram preventers (determine minimum size of rams required to suit the drillstring)
4. Blind or Shear rams
5. Choke manifold
6. HCR valves
7. Choke and Kill lines
8. Accumulator and BOP Control System (Koomey Unit)
9. Drilling spools: used as an element between rams to provide mud exit lines such as choke and kill lines. Drilling spools can be flanged, studded or clamp-on type.
10. For air drilling, rotating heads are used to allow well control while the pipe is rotating.

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11. Drillpipe Blowout Preventers: include:

- Kelly cock
- Drop in valve (check valve)
- Float valve (either flapper or spring-loaded ball valve)
- Full opening safety valves

BOPs are rated by API as 3M (3000 psi), 5M, 10 M and 15 M. For HPHT, BOPS are either 15 M or 20 M.

All the above equipment must be rated to the highest pressure to be expected at the well during a kick or during controlled testing and production.

In subsea operations, the BOP stack is installed at seabed. The stack has several back up units in case of failure, for example two annulars are used so that if one failed the other can be used. This back-up system principle is applied to all the BOP components. The subsea stack for HPHT operation may not be part of the rig contract and may have to be rented out separately, e.g. a 20K stack.

8.0 Derrick Capacity and Substructure

The derrick provides the necessary height and support to lift loads in and out of the well. The derrick must be strong enough to support the hook load, deadline and fastline loads, pipe setback load and wind loads.

There are two types of derricks:

1. **Standard Derrick**: is a bolted structure that must be assembled part by part, usually used on offshore platforms.

Derricks installed on floating structures such as ships and semisubmersibles are designed to withstand extra dynamic stresses due to rolling, pitching and heaving of the support and due to stresses from winds. The space available between the rig floor and the crown block must be higher to handle the wave-induced vertical movements of the floating support.

2. Mast or Portable derrick: This type is pivoted at its base and is lowered to the horizontal by the use of drawers after completing the well and the rig is ready to move to another location. the mast dismantles into a number of pin-jointed sections, each of which is usually a truck load.

The mast is usually used on land operations where the complete rig must be moved between well locations. at the new location, the sections are quickly pined together and the mast is raised to the vertical by the drawworks.

The derrick consists of four legs connected by horizontal structural members described as girts. The derrick is further strengthened by bracing members connecting the girts.

The derrick sits on a **substructure** on which drilling equipment is mounted. The substructure is composed of derrick supports and rotary supports.

The derrick supports consist of four posts and exterior bracing between the supports. The rotary supports consist of beams and braces to support the rotary table and pipe set back load.

The height of the substructure above the ground varies according to the size of the substructure and the size and rating of the wellhead and BOPs. For a base size of 30 ft, the height is 10- 14 ft.

8.1 Static Derrick Loading

= fast-line load + hook load + dead-line load

$$= \frac{Hl}{4} + HL + \frac{HL}{4} = \frac{3}{2} HL$$

For N lines, the static derrick load is given by:

$$= \frac{(N+2)}{N} HL \qquad (16.27)$$

where

N = number of lines strung to travelling block

HL = hook load

The **wind load** is given by: $0.004\ V^2$ (units: lb/ft^2)

where V is wind speed in miles/hour

The wind load in lb/ft^2 result must be multiplied by the WIND LOAD AREA which is given in API 4A for different derrick sizes in order to obtain the wind load in lb. For offshore operations in windy areas, this load can be very significant.

Example 16.7: Derrick Loading

The following data refer to a 1.5 in block line with 10 lines of extra improved plough steel wire rope strung to the travelling block.

Hole depth	= 10,000 ft
Drillpipe	= 5 in OD/4.276 in ID, 19.5 lb/ft
Drill collars	= 500 ft, 8 in/2,825 in, 150 lb/ft
Mud weight	= 10 ppg

Line and sheave efficiency coefficient = 0.9615

Calculate

(1) weight of drill string in air and in mud;

(2) hook load, assuming weight of travelling block and hook to be 23,500 lb;

(3) deadline and fast-line loads, assuming an efficiency factor of 0.81;

(4) dynamic crown load;

(5) wireline design factor during drilling if breaking strength of wire is 228,000 lb

(6) design factor when running 9 5/8 in casing of 53.5 lb/ft.

(7) dynamic derrick load when running the 9 5/8" casing

Solution

(1) Weight of string in air

=weight of drillpipe + weight of drill collars

=(10,000 - 500) x 19.5 + 150 x 500 =260,250 lb

Weight of string in mud =buoyancy factor x weight in air = 0.847 x 260,250 =220,432 lb

(2) Hook load

= weight of string in mud + weight of travelling block, etc.

= 220,432 + 23,500 = 243,932 lb

(3) Deadline load

$$= \frac{HL}{N} \times \frac{K^{10}}{EF} = \frac{243{,}932 \times 0.9615^{10}}{10 \times 0.81}$$

= 20,336 lb

$$\text{Fast-line load} = \frac{HL}{N \times EF} = \frac{243{,}932}{10 \times 0.81}$$

= 30,115 lb

(4) Dynamic derrick Loading during drilling

= DL + FL + HL = 20,336 + 30,115 + 243,932 = 294,383 lb

(5) Design factor $= \dfrac{\text{breaking strength}}{\text{fast-line load}}$

$$= \frac{228{,}000}{30{,}115} = 7.6$$

(6) Weight of casing in mud

$= 10{,}000 \times 53.5 \times BF$

$= 453{,}145$ lb

HL = weight of casing in mud + weight of travelling block, etc.

