Drilling Engineering Workbook

A Distributed Learning Course

80270H Rev. B December 1995

Baker Hughes INTEQ
Training & Development
2520 W.W. Thorne
Houston, TX 77073
United States of America
713-625-4415

Drilling En[illegible]d Learning Course

FORWARD

The *Drilling Engineering Workbook* is a correspondence (distributed learning) course which covers the important elements of drilling a well. The emphasis is on the theory behind these drilling elements in order to develop a greater understanding of the principles involved in drilling a well.

This is a [illegible] learning course. Individuals should study each section an[illegible]stions at the end of the section. Supplementary reading is [illegible]. This workbook, along with the related suppleme[illegible] basis for [illegible] involved in these [illegible] involved [illegible] drilling a well.

Comment[illegible] of the course material, should be directed to the technical [illegible] Aberdeen.

PREFACE

At Baker Hughes INTEQ, we pride ourselves on our people and their level of profes[illegible]siveness and adaptability at the wellsite, where time, money[illegible]ends on rapid, reliable information management. The INTEQ [illegible]eer Training System (IN-FACTS), is a system for trainin[illegible]sional advancement for field operations person[illegible]hese applications.

The IN[illegible]ardized career development path which utilizes a progre[illegible] learning, to turn potential into fully developed expert[illegible]les Baker Hughes INTEQ personnel to embark on, and develop successful careers within INTEQ, Baker Hughes, and the oil industry.

IN-FA[illegible]ily understood, orderly flow of learning experi[illegible]al to conce[illegible]nto other disciplines. Movement through the IN-FACT[illegible]y industry experience, skills, and knowledge acqui[illegible] of formal and informal training programs.

The tr[illegible] and are composed of formal course work, self-paced distrib[illegible]and on-the-job training.

Requi[illegible]ent in our wellsite services includes increased knowl[illegible]ous subjects involved in "wellbore construction and m[illegible]ative learning package will focus on these topics.

IN[illegible]STRUC[illegible]ING THIS WORKBOOK

The aim of [illegible]workbook is to provide you with the information on various dr[illegible]can best be studied outside a classroom. It is not the intention [illegible]at you complete all the assignments as soon as possible. [illegible] you to spend enough time on each particular subject in[illegible] to every d[illegible]workbook includes:

- [illegible]
- [illegible]
- [illegible]d Hydraulics
- Casing and Cementing
- Bit Technology
- Drillstring Basi[illegible]
- Directional Drilling
- Horizontal Wel[illegible]
- Stuck Pipe
- Well Control
- Cost Analysis
- Technical Writ[illegible]

At the end of each chapter there will [illegible] "Self Check" [illegible] which are designed to assist you in understanding the infor[illegible]ecommended that you do not proceed until you are con[illegible]dent that you fully understand the concepts, calculations, and applications of the c[illegible]questions you may have to the Technical Training Depa[illegible]mer[illegible]nical expert.

When you have completed the work[illegible]gnment (Appendix A). This is to be completed and retur[illegible]ng Department or local administrator. Using this assignment[illegible] will be able to assist you in the next step.

Upon satisfactory completion of the "[illegible]etu[illegible]" [illegible] "E[illegible]of-Project" test will be necessary [illegible]equirements. Passing requirement for this test is 70%. This [illegible]ninistrated by the training department or the local administr[illegible]

Summary

This workbook is designed to review those engineering principles that are unique to drilling a well and to increase your knowledge and understanding of how these principles apply to wellsit[illegible]

There [illegible] when the learning process will never end. There are no real shortc[illegible]arn for yourself, with guidance and assistance from experi[illegible] field personnel, local experts and the Technical Training Department.

The ai[illegible] at Baker Hughes INTEQ is to develop your individual skills [illegible] fully competent, reliable professional within the oil indust[illegible] assist you in this.

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Comments

The Techn[illegible] Hughes INTEQ is interested in your comments and suggestio[illegible] learning workbook. We want to constantly improve our produ[illegible]rovements will be even better. Please take the time to contact [illegible]

If possibl[illegible]m, E-Mail, to contact us. This way we can route the E-Mail to [illegible] accept an[illegible]

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Baker Hu[illegible]hes INTEQ
2520 WW[illegible]
Houston, [illegible]
U.S.A.
fax (713) [illegible]5-5890

Baker H[illegible]
Barclayhill Place
Aberde[illegible] AB1 4PF
Scotlan[illegible]
fax (44) [illegible]

