MAJOR PROJECT REPORT

ON

DETECTION OF DRILL STRING FAILURE & CEMENTATION OF PRODUCTION LINER IN DIRECTIONAL WELL

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DETECTION OF DRILL STRING FAILURE & CEMENTATION OF PRODUCTION LINER IN A DIRECTIONAL WELL

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

Bachelor of Technology (Applied Petroleum Engineering)

By

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CERTIFICATE

This is to certify that the work contained in this thesis titled "Detection of drill string failure and Cementation of production liner in a directional well" has been successfully carried out by Ms Reshma Raman and Mr Manmohan Singh Negi, students of B. Tech Applied Petroleum Engineering- final year under my mentorship and has not been submitted elsewhere for a degree.

Arun S Chandel

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We are privileged to extend our sincere thanks to all the faculty members and library section of UPES.

We also thank all those who directly or indirectly contributed towards the completion of this report.

ABSTRACT

Drill string failure is due to a lot of reasons, which may occur either individually or in-group. In order to prevent or at least minimize occurring drill string failure, all reasons should be recognized. Drillstem failures, even such routine failures as drill pipe washouts, can contribute significantly to the cost to drill today's wells. The project report includes determination of maximum permissible dogleg severity, maximum bending stress, neutral point of tension and compression, determination of critical buckling force and torque and drag analysis.

Cementing is a technique for placing cement slurries in the annular space between the casing and the boreholes. The cement then hardens to form a hydraulic seal in the wellbore, preventing the migration of formation fluids in the annulus. Cementing is therefore one of the most critical stages during the drilling and completion of a well. This procedure must be carefully planned and executed, because there is only one chance to complete the job successfully. The project deals with determination of number of sacks of cement required, volume of mix water required, water requirement and the slurry yield for the cementation process of production liner in a directional well.

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ABBREVATIONS

BHA- Bottom Hole Assembly

BF- Buoyancy Factor

CW- Collar weight

MOP- Margin of Overpull

SF- Safety Factor

SH- Hoop Stress

ST- Tensile Stress

Y-Slip taper

E- Youngs Modulus

WOB- Weight on Bit

K- Maximum permissible dogleg severity

P- Density of fluid

Ph- Hydrostatic pressure

CHAPTER I

INTRODUCTION

AIM:

1. Study the drill string failures occur in directional well.
2. Detect the drill string failures in a directional well of S-profile.
3. Study the cementation of production liner in a directional well.
4. Cementation of production liner calculations in a directional well

SCOPE:

1. INCLUSIONS: Understanding the drill string failures occurred in a directional well and cementation of production liner in a directional well. The various factors that an engineer must recognize in planning and engineering of the well are discussed. Case study with different parameters has been dealt with.

2. EXCLUSIONS: Selection of materials for cementing of production liner.

METHODOLOGY:

Initially the literature related to drill string failure and cementation of production liner of a directional well was gathered. This is included in CHAPTER II of the report. This information was studied and the problems related to drill string failure in directional well was understood. Case studies were studied to understand the problems in the field. The technical case study was solved and the results are presented in CHAPTER VI. A clear understanding of the thesis was developed.

CHAPTER – II: LITRATURE REVIEW

PART – 1

DRILL STRING FAILURE

INTRODUCTION

Drill string is an important part of rotary drilling. It is the connection between the drilling rig and the bit. The drill string is often a source of problems like twist-offs, wash-out and collapse failures. So, it is designed to prevent these problems from occurring.

Purposes and components:-

The drill string serves several purposes, including:-

- Providing a fluid conduit from rig to the drill bit
- Impart rotary motion to the bit
- Allow weight to be set on the bit
- Lower and raise the bit in the drilling well

The drill string also serves for following services:-

- Provide some stability to the bottom hole assembly to minimize vibrations and bit jumping
- Allow formation fluid and pressure testing through the drill string
- Permit through-pipe formation evaluation when logging tool cannot be run in the open hole

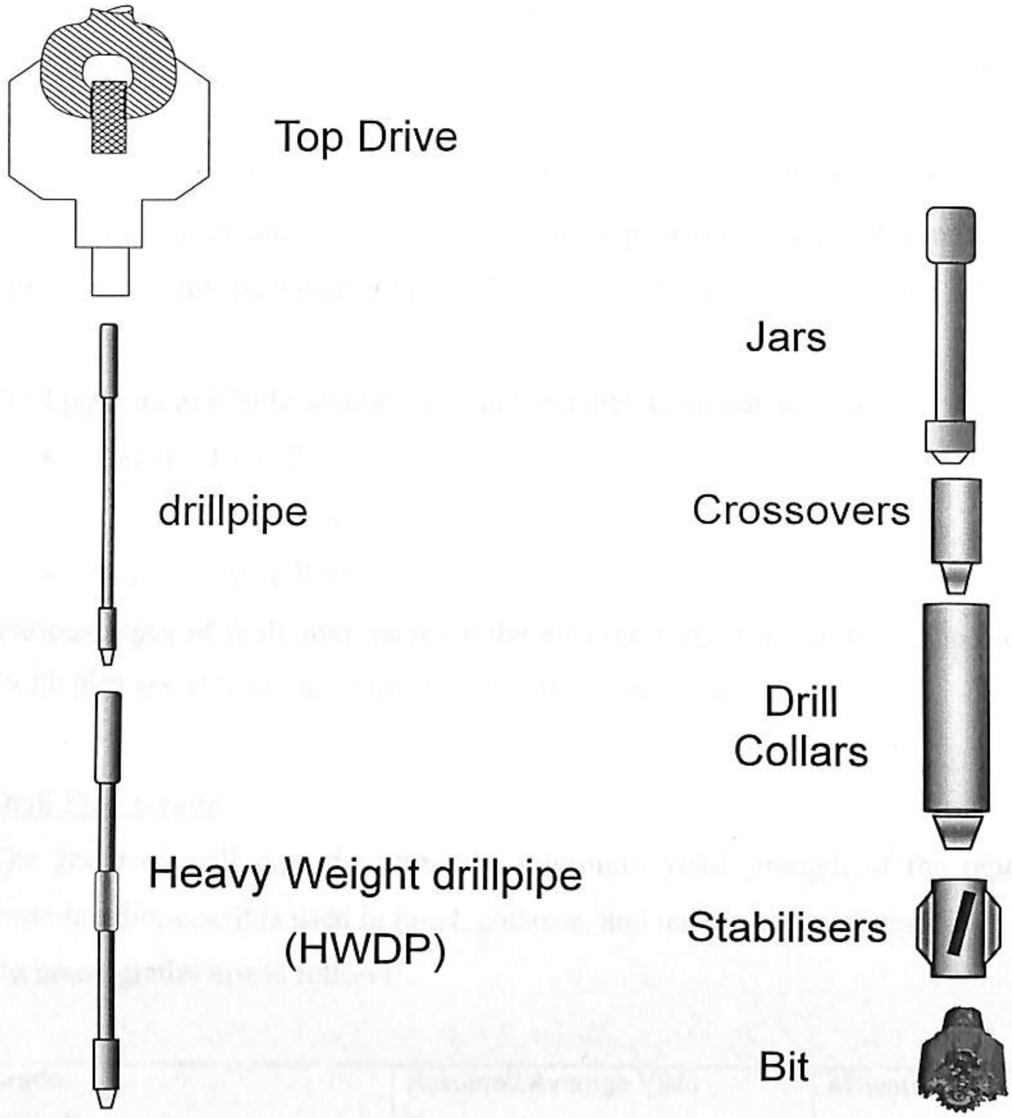
The components of drill string are varied and serve many purposes. Figure 1, shows a drill string assembly. It is important to observe that all connection from top drive to the bit in the figure.

The drill string consists of drill pipes and bottom-hole assembly (BHA). The drill pipe section consists conventional drill pipes, heavy weight drill pipe and occasionally a reamer.

The BHA contains the following:-

- Drill collars
- Stabilizers
- Jars
- Reamers
- Shock subs
- Bit, bit subs

Figure 1:



Drill pipe:

The longest section of the drill string is the drill pipe. The BHA is usually no longer than 1000 ft. Each joint of drill pipe includes tube body and the tool joint, which connects the sections of drill pipe.

Drill pipe is listed under three different weight titles. These are nominal weight, plain end weight and approximate weight.

Nominal Weight

Drill pipe is purchased and referred to by its nominal weight. The nominal weight is the pipes "given name" and refers to the wall thickness of the pipe it does not refer to its actual weight.

Plain End Weight

Plain end weight is the weight per foot of a non-upset, non-threaded and non tool-jointed piece of pipe.

Approximate Weight

This is the average weight per foot of a joint of complete drill pipe. It includes the non-upset section, the upsets and both tool joints. The approximate weight depends upon the size and type of tool joints on a piece of pipe. This is the value used in hook load calculations.

Drill pipe are available several sizes and weights. Common sizes are

- 31/2in – 13.30 lb/ft
- 41/2in – 16.60 lb/ft
- 5 in – 19.50 lb/ft

Various types of tools may increase the average weight per foot for the pipe eg: 16.60 are 18.60 lb/ft for 41/2 in pipe. However it still termed as16.60 lb/ft.

Drill Pipe Grade

The grade of drill pipe describes the minimum yield strength of the pipe. This value is important because it is used in burst, collapse, and tension calculations.

Common grades are as follows:

Grade Letter Designation	Assumed Average Yield Strength (psi) (*used for collapse*)	Minimum Yield Strength (psi)
D-55	65,000	55,000
E-75	85,000	75,000
X-95	110,000	95,000
G-105	120,000	105,000
S-135	145,000	135,000

Drill Pipe Class

Drill pipe is unlike most other oil-field tubular such as casing and tubing, because it is used in a worn condition. Casing and tubing are usually installed in a well. As a result, "classes" are given to drill pipe on account for wear. Therefore, drill pipe must be defined according to its nominal weight, grade, and class. The API has established guidelines for pipe classes in API Recommended Practice 7G.

They are summarized as:

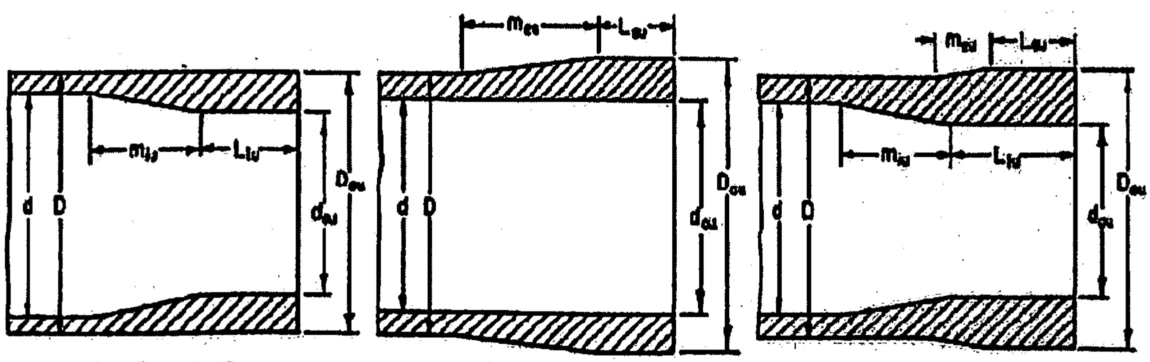
- **New** - No wear and has never been used.
- **Premium** - Uniform wear and minimum wall thickness of 80%.
- **Class 2** - Allows drill pipe with a minimum wall thickness of 65% with all wear on one side so long as the cross-sectional area is the same as premium class; that is to say, based on not more than 20% uniform wall reduction.
- **Class 3** - Allows drill pipe with a minimum wall thickness of 55% with all wear on one side.

Tool Joints

Tool joints are screw-type connectors that join individual joints of drill pipe.

- **IEU (Internal-External Upset)** Tool joint is larger than the pipe such that the tool joint ID is less than the drill pipe. The tool joint OD is larger than the drill pipe. Generally IEU connections are the strongest available couplings.
- **IF (internal flush)** Tool joints ID is approximately the same as the pipe. The OD is upset.
- **IU (internal upset)** Tool joint ID is less than the pipe. Tool joint OD is approximately the same as the pipe. This type is often termed "slim-hole" pipe because of the reduced outer clearance.

FIGURE 2



Heavy Weight Drill Pipe

The use of heavyweight drill pipe in drilling industry has become widely acceptable. The pipe is available in conventional drill pipe outer diameter. However its increased wall thickness gives weight 2-3 times greater than regular drill pipes.

Table shows weight of a common heavy weight drill pipe:

OD, in	ID, in	Weight, lb/ft
$3^1/_2$	$2^1/_{16}$	26
4	$2^9/_{16}$	28
$4^1/_2$	$2^3/_4$	42
5	3	50

Heavyweight drill pipe provides three major benefits to the users:

1. Reduces drilling cost by virtually eliminated drillpipe failure in the transition zone (that selection of pipe immediately above drill pipe collars)

2. Significantly increases performances and depth capabilities of small rigs in shallow drilling areas through the easy of handling and the replacement of some of the drill collars.

3. Provides substantial savings in directional drilling cost by replacing the largest past of the drill-collar string, reducing down hole drilling torque and decreasing tendency to change direction.

Drill collars

Drill collars are the predominant components of the bottom-hole assembly. Some of the functions of the drill collars are:

- Provide weight for the bit
- Provide strength needed to run in compression
- Minimize bit stability problems from vibrations, wobbling and jumping
- Minimize directional control problems by providing stiffness to the BHA

Proper selection of drill collars (BHA) can prevent many drilling problems. Drill collars are available in many sizes and shapes, as round, square, triangular, and spiral grooved. The most common types are round (slick) and spiral grooved. Spiral-grooved collars reduce the surface contact area between the drill pipe and well bore. The lower contact area reduces the probability of differential pressure sticking.

Table shows the API dimensions for collars of various outer diameters:-

Drill Collar Number	OD, in	Bore + 1/16 -0, in.
NC23-31 (tentative)	3 1/8	1 1/4
NC26-35 (2 3/8 IF)	3 ½	1 ½
NC31-41 (2 7/8 IF)	4 1/8	2
NC35-47	4 ¾	2
NC38-50 (3 1/2 IF)	5	2 ¼
NC44-60	6	2 ¼
NC44-60	6	2 13/26
NC44-62	6 ¼	2 ¼
NC46-62 (4IF)	6 ¼	2 13/16
NC46-65 (4IF)	6 ½	2 ¼
NC46-65 (4IF)	6 ½	2 13/16
NC46-67 (4IF)	6 ¾	2 ¼
NC50-70 (4 ½ IF)	7	2 ¼
NC50-70 (4 ½ IF)	7	2 13/16
NC50-72 (4 ½ IF)	7 ¼	2 13/16
NC56-77	7 ¾	2 13/16
NC56-80	8	2 13/16
6 5/8 REG	8 ¼	2 13/16
NC61-90	9	2 13/16
7 5/8 REG 3	9 ½	3
NC70-97	9 ¾	3
NC70-100	10	3
NC77-110 (tentative)	11	3

Stabilization:

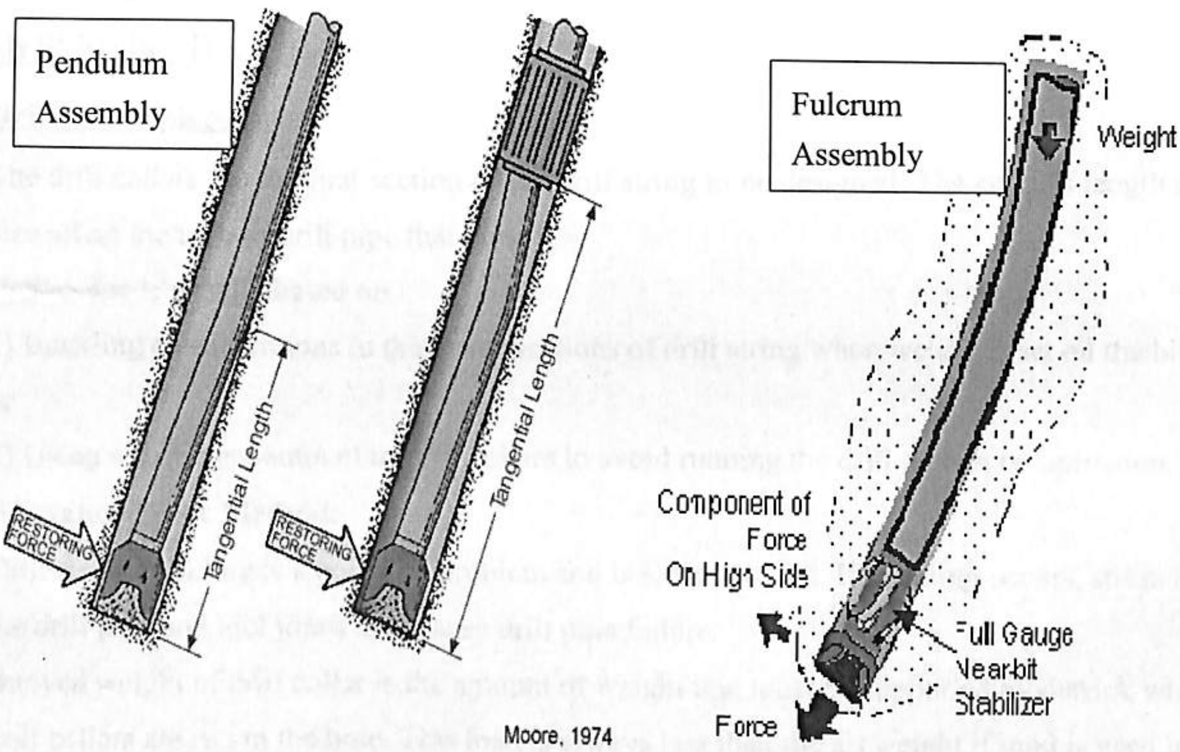
Drilling straight or directional holes requires proper positioning of stabilizers in the BHA. Although it seems contradictory that drilling straight and directional holes would require same principles, to control the direction of the bit. Stabilizers are used to achieve this goal. The common assembly arrangements are:- Pendulum, Fulcrum and Packed hole assembly.

Pendulum Assembly:

The pendulum technique 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 drill collars between the drill bit and the first point of tangency between the drill collar and hole. This length is called the active length of drill collars 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 drill collars 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 3



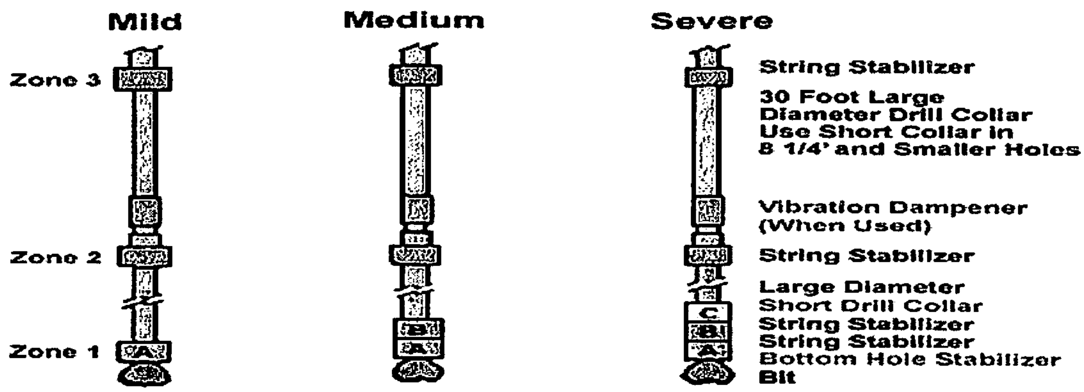
Fulcrum Assembly:

This is used to build angle (increase hole inclination) by utilizing a near bit stabilizer to act as a pivot or a fulcrum of a lever. The lever is the length of the drill collars from their point of contact with the low side of the hole and top of the stabilizer. The drill bit is pressed to the high side of the hole causing angle to be built as drilling ahead progresses. Since the drill collars bend more as more WOB is applied, the rate of angle build will also increase with WOB.