$= 453{,}145 + 23{,}500 = 476{,}645$ lb

$$FL = \frac{HL}{N \times EF} = \frac{476.645}{10 \times 0.81} = 58{,}845 \text{ lb}$$

$$DF = \frac{228{,}000}{58{,}845} = 3.9$$

(7) Dynamic derrick loading during running casing = FLL + HL + DLL

Deadline load (DLL)

$$= \frac{HL \quad K^{10}}{N \quad EF} = \frac{476{,}645 \times 0.9615^{10}}{10 \times 0.81} = 39{,}738 \text{ lb}$$

Dynamic derrick loading = 58,845+ 476,645 + 39,738 = 575,228 lb

Hence the derrick capacity must be approximately 750,000 lb to allow for extra loading such as wind, pipe setback load etc.

9.0 Total Power Requirements

The total power requirement of a rig is the sum of the power requirement of:

1. Drawworks
2. Mud pumps
3. Rotary system
4. Auxiliary power requirements for lighting etc.
5. Life support systems

The above total power may not be required in a continuous but in an intermittent mode.

The actual power required will depend on the drilling job being carried out. The maximum power used is during hoisting and circulation. The least power used is during wireline operations.

The majority of rigs in current use require between 1000 – 3000 horsepower.

The power on modern rigs is most commonly generated by diesel-electric power units. The power produced is AC current which is then converted to DC current by the use of SCR (Silicon Controlled Rectifier). The current is delivered by cables to electric motors attached directly to the equipment involved such as mud pumps, rotary table, Drawworks etc.

10.0 Learning Milestones

In this chapter, you should have learnt to:

1. List types of rigs
2. Calculate: fastline, deadline, hook, static and dynamic derrick loads
3. Calculate power requirements of drawworks
4. Calculate Ton-Miles of drilling line during tripping, drilling, coring and setting casing operations

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5. Calculate cut-off length for slip and cut practice
6. Calculate power requirement of a mud pump

11.0 EXERCISES

Exercise 1

The following data refer to a 1.5 in block line with 10 lines of extra improved plough steel wire rope strung to the travelling block.

hole depth= 12,000 ft

drillpipe = 5 in OD/4.276 in ID, 19.5 lb/ft

drill collars= 500 ft, 8 in/2,825 in, 150 lb/ft

mud weight= 10 ppg

line and sheave efficiency coefficient = 0.9615

Calculate:

(1) weight of drill string in air and in mud;

(2) hook load, assuming weight of travelling block and hook to be 23,500 lb;

(3) deadline and fast-line loads, assuming an efficiency factor of 0.81;

(4) dynamic crown load;

(5) wireline design factor during drilling if breaking strength of wire is 228,000 lb

(6) design factor when running 12000 ft of 7 in casing of 29 lb/ft.

Exercise 2

A blockline for a new desert rig is to be ordered for an expected operation of 2748 Ton-Miles The engineer decided on a 1¼" (32mm) line and a total of 8 lines to be wound round the crown block and travelling block. Derrick height is 124 ft above rig floor and the drum diameter is 26". From previous experience, it is known that the length of cut for 1¼" line is 16 TM/ft

Calculate the length of line that should be ordered. Assume the sheave diameter = 30 x block line diameter and a minimum of 4 laps of wire to be left on the hoisting drum.

A 1¼" line weighs 2.89 lbm/ft Also the drilling line can only contact a maximum of 50% of the sheaves.

Answer: (length = 2223.6 ft)

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17

WELL COSTING

Content

1.0 REASONS FOR COSTING

As will be discussed later, there are many elements which comprise the well cost. These range from rig, casing, people, drilling equipment etc.

The final sheet summarizing the well cost is usually described as the AFE: "**Authorisation For Expenditure**". The AFE is the budget for the well. Once the AFE is prepared, it should then be approved and signed by a senior manager from the operator.

The AFE sheet would also contain: project description, summary and phasing of expenditure, partners shares and well cost breakdown. Details of the well will be attached to the AFE sheet as a form of technical justification.

There are several reasons for producing a well cost, including:

1. Budgetary control

2. Economics
3. Partners recharging
4. Shareholders

The AFE is then used as a document for partners recharging, paying contractors and an overall control on the well spending.

2.0 Factors Affecting Well Costs

Well costs for a single well depend on:

1. Geographical location: land or offshore, country
2. Type of well: exploration or development, HPHT or sour gas well
3. Drillability
4. Hole depth
5. Well target(s)
6. Profile (vertical/ horizontal /multilateral)
7. Subsurface problems
8. Rig costs: land rig, jack-up, semi-submersible or drillship and rating of rig
9. Completion type
10. Knowledge of the area: wildcat, exploration or development

The total well costs for a development drilling programme comprising several wells depend on:

- Rig rate
- Well numbers and well type
- Total hole depth
- Well layout and spacing

- Specifications of equipment
- Target tolerances
- Water depth for offshore wells

3.0 DRILLING TIME ESTIMATE

The time spent on a well consists of:

- Drilling times spent on making hole, including circulation, wiper trips and tripping, directional work, geological sidetrack and hole opening.
- Flat times spent on running and cementing casing, making up BOPS and wellheads.
- Testing and completion time.
- Formation evaluation time including coring, logging etc.
- Rig up and rig down of rig.
- Non-productive time, see "Non Productive Time (NPT)" on page 762 for details.

Before an AFE can be prepared, an accurate "estimate" of the time required to drill the well must be prepared. The time estimate should consider:

1. ROP in offset wells. From this the total drilling time for each section may be determined.
2. Flat times for running and cementing casing
3. Flat times for nippling up/down BOPs and nippling up wellheads
4. Circulation times.
5. BHA make up times.

The following example gives details of how a drilling time estimate is prepared.

Example 17.1: Calculation of time -depth curve

Assume the following well design for Well Pak-1:

36" Hole / 30" Conductor	50 m BRT (below rotary table)
26" Hole / 20" Casing	595 m BRT
17.5"Hole / 13.375" Casing	1421 m BRT
12.25" / 9.625" Casing	2334 m BRT
8.5" Hole / 7" Casing	3620 m BRT
Total Depth	3620 m BRT

From three offset wells, the following data was established for average ROP for each hole section:

36" Hole	5.5 m/hr
26" Hole	5.5 m/hr
17.5"Hole	7.9 m/hr
12.25"	4.6 m/hr
8.5" Hole	2.5 m/hr

The expected flat times for this well are shown in **Table 17.1**:

Calculate the total drilling time and plot the depth-time curve.