Attn.: Training & Development Department

Drilling Engineering Workbook

P/N 80270H

Manual Date:___________________________ Today's Date: _____________________

Your Name: ____________________________

District Office:___________________________ E-Mail Address: ___________________

Street Address: ____

City: ________________________ State: ____________ Zip Code: __________

Country: _____________________

Comments:

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Drilling Fluids And Hydraulics

Upon completion of this chapter, you should be able to:

- Recognize the components in the various types of drilling fluids.
- Explain [illegible] vantages of the most common types [illegible]
- Provi[illegible] a "mo[illegible]ning re[illegible]
- Calculate bar[illegible]nges are made to a pre-existing [illegible]d sys[illegible]
- Calculate PV [illegible]nd YP from Fann viscometer readings.
- Perform hydr[illegible]ver Law Model.

Additional R[illegible]

EXLOG, *MS-3026 The[illegible]y An[illegible] and Hydraulics*

Baker Hughes INTEQ, [illegible]

API, *The Rheology of Oil[illegible]*[illegible]dition, May 1985

API, *Recommended Pra[illegible]ice f[illegible] Drilling Mud Report Form*, Report [illegible], 2nd Edition, May 1982

Chilingarian, G.V. and Vorabu[illegible]*ng Fluids*, Elsevier Science Publishers, 1983

Bourgoyne Jr., Adam, et al; *Ap[illegible] Drilling Engineering*, SPE Textbook Series, Vol. 2, 1986

Moore, Preston; *Drilling Prac[illegible]*[illegible], PennWell Publishing Co.; Tulsa; 1986

Rogers, Walter F., *Composition and Properties of Oil Well Drilling Fluids*, Gulf Publishing [illegible]

Drilling Fluids

A drilling fluid is any fluid which is circulated through a well in order to remove cutti[illegible]ion will discuss fluids which have water o[illegible] mist and foam, which can be used as dr[illegible] this time.

A drilling flu[illegible] successfully. [illegible] important functions are:

1. Re[illegible] drilled cuttings from under the bit
2. Ca[illegible] the hole
3. Suspend cuttings in the fluid when circulation is stopped
4. Release [illegible]ce equipment
5. Allow c[illegible]
6. Provide [illegible]ugh h[illegible] formation pore pressure[illegible]
7. Prevent [illegible]
8. Protect p[illegible]ing [illegible] could impair producti[illegible]
9. Clean, c[illegible], and [illegible]

Occasionally, thes[illegible]id to act in conflicting ways. It can be se[illegible]hat ite[illegible] a high viscosity, whereas items #4-5 are best accomplished with a low viscosity. Items #6[illegible]ecause drilled solids will tend to pack into the p[illegible] producing formation.

Make-up of a Drilling Fluid

In its most basic form a drilling fluid is composed of a liquid (either water or oil) and some so[illegible], whenever the hydrostatic p[illegible] than the formation pore pressure (and[illegible] and permeable) a portion of the fluid will be flushe[illegible]nce excessive filtrate can cause borehole pro[illegible] is generally added. In ord[illegible]ssure to balance abnormal pore pressur[illegible] increased by adding a weight mater[illegible]

In summary, a d[illegible]

The Base Liquid[illegible]

- Water [illegible]
- Oil - [illegible]esel or [illegible]
- Mineral Oil o[illegible]

Dispersed Solids

- Colloidal par[illegible]cles [illegible]f various sizes

Dissolved Solids[illegible]

- Usuall[illegible] salts, [illegible]st is important

All drilling fluids have [illegible] the magnitude varies. These properties [illegible]nclud[illegible] density, viscosity, gel strength, filter cake, water loss, and e[illegible]

Normal Drilling Flui[illegible]s

Though this type [illegible] describe, it is hard to define and even more diffic[illegible] normal fluid generally means there is little effo[illegible] is simple to mak[illegible]

1. It is u[illegible] where no unexpected conditions occur
2. Th[illegible]ze, so its properties are in the range re[illegible]uired [illegible]
3. The ci[illegible] co[illegible]trol

[illegible] mud are shales and sands.