Packed Hole Assembly

In this case, the assembly employs large diameter drill collars and multiple stabilizers to provide added stiffness to the bottom hole assembly and thus reduce deviation tendencies. Designing such an assembly requires a good knowledge of local drilling characteristics.

FIGURE 4



Drill String Design:

Drill collar selection:

The drill collars are the first section of the drill string to be designed. The collar's length and size affect the type of drill pipe that must be.

Drill collar is usually based on

1) Buckling considerations in the lower sections of drill string when weight is set on the bit or

2) Using a sufficient amount of drill collars to avoid running the drill pipe in compression.

Buoyancy Force Method:

Drill string buckling is a potential problem and is to be avoided. If buckling occurs, stress in the drill pipe and tool joints will cause drill pipe failure.

Buoyed weight of drill collar is the amount of weight that must be supported by derrick when drill collars are run in the hole. This load is always less than the air weight if mud is used in the well.

Buoyancy factor $BF = 1 - {\rho mud}/{\rho steel}$

$$BF=1-\frac{MW}{65.5}$$

MW= mud weight, lb/gal

65.5= weight of a gallon of steel, lb/gal

The available bit weight (ABW) with the buoyancy factor method is the buoyed weight of the drill collar (BHA) in the mud to be used.

ABW= (in-air collar weight) × (buoyancy factor)

The required collar length to achieve an arbitrary ABW can be calculated as:

$$\frac{ABW}{(BF) \times (CW)} = \text{length}$$

Where:

ABW = Available bit weight, lb

BF = buoyancy factor, dimensionless

CW =Collar weight (in-air), lb/ft

Length= required collar length, ft, to achieve the ABW.

Drill pipe section:

The controlling criteria for drill string are collapse, tension, slip crushing and dog-leg severity. Collapse and tension are used to select drill pipe weight, grades and couplings. Slip crushing affects the tension design and pipe selection. A dogleg severity analysis is performed to study the fatigue damage resulting from rotating in the dogleg angle change.

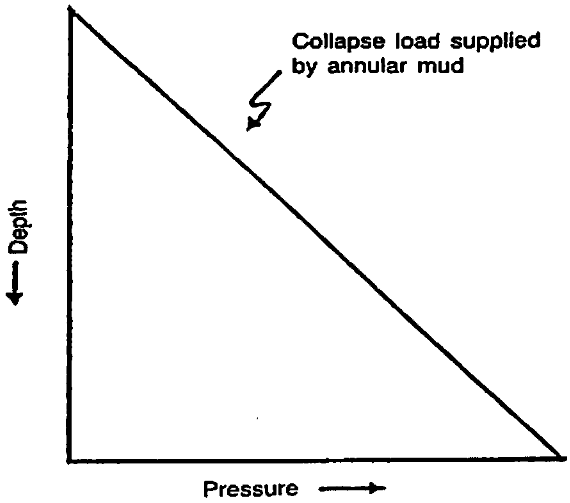
Collapse:

Drill pipe is used for several purposes, including providing a fluid conduit for pumping drilling mud, imparting rotary motion to the drill bit and conducting special operations such as drill stem testing and squeeze cementing. Drill stem testing (DST) causes the most severe collapse loading on the drill pipe. Since the DST is a commonly used operation, it will be used to control the collapse design.

The most severe collapse loading occurs when the evacuated (or partially empty) drill string reaches the bottom of the well. The load from the annular mud tends to cause pipe collapse. The fluid resisting collapse, the backup fluid, is essentially the weight of air and is considered negligible. The resultant loading i=on drill pipe, which is the difference between the load line and the backup fluid, is the load line when no backup fluid is present.

Although the design approach is based on drill string testing, it accounts for other common drilling conditions. Failure to fill the drill pipe when running into the well with a float valve in the drill string will give the loading seen in fig.

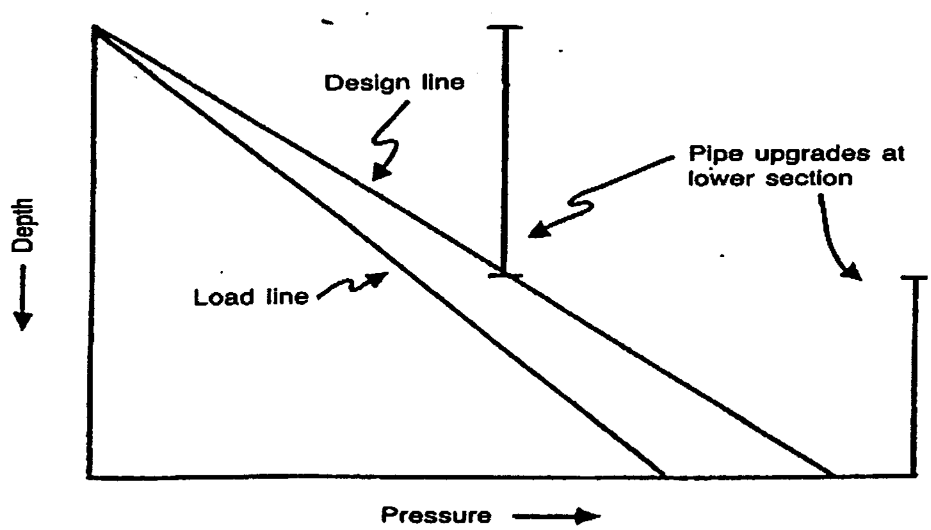
FIGURE 5



A design factor is usually added to the load line to obtain a design line from which to select pipe weights and grades. Casing and tubing design problems use design factor of 1-1.15 for collapse since the pipe is new and generally inspected at mill or site.

For drillpipe, design factor of 1.3 is taken. The design line, which is the load line with an applied design factor, can be seen in fig.

FIGURE 6



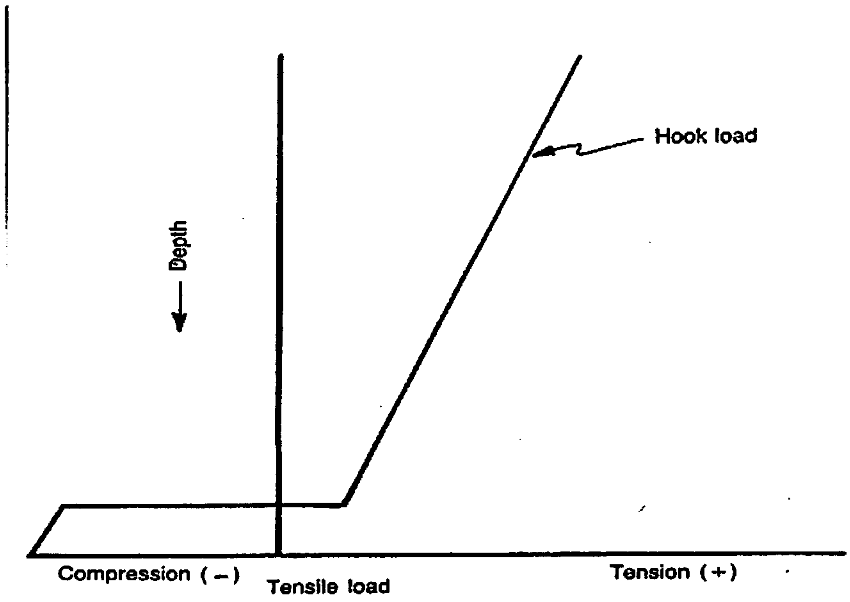
At this point, the collapse design line is established. The collapse pressures are known at every point in the well. The next step is to select drill pipe that satisfy the pressure requirements. The operator usually restricts the available choices of pipe by 1) Using Class1 or premium pipe only, 2) restricting the pipe weight, 3) establishing minimum acceptable section lengths of common pipe types and 4) using minimum grades.

Tension:

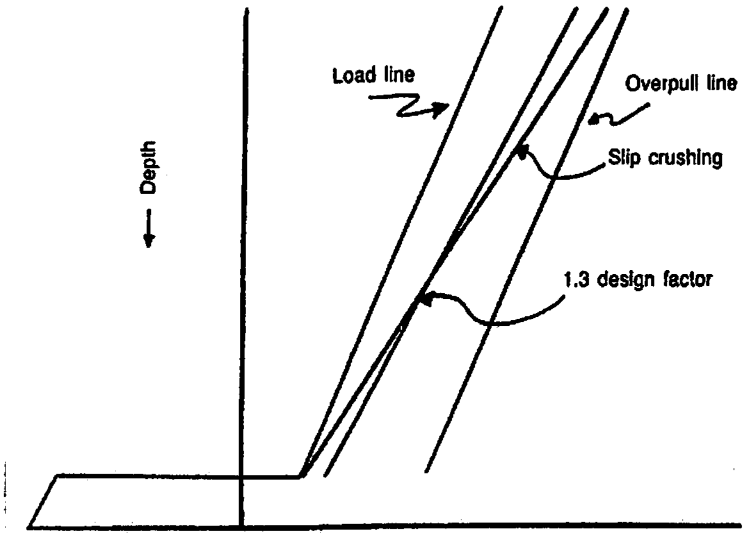
The tension load can be evaluated after the weights, grades and section lengths have been established from the collapse designs. Buoyancy is included in the tension evaluation due to the manner in which biaxial stresses alter the collapse properties of the pipe. Since drill string is designed with a maximum load concept, it is important that buoyancy be included in the design.

A typical tension load is shown in fig.

FIGURE 7



The tension design line is established as the maximum load resulting from applying three design consideration including overpull, design factors, and slips crushing. Each consideration is applied to the load line. The design line is selected as the worst case from the three design loads Fig FIGURE 8



FTEN =[(Ldp x WTdp) (Ldc x WTdc)] BF

where

FTEN= submerged load hanging below this section of drill pipe, lb

Ldp= length of drill pipe, ft

Ldc= length of drill collars, ft

WTdp= air weight of drill pipe, lb / ft

WTdc= air weight of drill collars, lb / ft

BF= buoyancy factor

The tensile strength can be calculated from the equation

Fyield = Ym ×A

where

Fyield= minimum tensile strength, lb

Ym= specified minimum yield strength, psi

A= cross section area, sq. in.

Margin of overpull:

A minimum over pull factor is applied to the tension load. The factor was originated to ensure the driller could safely pull a certain load on the pipe in the event of sticking; a typical range for the pull over value is 50,000 – 100,000 lb.

To prevent this condition a design factor of approximately 90% of the tabulated tension value is recommended.

Fdesign = Fyield x 0.9

Where

Fdesign= minimum tensile strength, lb

0.9 = a constant relating proportional limit yield to strength

Margin of Over Pull (M.O.P.)

M.O. P. = Fdesign - F_{TEN}

Safety Factor (S. F.)

$$SF = \frac{Fdesign}{F\ TEN}$$

By combining above equations,

$$Ldp = \frac{(Fyield \times 0.9) - M.O.P}{WTdp \times BF} - \frac{(Ldc \times WTdc)}{WTdp}$$

Slip crushing:

The maximum allowable tension load must be determined to prevent slip crushing. In an analysis of the slip crushing problem, Reinhold and Spini, and also Vreeland, proposed an equation to calculate the relation between the hoop stress (S_H) caused by the action of the slips and the tensile stress in the pipe (S_T), resulting from the load on the pipe hanging in the slips. If the dimensions for the cross-sectional area of the pipe (A) and the cylindrical surface area of the pipe under the slips (A_S) are used, the equation can be presented as follows:

$$\frac{SH}{ST} = \left[1 + \frac{DK}{2Ls} + \left(\frac{DK}{2Ls}\right)^2\right]^{1/2}$$

SH =hoop stress, psi
ST =tensile stress, psi
D =outside diameter of the pipe, in.
K =laterial load factor on slips, 1/tan(y+z)
y=slip taper, usually 9° 27' 45"
z= arctan μ
μ= coefficient of friction (= 0.08)
Ls= length of slips,in.

Slips are typically 12 or 16 in. long. The friction coefficient ranges from 0.06 - 0.14. In as much as tool joint lubricants are usually applied to the back of rotary slips, a coefficient of friction of 0.08 should be used for most calculations. The equivalent tension load from slip crushing can be calculated as :

T_s= T_L (S_H/S_T)

Where

T_s= tension from slip crushing

T_L= load line tension

S_H/S_T= hoop stress, tension stress ratio

Burst:

The drill pipe internal yield pressure can be calculated as follows:

$P_i = \frac{2Ym \times Wt}{D}$

Where

P_i= burst pressure, psi

Ym= specified minimum yield strength, psi

Wt= pipe wall thickness, in.

D= outside pipe diameter, in

Dogleg Severity Analysis:

The most common type of drill type of drillpipe failure is fatigue wear. It generally occurs in doglegs where the pipe goes through cyclic bending stresses. These stresses occur because the outer the outer wall of the pipe in dogleg is stretched and creates a greater tension load. As the pipe rotates a half cycle, the stresses change to the other side of the pipe. For example, the stress may change from 50000 psi to -20000 psi and again to 500000 psi in the course of one cycle or rotation of the pipe.

Fatigue damage from rotation in doglegs is a significant problem if the angle is greater than some critical value. Lubinski has published several works that describe this value. Rotation in angles below this value does not cause appreciable fatigue.

The maximum permissible dogleg severity for fatigue damage considerations can be calculated with the following equations:

$$c= \frac{432{,}000}{\pi}\frac{\sigma b}{ED}\frac{\tanh KL}{KL}$$

And:

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

Where:

C = maximum permissible dogleg severity, °/100 ft

E = Young's modulus, psi

= $30*10^6$ psi for steel

=$10.5*10^6$ psi for alluminium

D = drillpipe outer diameter, in.

L = half the distance between tool joints, 180 in. for Range 2 pipe, in.

T = tension load below the dogleg, lb

σ_b = maximum permissible bending stress, psi

I = drillpipe moment of inertia, π (D^4-d^4)/64.

The maximum permissible bending stress (σ_b) is calculated from the buoyed tensile stress (σ_t) and is grade dependent. The equation for blending stress with Grades E and S pipe are given in later equations and are valid for σ_t up to 67000 psi and 133400 psi, respectively:

$$\sigma_b= 19,500 - \frac{10}{67}\,\sigma t-\frac{0.6}{670^2}(\sigma_t-33500)^2$$

Where:

σ_b= maximum bending stress for Grade E pipe

$$\sigma_b = 20000(1 - \sigma_t/145000)$$

for Grade S-135 pipe.

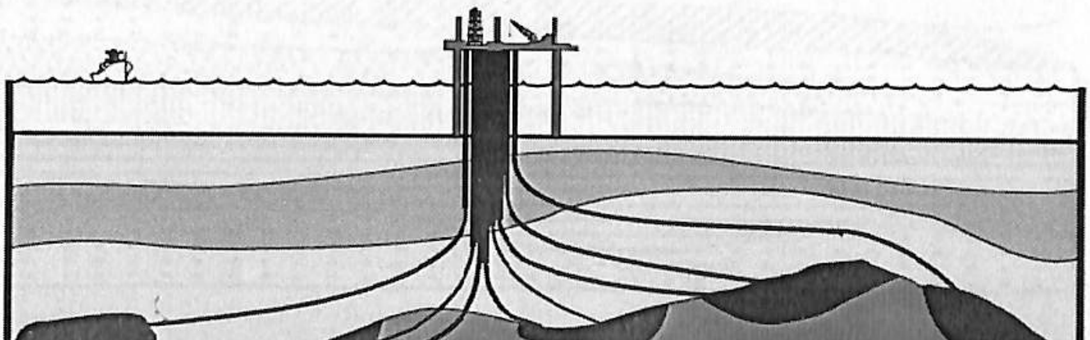
Directional Drilling:-

Definition of Directional Drilling:

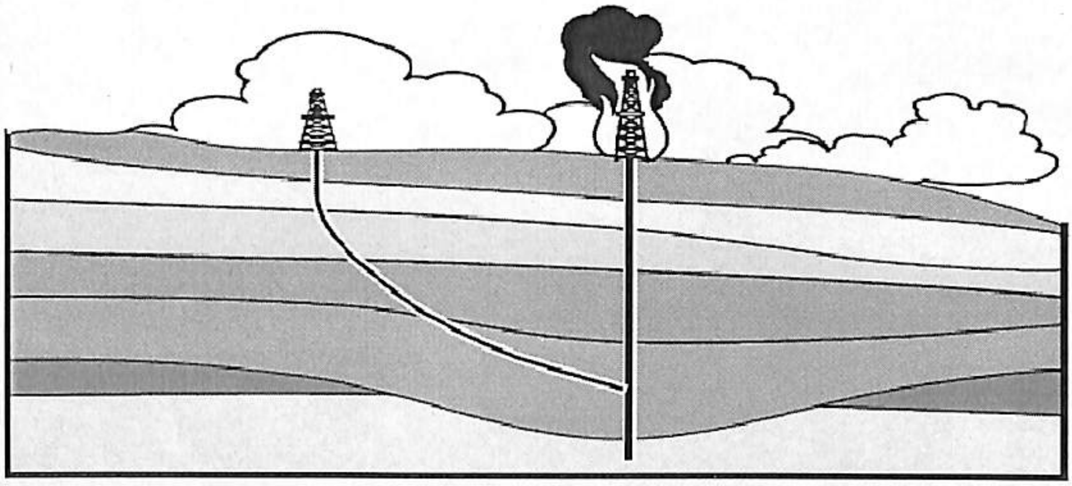
Directional drilling can generally be defined as the science of directing a wellbore along a predetermined trajectory to intersect a designated subsurface target.

Applications:

- **Multiple wells from offshore structures:**
- The most common application of directional drilling techniques is in offshore drilling. Many oil and gas deposits are situated well beyond the reach of land based rigs. Drilling a large number of vertical wells from individual platforms is both impractical and uneconomical. The obvious approach for a large oilfield is to install a fixed platform on the seabed, from which many directional boreholes can be drilled.

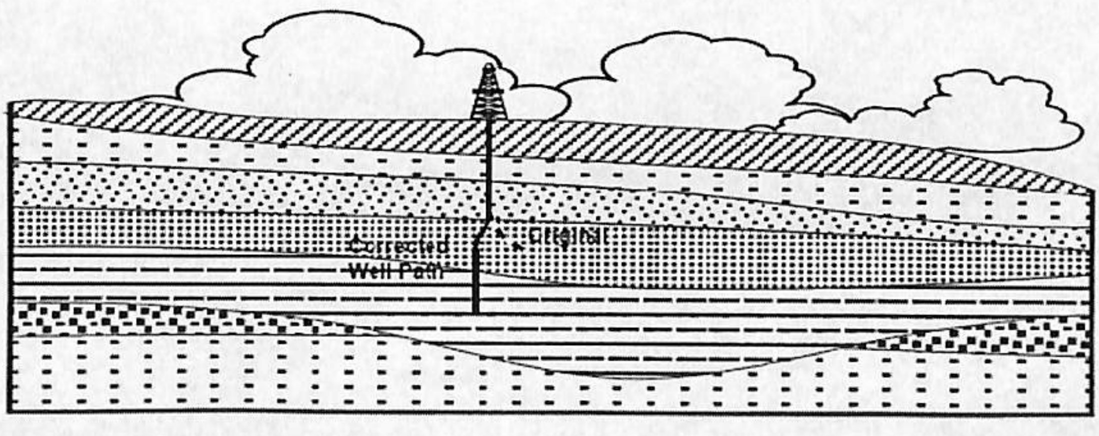


Relief Wells: Directional techniques are used to drill relief wells in order to "kill" blowouts. Relief wells are deviated to pass as close as possible to the uncontrolled well. Heavy mud is pumped into the reservoir to overcome the pressure and bring the wild well under control.