Table 17.1 Estimated flat times

Casing Size	Running & cementing (days)	NU (days)	Total (days)
26"	0.5	2	2.5
20"	1.0	1.5	2.5
13 3/8"	1.0	1.0	2.0
9 5/8"	1.0	1.0	2.0
7"	2.0	1.5	3.5
Total			12.5

Solution

1. We must first calculate the times required to drill each hole section using ROPs from offset data. At this stage it is advisable to use the best ROP values from offset well. This is because it is always possible to match or exceed previous performance if similar or better equipment is used. Indeed, some engineers may increase the possible ROP for the new well if it is known that high quality and up-to-date equipment may be used on the new well. Hence at this stage all drilling time estimates must not include allowance for down time. As will be seen later this is called the P10 time estimate.

Table 17.2 Calculations of planned drilling times

Hole Size	Metres To Drill A	Offset ROP (m/hr) B	Planned Hours A/B	Planned Drilling Days
26" x 36"	47	5.5	8.5	0.35
26"	545	5.5	99.1	4.13
17 1/2"	826	7.9	104.6	4.36
12 1/4"	913	4.6	198.5	8.27
8 1/2"	1286	2.5	514.4	21.43
			925.1	38.5

Using the given raw data, **Table 17.2** can be established for the planned drilling days:

Using the data from **Table 17.2** and the flat times from **Table 17.1**, **Table 17.3** can be constructed:

Table 17.3 Time-depth calculations

Operations Description	Depth MD m BRT	Days	
		Activity	Cum.
Rig up to drill		1.00	1.00
Drill 36" hole to 50m	50	0.35	1.35
Run / cmt 26" conductor / NU diverter		2.50	3.85
Drill 26" hole to 596m	596	4.13	7.98
Run / cmt 20" csg / NU wellhead		2.5	10.48
Drill 17.5"hole to 1422m	1422	4.36	14.84
Log hole		1.00	15.84
Run / cmt 13 3/8" csg / NU		2.0	17.84
Drill 12 1/4" hole to 2334m	2334	8.27	26.11
Log 12 1/4" hole		0.50	26.61
Run / cmt 9 5/8" csg / NU		2	28.61
Drill 8 1/2" hole to 3620m	3620	21.43	50.04
Log 8 1/2" hole (full open hole logging)		4.00	54.04
Run / cmt 7" liner , run CBL/VDL		3.5	57.54
Displace hole to completion fluids, prepare well for testing		1.5	59.04
Total Days			**59**

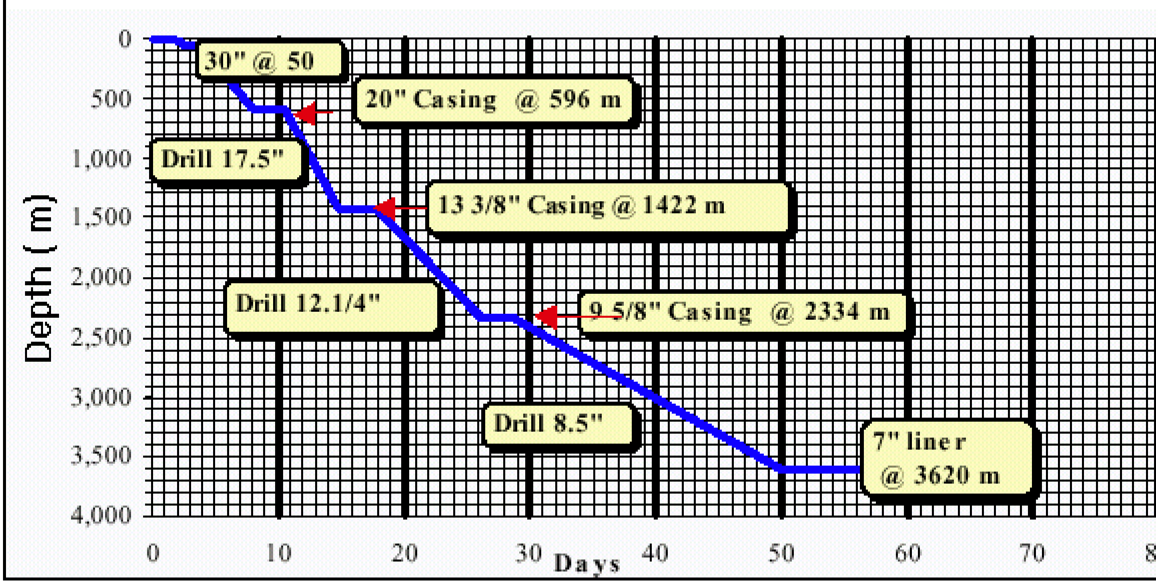
Using data from **Table 17.3**, a time-depth curve, **Figure 17.1** can be constructed. The graph shown is the planned time -depth curve. During drilling, actual drilling times are plotted on the same graph to compare actual performance against planned performance.

4.0 DETAILED TIME ESTIMATE

In the previous section, time estimates were based on major operations such as drilling a hole section where drilling time, tripping, circulating, making BHA etc. were lumped together.

Detailed time estimates can be prepared for each hole section by considering the individual operations involved. This exercise requires experience on part of the engineer and also detailed knowledge of previous drilling experience in the area. The expertise of the drilling contractor who will perform the drilling operation must also be considered. A new drilling crew will be on a learning curve, see **Table 17.4**.