Since viscosity i[illegible] amount and condition of the colloidal clay is [illegible] used:

1. Water [illegible]
   (a) the[illegible]
   (b) can be u[illegible]
   (c) if filter c[illegible] and [illegible]
   - add coll[illegible]al cla[illegible] to system
2. Caustic Sod[illegible]
   (a) the[illegible]
   (b) use[illegible] than phosphate treatment

The upper [illegible] “normal” muds

1. Care must be taken not to add chemicals which may hinder the making [illegible]

2. Native c[illegible] used [illegible]

Special Drilling Fluids

These drilling flui[illegible] are made to combat particular abnormal hole [illegible] specific objectives. These are:

1. Special Objectives

   (a) [illegible]

   (b) [illegible] protection to producing zones

2. Ab[illegible]

   (a) long [illegible] sections

   (b) high [illegible] pressures

Lime Base Muds

1. Water b[illegible]
2. Treated with larg[illegible] lime. Added in that or[illegible]
3. Ratio of 2 lb caus[illegible] 5 lb lime per 1 barrel of mud
4. Will go through [illegible] highly viscous stage, but will become st[illegible]ble at [illegible]
5. Good p[illegible]

   (a) [illegible] amounts of contaminating salts

   (b) rema[illegible] high

6. Weakne[illegible] it has [illegible] to high bottom-[illegible]

Lime-Treat[illegible]

1. Similar to lime based mud - differ only in degree
2. A compromise [illegible] high temperature gelation pr[illegible]
   (a) use less [illegible]
   (b) not nearly [illegible] resistant to salt contamination

Emulsion Muds - Oil in Water

1. Oil can be added to [illegible] ial muds with good results
2. [illegible] necessary
3. Natural or special emulsifying agents hold oil in tight suspension after mixing [illegible]
4. Oils used a[illegible]
   (a) Crude o[illegible]
   (b) Diesel
   (c) any oil [illegible]
5. Oil content in mud [illegible]
6. Advantages [illegible]
   (a) very stable properties
   (b) easily maintained [illegible]
   (c) low filtration and [illegible]
   (d) faster penetration [illegible]
   (e) reduces down-hole friction
7. Major objec[illegible] mask any oil from the formations

Inhibited Muds

1. Muds with inhibited [illegible]
2. Large amounts of di[illegible]
3. High pH usually nec[illegible]
4. Designed to reduce t[illegible] swelling caused by filtrate - inhibit clay [illegible]

5. Disadv[illegible]

(a) need specialized electric logs

(b) requires much [illegible]

(c) low mud weig[illegible]il

(d) hard to increa[illegible]

(e) salt destroys natural filter cake building properties of clays

Gypsum Base Muds

1. A specialized inh[illegible]

(a) contained larg[illegible]

[illegible]sum to mud system

(c) filtra[illegible]

2. Advantages

(a) mud is stable [illegible]

(b) economical to [illegible]

(c) filtrate does n[illegible]

(d) high gel stren[illegible]

3. Disadvan[illegible]

(a) fine abrasives [illegible]

(b) retains gas in [illegible]

Oil Based Muds

1. Oil instead of wa[illegible]

2. Additives must b[illegible]

3. Generally pre-mi[illegible]

4. To incre[illegible] slaked lime may be added

5. Advantage[illegible]

(a) will not hydra[illegible]

(b) good lubricati[illegible]

[illegible]ill rates

6. Disadvanta[illegible]

(a) expensiv[illegible]

(b) dirty to [illegible]k wit[illegible]

(c) requires special [illegible]

(d) viscosity varies [illegible]

Inverted Emulsions

1. Water in oil emulsio[illegible]. Oil largest component, then water added. Order of addition is [illegible]

2. [illegible]ntages of oil muds, but cheaper. [illegible]

Salt Water [illegible]uds

1. Can be use[illegible] [illegible]

2. Weight can [illegible]

3. No filter ca[illegible] buildi[illegible] formations

Silicate Mu[illegible]

1. [illegible]ter

2. [illegible]les which prevents heaving or sloughing

3. Will be 12 [illegible]

4. Corrosive, [illegible]og results

Low Solids Muds

1. [illegible]d [illegible]t a minimum, which [illegible]

2. Three ways [illegible]

(a) water di[illegible]

(b) centrifu[illegible]

(c) circulat[illegible] [illegible]ough [illegible]arge surface area pits

3. When clays [illegible] chemicals [illegible]

4. [illegible] w, clay solids are replaced by organ[illegible]

5. Other ad[illegible]tages[illegible]

(a) good [illegible] volumes

(b) alwa[illegible]ive f[illegible]

6. Problem[illegible]

(a) excessive dilu[illegible]

(b) can b[illegible]

Drilling Fluid Classific[illegible]ion

Non-Dispersed Sy[illegible]em

This mud system consists o[illegible], and other lightly treated systems. Generally [illegible]ll.

[illegible]s

[illegible] reducers. No[illegible] or where problems with vis[illegible]sity occur. [illegible] system, though other products are [illegible]hemicals [illegible]e added to maintain specific mud[illegible]

Calcium-Tr[illegible]

This mud sy[illegible]sium to inhibit the hydration of formation cl[illegible]d calcium chloride are the main con[illegible]ystem.