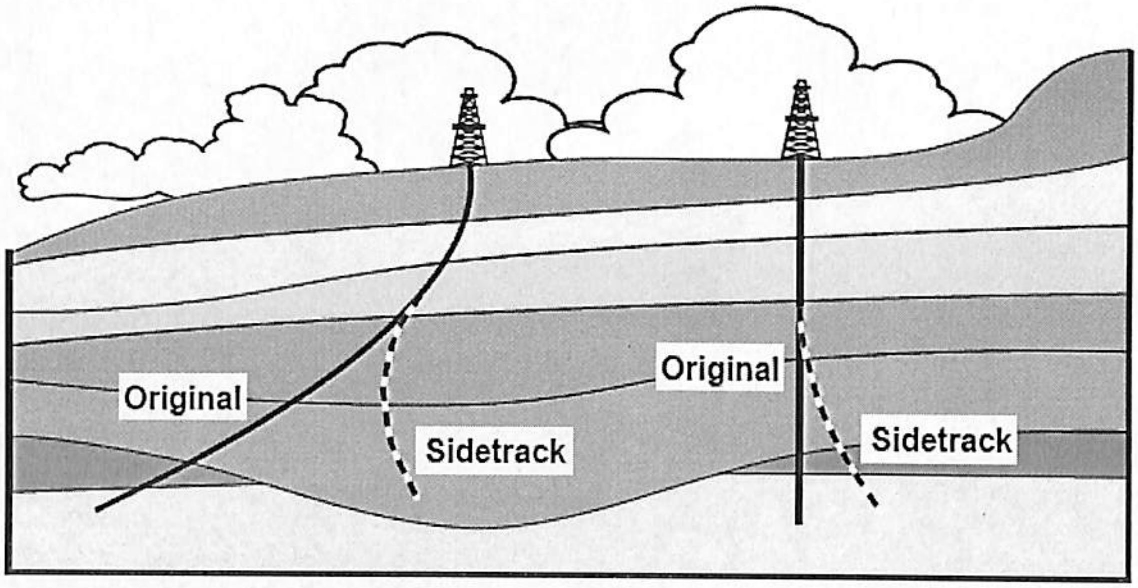
- **Controlling Vertical Wells:**

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



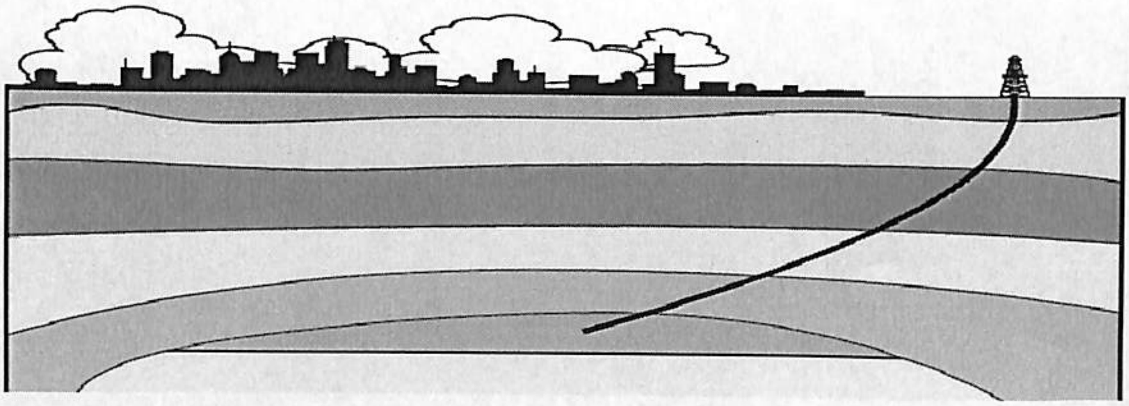
- **Sidetracking**

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



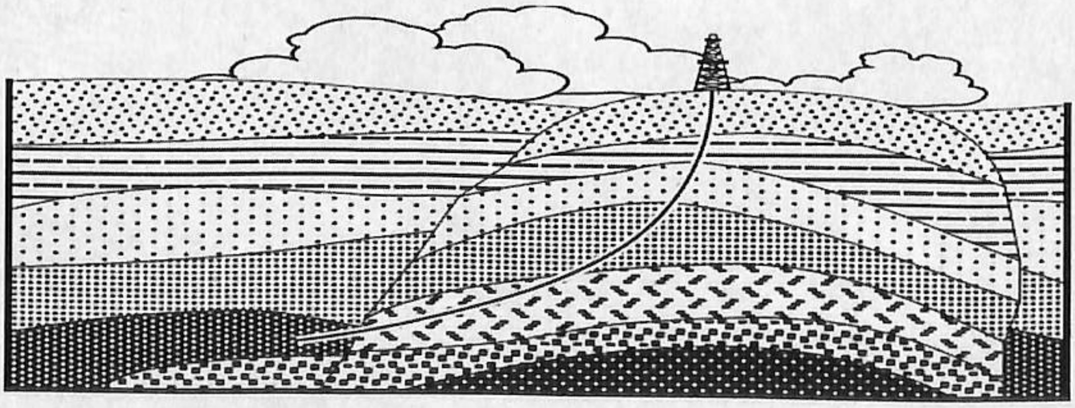
- **Inaccessible locations:-**

Directional wells are often drilled because the surface location directly above the reservoir is inaccessible, either because of natural or man-made obstacles.



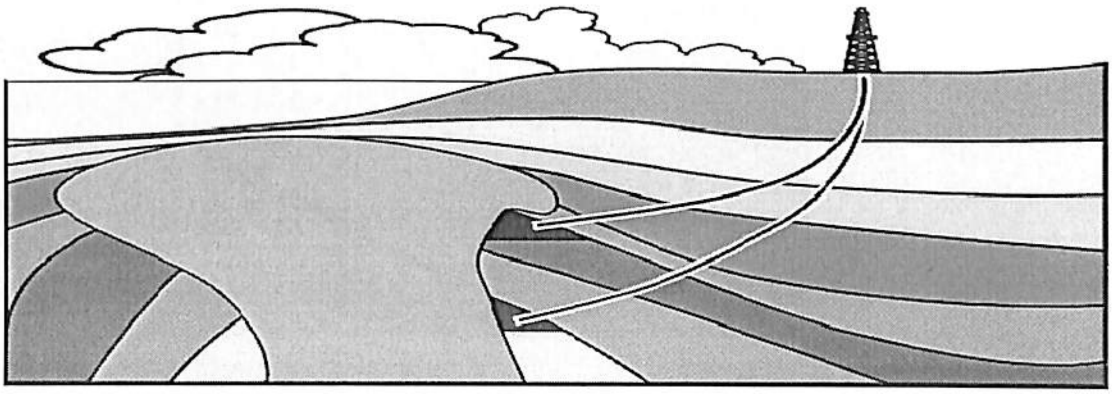
- **Fault Drilling**

  Directional wells are also drilled to avoid drilling a vertical well through a steeply inclined fault plane which could slip and shear the casing.



- **Salt Dome Drilling**

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



Types of Directional Patterns:

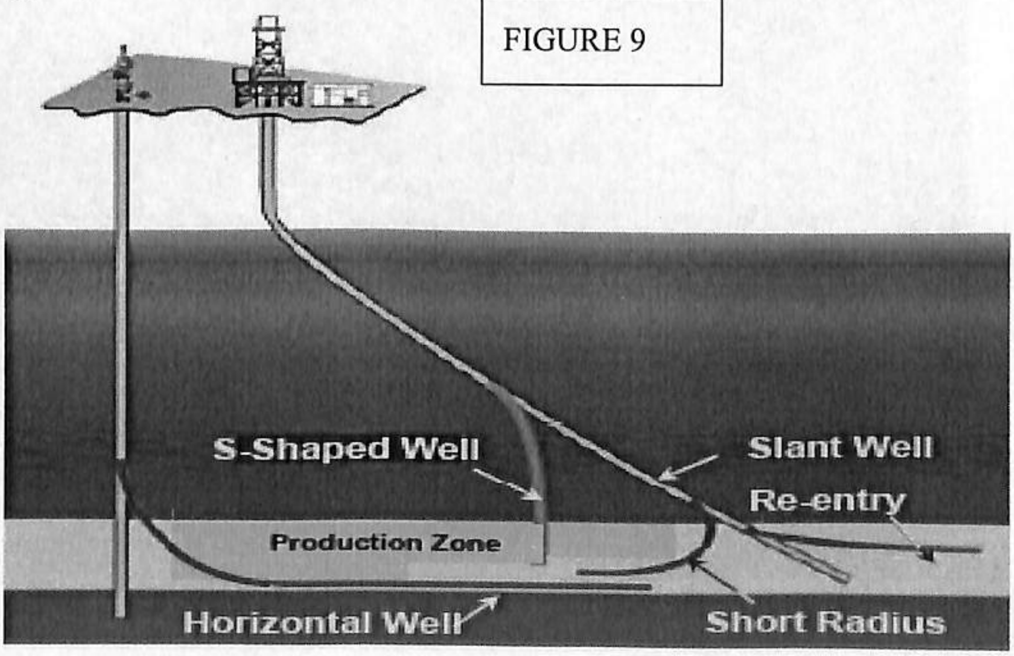
The advent of steerable systems has resulted in wells that are planned and drilled with complex paths involving 3-dimensional turns. This is particularly true in case of re-drill, where old wells are sidetracked and drilled to new targets.

These complex well paths are harder to drill and the old adage that "the simplest method is usually the best" holds true. Therefore, most directional wells are still planned using traditional patterns which have been in use for many years.

Common patterns for projections are shown on the following pages:

Type 1) L- TYPE
Type 2) S- TYPE
Type 3) J- TYPE

FIGURE 9



Type 1) (BUILD AND HOLD OR 'L' TYPE)

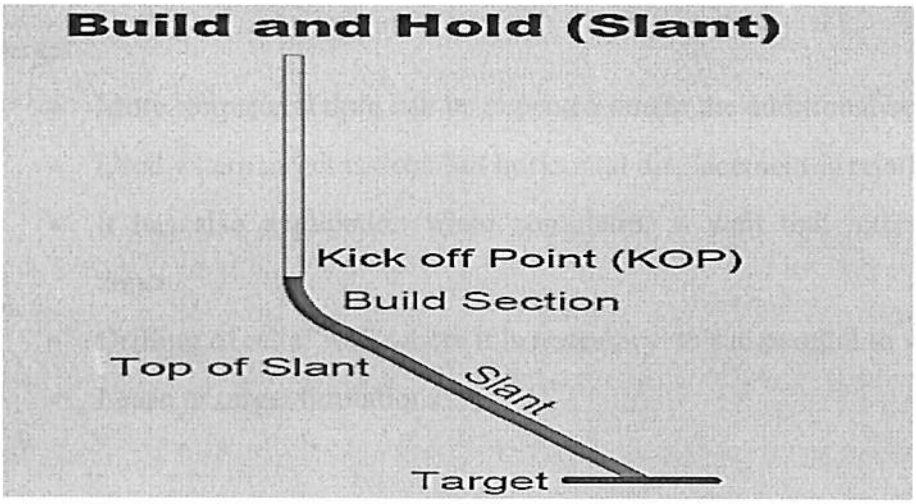


FIGURE 10

This is the most common and simplest profile for a directional well.

- The well is drilled down vertically to KOP, where the well is deviated to required inclination and further maintained to target.
- Shallow KOP is selected to reduce the inclination.
- This profile can be applied where large displacements are required at relatively shallow target depths.
- Under the normal condition inclination should be 15 to 55^0.

TYPE 2) (BUILD HOLD AND DROP OR 'S' TYPE):

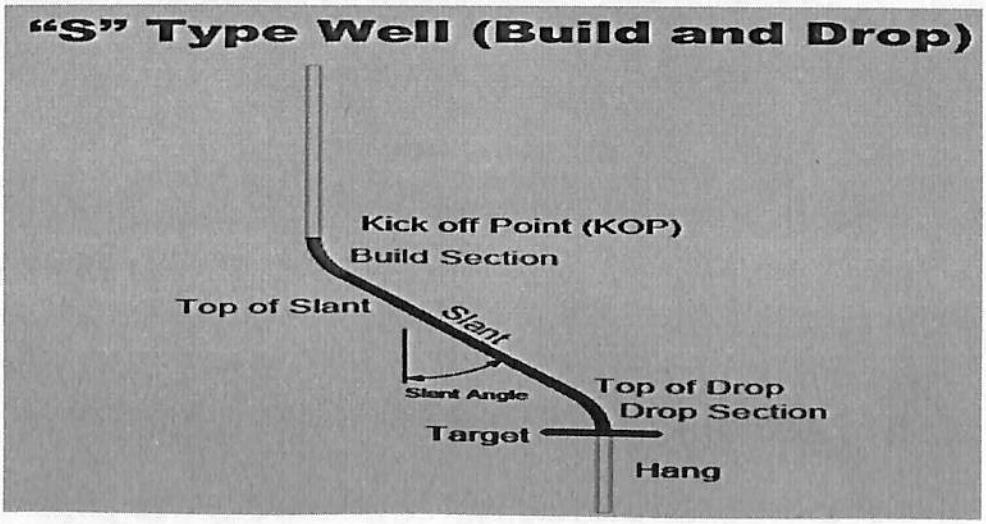


FIGURE 11

This profile is similar to type-I up to tangential section. Here the profile enters a drop of section where inclination is reduced and in some cases becomes vertical as it reaches the target.

- More torque and drag can be expected due to the additional bend.
- Used where target is deep but horizontal displacement is relatively small.
- It has also application when completing a well that intersect multiple producing zones.
- Drilling of relief well where it is necessary to run parallel to wild well
- Lease or target limitations.

<u>TYPE 3) (DEEP KICK OFF AND BULD 'J' TYPE):</u>

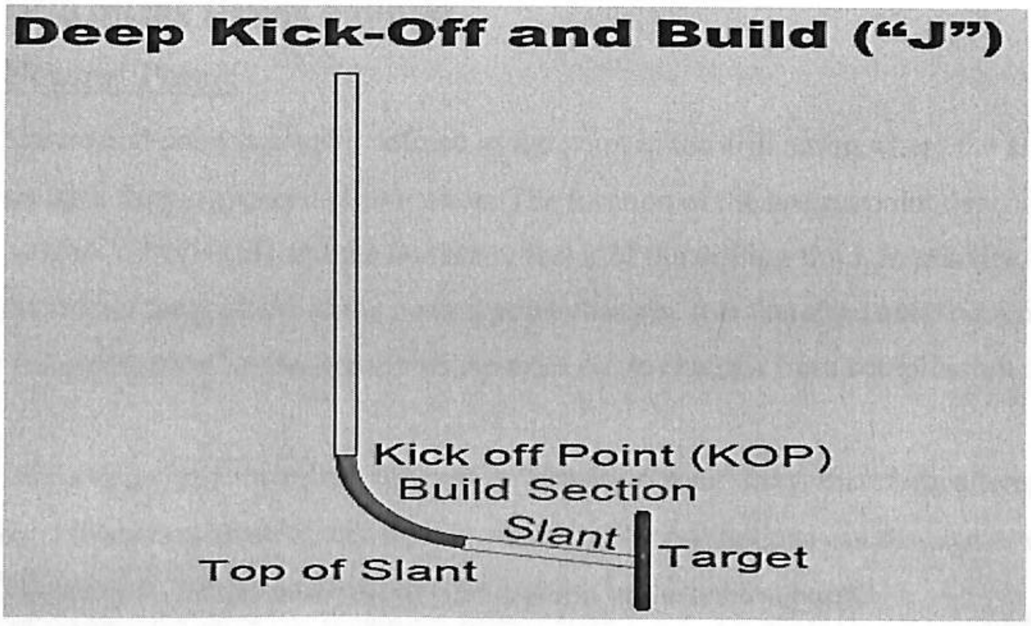


FIGURE 12

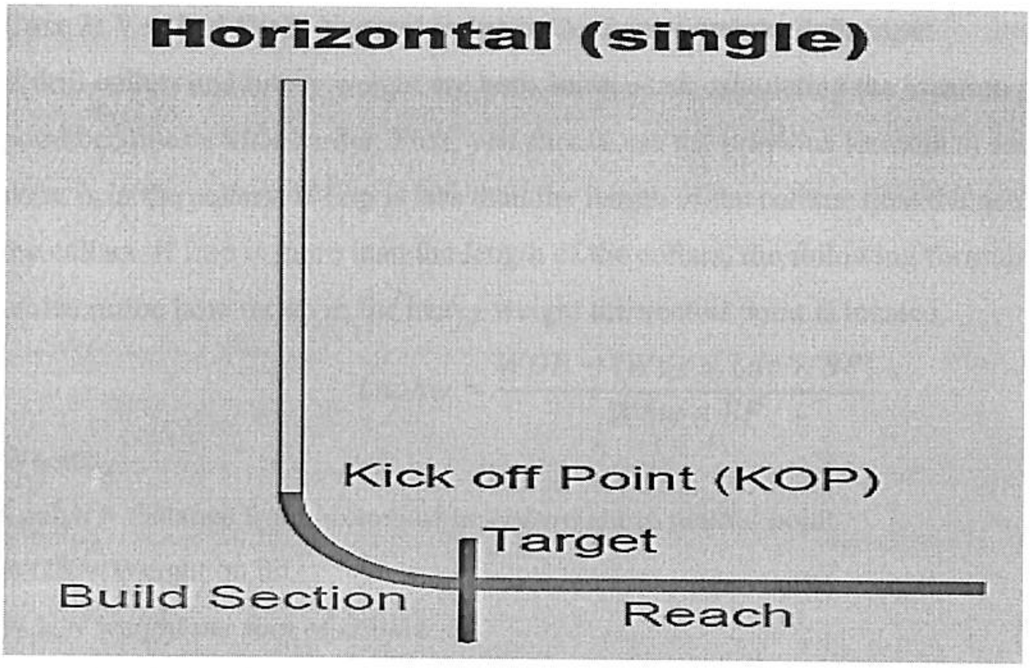


FIGURE 13

Drill String Design Failures:

Neutral Point:

The neutral point is usually defined as the point in the drill string where the axial stress changes from compression to tension. The location of the neutral point depends on the weight-on bit(WOB) and the buoyancy factor of the drilling fluid. In practice, since the WOB fluctuates, the position of the neutral point changes. It is therefore quite common to refer to a "transition zone" as the section where axial stress changes from compression to tension.

Drill string components located in this "transition zone" may, therefore, alternately experience compression and tension. These cyclic oscillations can damage down hole tools. Therefore it is important to know the location of the neutral point.

Calculation of Neutral point:

Case 1: Vertical Well, Neutral Point in the drill collars:

Where:

Lnp = distance from bit to neutral point

Wdc = weight per foot of the drill collar

BF = Buoyancy Factor

Case 2: Vertical Well, Neutral Point in the heavy weight drill pipe:

If drill collars and heavy weight are both being used, calculating the location of the neutral point becomes a little harder. First, you should use the previous formula to see if the neutral point is in the collars. If Lnp is less than the length of the collars, then the neutral point is in the collars. If Lnp is more than the length of the collars, the following formula should be used to determine how far up in the heavy weight the neutral point is located.

$$Lnphw = \frac{WOB - (Wdc \times Ldc \times BF)}{Whw \times BF}$$

Where:

Lnphw = distance from bottom of heavy weight to neutral point

WOB = Weight on bit

Wdc = weight per foot of collars

Ldc = length of collars

Whw = weight per foot of the heavy weight pipe

Case 3: Directional Well, Neutral Point in the drill collars:

When the neutral point is in the drill collar section and the collars are all of one diameter, the following formula should be used:

$$Lnp = \frac{WOB}{Wdc \times BF \times \cos I}$$

where:

Lnp = distance from bit to neutral point in feet

Wdc = weight per foot of the drill collars

BF = Buoyancy Factor

WOB = weight on bit

I = borehole inclination

Case 4: Directional Well, Neutral Point in the heavy weight drill pipe:

$$Lnphw = \frac{WOB - (Wdc \times Ldc \times BF \times cosI)}{Whw \times BF \times \cos I}$$

where:

Lnphw is the distance from the bottom of the HWDP to the neutral point.