Figure 17.1 Time-depth curve



5.0 ELEMENTS OF WELL COSTING

There are three main elements of the well cost. No matter what service or product is used, it will fall under one of the following three cost elements, namely:

1. Rig costs
2. Tangibles
3. Services

5.1 Rig Costs

As the name implies, rig costs refer to the cost of hiring the drilling rig and its associated equipment. This cost can be up to 70% of well cost, especially for semi-submersible rigs or drilling ships.

Rig cost depends entirely on the rig rate per day, usually expressed as $/day.

Rig rate depends on:

- Type of rig
- Market conditions
- Length of contract
- Days on well
- Mobilisation/ Demobilisation of rig and equipment
- Supervision
- Additional rig charges

Table 17.4 Detailed time estimate for 30” conductor

	OPERATION	HOURS	MD	CUM HOURS	CUM DAYS
1	Jack Up Transit	48.0	0.0	48.0	2.00
2	Jack up	6.0	0.0	54.0	2.25
3	Pre-Load	12.0	0.0	66.0	2.75
4	Skid Rig	6.0	0.0	72.0	3.00
5	Make Up 36" hole opener & 26" bit	4.0	0.0	76.0	3.17
6	Drill Mudstone at 90 ft/hr (340ft)	3.8	617.0	79.8	3.32
7	Pump 100 bbl pill/drop totco	1.0	617.0	80.8	3.37
8	POOH recover Totco	0.5	617.0	81.3	3.39
9	Rest Hole	1.0	617.0	82.3	3.43
10	RIH check for Fill	0.5	617.0	82.8	3.45
11	Circulate to Hi Vis Mud	1.0	617.0	83.8	3.49
12	POOH	1.0	617.0	84.8	3.53
13	Rig up to run 30" Conductor	3.0	617.0	87.8	3.66
14	Run 30" conductor	5.0	617.0	92.8	3.87
15	Run Cementing stinger	2.0	617.0	94.8	3.95
16	Circulate annulus clean	2.0	617.0	96.8	4.03
17	Pump cement	2.5	617.0	99.3	4.14
18	Rig down cementing stinger	1.0	617.0	100.3	4.18
19	Install riser support	3.0	617.0	103.3	4.30
20	Cut and dress 30" conductor	3.0	617.0	106.3	4.43
21	Install diverter	6.0	617.0	112.3	4.68
22	Make up 26" bit and BHA	4.0	617.0	116.3	4.84
23	Drill Quaternary & Mercia at 80 ft/hr (663ft)	8.3	1280.0	124.6	5.19
24	Pump 100 bbl pill/drop totco	1.0	1280.0	125.6	5.23
25	POOH recover Totco	1.0	1280.0	126.6	5.27
26	Rest Hole	1.0	1280.0	127.6	5.32
27	RIH check for Fill	1.0	1280.0	128.6	5.36
28	Circulate to Hi Vis Mud	1.0	1280.0	129.6	5.40
29	POOH	2.0	1280.0	131.6	5.48

30	R/U & run logs - BHC/GR	3.0	1280.0	134.6	5.61
30	Rig up to run 20" Conductor	3.0	1280.0	137.6	5.73
31	Run 20" conductor	7.0	1280.0	144.6	6.02
32	Run Cementing stinger	3.0	1280.0	147.6	6.15
33	Circulate annulus clean	2.0	1280.0	149.6	6.23
34	Pump cement	2.5	1280.0	152.1	6.34
35	POH & Rig down cementing stinger	1.0	1280.0	153.1	6.38
36	Open washports	2.0	1280.0	155.1	6.46
37	Flush Washports	1.0	1280.0	156.1	6.50
38	Close Washports	2.0	1280.0	158.1	6.59
39	Cut and dress 20" conductor 6" below 30"	3.0	1280.0	161.1	6.71
40	Run Gyro	5.0	1280.0	166.1	6.92
	Section Totals	166.1		166.1	6.92

5.2 TANGIBLES

Tangibles refer to the products used on the well. These include:

- Casing
- Tubing/completion equipment
- Wellhead/accessories
- Bits
- Coreheads
- Cement products
- Mud products
- Solids control consumables
- Fuel and lubes
- Other materials and supplies

Costing of tangibles should look at the individual elements making up that item.For example, the costing of casing should begin by selecting the appropriate casing seats (length of casing) and selecting the appropriate casing grades/weights (see **Chapter 5**) for each hole section.

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Then each casing string for each hole size should be costed and the total costs of all the casing strings are added to produce the total casing costs for the well in question.

The same method applies to each tangible item which requires design, selection and breaking into individual groups, e.g tubing/completion equipment, drillbits, coreheads and wellhead equipment.

Cementing and mud products should be costed for each hole section by calculating the quantities of mud or cement products and additives required, see **Chapter 6** and **Chapter 7** for details.

Table 17.5 gives details of these individual costs.

5.3 SERVICES

This group of costs refers to any service required on the well. Services include:

1. Communications

This refers to telephones, data transfer etc. A lump sum cost or cost per day is usually used.

2. Rig positioning

The cost required to position the rig. This is usually required in offshore operations. This is a one off cost.

3. Logging (wireline)

The cost of running and producing wireline logs, both open hole and cased hole logs.

4. MWD

This is the cost of renting and running MWD /LWD (measurement while drilling or logging while drilling).

5. Downhole Motors

The cost of using downhole motors during directional drilling or during drilling long sections of vertical wells.

6. Solids Control Equipment

This cost refers to the consumables required for solids control equipment and any special equipment the rig contractor does not normally provide.

7. Mud Engineering

This is the cost of the mud engineer and the services required to maintain the mud. This is not the cost of mud products which was explained earlier under tangibles.

8. Directional Engineering

This is the cost of the directional engineer, software and support required during directional drilling. In vertical wells, this service is usually not required.