Polymer Mu[illegible]

Polymers are[illegible], which are used to incre[illegible] the borehole.[illegible]-linked polymers, which have good shear-thinnin[illegible]

Low Solids [illegible]

This type of [illegible] Total solids should not be[illegible]nt should n[illegible] be greater than 3%. Dri[illegible]

Saturated S[illegible]

A saturated s[illegible] saltwater sys[illegible] from 6,000 to 189,000 ppm. Those [illegible] systems.

These muds con [illegible] water, then sodium chlori [illegible] or other salts (p [illegible] e clay, CMC or starch is added to main [illegible]

Oil-Based Mud [illegible]

There are two ty [illegible] where water is the dispersed phase [illegible] d), and 2) emulsion muds, [illegible] water is the continuous phas [illegible] added to control the rheological prop [illegible]

Air, Mist, Foa [illegible]

These "lower th [illegible] air or gas is inje [illegible] and can be used until appreciable amounts of water are encountered, 2) mist drilling is then used, which inv [illegible] drilling is used [illegible] encountered, which uses chemical deterg [illegible] a mud system in [illegible] the hydrostatic pressure.

Workover Mu [illegible]

Also called com [illegible] systems designed to 1) minimize forma [illegible] fracturing fluids [illegible] hydration. They are usually highly treated b [illegible] ds.

Drilling Fluid Additi [illegible]

Many substance [illegible] perform speciali [illegible] common functions are:

Alkalinity and [illegible]

Designed to con [illegible] of the drilling fluid. Most common a [illegible] rbonate of soda.

Bactericides

Used to reduce [illegible] bacteria count. Paraformaldehyde, caustic soda, lime and [illegible]

[illegible]

These are used t [illegible] e the contamination effects of calcium sulf [illegible] The most common are caustic soda, soda ash, [illegible]

Corrosion In[illegible]

Used to contr[illegible] hydrogen sulfide corrosion. Hydrated lim[illegible]ded to check this type of corrosion. O[illegible]osion inhibition properties.

Defoamers

These are us[illegible] salt and saturated saltwater mud systems[illegible]

Emulsifiers

Added to a m[illegible]mogeneous mixture of two liquids (oil and wate[illegible] modified lignosulfonates, fatty acids and amine de[illegible]

Filtrate Red[illegible]

These are us[illegible]t to the formations. The most commo[illegible]odium carboxymethylcellulose) and pre-gela[illegible]

Flocculants

These are us[illegible]les in suspension to form into bunches, ca[illegible] common are salt, hydrated lime, gypsu[illegible]ates.

Foaming Ag[illegible]

Most comm[illegible] foam in the [illegible]sence of water.

Lost Circul[illegible]

These inert s[illegible]s in the formations, to prevent the l[illegible]d. Nut plug (nut shells), and mica flakes are co[illegible]

Lubricants

These are us[illegible]cing the coefficient of friction. Cert[illegible] used.

Pipe-Freein[illegible]

Used as spot[illegible] lubricity and [illegible]nhibit formation hydration. Commonly used are oils, detergents, s[illegible]

Shale Control [illegible]

These are used to control the hydration, caving and disintegration of clay/shale formations [illegible], sodium silicate and calcium lignosu[illegible]

Surfactants

These are used to reduce the interfacial tension between contacting surfaces (oil/wa[illegible].).

Weighting Age[illegible]

Used to provide [illegible] the fluids specific gravity. Materials are ba[illegible] and galena.

Material Balance Equations

Material balance equations are used for calculating volumes and densities when two or [illegible] mixed together.

The Material [illegible]

$V_1W_1 + V_2W_2 \ldots = V_FW_F$ where: $V_1 + V_2 \ldots = V_F$

where: V_1 = Volume of first material to be mixed together
W_1 = Density of first material
V_2 = Volume of second material to be mixed together
W_2 = [illegible]
V_F = [illegible]
W_F = Density of tot[illegible] of all volumes mix[illegible]

The most commonly used vari[illegible]ons are:

Barite

1. Weight of a barrel of barite ($BaSO_4$) s.g. = 4.2 g/cc

   42 gal/bbl x 8.33 lb/gal x 4.2 = 1470 lb/bbl

   * s[illegible]cks, one barrel contains 14.70 sacks

2. Weight of a gallon of barite

   [illegible] lb/gal

Hematite

1. Weight of a barrel of hem[illegible] g/cc

   42 gal/bbl x 8.33 lb/gal x 5.0 = 1749 lb/bbl

2. Weight of a gallo[illegible]

   8.33 lb/gal x 5.0 = 41.65 lb/gal

Light Oil

1. Exampl[illegible] 41° API Gravity[illegible]

2. Weight of a gallon of oil

   [illegible] lb/gal

Example Problem #1-1:

Calculate how many sacks of barite are required to increase the density of an 800 barrel mud system from 12.7 lb/gal to 14.5 lb/gal.