Ldc is the total length of the drill collar section.

Whw is the weight per foot of the HWDP

Dogleg Severity Analysis:

The most common type of drill type of drillpipe failure is fatigue wear. It generally occurs in doglegs where the pipe goes through cyclic bending stresses. These stresses occur because the outer the outer wall of the pipe in dogleg is stretched and creates a greater tension load. As the pipe rotates a half cycle, the stresses change to the other side of the pipe. For example, the stress may change from 50000 psi to -20000 psi and again to 500000 psi in the course of one cycle or rotation of the pipe.

Fatigue damage from rotation in doglegs is a significant problem if the angle is greater than some critical value. Lubinski has published several works that describe this value. Rotation in angles below this value does not cause appreciable fatigue.

The maximum permissible dogleg severity for fatigue damage considerations can be calculated with the following equations:

$$c = \frac{432{,}000}{\pi}\frac{\sigma b}{ED}\frac{\tanh KL}{KL}$$

And:

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

Where:

C = maximum permissible dogleg severity, °/100 ft

E = Young's modulus, psi

= $30*10^6$ psi for steel

=$10.5*10^6$ psi for aluminium

D = drillpipe outer diameter, in.

L = half the distance between tool joints, 180 in. for Range 2 pipe, in.

T = tension load below the dogleg, lb

σ_b = maximum permissible bending stress, psi

I = drillpipe moment of inertia, $\pi\,(D^4-d^4)/64$.

The **Maximum Permissible Bending Stress (σ_b)** is calculated from the buoyed tensile stress (σ_t) and is grade dependent. The equation for blending stress with Grades E and S pipe are given in later equations and are valid for σ_t up to 67000 psi and 133400 psi, respectively:

$$\sigma_b = 19{,}500 - \frac{10}{67}\,\sigma t - \frac{0.6}{670^2}(\sigma_t - 33500)^2$$

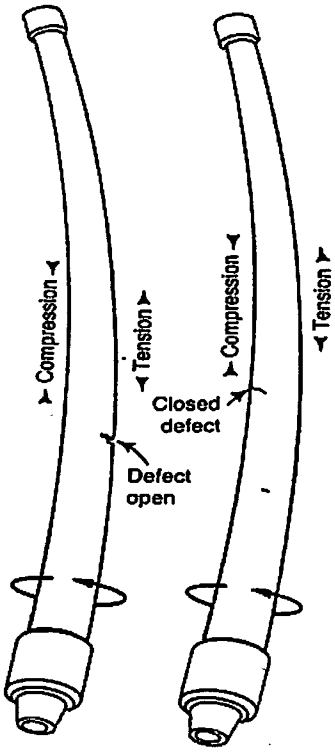
Where:

σ_b= maximum bending stress for Grade E pipe

$$\sigma_b = 20000(1 - \sigma_t/145000)$$

for Grade S-135 pipe.

FIGURE 14



Torque and Drag Analysis:

Drag is the increase in string weight when pulling out of the hole or the reduction in string weight while tripping in the hole.

Torque is the force required to turn the drill string. In a perfectly vertical well, the torque and drag in a well are negligible.

Torque and drag is caused by the friction between the drill string and the wall of the well.

The magnitude of torque and drag is determined by the magnitude with which the pipe contacts the hole wall and the friction coefficient between the wall and pipe.

Figure shows the forces associated with the object on an inclined well.

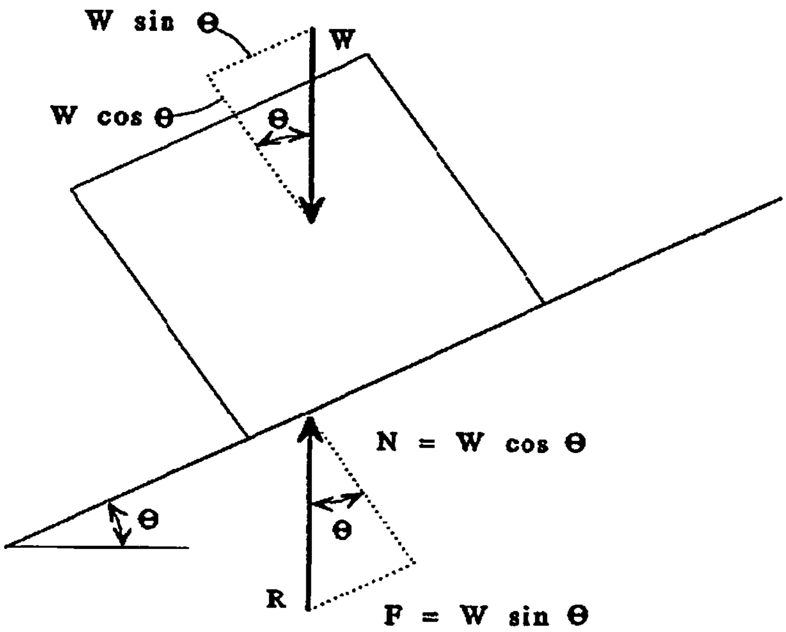


FIGURE 15

The weight component along the axis of the incline ($W\ sin\theta$) would be the force required to move the object in a frictionless environment.

The plane is inclined, the normal force is a function of the cosine of θ, The friction force is equal to the normal force times the friction coefficient. Therefore, the force required to pull the block up the plane is:

$$\mathbf{T=-W\ sin\ \theta + \mu\ W\ cos\ \theta}$$

T = Axial Tension

W = Buoyed Weight of Pipe

μ = Friction Coefficient

θ = Angle of Incline

The force required to push the block down the incline is:

$$\mathbf{T=-W\ sin\ \theta - \mu\ W\ cos\ \theta}$$

If $\theta\mu\cos W$ is greater than $\theta\sin W$, the object will have to be pushed down the incline. The same is true for pipe in a wellbore only the inclination is equal to 90° less the angle of the incline. The incline of the plane is measured from the horizontal but the inclination of a well is measured from the vertical. A perfectly vertical well has an inclination of 0°.

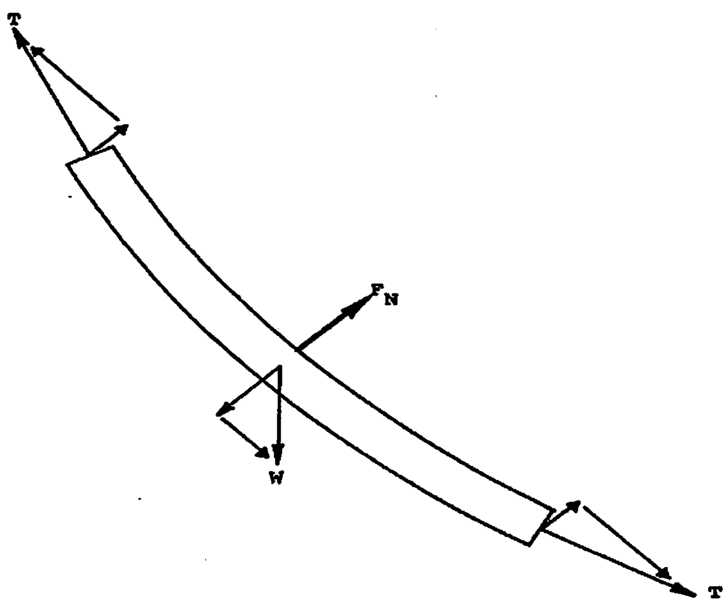
TORQUE AND DRAG MODEL:-

Friction coefficient:-

- The friction coefficient depends upon the type of drilling fluid in the wellbore and the roughness of the wellbore walls.
- Cased hole should have a lower friction coefficient than open hole.
- Untreated water based muds will have a higher friction coefficient than oil based muds.
- Friction coefficients have been reported to range from 0.15 to 0.25 for oil based muds and 0.25 to 0.40 for water based muds.
- Clear brines will have higher friction coefficients usually between 0.30 and 0.40.
- Air drilling has the highest friction coefficients with friction coefficients between 0.40 and 0.50.

In lower inclination wells, the drag associated with the inclination is relatively low. The inclination drag in high angle wells, horizontal wells and extended reach wells can be significant. When hole curvature is considered, an additional force is added to normal force from the pipe weight and is the source of most of the drag experienced in directional wells. Pipe placed in a curved wellbore under tension will exert a force proportional to the tension and rate of curvature change (dogleg severity).

Fig.shows the forces involved. FIGURE 16



The resultant normal force is the sum of the normal forces due to tension and pipe weight.

Assume x-axis as vertical planes y-axis as horizontal plane along the axis of hole.

$$F_x = T\sin\Delta I + W\sin I_{(avg)}$$

$$F_y = T\sin\Delta A\sin I_{(avg)}$$

The vectorial sum of the forces is the resultant normal force due to tension and is:

$$F_N = \sqrt{\left(T\sin\Delta I + W\sin I_{(avg)}\right)^2 + \left(T\sin\Delta A\sin I_{(avg)}\right)^2}$$

Calculating the normal force at each point along the drill string and multiply it by the friction coefficient will yield the increased tension caused by drag. The sum of the drag and weight will equal the drill string tension at any point in the well.

In Figure, the tension on the drill string at Point "C" is designated by T_1.

The tension at Point A will be $T_1 + \Delta T$, where the ΔT is the increase in tension due to weight and friction.

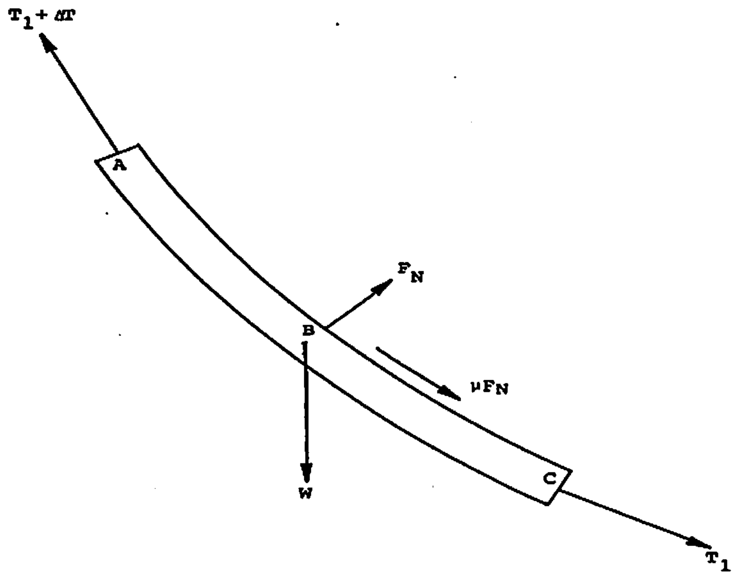


FIGURE 17

- The drill string is broken into segments starting at the bit where the tension is known.
- The normal force is calculated and the tension at the top of the segment is calculated based on drag and pipe weight

While tripping out, the drag will increase the tension in the string

$$T_2 = T_1 - W\cos I_{(avg)} + \mu F_N$$

While tripping in the hole, the drag acts in the opposite direction,

$$T_2 = T_1 - W\cos I_{(avg)} - \mu F_N$$

The process is repeated until the calculations reach the surface, which is the hook load.

Critical Buckling:-

In inclined holes, two additional factors must be considered when calculating the maximum weight on bit that can be run without buckling the drill pipe.

• Weight on bit is applied at the inclination of the well, but the weight of the BHA continues to act vertically.

• To allow for the reduction in available BHA weight, the buoyed weight must be reduced by a factor equal to the cosine of the well inclination.

The drill string generally lies on the low side of the hole and obtains some lateral support from the bore hole wall. In these circumstances, pipe above the neutral point of bending buckles only when the compressive forces in the drill string exceeds a critical load, calculated as:

$$F_{crit} = \sqrt{\frac{9.82\times10^5(OD^4 - ID^4)(Wt/ft)B\sin I}{(D_h - OD)}}$$

F_{crit} = Critical buckling force,

OD = Outside diameter of pipe, inches

ID = Inside diameter of pipe, inches

BF = Buoyancy factor

D_h = Diameter hole, inches

I = Hole inclination, degrees

FACTORS THAT AFFECT TORQUE AND DRAG

There are essentially three ways to reduce the drag in a directional well. They are:

1. Reduce the friction coefficient.
2. Change the directional profile.
3. Reduce the string weight or tension

CHAPTER II

LITERATURE REVIEW

PART-2

CEMENTATION OF PRODUCTION LINER

1. INTRODUCTION

Cementing is a technique for placing cement slurries in the annular space between the casing and borehole. This cement then hardens to form a hydraulic seal in the wellbore, hence prevents the migration of formation fluids in the annulus. Therefore cementing is one of the most critical planned and executed, because there is very less chance it complete the job successfully.

In addition to provide zonal isolation, the sheath of cement should anchor and support casing string (caving into borehole and preventing formation sloughing) and protect the casing string against corrosion by formation fluids. When exposed to hot formation brines, hydrogen sulphide and carbon diocide, uncemented steel can rapidly corrode. When solid particles such as formation sand are being transported, iemented casingt can also be subjected to erosion by the high velocity of produced fluids. Ovaling, buckling or complete collapse because of overloading at certain points can take place because of lateral loads on poorly cemented casing strings. Also properly cemented casing is subjected to a nearly uniform loading approximately equal to the overburden pressure.

Cementing techniques are the same regardless of casing string purpose and size, in principle. The cement slurry is pumped down inside the string to be cemented; the bottom is exited and displaces drilling mud while moving up the annulus.

There are two types of cementing process:

(1) Primary Cementation.

(2) Secondary Cementation.

The cementation that takes place soon after the lowering of casing is called the primary cementation and any cementation job after primary cementation is known as secondary cementation.

FUNCTIONS OF PRIMARY CEMENTING

Oil well cementing is the process of mixing a slurry of cement and water and pumping it down through steel casing to the critical points in the annulus between casing and open hole.

The main functions of primary cementation are:

(1) to bond and support the casing.

(2) protecting the casing from corrosion.

(3) to restrict fluid movement between formations.

(4) preventing blowout by quickly forming a seal.

(5) protecting the casing from shock loads during drilling deeper.

(6) sealing-off zones of lost circulation.

TECHNIQUES OF PRIMARY CEMENTING

Following different techniques are used for primary cementation.

(1) Single stage cementation

(2) Double stage cementation

(3) Multistage cementation

(1) Single stage cementation

Single stage cementation is the most commonly used technique for primary cementation.

The single stage primary cementing is normally accomplished by pumping one batch of cement down the casing between two rubber plugs. The plugs are equipped with wiping fins to help prevent contamination of the cement by mud and also help in cleaning the interior of the pipe. The plugs are introduced into the primary cementing system at the proper time by the plug container located on the top of the casing at the surface. The bottom plug is placed in the casing and followed by cement slurry .When the bottom plug reaches at the float collar, it stops. Pressure is built up, rupturing the diaphragm of bottom plug and allowing the cement slurry to proceed down the casing through the plug, floating equipment, guide shoes into the annulus between the casing and the open hole.

When the batch of cement has been pumped into the casing" a top plug is released from the plug container to follow the cement down the casing and also helps prevent contamination with the displacing fluid. The top plug is pumped down until it lands on the top of float collar. Thus completing the cement job.

(2) Double stage cementation

It is the convention of placement of cement slurry around the lower portion of a casing string followed by placement of successive upper stage through ports of stage collar. Cementation can be done in more than two stages also.

(3) Multistage cementation

Cementation is required to be done in two or more stages because of following reasons.

(1) When along column of cement cannot be handled with the limited cementing equipment.

(2) When hydrostatic head of long column of cement cannot be supported by downhole formation.

(3) Stage cementation is economical as it reduces the quantity of cement needed to cement widely separated intervals.

(4) In case of deep wells, the long column of cement may have wide difference of temperature at the top and bottom which cannot be covered with one type of slurry and the two slurries have to be designed with two different temperatures and to be pumped in two stages, one may be retarded cement and other may be normal or accelerated cement with adequate thickening time.

Stage cementation is also required when different density cement is pumped to cover different intervals.

STAGE CEMENTING EQUIPEMENT

Stage collar

Stage'collar is a casing joint with ports which can be opened or closed or sealed off by pressure moved sleeves.

It has got the following components.

(a) Lower opening sleeve

When the slide by the tripping plug, slides it down, then the ports are opened for circulation. It is made of drillable material.

(b) Upper closing sleeve

By the top plug the upper closing sleeve slides and closes the ports. Alongwith this sleeve another outer sleeve moves and it seals off the ports from outside even after drilling out of both the sleeves. The sleeves slide with a pressure of 35 kg/cm2 by which shear pins get sheared off.

(c) First stage plug

It is used to separate the slurry from drilling fluid and gives a positive indication to the end of displacement after sitting over the baffle rubber plate mounted over the float collar. This plug easily passes through the stage collar without disturbing the sleeves.

(d) Trip plug or opening plug or bomb plug

It is dropped after the first stage and is allowed to reach stage collar by gravity. Subsequent application of pressure 70 to 105 kg/cm2 (1000 to 1500 psi) will move the lower sleeve and the ports will open for circulation. The opening plug is made heavy by Lead and is of drillable material.

(e) Closing plug

It is pushed by mud after pumping of cement slurry of second stage. After complete displacement of cement slurry it reaches at stage collar and sits on the upper sleeve and by applying a pressure of 70 to 105 kg/cm2 the upper sleeve moves down alongwith inner/outer sleeve which closes the ports and seals the stage collar.

STAGE CEMENTATION

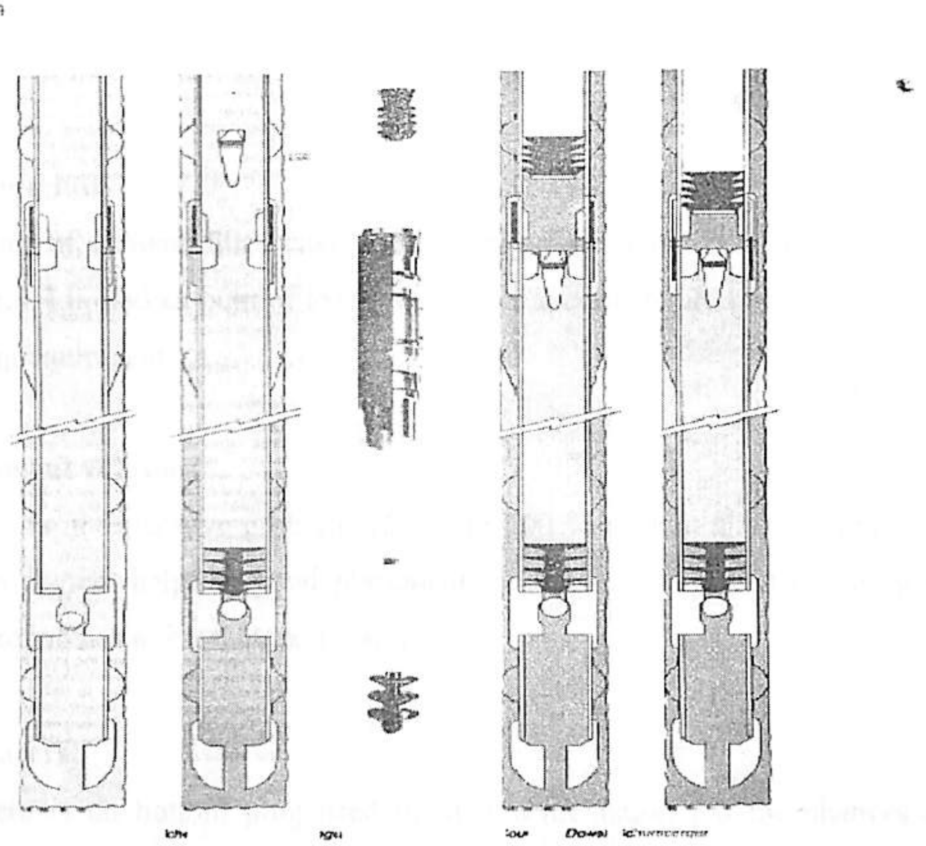
Cementing the first stage

The pumping of cement slurry and displacement by mud in first stage cementation is similar to single stage cementation. After completion of the job, opening plug is dropped and allowed to reach stage collar. Now pressure is applied to open the ports, a sudden drop in pressure indicates the opening of the ports. After circulation, the well is ready for second stage cementation.