9. Surveying

This is the cost of running surveys inside the hole to determine hole angle and azimuth. This usually includes the cost of single shots, magnetic multi-shots (MMS) and gyros plus the cost of the engineer and rental of the equipment to run the surveys.

10. Cementing

This is the cost of renting the cementing unit and the cement engineer.

11. Mud Logging

This is the cost of renting the mud logging unit and the engineers required to run the unit.

12. Fishing

This is an ad-hoc cost of renting fishing equipment and cost of engineers. It is only included if experience in the area dictates that fishing may be required in some parts of the hole and that fishing equipment must be available at the rig site to be used for such eventualities.

13. Downhole tools

Any tool required which is not supplied by the drilling contractor; including jars, shock subs etc.

14. Casing services

This refers to the equipment required to run the casing and cost of engineers. This cost element will always be included.

5.3.1 Total Cost of Services

Once again each of the above items should be costed for each individual hole section (if applicable) and a total cost is produced.

For example, under surveying and directional, the engineer can easily determine the requirements for each hole section (**Chapter 11**) and add the individual costs to obtain a total cost for surveying and directional work, if required.

Most of the above items require input from contractors who will supply these costs either during the bidding stage or as part of an ongoing contract.

For offshore wells there are other costs which must be included:

- Supply boats
- Stand-by boats
- Helicopters

6.0 Total Well Costs

Table 17.5 shows the detailed cost calculation for the land well Pak-1 given in **Example 17.1**. The table also gives details of miscellaneous well costs which were not discussed here but they are trivial in nature.

7.0 Non Productive Time (NPT)

The time required for any routine or abnormal operation which is carried out as a result of a failure is defined as Non Productive Time (NPT)

Waiting on weather or waiting on orders, people or equipment is not NPT. This is standby time.

Non-Productive Time (NPT) in drilling operations currently account for 20% of total drilling time. With the increasing pressures on drilling budgets and measures to improve performance, a slight reduction in NPT can result in substantial savings. An article in one major operator’s magazine reported that savings from reductions in NPT are enough to drill several wells for that operator alone.

Some operators include NPT time in the time estimate especially if known drilling problems are expected, e.g. formations causing stuck pipe. Hence the engineer must decide when studying the list below which item is applicable to his well. He must then decide whether to allow any down time for the item chosen or a certain percentage of the previously recorded down time. This subject will also be discussed under **“Risk Assessment In Drilling Cost Calculations” on page 764**.

7.1 Classification of NPT

1. **Rig equipment**

   (Down time due to: Mud pumps, generators, shakers, rotary table, top drive/Kelly, hoist, drilling line, gauges, compressors and anchors.

Note that within the rig contract a fixed time is allowed for rig repairs/ maintenance. The NPT rig time should be the time recorded above the agreed fixed repair time).

2. 2. Surface Equipment
3. 3. Downhole Equipment
4. 4. Drillstring Equipment
5. 5. Logging equipment
6. 6. Stuckpipe and Fishing of BHA equipment
7. 7. Casing Hardware and Cementing Equipment
8. 8. Fluids
9. 9. Hole problems
10. 10. Well Control
11. 11. Testing and Completion NPT

7.2 Calculation of NPT

In all of the above**,** the NPT is calculated as the time from when the problem occurred to the time when operations are back to prior to the problem occurring. The NPT time includes normal operations such as POH, RIH, circulating etc. It is as if these operations are not part of the drilling process and they are merely carried out to get us to where we were before the problem occurred.

Accurate calculation of NPT is essential if the operator attempts to improve future drilling operations. Understanding the reasons for the NPT is the starting point to reducing drilling time and saving money.

Details of the NPT should be recorded by the operator on a daily basis and should be checked against historical NPT in the area to obtain trends and then arrive at solutions.

8.0 Risk Assessment In Drilling Cost Calculations

The decision whether an individual well will be drilled will depend on the estimated cost of drilling the well. Hence it is essential that cost estimates are made realistic, as low as possible and produced in a consistent manner. These criteria are achieved through the application of risk assessment.

Well cost estimates are made up of two major elements:

- Time dependent costs
- Tangible costs

Time dependent costs are dependent entirely on the time required to drill the well, as each extra day either under or over the planned duration will impact costs. Rig costs and services are greatly impacted by the time estimate.

Tangible costs can be estimated at the budgetary stage (before a detailed well plan is made) or at the AFE stage after the detailed well plan is made. The risk involved in estimating tangibles is usually small.

Risk assessment is defined in terms of the probability of meeting a given target. There are three levels of risks:

1. P10
2. P50
3. P90

8.1 P10 Estimate

This is an estimate which has only a 10% chance of being achieved. This is a highly optimistic estimate which can only be achieved under exceptional circumstances. This level may represent the limit of technology or some stretched target that the company believes can be achieved.

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8.2 P50 Estimate

This is the key figure in most well cost estimates. As implied, there is a 50% chance that the well will be drilled for less than this figure and a 50% chance that it will cost more.

This estimate will be based on known information derived from offset data.

8.3 P90 Estimate

This is an estimate of well cost which is likely to be met 90% of the time and that well costs can not be exceeded except under exceptional cases. This estimate was widely used in the oil industry before accurate cost estimating was introduced in the early 1990's.

8.4 Estimating the P10 value

In terms of drilling operations, assume the time required to drill a given hole section is 5 days based on the average of several wells in a given area, excluding NPT. The 5 days include making up the BHA, tripping, circulating and drilling a given hole section. If one were to produce a new estimate for a new well, then the 5 days may be taken as the P50, as it is likely to be met at least 50% of the time.

The P10 for the above example is a little bit more difficult to determine. This is because if it is based on the best well in the area which say took 4 days, then all that implies is that all operations went according to plan (to the nearest minute) and the lithology encountered was homogeneous. However, this time may also be improved on if a better technology is used in drilling the new well.