Using: $V_1W_1 + V_2W_2 = V_FW_F$

where: V_1 = 800 bbls
W_1 = 12.7 lb/gal
V_2 = unknown volume of barite
W_2 = 34.9 lb/gal (density of barite)
V_F = $V_1 + V_2$ (or $800 + V_2$)
W_F = 14.5 lb/gal

therefore: $800(12.7) + V_2(34.9) = (800 + V_2)14.5$

$10{,}160 + 34.9V_2 = 11{,}600 + 14.5V_2$

$20.4V_2 = 1440$

V_2 = 70.6 bbls of barite

70.6 bbls x 14.7 sk/bbl = 1038 sacks of barite

Example Problem #1-2:

Calculate how much water and barite are required to make 800 barrels of a 10.5 lb/gal water-based drilling mud.

Using: $V_1W_1 + V_2W_2 = V_FW_F$

where: V_1 = unknown volume of water
W_1 = 8.33 lb/gal
V_2 = unknown volume of barite or $(800 - V_1)$
W_2 = 34.9 lb/gal
V_F = 800 bbls
W_F = 10.5 lb/gal

therefore: $V_1(8.33) + (800 - V_1)34.9 = 800(10.5)$

$8.33V_1 + 27920 - 34.9V_1 = 8400$

$-26.57V_1 = -19520$

V_1 = 735 bbls of water

V_2 = 800 bbls - 735 bbls = 65 bbls x 14.7 sk/bbl = 956 sacks

Oil-[illegible]luids

These fluids, because of their special nature of being a mixture of two immiscible li[illegible] special treatments and testing procedures.

Dispersed Ph[illegible] of finely divided droplets.

Continuous Phase: The liquid present in the form of the matrix in which [illegible]

To keep thes[illegible] [illegible] [illegible]ulsifier is added to form an interfacial film around the dispersed [illegible] each other, so they remain dispersed.

The effective [illegible] depends on the alkalinity and electrolytes [illegible] the drilling f[illegible]

Electrical Stability

The electrical stability (E.S.) of an oil-based drilling fluid is the stability of the emulsion [illegible] amount of current required to break the emulsifier d[illegible]

1. An [illegible]ed into the drilling fluid and the vo[illegible]

   a. [illegible] breakdown is indicated by current [illegible]

   b. [illegible] as the amount of voltage at the [illegible]

2. E.S. [illegible] reading and temperature of the dri[illegible]

   a. [illegible]

   b. [illegible]

   c. during drilling the E.S. can increase to 800 or higher

Oil: Water Ratio

The Oil: Water Ratio is defined as the percent oil in the liquid phase and the percent water in the liq[illegible] from a retort analysis of the dr[illegible]

Example Problem: #1.3

Determine the oil: [illegible] retort analysis:

oil = 54% water [illegible] solids [illegible]

$oil\% = \frac{5[illegible]}{54 + [illegible]}$ [illegible]

The oil: water ratio [illegible] 60: [illegible]

To change the oil: water [illegible] ratio, and water [illegible], the oil req[illegible]red to increase the oil: [illegible]

[illegible]

where: $\%V_{[illegible]}$ = [illegible] volume (%)
$\%V_{[illegible]}$ = [illegible]
$\%V_i$ = initial total liquid volume (%)
$V_{[illegible]}$ = total fluid volume (bbls)

The water required to reduce the oil: water [illegible]

[illegible]

where: $\%V_{[illegible]}$ = initial % of oil by [illegible]
$\%V_{[illegible]}$ = final % of oil in [illegible]

Aniline Point

Another common term used when [illegible] the aniline point [illegible] which an oil con[illegible] 50% by volume aniline (C[illegible] cloudy. The solvent powers for rubber are related to [illegible] aniline. Oils having an aniline point above 140°F are [illegible] to use.