Cementing the second stage

The second stage cementation can be performed any time after the completion of the first stage depending upon the design of the job. The annulus of second stage should be thoroughly flushed out of any extra/contaminated cement from the first stage. The pumping of preflush, cement slurry and displacement by mud is done similar to first stage. After that the ports are closed by hitting the top plug or second stage seal off plug at upper sleeve and an additional 50 kg/cm2 pressure moves down the sleeve to seal the stage collar.

FIGURE 18



LINER CEMENTATION

Cement slurry design considerations for liner cementation

A liner is a standard casing string which does not extend all the way to the surface upto the well mouth but is hanged from inside the previous casing.

A special care is to be taken while designing the cement slurry for liner cementation. Each liner cementation has to be defined as per hole condition and specific cement slurry properties are to be developed for each job as per depth, temperature and pressure to be encountered during the job.

Designing slurry for liner cementation job includes following specific considerations.

(a) **Thickening time**

It is usually designed to include reversing out excess slurry out of the hole. In gas wells, usually thickening time is planned comparatively shorter to reduce chances of gas migration through cement.

(b) Slurry design

High density low water ratio cement is used to prevent water separation while entering the fluid into wellbore, but differential and pumping pressure must remain below the fracture pressure of the weakest zone.

(c) Fluid loss

Building of cement filter cake should always be avoided to reduce chances of annulus bridging. Limited amount of lost circulation material should be used as it causes plugging of floating equipment.

(d) Cement volume

If there is no operative problem 150 % to 200 % cement slurry is required to be pumped. Excess cement helps in good placement of cement. For a better sealing effect in annulus squeeze job has to be planned in advance.

(e) Spacers

As there is no bottom plug used in liner cementation job the chances of contamination increases. Hence, a spacer of about 2 to 3 m3 must be pumped ahead of the plug.

SECONDARY CEMENTING

Secondary cementation is the cementing operation performed after the primary cementation, to repair some segments in bore hole having poor cement in annulus. This is also known as remedial cementing. The cement squeezing and cement plugging are the main two types of secondary cementing processes.

1. SQUEEZE CEMENTING

It is the process of forcing cement slurry under pressure against a formation.

PURPOSES OF SQUEEZE CEMENTING

(1) To repair a primary cement job that failed due to cement bypassing the mud (channeling) or insufficient cement height in the annulus.
(2) To eliminate water intrusion from above, below or within the hydrocarbons producing zone.

(3) To reduce the producing gas oil ratio by isolating gas zones from adjacent oil intervals.

(4) To repair casing leak due to corrosion or split pipe.

(5) Plug all or part of one or more zone in a multizone injection well so as to direct the injection into the desired intervals.

(6) Plug and abandon a depleted or watered out producing zone.

(a) Repair of primary cement job

The drilling mud which the cement bypasses may leave pockets or channels behind the casing. These channels may be cemented by using either low or high pressure squeeze techniques. At low pressure the channels connected to a permeable formation will be cemented. High pressure squeezing may improve the cement fillup breaking weak nodes in the set cement structure. Circulation of cement slurry between two perforations at the top and bottom of the desired interval is another technique often used.

(b) Elimination of water intrusion or reduction of Gas Oil Ratio

Water or gas intrusion into the oil zone may occur as the oil zones become depleted. The usual procedure is to plug all the ports in the oil, water and gas zones and then reperforate in the shorter producing interval.

(c) Repair of casing leaks

This operation is usually performed at very low pressure in order not to extend the damage.

(d) Plugging of zones / perforations in multizone injection wells

Division of injection fluids such as water, polymer solutions or gas is difficult to accomplish. If, no vertical permeability exists between zones and the isolation of zones is satisfactory the plugging of perforations in high permeability zones will direct the injected fluids to the others.

(e) Plug and abandonments

This job is done at low pressure to avoid damaging a zone which may be economically explorable in the future.

BUMPING THE PLUG

The bottom plug 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.

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 precalculated design value 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.

SLURRY DESIGN

The properties of cement slurry must be designed according to the characteristics of the formation to be squeezed off and the technique to be used. Care should be exercised about the following:

(a) Fluid loss control

It is very important to control fluid loss of slurry when squeezing against a high permeable formation. A properly designed slurry should allow the complete filling of perforation cavities leaving a minimum mode build up into the casing. Excessive fluid loss might allow the dehydration of slurry to continue into the casing build mode in front of the perforation. For squeeze job the filtration loss should be less than 100 cc at 70 kg/cm2 and it is better to have less than 50 cc in case of high pressure squeeze.

(b) Slurry volume

The optimum amount of cement slurry is the minimum volume required to fill voids being squeezed. Control of the amount of cement squeezed is not precise and is more of an art than science.

The quality of cement mixed should completely fill the casing through the perforated interval and provide sufficient cement above the perforation for the squeezing operation, which vary from area to area but an excess 50 lts of slurry per foot of perforation to be squeezed should be sufficient. The volume of cement rarely exceeds 1 to 1.5 cubic metre except when squeezing exceptionally long intervals. This also holds true for channel repairs except where large volume channels are known to exist e.g. if plug failure during primary cementing allowed substantial amount of displacing fluid to be pumped into the annulus around the shoe. Reversing pressure becomes excessive if large volumes are used and could exceed final squeeze pressure if all the cement is not squeezed out.

(c) Mixing the cement slurry

Squeeze cement slurries should always be mixed by the batch method rather than by the hopper method as in primary cementing. Batch mixing ensures more uniform slurry and allows for surface testing of the slurry after mixing.

(d) Thickening time

When squeezing deep perforation having low permeability formations or when reversing out of excess slurry is planned it might be necessary to have long thickening time.

(e) Dispersion

The capacity of the slurry to flow into narrow small cracks is proportional to its fluidity. Thick slurries although useful when cementing large voids. Thick slurry will not flow into narrow channels unless they are subjected to high differential pressures which in all cases are limited by the formation fracture strength. Thin slurries with a low yield point are achieved by using dispersant.

(f) Injection rate

Nearly all the in formations needed to conduct a squeeze job can be obtained from a properly executed injection rate to determine if and at what rate below the fracture gradient can fluid be pumped into the formation.

Properly executed a high injection rate will have a low pump pressure. Conversely, a high pump pressure will have a low injection rate. It is not necessary to achieve a rate of 1 m3 /min, if 0.5 m3/min is able to put the cement below the squeeze packer. Accordingly 300 lts/min is not necessary if 150 to 100 lts/min is sufficient. A high injection rate with a high pressure is almost never acceptable on a squeeze job. A high injection rate with a high pressure yields a high fractured formation that requires a large volume of cement slurry to fill these fractures before the actual squeeze job begins.

When obtaining an injection rate, consideration should be given to the possibility of spotting a clear fluid such as water across the perforation, as drilling mud contains solids and cannot enter the formation.

CLASSIFICATION OF SQUEEZE JOBS

The squeeze job can be classified by pressure requirements.

(1) High pressure squeezing

It involves breaking down the formation and pumping down the cement slurry into the formation until a specific surface pressure can be maintained without bleed off.

(2) Low pressure squeezing

It involves placing of cement over the interval to be squeezed by applying a pressure sufficient to form a filter cake of dehydrated cement in perforations, channels or fractures.

SQUEEZE TECHNIQUES

(A) Bradenhead squeeze method

In this method, tubing or drill pipe is lowered without packer upto the perforations. A predetermined amount of slurry is mixed and pumped to the specific height outside the tubing or drill pipe to make a balanced plug. The tubing or drill pipe then pulled out of the slurry and B.O.P is closed at the surface. The displacing fluid is pumped down the tubing/drill pipe until the desired squeeze pressure is reached or until a specific amount of the fluid has been pumped usually, this method is used for squeezing shallow wells.

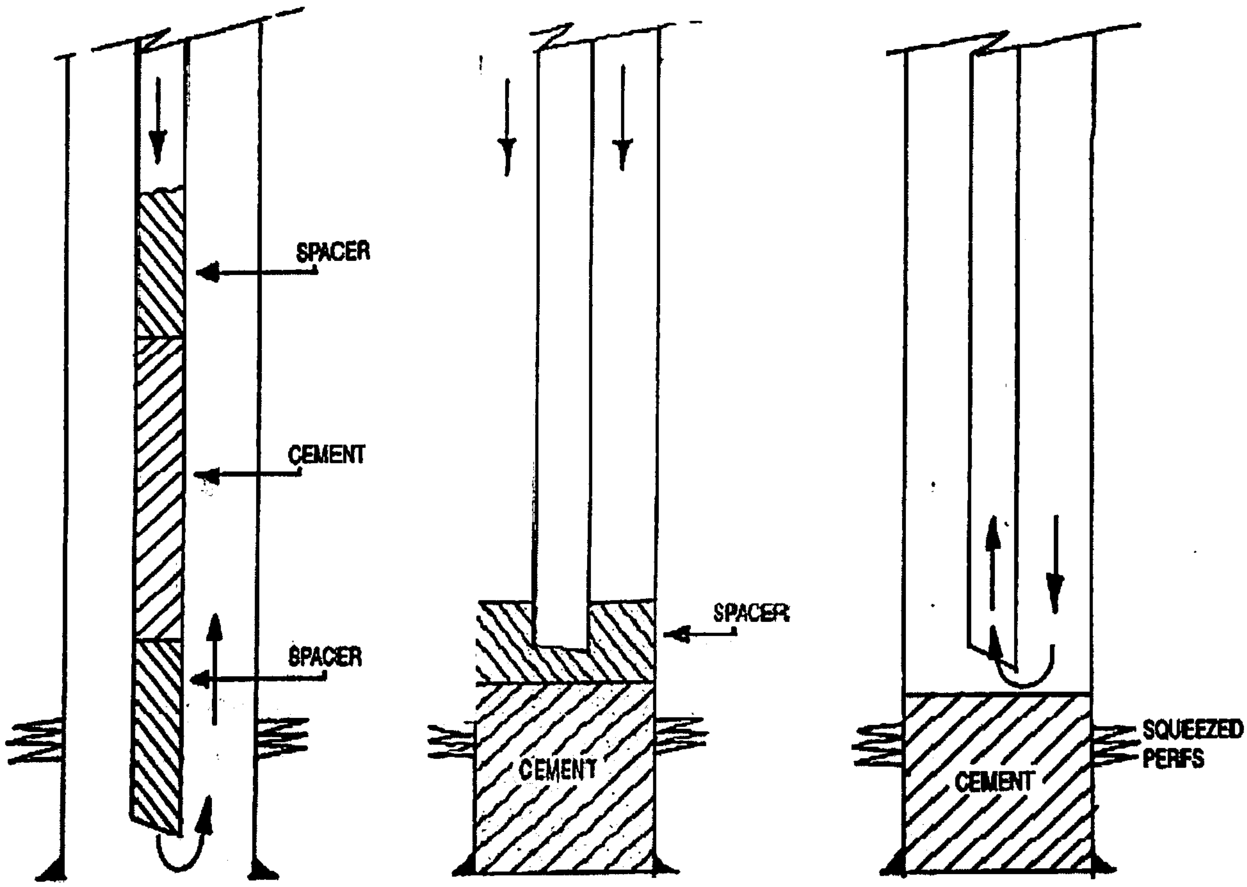


FIGURE 19

(B) Squeeze packer method

This method uses a retrievable or a non retrievable tool run on tubing to a position near the top of the zone to be squeezed. It confines pressures to a specific point in the hole. Before the cement is placed, a pressure test is conducted to determine the formation injectivity pressure. In certain cases the section below the perforation to be squeezed must be isolated with a bridge plug. When the desired squeeze pressure is obtained the remaining slurry is reversed out.

(C) Building squeeze pressure

One common denominator to successful squeezing is reduction of the pump rate as cement slurry starts passing through the perforations. It is true for hesitation as well as running squeeze method. Once slurry enters the perforation it can contact the face of the formation. Depending upon the permeability, slurry cake can begin to build immediately. The rate should be reduced to allow this build up without unnecessary fracturing.

A loose formation will need a long hesitation period to begin building the squeeze pressure.

A first hesitation period of 30 minutes or more is not unreasonable. When pumping is resumed after this period the slurry should be moved as slowly as possible. Monitor the pressure gauge on the cementing unit and continue pumping as long as the pressure steadily increases. If shut in pressure is no more than the first period, a longer waiting period is needed. As shut in pressure increases, hesitation period can be shortened, continue pump-hesitation-pump cycles until squeeze pressure is attained.

PLANNING OF A CEMENTING JOB

1. Planning of work

With close co-ordination of drilling engineers, a detailed programme of hole preparation, casing running in and cementing procedures are to be formulated which should include :

1) Required drilling fluid, having proper plastic viscosity and yield point.
2) Leak proof casing joint make up and fill ups.
3) Type of floating equipment and their operation.
4) Hole conditioning prior to running-in of casing and after completion of casing.
5) Selection of surface equipment, their testing schedule.
6) Mechanical aids, centralizer position.
7) Lowering rate of casing to prevent damage to formation.
8) Reciprocation and rotation of casing during cement pumping and displacement.

For securing good cementation, cementing engineers should be associated with casing running in and fixing centralizers and other mechanical aids at the casing pipes. By reciprocation/rotation of casing, the mud cake will be removed and good cement bond can be achieved. For this, scratchers are placed over the casing pipe against pay horizons. The spacing should be such that the distance between two scratchers should be less than the length of reciprocation.

By reciprocation/rotation of casing pipe a perfect and uniform cement sheath can be obtained and will provide good cement bonding condition, with the cement at the formation alongwith the casing surface

OPERATION DURING CEMENTATION

1) During running in of casing, make intermediate circulation and ensure minimum gelation. At various intervals for 20 to 40 minutes, circulation is done to break the gel

and it is to be followed by reciprocation for 2 to 3 metres to activate the scratchers in the critical areas where an absolute cement sheath is required.

2) To get a good cement sheath cement slurry should be heavier than mud by 0.2 to 0.5 gm/cc.

3) Displacement is done at a rate that will produce turbulent flow, the highest rate compatible with hole conditions and pumping equipment. While reciprocating the casing, be careful and do not be confused with the change in weight. It is the difference in weight between the up and down cycle that counts, when the cement is displaced outside of the casing, the casing becomes lighter and when cement remains in casing, it becomes heavier, weight should remain fairly constant if casing is moving freely. Continue to reciprocate casing slowly until plug bumps.

ROTATION vs RECIPROCATION CASING MOVEMENT

Based on experiments, rotation appears to be more effective than reciprocation, for better cementation results, where casing is severely off center, casing cement drag forces tend to pull the cement into the by passed mud column instead of alongside during rotation of casing pipe.

Rotation of casing pipes at 15 to 25 RPM provides more pipe movement relative to annular fluid than reciprocating 5 to 7 metres on a one minute cycle but reciprocation can create lateral casing movement which alters the flow area and encourages bypassed mud displacement and also effects flow rate and velocity of fluid in annulus and creates surges in well bore which improves cementation quality.

Thread compounds with Teflon and/or silicon additives should be avoided where high torque ranges are required for rotation. The low friction character of these compounds may allow over torquing and excessive make up that exceeds pin or collar yield strength.

While reciprocating pickup loads should be less than pipe tensile strength. Stuck pipe is indicated by an increase in the weight difference on up and down strokes and not by weight increase alone. Though casing reciprocation is relatively easy in most single stage jobs. but reciprocation should be controlled to avoid pressure surges during the down stroke which could break weak formation or a swabbing effect during the up stroke which may cause a blowout.

Casing rotation can be easily practiced in shallow wells upto 2000 m straight holes. Fear of twisting of casing often prevents the use of this technique in deep crooked or directional wells. The quality of cement around the liner can be greatly improved by using special liner hangers allowing rotating the liner after the hanger is set. Reciprocation and rotation can certainly improve the cementation if done properly with mechanical aids.

A good cement job means carefully running of a casing and cementation without damaging the producing formation. A bad primary job creates difficulties for recovery of the oil and gas.

Different methods can be used to obtain a good cement job by:

(1) Reviewing well logs and production history of the area.

(2) Studying drilling data and past cementation jobs of the area.

(3) Proper design of cement slurry.

(4) Achieving maximum displacement of mud by:

(a) Proper centralization of casing.

(b) Controlled mud property.

(c) Displacement of cement in turbulence regime.

(d) Reciprocation and rotation of casing during displacement.

LINERS

RUNNING A LINER

A liner is a string of standard casing which does not extend all the way to the surface, but is hung from inside the previous casing string. The overlap depends on the purpose of the liner, and could vary from 50 ft (15 m) for drilling liners to as long as 500 ft (152 m) for production liners. Liners can be classified as follows:

- **Production Liners**: Run from the last casing to total depth, they replace production casing. Cementing is usually critical as zonal isolation is essential during production and any subsequent stimulation treatments that may be necessary.
- **Drilling or Intermediate Liners**: These are set primarily to case off and isolate zones of lost circulation, highly overpressured zones, sloughing shales, or plastic formations, so that drilling may be continued. Cementing these liners is often difficult due to the circumstances mentioned.

Tieback Stub Liners: These extend from the top of an existing liner to a point uphole inside another casing. They are generally used to repair damaged, worn, corroded, or deliberately perforated casing above the existing liner, and to provide additional protection against corrosion or pressure.

Similar to a casing, liner is made up joint by joint at the rotary table and lowered into the well. Float shoe and Float collar is lowered as usual but a landing collar is included one joint above the float collar . The centralizers are used carefully as the annulus clearance is small.

The liner hanger which supports the weight of the liner is installed at the top of the liner. The liner when landed is kept in tension on slips to avoid buckling due to its own weight.

The liners are run into the well with the help of drill pipe and special setting tool which is retrievable. The setting tool provides a pressure tight seal between the drill pipe and liner and holds the weight of liner. It also provides the housing for the wiper plug attached with shear pins.

After conditioning the mud the liner hanger is set hydraulically or mechanically and the setting tool is released.

CEMENTING THE LINER

After installing the cementing head, the pump down wiper plug is placed. After connecting the cementing lines from cementing units, preflush 01" spacer is pumped.lt is followed by cement slurry. After pumping of cement slurry pump down plug is released and is displaced by calculated amount of mud. This plug latches down with the liner wiper plug and both the plugs as one combination will land at landing collar and at this point a pressure rise will indicate the completion of displacement. Then the pressure is released to check the NRV (non return valve). If packer of liner hanger is used then packer is set. The setting tool is pulled out and made free from the liner hanger and excess cement is reversed out.

Precautions

(1) Enough excess cement must be planned to reverse out contaminated cement.

(2) Extra thickening time of cement slurry must be kept to allow the operation.

(3) If squeezing is necessary it should be done within thickening time before reversing out.

A liner is installed at the top of liner. This supports the weight of the liner string when set at the desired depth. Hence it is kept under tension which prevents the liner from buckling under its own weight. The hangers have slips which when set, provide the anchor to support the liner. Once the liner is cemented, the liner remains permanently in place.