As there is no exact method for estimating P10, it is now customary to base P10 value on the best possible performance on any operation on any well in the area. For example, if it took 10 hours to run and cement casing in well 1, but took longer on other wells, then the P10 value for running and cementing the casing is 10 hours. A similar logic applies to other operations, e.g. tripping, making up BHA, drilling a given section etc. Hence the total P10 value for a given section will be the best individual values from several wells for all operations required to drill, case and cement the given hole section.

Table 17.4 gives detailed time estimates for every individual operation on the 36” hole / 30“conductor based on the best times recorded in the area.

Because of the way the P10 value is derived, it is unlikely that this value can be met exactly more than 10% of the time. Indeed, some may argue that it is more difficult to produce a P10 value than a P50 value. After all, the P50 value is based on the most likely time to carry out a given operation which can be easily established.

8.5 ESTIMATION OF P50 VALUE

Assume that the approach for calculating well costs was based on first estimating the P10 value. The P50 value should then be derived from the assumed P10 value. This P50 probability of any event occurring should be derived from “engineering judgment” by the drilling engineer and is an estimate of the normal expected occurrence frequency for that event.

As an example, consider the top hole section in an offshore operation where 36” hole is drilled and 30” conductor is run and cemented. The following events may occur and increase drilling time:

Potential Problem	Time Implication	P50 of Problem Occurring	Result	Time Delay (result x prob) (days)
Boulder in 36” hole	Boulder double drilling time	10%	4 hrs rig time	0.02
Cement job on 30” conductor slump	Losses during cement job requiring two top jobs	40%	6 hours rig time	0.1
Problems rigging up diverter	This may happen on a new rig or with new crew	20%	6 hours rig time	0.05
Total				0.17 days

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Hence if the P10 time for drilling 36” hole, running and cementing 26” conductor is 1.5 days, then the P50 value is: 1.5 + 0.17 =1.67 days

The same logic can be applied to all hole sections citing all known hole and equipment problems and assigning probabilities to them.

The reader should not take this approach as a license to increasing drilling time but merely to obtain realistic drilling times. Indeed, the P50 estimate obtained should be close to the average drilling time in the area. The onus is on the engineers and crews to approach the P10 value and may even improve upon it. This can be achieved by innovation through improved well designs, modification of equipment or new practices such as **“Technical Limit Drilling” on page 768**.

8.6 Estimation of P90 Value

Applying the same approach as for the P50 value, the P90 for the 36” hole may be derived as follows:

Potential Problem	Time Implication	P90 of Problem Occurring	Result	Time Delay (result x prob) (days)
Boulder in 36” hole	Boulder double drilling time	30%	4 hrs rig time	0.05
Cement job on 30” conductor slump	Losses during cement job requiring two top jobs	50%	6 hours rig time	0.13
Problems rigging up diverter	This my happen on a new rig or with new crew	40%	6 hours rig time	0.1
Total				0.28 days

The P90 value is the P10 value plus 0.28 days, i.e. 1.78 days.

It is recommended that for each area, a list of potential problems is complied and probabilities of problems occurring are established to help in future cost estimates.

The reader should note that drilling operation follow a **learning curve** where the first well typically takes longer than the average well and the last few wells take less time than the average.

9.0 Technical Limit Drilling

Technical Limit Drilling (TLD) is defined as follows:

A theoretical limit representing a stretched target of what is theoretically possible in a perfect world where both ideal and optimised drilling conditions [3].

The difference between historical performance and TLD represents an opportunity to reduce costs [3].

Traditionally, planning time for well engineering has been very small in comparison with other industries as shown below:

Planning Time Comparison [3]

1.Construction industry spends up to 15% of its budget on up front planning

2.Drilling industry spends less than 5% on well engineering

TLD requires very detailed planning of every aspect of the drilling operation and this usually requires every process to be broken down into its smallest possible constituent and the time for each constituent to be established.

9.1 Basis of TLD

TLD requires detailed numerical answers to the following questions:

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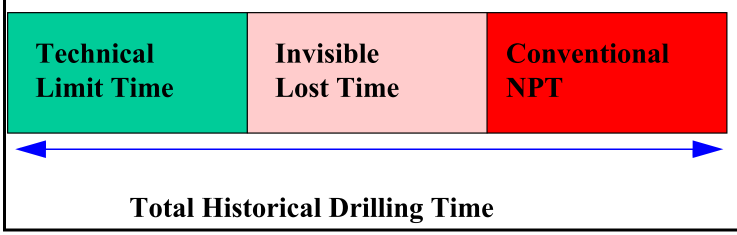
1.What is the current performance? This gives the normal average

2.What is possible? This gives the theoretical limit

3.What is needed to get there? This determines the resource investment to achieve TLD.

Figure 17.2



TLD requires that drilling estimates are made without the inclusion of invisible lost time or non-productive time, **Figure 17.2**. Non productive time was discussed in detail in “Non Productive Time (NPT)” on page 762

Invisible Lost Time: This time is usually absorbed in productive time and is made up of the total of previously acceptable wasteful events such as [3]:

1. Use of sub-optimal equipment

2. Lack of personnel

3. Application of sub-optimal operations and procedures

Examples of invisible lost time [3]:

1. Bit trips before reaching TD

2. Wiper trips

3. Check trips

4. Mud conditioning

5. Double checking directional motors and MWD tools

As an example of what can be achieved using the technical limit and unlimited number of experts, consider the process of changing the car's tyres:

1. A team of Formula One can change 4 tyres in 6 seconds

2. It takes a garage mechanic 2- 5 minutes to change one tyre

3. It takes an ordinary driver 5-15 minutes to change one tyre

In summary, time estimates for TLD are meant to use the limits of current technology with no restriction on equipment or personnel. Clearly, TLD can only be applied by a very few companies that have very large resources.In the author's opinion, most companies would opt to calculating the P10 value using the best performance from offset wells.