Drilling Fluid Economics

Table 1: Typical Composition/Costs - Unweighted Drilling Fluid
([illegible] to mix one barrel)

Component	Volume	Cost($) Unit	Cost($) Component
Lo[illegible]			
Diesel Oil	0.8 bbl	142.00	33.60
Emulsifier/Wetting Agent	6.0 lbs	1.50	9.00
Water			
Gel	[illegible]	[illegible]	6.00
Calcium Chl[illegible]	[illegible]	[illegible]	[illegible]
Lime	[illegible]	0.10	0.30

Total Cost ([illegible]			52.9[illegible]
Fresh-Water Dispersed Drilling Fluid			
Bentonite	25.0 lbs	0.07	1.75
Chrome Lignosulfonate	6.0 lbs	0.50	3.00
Lignite	4.0 lbs	0.30	1.20
Caustic Soda	3.0 lbs	0.40	1.20
Water	1.0 bbl	-	-

Total Cost (1 bbl)			7.15
KCl Polymer Drilling Fluid			
Bentonite (pre-mixed w/ H_2O)	5.0 lbs	0.07	0.35
Chrome Lignosulfonate	1.0 lbs	0.50	0.50
Caustic Soda	0.3 lbs	0.40	0.12
Potassium Chloride	35.0 lbs	0.20	7.00
Polyanionic Cellulose	2.0 lbs	3.00	6.00
Potassium Hydroxide	0.3 lbs	0.80	0.24

Total Cost (1 bbl)			14.21

Table 2: Typi[illegible]5 ppg Drilling Fluid
(Barrels or pounds [illegible] barrel)

Component	Volume	Cost($) Unit	Cost($) Component
Low Colloid Oil Based Drilling Fluid			
Diesel Oil	[illegible].55 bbl	42.00	23.10
Emulsifier/Wetting Agent	8.0 lbs	1.50	12.00
Water	[illegible]	[illegible]	[illegible]
Gel	4.0 lbs	1.20	4.80
Calcium Chloride	[illegible]	0.20	3.00
Lime	[illegible]	0.10	0.30
Barite	[illegible]	0.07	35.00

Total Cost (1 bbl)			78.20
Fresh [illegible]			
Bentonite	[illegible]	0.07	1.40
Chrome Lignosulfonate	9.0 lbs	0.50	4.50
Lignite	6.0 lbs	0.30	1.80
Caustic Soda	4.0 lbs	0.40	1.60
Barite	450.0 lbs	0.07	31.50
Water	1.0 bbl	-	-

Total Cost (1 bbl)			40.80
KCl Polymer Drilling Fluid			
Bentonite (pre-mixed w/ H_2O)	5.0 lbs	0.07	0.35
Chrome Lignosulfonate	1.0 lbs	0.50	0.50
Caustic Soda	0.3 lbs	0.40	0.12
Potassium Chloride	24.0 lbs	0.20	4.80
Polyinosinic Cellulose	3.0 lbs	3.00	9.00
Modified Starch	5.0 lbs	1.00	5.00
Potassium Hydroxide	0.3 lbs	0.80	0.24
Barite	400.0 lbs	0.07	28.00

Total Cost (1 bbl)			43.01

Table 3: Drilli[illegible]

Drilling Conditions													
High Angle Hole ([illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	x			x	x	x		x
Very Reactive Shales		x	x	x	x	x	x	x	x	x	x		x
Sticking Problems	x			x		x	x	x	x	x	x		
Lost Circulation	x	x	x		x		x				x		
Mud Weights (>16ppg)	x	x			x	x		x	x			x	x
Temperatures (>325F)						x		x	x			x	x
Gas Hydrates				x		x					x		
Recommended Mud Type													
Oil-Based						1		1	1	1	2	1	1
Lignosulfonate	1	2					1	2				2	
Polymer			2	1			2	3		2	1		3
Potassium Lime		1	1		1		3			3			2

To use this chart: If the well was a high angle well with possible reactive shales and the possibility of differential sticking, drilling fluid choices (in order of preference) are: (1) oil-base, (2) polymer and (3) potassium lime

Drilling [illegible]

For those working at wellsites, a basic knowledge of "fluid" properties is required, especi[illegible]nguish fluids from solids. Fluids can be ei[illegible]re highly compressible and its volume b[illegible]emperature. Liquids, on the other han[illegible]ble, and their volume being only slightly dep[illegible]

We shall be dea[illegible] text. Since drilling muds are commonly refer[illegible]e term "fluid" will be used throughout the t[illegible] drilling fluid wil[illegible] be ignored.

A cube of water [illegible]h edge weighs 62.4 lbs. The density or "spec[illegible] the gravitational [illegible]ass density" or just density. This same cube of w[illegible]ressure of 62.4 lbs distributed evenly over its b[illegible]

Hydrostatic pres[illegible]

H_p = (Dv - Fl[illegible]

where: [illegible]

[illegible]

[illegible]

MD = fluid density.

g = gravitational constant.