Liner is usually run into the well using drillpipe and a special setting tool. The tool is retrievable i.e., it can be pulled out of the well with the pipe after the liner is run and cemented. It performs the following functions:

- A pressure-tight seal is provided between the drillpipe and liner. Hence the fluids which are pumped into the pipe have to circulate down inside the liner and out of the shoe before returning up the annulus.
- It can hold the weight of the liner because it is run into the well.
- It provides attachments for the liner wiper plug. The liner wiper plug which is attached by shear pins has a hole through its center to allow the passage of fluids and cement slurry until the pumpdown drillpipe plug closes it. Shearing of the pins will

take place because of applied pressure and behind the cement slurry the wiper plug can be pumped down the liner.

Before the hanger is set, with the liner is at the desired depth , connections are made and the liner and hole are completely circulated with the rig pumps. The mud is conditioned and hence ensures the circulation is possible before the liner is hung. In some deep liner setting assemblies, a circulation valve is also included, above the liner before closing the valve, allows circulation to be established.

Once the conditioning of mud occurs, the liner hanger is set, and the pipe and setting tool are then raised slightly which verifies that the tools are released from the liner. The seal assembly which holds the liner wiper plug is usually 3.0 to 4.6 m (10 to 15 ft) long to enable this operation to be performed without the seal between the liner and the pipe. This operation should be performed to make sure that the pipe and the setting tool can be freed from the liner after the cement is in place,

LINER CEMENTING PROCEDURES

1. Mud removal

Efficiency of the mud removal gives the success of any cement job. Liner cementing can be one of the most difficult cases. Mostly the annular space is small enough such that the pipe may not be well centralized. A 5-in OD liner hung from a 7-in casing string inside a 69/16-in drilled open hole will have a maximum clearance of 8 in, if the liner is perfectly centered. Because of thin, nonremovable mudcake on the wall of permeable formations the annular clearance will be less in some parts of the hole. Inhibition of the use of centralizers takes place because of crooked hole and small clearances between the casing and formation resulting in eccentration of liners. Actual borehole contact occurs under severe conditions. Under these circumstances it became difficult to remove mud for cement slurries.

Because of these reasons that pipe movement during diaplacement becomes critical. Bowman and Sherer (1988) reported that less than 20% of all liner jobs include plans to move the liner during cementing. Many industry misconceptions are there about liner reciprocation ans /or rotation –

1. After cementing, the fear of not becoming unlatched from the liner.
2. During drillpipe movement, a large/stronger string may be required for fear of drill string parting.
3. Excessive drag caused by centralizers
4. Swabbing or surging the pay zone
5. Because of moving the pipe hole deterioration which could lead to annulus bridging
6. Fear that the liner may become stuck and have to be cemented without the designed tension.

Actually the advantages of liner movement during cementing far outweigh the drawbacks listed above. Fewer problems would probably be experienced and certainly better cementing results would be achieved with the hole in good condition and correctly selected centralizers on the liner. Bowman and Sherer (1988) stated that, in their study of over 300 liner jobs, twice occurred that the inability to release the liner setting tool. One caused by premature setting of the cement, and the other because of a very early tool design which has been successfully modified.

Rotation has advantages over reciprocation, in many instances. Up and down motion would not remove the drilling fluid effectively if the liner is in contact with the hole at any point. However, pipe rotation would allow slurry to be dragged behind the pipe, hence ensuring a sheath of cement around the liner. As stated by Bowman and Sherer (1988) , the inability to rotate liners is often due to insufficient starting torque. The torque required for rotation will probably be much less assuming good centralizer design, once the insufficient starting torque has been overcome.

Because of the above problems, the use of adequate volumes of washes and spacers is even more critical in liner cementing than in casing cementing. The chances of a good cement bond increases by maximizing the contact time and washes and spacers should be used. Contact time can be improved by increasing the volume of the scavenger slurry in conventional casing strings. However slurry volumes can be critical because of the formation hydrostatic in a liner situation.

For mud removal, turbulent-flow-displacement techniques are more efficient than plug flow but care must be taken not exceed allowable downhole pressures. At low pump rates fortunately small annular clearances make it easier to accomplish turbulent flow. Spacer volumes may be designed to allow for the lower mud displacement efficiency of these techniques if a job must be performed using plug or laminar flow regimes.

REGULAR LINER CEMENTING

The liner cement head and manifold are installed on the drillpipe with the pumpdown slurry displacement plug placed between the two inlets. The plug releasing stem holds the plug in the cement head. The chemical wash or spacer is pumped down the pipe, after the cementing lines are rigged up and pressure tested. No bottom wiper plug is used ahead of the spacer or slurry. To obtain homogeneous slurry of desired density the cement slurry should be batch mixed if possible.

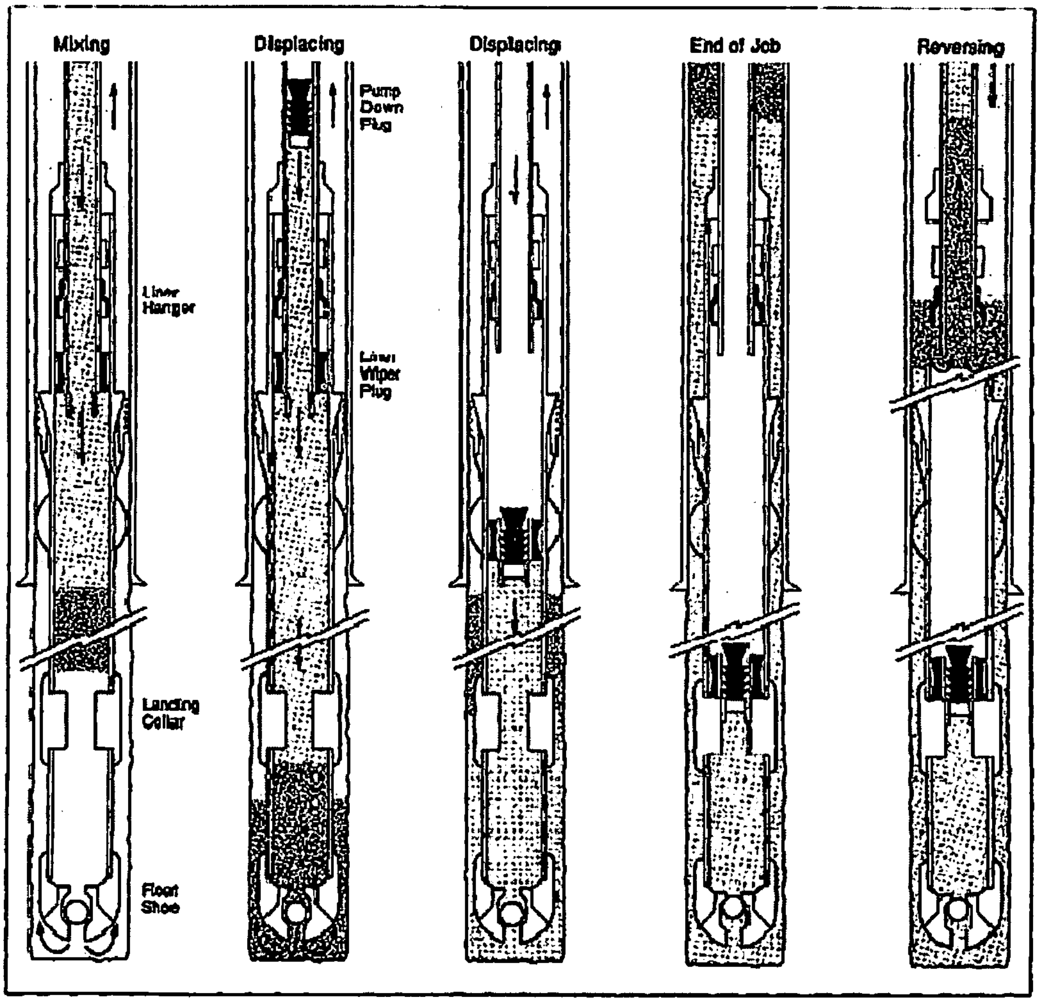


FIGURE 20

As shown in figure, once the slurry is mixed and pumped into the pipe, the pumpdown plug is dropped and displaced to the liner hanger. The pumpdown plug passes through the liner setting tool at this point and then latches into and seals the hole in the liner wiper plug. As an indication of the plug landing the surface pressure will rise. Further applied pressure of approx 1200 psi will shear the pins holding the liner wiper plug in place. Once released, the two plugs move as one inside the liner as displacement is continued. The plugs seat on the float or landing collar when the internal volume of the liner has been completely displaced and a further pressure rise will occur indicating completion of job.

The packer between the liner and the upper casing is set at this time if a packer-type liner hanger has been used, the setting tool is pulled free from the liner hanger, and any excess cement is reversed out. If no packer is incorporated into the hanger, the reversing out depends on the quantity of excess cement expected, and whether lost circulation is anticipated. This is an important decision in liner cementing design, as proper isolation of the liner/ casing annular space is critical.

The amount of cement excess must be carefully calculated by taking into account the well conditions and operator requirements. The following factors must be balanced.

- Sufficient excess cement must be planned for, if noncontaminated cement at the liner hanger is needed. A four-arm caliper should be run prior to the liner operation, and the slurry volume determined from the caliper logs. A recent study by Graves (1985) pointed out that hole volumes can change by as much as 31%.
- Displacement efficiency also becomes a key variable in determining cement slurry volumes; although 100% efficiency is the deal, it is not uncommon to have 60% to 80% displacement efficiency in liner cementing. The volumes become more adversely affected the longer the pipe to be cemented.
- If excess slurry is to be reversed out, weak formations could pose a problem. The thickening time of such slurries must be extended to allow for the reversing operation.
- If reversing out is not scheduled, operators usually do not want to drill out long columns of cement; therefore, the excess slurry may have to be limited. This could definitely affect the quality of cement around the overlapped interval.

PLANNED SQUEEZE

In two stages long liners can be cemented when they inverse weak formations which would not withstand the hydraulic static pressure of a long column of cement. The first stage is performed through the casing shoe using a limited, calculated amount of cement to cover the weak zone placing the cement top as close to the last casing shoe as possible. When the first stage is completed, the setting the tool and pipe are pulled out of the hole, and the cement is allowed to cure. Pipe with a standard squeeze packer is then run into the borehole, and the pacjer is set 2 or 3 joints above the liner hanger. The formation fracture pressure in the openhole section must be overcome to be able to squeeze cement into the annular space.

The advantages of the method are :-

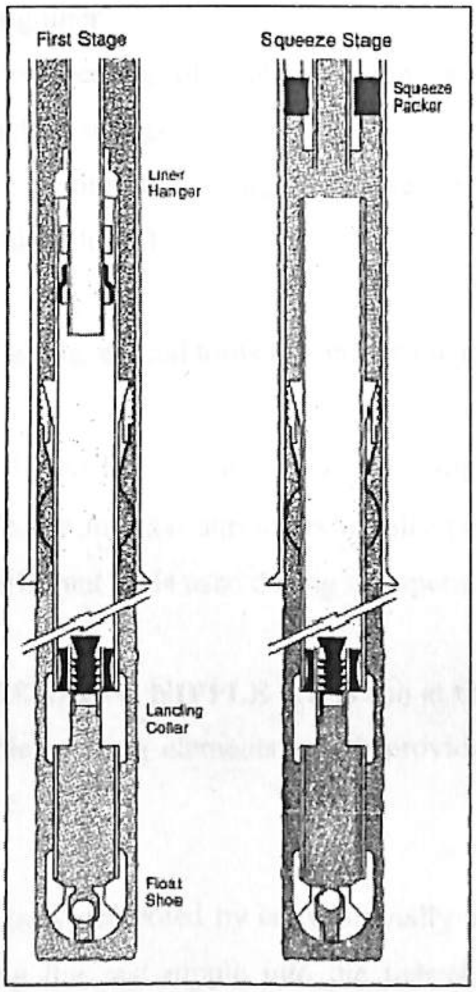
- It avoids the damage caused to weak productive formations
- Uncontaminated cement is placed at the liner hanger
- No excess cement is necessary.

The disadvantages include :-

- The complete annular space may not be cemented
- The technique is more expensive.

This procedure is obsolete, with the advent of ultra low-density microsphere and foamed cement systems.

FIGURE 21



WAITING-ON-CEMENT FOR LINERS

There may be considerable temperature differential between the bottom end top of the liner when long liners to be set. A slurry is designed for sufficient thickening time at the total depth may take a very long time to set at the liner top. After the cement develops the minimum compressive strength to withstand the shock caused by drilling tools, drilling of cement must be done.

TIEBACK LINERS

Situations may arise when it may be necessary to extend an existing liner further uphole with a tieback "stub" liner, or to surface with a tieback casing string. Reasons for running tieback stub liners or tieback casing are:-

- It is to cover up damaged casing above the top of an existing liner.
- To allow for multiple production strings, the need for a bigger casing on the top of existing liner.
- Selective testing of multiple zones to design future production assemblies and production strings.
- Before running the casing string , cementing of troublesome intervals (high pressure, sloughing shales)

To accomplish this, special tools to connect the two liner strings are used.

TIEBACK SLEEVE – It is installed on the top of the liner. It provides a receptacle for the sealing nipple. Its internal surface is usually polished and beveled on the top to guide the entry of the different tools used during the operation.

TIEBACK SEALING NIPPLE – It is run at the bottom of the tieback stub liner or casing. It has multiple packing elements which provide a seal against the polished surface of the tieback sleeve.

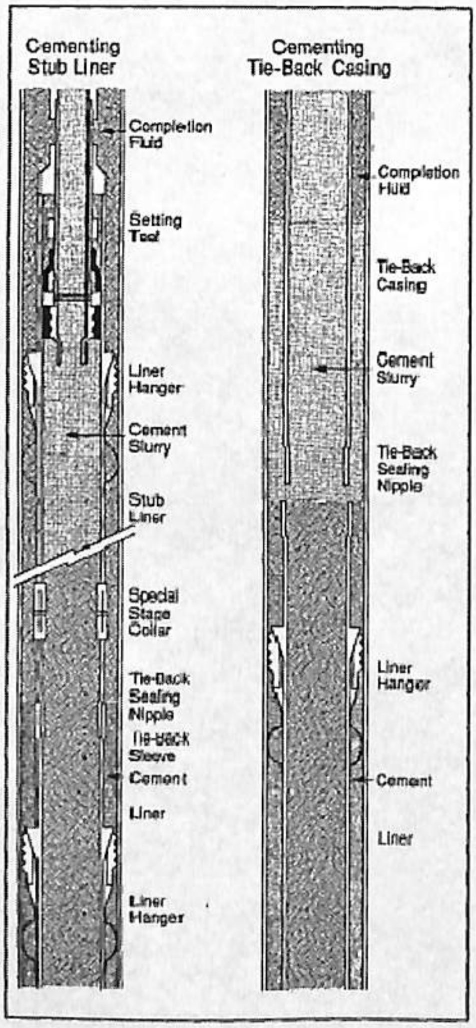
These are usually cemented by conventionally circulated the slurries. This job is performed before landing the seal nipple into the tieback sleeve. However, cementing may also be conducted with the tieback casing in place, using a stage collar located above the sealing nipple.

After tieback liners hangers have been set, tieback liners must be cemented and with the seal nipple landed into the sleeve. In the open position a stage collar can be run on top os the seal nipple. On the upper seal, the liner wiper plug must be able to close the upper ports.

The considerations are applicable to all cement jobs equally apply to tieback line cementing apart from the special procedures given above. Hydrostatic pressures are not significant because cementing is done between casings in most cases and usually with extended slurries.

The use of washes ahead of cement slurries will prevent mud/cement contamination and help to remove the mud from the annular space. This is important in case of tieback liner cementing, where no bottom plug is used to separate the mud from cement inside the liner. Compatibility with the cement must be checked or large volumes of fresh water be pumped ahead of the slurry if a completion fluid is in the hole. Salts used in completion brines may drastically affect a cement slurry's thickening time, causing a premature set resulting in excessively long times for the development of early compressive strength.

FIGURE 22



CEMENTING CALCULATIONS

The performance of calculations is an integral part of a cement job. Calculations are necessary to determine the properties of a cement system including density, yield, volume of mix and proportions of additives. In addition calculations are necessary to determine the volume requirements, pressures etc depending upon the type of cement job.

Categories of calculations includes :-

1. Cement slurry properties
2. Primary cement job design
3. Squeeze cement job design
4. Cement plug design
5. Foamed cement job design

CEMENT SLURRY PROPERTIES

The API spec 10 (1988) specifies an amount of water to be mixed with neat cements. These API water concentrations as well as the corresponding slurry densities assuming a specific gravity of 3.14 g/cm3 for Portland cement are dependent upon the class of cement (table 1) and are mainly a function of the cements' surface areas. The appropriate water concentration may change when additives are present in the system. The properties including like densities are discussed for well control and avoiding lost circulation, free water, sedimentation, rheology, compressive strength, fluid loss control and permeability.

Class	Mix Water (% BWOC)	Slurry Density (lb/gal)	Slurry Density (g/cm^3)	Yield (ft^3/sk)
A	46	15.6	1.87	1.18
B	46	15.6	1.87	1.18
C	56	14.8	1.77	1.32
D	38	16.45	1.97	1.05
E	38	16.45	1.97	1.05
F	38	16.45	1.97	1.05
G	44	15.8	1.89	1.15
H	38	16.45	1.97	1.05

1. Specific gravity of Portland cement

It varies between about 3.0 to 3.25 depending on the raw materials used in its manufacture to make the calculation precise, the specific gravity of each cement should be measured. A specific gravity of 3.14 is assumed.

2. Absolute and bulk volumes.

The absolute volume of a material is the volume occupied only by the material itself not including the volume occupied by the air surrounding its particles. Its bulk volume is the volume occupied by the dry material plus the air surrounding it. Portland cement normally has a bulk volume of 1 cubic foot for 94 lb which is referred as a "sack'. The absolute volume occupied by a 94-lb sack of cement is 3.59 U.S. gal or 0.48 ft3.Absolute value is different for other cements like commercial lightweight formulations or calcium aluminate cement.

Material	Absolute Volume (gal/lb)	(m³/T)	Specific Gravity
Barite	0.0278	0.231	4.33
Bentonite	0.0454	0.377	2.65
Coal (ground)	0.0925	0.769	1.30
Gilsonite	0.1123	0.935	1.06
Hematite	0.0244	0.202	4.95
Ilmenite	0.0270	0.225	4.44
Silica Sand	0.0454	0.377	2.65
NaCl (above saturation)	0,.0556	0.463	2.15
Fresh Water	0.1202	1.000	1.00

	Sack Weight (lb)	Bulk Volume (ft³/sk)	Absolute Volume (gal/lb)	(m³/T)
API Classes A through H	94	1.0	0.0382	0.3'7
Class J	94	1.0	0.0409	0.341
Trinity Lite-Wate™1	75	1.0	0.0409	0.375
TXI Lightweight	75	1.0	0.0425	0.355
Ciment Fondu™2	87.5	1.0	0.0373	0.312
Lumrite™3	94	1.0	0.0380	0.317

1 Trademark of Lafarge Corporation
2 Trademark of Lafarge Fondu International
3 Trademark of Lehigh Portland Cement Company.

Table 2 is a listing of bulk and absolute volumes of several cements presented in English and SI units. Table 3 is a listing of absolute and bulk volumes of cement additives of some commonly used materials.

Materials that dissolve in the water do not occupy as much space as their dry absolute volumes. For soluble additives like retarders, dispersants, and fluid-loss additives, which are added in relatively small amounts, the difference is negligible. However, salt (NaCl) is usually added in much larger concentrations; consequently, the difference must be taken into account.