10.0 COST REDUCTION

The objective of all E&P companies is to drill and produce wells in the least possible time, consistent with safe operations. In the oil industry, time really means money. The longer an operation takes, the more it will cost. This is because as you spend more time say on drilling operations, the company will be paying more money for equipment and people which will make the operation more expensive. Also any delay to drilling operations will mean a delay to actual production. If there is no production, there is no income and the company is not making money.

There are two elements of costs which must be controlled:

1. **Capital Expenditure (Capex)**: This includes the cost of finding and developing an oil/gas field. The cost of drilling operations is the major cost element and must be kept to an acceptable value.

2. **Operating Cost (OPEX)**: This includes the actual cost of production: cost of maintaining the platform, wells, pipelines etc. We will not be concerned with these costs as they are part of production operations.

E&P companies aim to reduce time to develop fields in order to reduce CAPEX and OPEX. At the time of writing this book, there are several ways of judging a minimum price per barrel of oil. In the North Sea, it is accepted that the principle of 1/3/3 results in a profitable operation. The 1/3/3 stands for: $1 for finding, $3 for developing and $3 for production. This gives a combined cost of $7 per barrel. In the Middle East, this combined cost can be as low as $2 for some giant fields.

In general the more remote the area the more expensive is the final cost of barrel of oil. This is particularly true for deep waters in hostile environments.

The following is a list of measures to reduce costs:

1. Technical innovation
2. Productivity improvement: e.g. faster drilling operations
3. Increased operational effectiveness
4. Incentive contracts (sharing gains and pains)
5. Less people

Cost reduction is a wide subject and is beyond the scope of this book. We will only concentrate on the most important aspects relating to drilling operations, namely, drilling contracting strategies.

11.0 Drilling Contracting Strategies

There are basically four types of contracts which are currently used in the oil industry:

1. Conventional
2. Integrated Services (IS)
3. Integrated Project Management (IPM)
4. Turn Key

The type of drilling contract used can mean the difference between an efficient and a less efficient operation. The operator must weigh all the relevant factors before opting to one of the above strategies. Indeed, going for one type, say turn key, can mean that the operator has no control over the operation whatsoever and has no means of building knowledge for future operations.

11.1 Conventional Contract

In this type of contract, the E&P company does every thing using its own staff or contractors. This is the most involved type of contract and can mean handling up to 100 contracts per well.

In this contract, the operator has total control over the operation and carries full risk. The contractor has no risk and it could be argued that the contractor has no incentive in speeding up the operation.

This type of contract has the advantage that lessons learnt during drilling operations are kept within the company and used to improve future operations. Nowadays, only large operators opt for this type of contract.

A variation of the above contract is to include an incentive clause for completing operations early or if a certain depth is reached within an agreed time scale. The contractor will be paid a certain percentage of the savings made if operations are completed ahead of the planned agreed drilling time.

11.2 Integrated Services (IS)

In this type of contract, major services are integrated under two or three main contracts. These contracts are then given to lead contractors who, in turn, would subcontract all or parts of the contract to other subcontractor. The lead contractor hold total responsibility for his contract and is free to choose its subcontractors.

The operator still holds major contracts such as rig, wellheads and casing. Also the operator appoints one of its staff to act as a coordinator for the drilling operation.

11.3 Integrated Project Management (IPM)

In this type of contract, a main contractor is chosen. This contractor is the Integrated Project Management (IPM) contractor. The contractor is responsible for 20-30 service companies. Service companies may be responsible for other service companies.

The drilling operation will be controlled by a representative from the IPM contractor.

The operator may hold one or two major contracts.

There is also a built-in incentive in the contract between the IPM contractor and the operator. This is either based on the time-depth curve, safety or other criteria. An incentive contract based on beating the time curve is the most common one. In this type, an agreed time-depth curve is first established. If the IPM contractor beats this time curve, then he is eligible for all or a percentage of the savings.

In the author's experience, this type is one of the worst kind of contracts for the operator because:

- There is virtually no learning for the operator. Lessons learnt are lost as the IPM contractor traditionally has a large staff turnover. Electronic means of gathering information and building knowledge bases are alleviating this problem. However, there is no substitute for hands on experience of drilling problems and passing this knowledge to new staff and trainees.
- The incentive contract is built on a time-depth curve developed and based on the contractor's experience. Use of better equipment and personnel may beat the IPM contractor's time-curve.
- Experience in drilling HPHT wells in the North Sea has shown that an operator can beat the P10 curve developed by any contractor. Incentives are usually given to contractors when beating the P50 time -depth curve, which has a less stringent time estimate.

11.4 Turn Key Contract

This is the easiest of all the above contracts. The operator chooses a contractor. The contractors submits a lump sum for drilling a well: from spud to finish with operator virtually not involved. The contractor carries all risks if the well comes behind time and also gains all benefits if he should drill the well faster.

Contractors only opt for this type of contract if they know the area extremely well or during times of reduced activities. The operator opts for this type of contract if he has a limited budget or has no knowledge of drilling in the area.

11.5 Current And Future Trends In Drilling Contracts

There are two new development in drilling and production contracts:

- Production Sharing Agreement
- Capital Return Agreement Plus Agreed Production

These new types of contracts were initially initiated in some Middle Eastern countries attempting to draw western investment. These contracts are still developing in nature and have now been used by a number of third world countries.

A Production Sharing Agreement stipulates that the contractor will be paid a certain percentage of the produced fluids (oil or gas) in return for the services of the contractor in drilling and producing the wells. The agreement may be time-dependent running for a fixed number of years or may include an initial payment for the contractor in addition to a percentage of the production.

A Capital Return Agreement Plus Agreed Production stipulates that the contractor will develop a field using his own finance. In return, the operator (or national oil company) will pay the contractor all his capital expenditure plus an agreed percentage of the production. In Iran where this type of contract is used, the agreed production is limited to a fixed number of years. The ownership of the field and its facilities always remain with the operator.