Note that this is [illegible] depth and fluid density.

In oilfield units [illegible] conversion facto[illegible] 0.[illegible]tor is derived from:

There are 7.48 g[illegible]

because: lb/gal x [illegible]

and: 7.48/144 = psi/ft/lb/gal

therefore: 0.0519 = psi/ft/lb/gal

A drilling fluid of 8.34 lb/gal exerts a [illegible]

8.34 x 0.0519 = [illegible]

In SI units the c[illegible], therefore:

Hp (kPa) = M[illegible]

Pre[illegible]

Pressure is de[illegible]ned as the force acting on a unit area. In the oil field, pressure is co[illegible] per square inch (psi).

At the wellsi[illegible] the pressures throughout the circulatin[illegible] system. We may need to know the pressure at a particular point in the [illegible] we may wan[illegible] to pump a certain mud volume at a [illegible] mechanisms, [illegible]tatic, hydraulic, or **imposed.** Al[illegible] force acting on a unit area, even though their [illegible]

Note: *[illegible]he pressure at any given point in the circulating system [illegible] pressures wh[illegible]*

Hydrostatic Pressure

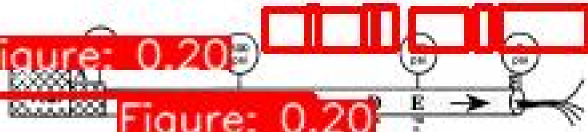
As mentione[illegible] earlier, this is [illegible] colu[illegible]n of fluid due to its density [illegible] always exists and may be calculated whether the [illegible] It can be calculated using:

$$Hp(psi) = MW \quad 0.0519 \quad TVD(ft)$$

Hydraulic Pressure

This is the pr[illegible] drilling fluid through pipe. [illegible] by the mud pump in order to move the dri[illegible] around the system and back to the flowline. [illegible] **Pressure** wi[illegible]. This type of pressure can be calculated at [illegible] point in the circulating system.

Pressure dro[illegible] or pres[illegible] loss [illegible] fluid over a [illegible]tance, for example;



the hydraulic [illegible] at point B in the figure is 600 psi. How[illegible] 300 psi is needed to pump the mud from point A to point B.

The hydraulic p[illegible]t point E in the figure is 225 psi. Howe[illegible]nt E is 675 psi. That is, 675 psi is requi[illegible] point E. (300 psi from A to B and 375 [illegible]

Exercise 1-4: [illegible] a[illegible]d D?

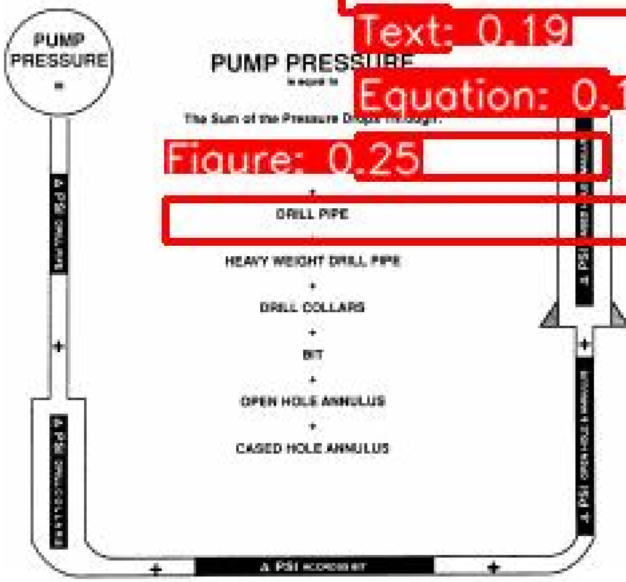
P[illegible]int C ________ psi [illegible]

Exercise 1-5: What is the pressure [illegible]rop (loss) between the following points?

A to C ________ psi B to C ________ psi

B to D ________ psi [illegible]

The total system pressure loss in the [illegible] is 900 psi.