3. Concentrations of Additives

The concentrations of most solid cement additives are expressed as a percentage by weight of cement (BWOC) or cementitious material. This method is also used for water. For example, if 35% (BWOC) silica sand is used in a cement blend, the amount for each sack of cement is 94 lb x0.35 =32.9 lb of silica sand. This result in 94 + 32.9 = 126.9 lb of total mix. The true percent of silica sand in the mix is 32.9 / 126.9 = 25.9%. Salt is a special exception. It is added by weight of mix water (BWOW). In addition, weighting materials such as barite are often added on a "pounds per sack (lb/Sk)" basis. This is done for convenience, as it eliminates the need to convert from percent BWOC to pounds in the bulk plant.

Liquid additive concentrations are most commonly expressed in gallons per sack of cement or cementitious material. For example, liquid sodium silicate has an absolute volume of 0.0859 gal/lb. If a concentration of 0.4 gal/Sk sodium silicate is prescribed, the weight of the material is (0.4 gal/Sk) / (0.0859 gal/lb) = 4.66 lb/Sk.

4. Slurry Density and Yield

The slurry density is calculated by adding the masses of the components of the cement slurry and dividing by the total of the absolute volumes occupied. In other words, to determine the density in lb/gal, divide the total pounds by the total gallons.

$$\rho_{slurry}\ (\text{lb/gal}) = \frac{lb_{cement} + lb_{water} + lb_{additives}}{gal_{cement} + gal_{water} + gal_{additives}}$$

The yield of a cement system is the volume occupied by one unit of the cement plus all of the additives and mix water. For cement measured in sacks, the yield is expressed in cubic feet per sack (ft"/sk). This value is then used to calculate the number of sacks required to achieve the desired fill-up in the annulus. Most slurry density calculations are performed on the basis of one sack of cement (94 lb). This simplifies the calculation of the slurry yield.

Amount of mix water required – This is necessary to ensure that enough water is available for the cementing operation. It is simply the gallons calculated above (4.97) multiplied by the number of sacks of cement to be mixed. When the calculations are performed by hand, the additives present in minor amounts (less than 1%) are ignored. Today, most laboratories use computers to calculate the slurry mixes and the density, and to determine the amounts of additives to use in the laboratory mix. All additives are taken into consideration.

5. Special additives

Salt - percentage by weight of water (BWOW). The absolute volume of NaCl when mixed with water is less than it is dry; since it is usually added at a high concentration, this must be reflected in the density and yield calculations. The absolute volume of salt is dependent upon its concentration in the water. Table C-4 is a listing of the absolute volumes that should be used for various salt concentrations.

Concentration (% BWOW)	Absolute Volume in Water (gal/lb)	(m³/T)
2	0.0371	0.310
4	0.0378	0.316
6	0.0384	0.321
8	0.0390	0.326
10	0.0394	0.329
12	0.0399	0.333
14	0.0403	0.336
16	0.0407	0.340
18	0.0412	0.344
20	0.0416	0.347
22	0.0420	0.351
24	0.0424	0.354
26	0.0428	0.357
28	0.0430	0.359
30	0.0433	0.361
34	0.0439	0.366
37.2 (saturated)	0.0442	0.369

Fly Ash - Fly ash is a pozzolanic extender which is often used to replace part of the cement. A special convention is used to describe fly ash/cement blends. These mixtures are normally written as ratios, with the ratio indicating the absolute volume contribution of the two components. A ratio of 35165 refers to 35% fly ash and 65% cement (the first number always represents the fly ash and the second the cement). Other common ratios are 50:50 and 75:25. The quantity of fly ash necessary to prepare 3.59 gallons of blend may be calculated from the following formula.

$Weight_{fly\ ash}$ = weight of cement replaced x $\frac{SG_{fly\ ash}}{SG_{cement}}$

The weight of the cement replaced is 94 lb minus the amount of cement remaining. For a 35:65 fly ash:cement blend, this is 94 lb - (0.65 x 94 lb) = 32.9 lb. Thus, for a 35:65 fly ash:cement blend, using a cement with a specific gravity of 3.14 and a fly ash with a specific gravity of 2.46, the required weight of fly ash is

$Weight_{fly\ ash}$= 32.9 lb x s = 25.8 lb.

The weight of cement is

$Weight_{cement}$=0.65 x 94Ib =61.1 lb.

The mixture of 25.8 lb of fly ash with 6 1.1 lb of cement weighs 86.9 lb. This mixture is referred to as the equivalent sack, because the absolute volume of the blend is 3.59 gal. For such systems, additive concentrations are calculated as a function of the equivalent sack, nor a 94-lb sack of Portland cement. Those calculated BWOC are calculated based on the 86.9-lb equivalent sack. There is much variation in the specific gravity of fly ashes, and it must be determined for each. The water requirements for the different fly ashes will vary according to the desired performance properties, fineness, and chemical composition.

PRIMARY CEMENTING CALCULATIONS

Calculations are used for primary cementing to determine the following.

1. Cement Volume (annular volume)
2. Water to 'Mix Cement
3. Cement Density and Yield
4. Displacement to Land Plug
5. Pump Pressure to Land Plug
6. Hydrostatic Pressure on Formation (fracture and pore pressures)

ANNULAR VOLUMES

Annular volumes are calculated to determine the amount of cement required to obtain the desired fill-up. Often, during the design stage, these calculations are performed based on the bit size plus an excess volume determined from experience in a field. This allows the service company to determine the total time required to mix and pump the cement, and displace it into the annulus.

After the casing point is reached, caliper logs should be run, and the cement volume should be adjusted based upon the actual hole size. Even with the caliper, it is common practice to use an excess volume to ensure fill-up by cement across all critical zones. The type of caliper can affect the amount of cement computed, and the resulting fill by the cement. Two- and three-arm calipers, with arms that operate together, may underestimate (or overestimate in the case of the two-arm caliper) the sizes of the holes tend to be oval. For these situations, four-arm calipers (with independently operating arms) are preferred. Normally, the interval being cemented is divided into increments, and the average hole diameters are estimated for each increment.

Having calculated the annular volume, an excess is added (normally 10% to 15%, based on experience in the field) and then the number of sacks required to fill this volume is computed based on the "yield" of the cement.

Excess factors must be based on experience, whether excess over caliper, or excess over bit size. Normally, the excess is calculated only for the openhole portion being cemented. This excess is to account for cement which may be lost into the formation, for enlarged hole, or for fluid which may be lost from the cement into permeable zones. When returns to the surface are desired or required, excess volumes may be used to assure that this is achieved.
The final step in calculating the amount of cement to be used is that which will remain in the shoe joints, between the float collar and the shoe. This is simply the casing volume between those two points. This volume should be added to that required based on the hole size and excess.

DENSITY, YIELD and MIX WATER

It is common for the calculate the volume of mix water required. This is the sum of the water required for mixing cement, spacers and preflushes, filling the dead volume of tanks, and for displacement. A safety factor or contingency factor volume should also be added.

DISPLACEMENT VOLUME TO LAND PLUG

The displacement volume to land the plug is simply a calculation of the capacity of the pipe. This is normally done by multiplying the length of the pipe (or segments of pipe if the entire string is not the same size or weight) times the capacity of that pipe. The capacity of the pipe is normally determined by looking in standard tables. The volume should be that between the pumps and the landing collar. A small excess volume may be pumped to allow for the compression of any air which may be entrained in the displacing fluid, and to account for pump inefficiency.

HYDROSTATIC PRESSURE ON THE FORMATION (FRACTURE AND PORE PRESSURE)

To ensure the safety of the well, it is necessary to determine if it is likely that the well will flow or be fractured during or after the cement treatment. This is done by calculating the hydrostatics at the critical points in the wellbore. Such calculations are a good first approximation, but friction pressure is particularly important when ascertaining the possibility of fracturing weak formations. Since the hydrostatic and friction pressures are constantly changing during a primary cement job, the only truly appropriate method is to use computerized placement simulators.

To determine the hydrostatic pressure component, the following equation is used,

$$P_h = 0.052 \times \rho \times H$$

Where,

P_h = hydrostatic pressure (psi)

P = density of the fluid (lb/gal)

H = height of column having density ρ, (ft)

If there are several fluids in the wellbore, then this calculation must be made for each, and the Po, for all the fluids totalled. This value should then be compared with the pressures of the critical formations to ensure that it lies between their pore pressures and fracturing pressures.

CHAPTER III

CASE STUDY

CASE STUDY 1:

A 2343 ft S profile directional well was drilled in the basin of Cambay, Gujarat. The operator was Reliance Industries Ltd (100%). The co-ordinates are latitude: **22□ 17' 23.9" North,** longitude **72□ 47' 45.7" East**. The kick off point is at **550 m**. The Azimuth is at **168.5 degree**. The ground level is at 24.773 m and rotary table elevation is at 33.913ft. Target depths are at 2250ft TVDSS, 2248ft TVDRT and 2343ft MDRT. Maximum angle is 29.33 deg.

Depth 0 to 400ft:

Collection of cutting is done at every 20 ft interval. Expected formation temperature is 27 deg @ GL and expected formation pressure is 8.6 - 9.5 ppg upto 880ft TVDRT. Logging is not carried out. Type of drilling is of rotary type. Discharge of pump is 51 ltr per sec/810 GPM. The pressure in stand pipe at section TD with maximum discharge is 84-91 kg/cm2/1200-1300 psi. BHA used is Bit + Bit Sub + 9 ½" x 3" Dc x 2 + 1 string stb + *" x 2 13/16" Dc x 6 + 5" HWDP x 6. Number of bit used is one. Weight on bit is 10-14 tons. Casing type used is of J-55, 54.50 ppf, BTC Range- III casing. Cement used is 15.35 ppg, API class "G" and the cement rised upto surface. Mud type is bentonite suspension, mud weight is 9.4 ppg and pH is 8.5-9.5.

Depth 400ft to 1490ft

Collection of cutting is done at every 5m interval. The dip of formation is gentle. Expected formation temperature is 50□ C @ 400 TDVRT and expected formation pressure is 9.5 - 10.6 ppg from 880ft-1430ft TVDRT. Expected mud loss/caving is occurred while drilling and cementation. LWD: Resistivity-Gamma-Annular Pressure – MWD and Wireline HDIL-DSL-CAL-SP-XMAC-ZDL-CN logging is carried. Type of drilling is of directional. MWD survey is carried.Discharge of pump is 41-44 ltrs per sec/650-700 GPM. The pressure in stand pipe at section TD with maximum discharge is 168-175 kg/cm2/2400-2500 psi. BHA used is Bit + Motor + 1 SS + NMDC (MWD) + 8" x 2 13/16" DC x 9 + 6 ½" x 2 13/16" DC x 6 + 5" HWDP x 6. Number of bit used is one. Weight on bit is 12-18 tons. Casing type used is of N-80, 40 ppf, BTC Range- III casing. Cement used is API Class "G" Lead - 13 ppg, 1190ft to 300ft or 100 ft inside 13 3/8" shoe Tail- 15.8 ppg, 1490ft to 1190ft. Mud type is WBM-K2SO4 Polymer, mud weight is 9.4 – 11.7ppg and pH is 8.5-9.5.

Depth 1430ft to 2284ft

Collection of cutting is done at every 5ft interval. Shows expected oil/ gas zone.Expected formation temperature is 91 deg C @ 1430 TDVRT & 124 deg C @ TD 2248ft TVDRT and expected formation pressure is 10.6 – 9.0 ppg from 1430ft TVDRT upto TD @ 2284 ft TVDRT. Possible hole cavings in Cambay Shales/ Olpad. LWD: Resistivity-Gamma-Annular Pressure – MWD and Wireline HDIL- DSL-CAL-SP-XMAC-ZDL-CN-EI-DCBIL-RCI-VSP-RCOR/SWC logging is carried. Type of drilling is of rotary motor drilling. MWD/LWD survey is carried. Discharge of pump is 22-25 ltrs per sec/350-400 GPM. The pressure in stand pipe at section TD with maximum discharge is 130-137 kg/cm2/1850-1950 psi. BHA used is Bit + 6 ½" Motor + NMDC (MWD/LWD) + 6 ½" x 2 13/16" DC x 1 + 1 string stb + 6 ½" x 2 13/16" DC x17+ 5" HWDP x 6. Number of bit used is one. Weight on bit is 10-15 tons. Casing type used is of K-55, 17 ppf, BTC Range- III casing & N-80, 17 ppf BTC Range III casing. Cement used is API Class "G" Tail- 15.8 ppg, 2343ft to 1300ft. Mud type is Syn. Oil Base Mud, mud weight is 11.7ppg will be increased if necessary and pH is 8.5-9.5.

INTRODUCTION

Reliance Industries Ltd. Oil Company is planning a land well in Cambay Basin Field, Cambay, Gujarat. The well will be CB10B-A1 and will be drilled and completed as an oil producer. There is probable non-proven hydrocarbon sand which will have to be evaluated before its commerciality is declared. The drill string failure has to be detected.

Solutions:

Critical Buckling Load:

Heavy Weight Drill Pipe (HWDP)

OD = 5"

ID = 3"

Weight = 50 lb/ft

Mud wt. = 10 ppg

I = 29.33°

Hole Size = D_h = 12 1/4" = 12.25'

$$F_{\text{critical buckling}} = \sqrt{\frac{9.82\times10^5\times(OD^4-ID^4)\times(\frac{wt}{ft})\times BF\times\sin I}{Dh-OD}}$$

$$= \sqrt{\frac{9.82\times10^8\times(5^4-3^4)\times50\times0.85\times\sin 29.33°}{12.25-5}}$$

= 39,165.83 lbs

It takes 39,165.83 lbs to buckle 5" OD HWDP in a 12.25" directional well of max angle 29.33°.

Neutral Point:

Given,

1st Drill collar DC_1 = 8"× $2\frac{13}{16}$ " × 9, length L_{dc1}= 31×9 = 279ft, Weight W_{dc} = 150.8 lb/ft +

2nd Drill collar DC_2= $6\,{}^1/_2$ " × $2\,{}^{13}/_{16}$ " × 6, length L_{dc2}= 31× 6 = 186ft, Weight W_{dc} = 92.8 lb/ft + HWDP = 5"× 3" × 6, length = 1082 ft, weight = 50 lb/ft.

Weight on bit WOB = Air weight of Drill Collars × BF × 0.85

$= DC_{length} \times W_{dc} \times BF \times 0.85$

$= [(279 \times 150.8) + (186 \times 92.8)] \times 0.85 \times 0.85$

= 42868.815 lb

$$L_{np1} = \frac{WOB}{Wdc \times BF \times cosI}$$

$$= \frac{42868.815}{150.8 \times 0.85 \times cos29.33}$$

$$= 383.61 \text{ ft} > 279\, ft$$

Length of neutral point L_{npl} is greater than length of 1st Drill Collar L_{dc1}.

$$L_{np2} = \frac{WOB - [Wdc1 \times Ldc1 \times BF \times cosI]}{Wdc2 \times BF \times cosI}$$

$$= \frac{42868.815 - [150.8 \times 279 \times 0.85 \times cos29.33]}{92.8 \times 0.85 \times cos29.33}$$

$$= 170 \text{ ft} < 186 \text{ ft } (L_{dc2})$$

Neutral point is in the Drill Collar 2 (DC_2)

Maximum Permissible Bending Stress (σ_b):

T = Tension load below dogleg

= [(279×150.8) + (186×92.8) + (482×50)]×0.85

=70919 lb

Pipe Area = Pipe weight (lb/ft)×0.2945

=50 lb/ft×0.2945

=14.725 in^2

Tension stress (σ_T) = 70919lb/14.725 = 4816psi

Maximum Permissible Bending Stress:

$$\sigma_b = 19{,}500 - \frac{10}{67}\sigma_b - \frac{0.6}{670^2}(\sigma T - 33{,}500)^2$$

$$= 19{,}500 - \frac{10}{67}(4816) - \frac{0.6}{670^2}(4816 - 33{,}500)^2$$

$$= 19{,}500 - 718.8 - 1100$$

$$= 17681.2 \text{ psi}$$

Maximum Dog Leg (DLS):

$$K = \sqrt{\frac{T}{EI}} = \sqrt{\frac{70919}{30\times10^6\times\frac{\pi}{64}(5^4-3^4)}} = \sqrt{\frac{70919}{801.4285\times10^6}} = 0.009407$$

$$c = \frac{432{,}000}{\pi} \times \frac{\sigma b}{ED} \times \frac{\tan h\ KL}{KL}$$

$$= 137509.87 \times \frac{17681.2}{30\times10^6\times5} \times \frac{\tan h\ 0.009407\times180}{0.009407\times180}$$ [L= 180in for range 2 pipe]

$= 9.572\times 0.26117$

$= 2.5°/100$ ft

Severe pipe damage occurs when the dog-leg severity is greater than 2.5°/100ft.

Torque and Drag Analysis:

The following survey data is give for the well with average inclination of 19.75°

Measured Depth MD, ft	I°	A°	DLS
700	16	168.5	2.5°/100 ft
800	18.5	168.5	2.5°/100 ft
900	21	168.5	2.5°/100 ft
1000	23.5	168.5	2.5°/100 ft

Tension below 1000ft is

$T = [(279 \times 150.8) + (186 \times 92.8) + (50 \times 82)] \times 0.85$

$= 63434$ lb

Mud weight = 10 ppg

Friction coefficient = 0.40

The air weight of 5" drill pipe is 50 lb/ft

Calculation the buoyant weight per 100 ft,

$W = (\text{Length}) \times (W_f)\times(BF)$

$= 100\times50\times0.85$

$= 4250$ lbs/ft

The drag force is equal to the normal force times the friction coefficient:

$$T=\mu F_N$$

$$F_N=\sqrt{\{2T\sin\left(\frac{\Delta I}{2}\right)+W\sin I(avg)\}^2+\{2T\sin\left(\frac{\Delta A}{2}\right)\ \sin I(avg)\}^2}$$

Making calculation at 100 ft interval,

63434 pound tension.

$I_{(avg)} = (21+23.5)/2 = 22.25$

$\Delta I = 23.5 - 21 = 2.5$

$\Delta A = 168.5 - 168.5 = 0$

$T=\mu F_N$

$$= 0.40\sqrt{\{2\times 63434\sin\left(\frac{2.5}{2}\right)+(-4250\sin(22.25)\}^2+\{2\times 63434\sin\left(\frac{0}{2}\right)\ \sin(50)\}^2}$$

$=0.40 \times 1158.3542$

$=463.341$ lbs drag

Therefore, the drag in the first 100 feet is 463.341 pounds. Note the weight 'W' must be entered as a negative number. Weight 'W' acts down along the axis of the borehole and is a negative force. Sign convention must be watched closely.

In order to calculate the drag in the next interval, the tension at 900 ft must be calculated:

$T_2=T_1-W\cos I_{(avg)}+\mu F_N$

$T_2 = 63434 - (-4250)(\cos 22.25) + 463.341$

$T_2 = 67830.89$ lbs

The tension at 900ft is 67830.89 lbs. Now the drag for the 100 foot interval between 800 and 900 ft can be calculated.

$I_{(avg)} = (18.5+21)/2 = 19.75$

$\Delta I = 21 - 18.5 = 2.5$

$\Delta A = 168.5 - 168.5 = 0$

$T=\mu F_N =$

$$0.40\sqrt{\{2\times 67830.89\sin\left(\frac{2.5}{2}\right)+(-4250\sin(19.75)\}^2+\{2\times 67830.89\sin\left(\frac{0}{2}\right)\ \sin(19.75)\}^2}$$

$=609.32$ lbs drag

$T_2=T_1-W\cos I_{(avg)}+\mu F_N$

T_2 =67830.89 – (- 4250) (cos 19.75) + 609.32

T_2 =72440.20 lbs

Now calculate the drag from 700 ft to 800 feet.