Table 17.5 AFE For Well Pak-1 Based On P50 Estimate

Cost Code	Description	Comments	Lump Sum	Unit Cost	Qty	Days	Sub Totals	Totals
	SITE COSTS							
110	Site Planning Survey		10,000				10,000	
	sub total						10,000	
120	Site Construction	Road Construction					0	
		Site Construction	1,816,079				1,816,079	
		Airstrip Construction					0	
		Waterline Construction					0	
		Constr'n Equip Mob					0	
		Constr'n Equip Demob					0	
		Road Maintenance					0	
		Water Well					0	
		Water Pump					0	
	sub total						1,816,079	
130	Site Reinstatement		15,000				15,000	
	sub total						15,000	1,841,079
	RIG COSTS							
201	Rig Operating Day rate			14,500		59.00	855,500	
	sub total						855,500	
220	Rig Mob / Demob		690,000				690,000	
	sub total						690,000	
230	Additional Rig Charges		94,027				94,027	
	sub total						94,027	
240	Supervision			1,931		59	113,904	
	sub total						113,904	1,753,431
	TANGIBLES							
201	Casing		561,189				561,189	
	sub total						561,189	

211	Wellhead & Accessories		84,775				84,775	
	sub total						84,775	
221	Other Tangibles		25,000				25,000	
	sub total						25,000	670,964
	MATERIALS/SUPPLIES							
301	Rock Bits		218,428				218,428	
	sub total						218,428	
305	Coreheads / Spares						0	
	sub total						0	
310	Diamond / PDC bits		46,250				46,250	
	sub total						46,250	
315	Mud Products		350,000				350,000	
	sub total						350,000	
320	Cement Products		155,000				155,000	
	sub total						155,000	
325	Solids Ctrl. Consumables		25,000				25,000	
	sub total						25,000	
330	Other Materials / Supplies		35,000				35,000	
	sub total						35,000	
335	Fuel & Lubes		180,000				180,000	
	sub total						180,000	1,009,678
	TRANSPORTATION							
410	Supply & standby boats	N/A					0	
	sub total						0	
420	Air Support	General	48,447				48,447	
	sub total						48,447	
440	Shipping/Freight/Customs	General	181,474				181,474	
	sub total						181,474	
450	Equipment Transport	Loads	300,000				300,000	
	sub total						300,000	529,921

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	SERVICES							
501	Radio / Comms. Services	General		1,104		59	65,130	
	sub total						65,130	
503	Rig Positioning						0	
	sub total						0	
506	Diving (ROV)						0	
	sub total						0	
509	Logging (wireline)		302,027				302,027	
	sub total						302,027	
512	M.W.D.		10,884				10,884	
	sub total						10,884	
515	Downhole Motors		81,519				81,519	
	Personnel						0	
	sub total						81,519	
518	Solids Control Equipment		46406				46,406	
	sub total						46,406	
521	Fishing		10,000				10,000	
	sub total						10,000	
524	Mud Logging						0	
		Unit & Personnel		1,610		59	95,013	
							0	
							0	
	sub total						95,013	
527	Mud Engineering			1,371		50	68,567	
	sub total						68,567	
530	Cementing		75,645			59	75,645	
	sub total						75,645	
533	Jars & Shock Subs		30,000			59	30,000	
	sub total						30,000	
536	Downhole tools		65,000				65,000	
	sub total						65,000	
539	Directional Engineer-ing						0	
	sub total						0	

542	Directional Navig'n Tools						0	
	sub total						0	
545	Surveying (inc. Personnel)		23,525				23,525	
	sub total						23,525	
548	Casing Services (inc. Pers'l)		47,638				47,638	
	sub total						47,638	
551	Other Equipment Rental	Miscellaneous Rentals	6,192				6,192	
	sub total						6,192	
554	Other Services		720,000				720,000	
	sub total						720,000	1,647,546
	BASE EXPENSES							
620	Crane Hire			415		59	0	
	sub total						0	
641	Local Labour / Land Lease			130		59	7,662	
	sub total						7,662	
642	Dockers	not applicable					0	
	sub total						0	
661	Base Run. Costs & Maint.			1,373		59	80,994	
	sub total						80,994	
662	Security			1,786		59	105,389	
	sub total						105,389	
663	Storage & Warehouse						0	
	sub total						0	
664	Base Equipment & Repairs						0	
	sub total						0	
665	General Base Expenses						0	
	sub total						0	194,045
	O/HEADS (DRILLING)							

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652	Office Costs	Drilling Management	20,000				20,000	
	sub total						20,000	20,000
	O/HEADS (PET'L. ENG.)							
642	Petroleum Engineer.	Well Test Planning	10,000				10,000	
	sub total						10,000	10,000
	GEOLOGICAL SERV'S							
301	Wellsite Geology			845		59	49,848	
	sub total						49,848	
302	Core Handling	not applicable					0	
	sub total						0	
303	Core Analysis	not applicable					0	
	sub total						0	
335	Geochemistry		10,000				10,000	
	sub total						10,000	
336	Biostratigraphic Analysis		8,000				8,000	
	sub total						8,000	
337	Sedimentology		0				0	
	sub total						0	
501	Data Transmission			87		59	5,146	
	sub total						5,146	
610	Geology Dept. Overheads			1,557		59	91,848	
	sub total						91,848	164,842
TOTAL WELL COST ESTIMATE							USD 7,841,505	

12.0 LEARNING MILESTONES

In this chapter, you should have learnt to:

1. List factors affecting well costs
2. Estimate drilling time

3. List elements of well costing
4. Calculate well costs
5. Understand Non Productive Time (NPT)
6. Understand risked well cost estimates
7. Understand Technical Limit Drilling
8. Understand Drilling Contracting Strategies

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