$I_{(avg)} = (16+18.5)/2 = 17.25$

$\Delta I = 18.5-16 = 2.5$

$\Delta A=168.5 - 168.5 = 0$

$T=\mu F_N=$

$$0.40\sqrt{\{2 \times 72440.20 \sin\left(\frac{2.5}{2}\right) + (-4250 \sin (17.25))\}^2 + \{2 \times 72440.20 \sin\left(\frac{0}{2}\right) \sin (17.25)\}^2}$$

=760.22 lbs drag

$T_2=T_1-W \cos I_{(avg)} + \mu F_N$

T_2 =72440.20– (- 4250) (cos 17.25) + 760.22

T_2 =77259.254 lbs

Total drag for the 300 foot interval 63434 lb tension is

Drag = 463.341 + 609.32 +760.22

Drag = 1832.881 lbs

Depth(ft)	Tension (lbs)	Interval Drag (lbs)
1000	63434	
900	67830.89	463.341
800	72440.20	609.32
700	77259.254	760.22
	TOTAL	1832.881

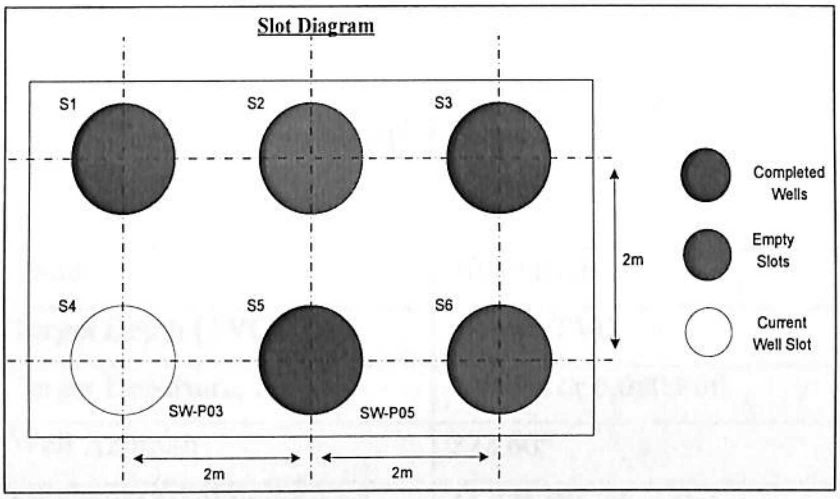
CASE STUDY 2:

INTRODUCTION

Big Country Oil Company is planning a land well in one of the six slot centres in Soggy Wetlands Field. The well will be SW-P03 and will be drilled and competed as an oil producer (27° API) with an anticipated flow of +/- 8000bpd. There is probable non-proven hydrocarbon sand which will have to be evaluated before its commerciality is declared.

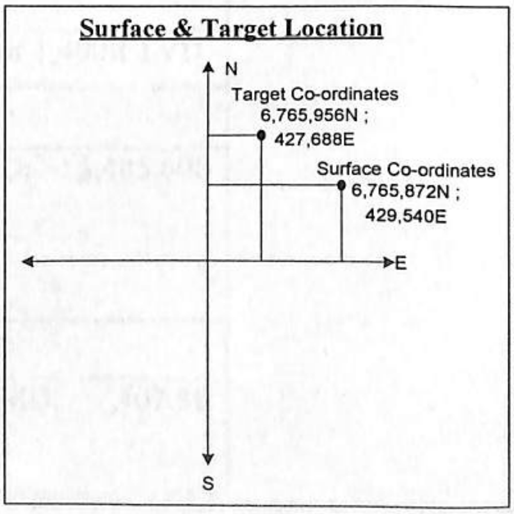
BRIEF SUMMARY

SW-P03 would be drilled from a six well-slot land drilling centre and will be drilled from slot number 4 (S4). The slot diagram is given below for reference.



The co-ordinates are as given below.

	Northing	Easting
Surface Co-ordinates (Slot Centre)	6,765,872	429,540
Target Co-ordinates (Top Sands)	6,765,956	427,688



A surface casing (18-5/8", 96.5 lb/ft, J55) has been batch set at +/-1200ft at no more than 1° inclination. The well will be drilled in three sections. A 17 ½" hole will be drilled first to 4000ft TVD (4486ft MD) and 13-3/8" casing set at +/- 4480ft MD. The hole section will include a build to 46.72° and holding the angle to the casing point. Then, a 12 ¼" hole section will be drilled through to 9300ft TVD (11,502ft MD) covering the over pressure shale zone. This section will have a hold section till 9,456ft MD after which the well inclination will drop to 16° which will be finally held to the casing point. After a detailed logging suite, 9-5/8" casing will be run across the zone to +/- 11,500ft MD. The final hole section drilled will be 8 ½" hole through the reservoir section holding the 16° hole inclination through the target top into the shale zone below the reservoir sands to 10,250ft TVD (12,490ft MD). A 7" liner will be set at +/- 12,485ft MD. The build up rate and drop off rate are both taken to be 2°/100ft.

Well Data

Datum	0ft @ RKB
Target Depth (TVD), D_4	9,600ft TVD
Target Departure, X_6	1,854m or 6,080.80ft
Well Azimuth	272.60°
Maximum Well Inclination	46.72° (Build angle)
Final well Inclination	16° (Drop angle)
Final Well TD (MD)	12,490ft
Final Well TD (TVD)	10,250ft
Kick off Point (KOP), D_1	1,400ft MD or 1,400ft TVD
Build up Rate (BUR)	2°/100ft
End of Build (EOB), D_2	3,736ft MD; 3,485.60ft TVD
End of Build displacement, X_2	900.79ft
Drop-off Point (DOP), D_3	9,456.37ft MD; 7,407.3ft TVD

Drop-off Point displacement, X_3	5,065.26ft
Drop-off Rate (DOR)	2°/100ft
End of Drop (EOD), D_5	10,992.4ft MD; 8,810.36 TVD
End of Drop displacement, X_4	5,855ft
Radius of curvature of build, r_1	2864.79ft
Radius of curvature of drop, r_2	2864.79ft

PROPOSED TOPS OF CEMENT JOBS

Casing Type	Casing Size (in)	Casing interval (ft MD)	Proposed Cement Top (ft MD)	Cement Interval (ft MD)
Conductor	20	0 – 20	0	0 - 20
Surface	18-5/8	0 – 1200	0	0 - 1200
Intermediate	13-3/8	0 – 4486	1000	1000 - 4486
Intermediate	9-5/8	0 – 11502	4250	4250 - 11502
Production Liner	7	11174 – 12490	11174	11174 - 12490

d) CEMENT PROGRAMME OUTLINE – Production Liner

The 7" liner is run through the reservoir pay zone and hence this will act as a production liner. So, the calculations and programme outline will be for the 7" production liner. The cementing programme will be carried out in single stage operation.

The slurry will be formulated with the High Temperature fluid loss additive FL-63L. This additive is used in this case to provide zero free water and fluid loss control to the slurry. Additionally, the composition will also include CD-31LS liquid dispersant to improve the slurry mixability & to induce turbulent flow and BA-58LS to provide anti-gas migration property.

A Sapp pre-flush will be used to thin the drilling mud for better clean-up. The spacer proposed for this job is Ultraflush II. This is a water based turbulent flow spacer, used to efficiently remove the drilling mud.

The slurry density with additives is 13.7ppg.

The cement programme outline is provided below.

WELL DATA	Unit	Figure		MUD DATA	Unit	Volume
Liner	Inches	7		Mud weight	Ppg	10.7
Liner weight	Lbs/ft	29		P_v	Cp	25
Liner Shoe depth	Feet MD	12490		Y_p	lbf/100 ft^2	22
Liner Collar depth	Feet MD	12370				
Top of liner	Feet MD	11174		**CHEMICAL WASH**	**Unit**	**Volume**
Previous casing	Inches	9 5/8		Sapp Spacer	bbls	70
Previous casing weight	Lbs/ft	53.5				
Previous casing shoe	Feet MD	11502				
Open hole	Inches	8.5				
Open hole excess	Percentage	30 %				
BHST (Assumption)	Degrees F	224		**SPACER**	**Unit**	**Volume**
Temperature gradient	DegF/100ft	2.07		Ultra-flush	bbls	60
Frac pressure gradient	Psi/ft	17.6				
Pore pressure gradient	Psi/ft	10.4				

FUNCTION/ADDITIVES	MATERIAL	Unit	Tail
Cement Class	Class G	Sk	118
Antifoam	FP-9L	Gal/sk	0.15
Strength Retrogration	S-8	% BWOC	25
Gas Block	BA-58LS	Gal/sk	0.18
Dispersant	CD-31LS	Gal/sk	0.16
Fluid Loss	FL-63L	Gal/sk	0.22
Retarder	R-8L	Gal/sk	0.22
Mix Water		Gal/sk	4.97
Density		Ppg	13.7
Yield		Cf/sk	1.99
Free Water		Percentage	Nil
P_v		Cp	168
Y_p		$Lbf/100ft^2$	10
Thickening time		hr:mins	4:50
Compressive Strength		24 hrs (psi)	2500

CEMENT VOLUME CALCULATIONS – Production Liner

The density of cement to be used for the cementing job depends on the fracture pressure of the formation being cemented. It is absolutely necessary that the cementing job is completed with minimal losses or no fracture.

To avoid the fracture of the formation, it is necessary to have the total hydrostatic pressure of mud, spacer and cement slurry in the annulus to not exceed the fracture pressure of the formation.

The fracture pressure of the formation is 17.6ppg EMW.

Now, for the liner cement job, the top of cement will be the top of liner inside the previous casing shoe. Hence, the hydrostatic pressure exerted in the annulus on the formation will be that of the cement in the annulus.

The cement class used is class G of 15.8ppg neat slurry density.

Known factors,

Top of liner	11174ft MD
Well TD	12490ft MD
Liner Shoe depth	12488ft MD
Previous casing shoe – 9 5/8”	11502ft MD
Open hole length	12490 – 11502 = 988ft MD
9 5/8” csg – 7” liner annulus length	11502 – 11174 = 328ft MD
Shoe track length (3jts)	3 x 39.36 = 118.08ft MD
Total annulus length	988 + 328 = 1316ft MD
7”, 29ppf liner ID	6.184 inches
9 5/8”, 47ppf casing ID	8.681 inches

Additives list:-

ADDITIVES	MATERIAL	Unit	Specific Gravity	% Addition	Addditives Amount
Antifoam	FP-9L	Gal/sk	1.24	1	0.15
Strength Retrogration	S-8	% BWOC	2.7	25	25
Gas Block	BA-58LS	Gal/sk	1.0	1.2	0.18
Dispersant	CD-31LS	Gal/sk	1.18	1.1	0.16
Fluid Loss	FL-63L	Gal/sk	1.22	1.5	0.22
Retarder	R-8L	Gal/sk	1.53	1.5	0.22

1. **Volume of class G slurry = Volume of shoe track + Volume of annular space + Volume of Pocket below casing shoe**

$= \left[\frac{\pi}{4} \times (6.184^2) \times \frac{1\,ft^2}{144 ftx^2} \times 118.08\,ft\right] + \left[\frac{\pi}{4}(8.5^2 - 7^2) \times \frac{1\,ft^2}{144 ftx^2} \times 1316\,ft\right] + \left[\frac{\pi}{4} \times (8.681^2) \times \frac{1\,ft^2}{144 ftx^2} \times 328\,ft\right]$

= 24.616 + 166.796 + 134.9

= 326.34 ft^3

Number of sacks of class G cement required = $\frac{326.34 ft^3}{1.15 \frac{ft^3}{sack}}$ = 284 sacks

2. **Volume of mix water**

= water require for class G cement

= 284 × 4.97 gal/sack [$Mix\ water$ = 4.97 gal/sack]

=1411.48 gal [1 gallon = 0.238 bbls]

3. **Water requirement**

Class G cement, slurry wt. = 15.8 lbs/gal

Mixing water = 4.97 gal/sack ; 8% Bentonite; specific gravity = 3.14

1 sack of class G cement = 94 lb which occupies a volume of 3.59 gal

Water required = y gal/sack

- **Weight of material, lb/sack**

= 94 + (0.08 × 94) + (8.33 × y)

= 94.14 + 8.33y

- **Volume of slurry, gal/sack**

$= \frac{94}{3.14 \times 8.33} + \frac{0.08 \times 94}{3.14 \times 8.33} + y$

= 3.87 + y

- **Water requirements using material balance equation**

94.14 + 8.33y = (3.87 + y) × 13.7 {Given density = 13.7 ppg}

→ 94.14 + 8.33y = 53.019 + 13.7y

→ 46.121 = 5.37y

→ **y =8.588 gal/sack of cement**

Water required = 8.588 gal/sack of cement

4. **Slurry yield, $ft^3/sack$**

$$=\frac{3.6+0.275+8.588}{7.48}$$

$$=1.136\ ft^3/sack$$

5. **Check Slurry density**

$$\text{Density, lb/gal} = \frac{94+(0.08\times94)+(8.33\times8.588)}{(3.87+8.588)}$$

$$= 13.7\ \text{ppg}$$

CHAPTER IV

RESULTS

The technical case study, dealing with "Detection of drill string failure and Cementation of production liner in a directional well" has been solved in the previous chapter.

The results obtained for technical case study is as follows:

Detection of drill string failures

- Critical Buckling Load = 39,165.83 lbs

It takes 39,165.83 lbs to buckle 5" OD HWDP in a 12.25" directional well of max angle 29.33°.

- Neutral Point:

$L_{np1} = 383.61$ ft $> 279\ ft$ (L_{dc1})

Length of neutral point L_{np1} is greater than length of 1st Drill Collar L_{dc1}.

$L_{np2} = 170$ ft < 186 ft (L_{dc2})

Neutral point is in the Drill Collar 2 (DC_2)

- Maximum Permissible Bending Stress (σ_b):

σ_b= 17681.2 psi

- Maximum Dog Leg (DLS):

c = 2.5°/100 ft

Severe pipe damage occurs when the dog-leg severity is greater than 2.5°/100ft.

- Torque and Drag Analysis:

Total drag for the 300 foot interval 63434 lb tension is

Drag = 463.341 + 609.32 +760.22

Drag = 1832.881 lbs

Depth(ft)	Tension (lbs)	Interval Drag (lbs)
1000	63434	
900	67830.89	463.341
800	72440.20	609.32
700	77259.254	760.22
	TOTAL	1832.881

Cementation of production liner

- Volume of class G slurry = 326.34 ft^3
- Number of sacks of class G cement required = 284 sacks
- Volume of mix water =1411.48 gal
- Water requirement=8.588 gal/sack of cement
- Slurry yield =1.136 ft^3/sack
- Check Slurry density = 13.7 ppg

CHAPTER V

CONCLUSIONS

Drill string failure does not occur due to a unique factor or a unique reason. There are lots of factors and reasons that could be accumulated and lead to drill string failure. The best way to avoid drill string failure before and while drilling is by running the program which could be diagnosed and detected carefully while the string is close to fail. An immediate action is taken to improve the drilling parameters to prevent the drill string failure.

Hence the major factors that causes drill string failure is dogleg severity, rotary bottom hole assembly, higher operating torque by drilling, bad formation and hole size.

The basic mechanics of primary and secondary cementation techniques has been presented in the above chapters. It is essential that the engineer be intimately familiar with the procedures and devices which are used for primary and secondary cementing. The values of all the required parameters have to be determined accurately.

CHAPTER VI

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CHAPTER VII

APPENDICES

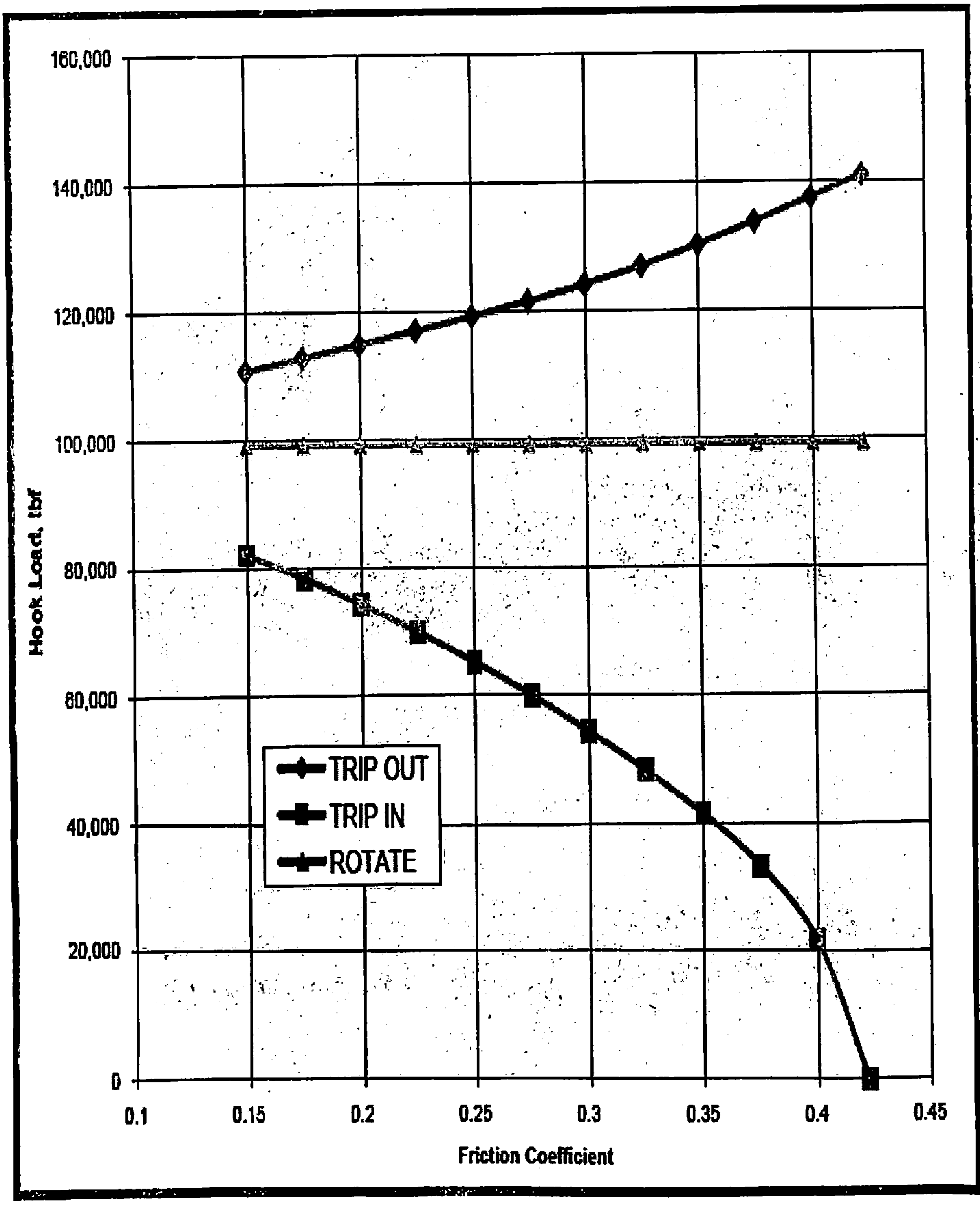
APPENDIX 1

FRICTION COEFFICIENT

The drag is a function of the friction coefficient and pipe normal force. If the friction coefficient is reduced by one-half, then the drag will be reduced by one-half for the same normal force. The friction coefficient can be affected by the mud type, bentonite content, solids content, and various additives in the mud. Generally, oil based muds will have the lowest friction coefficients and dry air and water will have the highest friction coefficients. Friction coefficients are usually lower in casing than in open hole. The friction coefficients also assume that the hole is clean and that the drill string is not tending to get differentially stuck.

Table showing Common Friction Coefficients Used in Torque and Drag Models

DRILLING FLUID	μ IN CASING	μ IN FORMATION
Oil or Synthetic Base Mud	0.15 to 0.20	0.17 to 0.25
Water Base Mud	0.25 to 0.35	0.25 to 0.40
Brine	0.30 to 0.40	0.30 to 0.40
Air and Mist	0.40 to 0.50	0.40 to 0.50



Plot showing hook load with changing friction coefficient for a horizontal