Note: *The pressure at any given point in the circulating system is the sum of the hydrostatic, hydraulic, and imposed pressures which exist at that point.*

Typically, hy[illegible] in order to:

- Determine the total pressure being exerted at the casing shoe (generally th[illegible]ing system); the bottom of the [illegible] this pressure is d[illegible] a mud density equivalent a[illegible] Density) for tha[illegible]
- Determine the [illegible]
  - mud propert[illegible]
  - drill string c[illegible]
  - bit size
  - total flow[illegible]
  - flow rate
- Determine th[illegible]
  - maximum pum[illegible]
  - mud properties
  - drill string conf[illegible]
  - bit size
  - flow rate

Imposed Pressure

These are external p[illegible]nto the well. Since the well is open to the [illegible] imposed pressure. This typ[illegible]formly throughout the shut-in well [illegible] from:

1. the pumps (i.e. w[illegible]
2. the formation (i.e. when the well kicks)

Pr[illegible] Pump

[illegible] on page 1-21 is shut in (annular preventer & [illegible]mall amount of mud is pumped into [illegible] pressure will begin to increase immediately. [illegible]**osed pressure**, and is felt uniformly throughout t[illegible]

As an examp[illegible] pressure (90[illegible] bottom of the hole [illegible]he circulating system.

Such procedures a[illegible] string. It is referred to as testing the casi[illegible] press[illegible]shoe can withstand. Under normal conditions, the formation [illegible] with depth. This means that formations norm[illegible]e harder to fracture, as depth increases.

Note: *Un[illegible]er normal conditions, the weakest point in the ann[illegible]*

It is possible to conduct three diffe[illegible]e tests:

- Leak-OffTest: Pumping into the shut-in well continues until mud is lost to [illegible]d by a non-linear relationship betwe[illegible]
- Pressure [illegible] imposed (pum[illegible]ithout any loss of mud into the forma[illegible]
- Fracture Test: P[illegible] Although this type o[illegible]test is occasionally done, it is not a normal way of condu[illegible]

Exercise 1-6: After setting 13[illegible] shoe was drilled [illegible]t was run. Leak-off pressure [illegible] conducted with a mud density of 12.8 ppg in the hole. Calculat[illegible]

Pressure @ Shoe = [illegible]
Gradient @ Shoe = [illegible]
EQMD @ Shoe = ______ ppg

Exercise 1-7: After running the leak-[illegible]se, drilling proceede[illegible] density was increase[illegible]-off test was conducted. The leak-o[illegible]alculate the following:

Pressure @ Shoe = ______ psi [illegible] ______ psi

Gradient @ Shoe = ______ psi/ft [illegible]ft

EQMD @ Shoe = ______ ppg [illegible]

Pressure @ 10,000 ft = ______ psi [illegible] ______ psi

Gradient @ 10,000 ft. = ______ psi[illegible] psi/ft

EQMD @ 10,000 ft = = ______ pp[illegible]

Exercise 1-8: If while drilling at [illegible] of 14.4 ppg, a leak-off test had b[illegible] the leak-off pressure (pump pr[illegible] formation at the casing shoe [illegible] the experienced the ex[illegible] exercise.

Leak-Off pressure [illegible]

If the formation at the shoe is the weakest point in the borehole at what depth did the formation take mud [illegible] ft. (Hint: compare the values of EQM[illegible] calculated.)

Pressure Impos[illegible]

Imposed pre[illegible] formation. If formation pressure exc[illegible], and the well is shut-in, the pressure differential between the hydrostatic of the drilling fluid and the formation pressure, wil[illegible] at th[illegible] different readings will be noted. These will be the drillpipe (pump) pressure and the casing (choke) pressure.

- If no [illegible], then the hydrostatic pressure in [illegible] equa[illegible]
- Usua[illegible] will have a density less than the drill[illegible] hydro[illegible] will be less than the hydrostatic press[illegible] ce the formation pressure is constant for th[illegible] annu[illegible] differ[illegible] The s[illegible] be less than the annular pressure sinc[illegible]

Exercise 1-9: Whil[illegible] density of 14.4 ppg, the well [illegible] After the system stabil[illegible] entered [illegible]

What is [illegible] kicking formation?

____

What m[illegible] the kicking formatio[illegible]

Exercise 1.10: The formation fluid fro[illegible]sity of 6.8 ppg. The influx co[illegible] annulus.

What is the surface ca[illegible] ________ psi

What is the pressure o[illegible]si

Depending on the situation, one or m[illegible] may exist in the well at any given time. If [illegible] in the well bore, it exists everywhere in the system. However, it's magnitude may vary throughout the s[illegible]

Pascal's Law

"The pressure a[illegible] in all directions. Any pressure applie[illegible] throughout the fluid."

[illegible] when applied to dr[illegible]ling practices are important. When a well is shut in during a kick, the pressure is exerted throughout the [illegible]. Which means formations uphole experience the same pressur[illegible]

Dril[illegible]

One of the most important reports at the wellsite is the daily drilling fluid report, or "m[illegible]ining basic well and rig information, [illegible] costs, the mud report will contain a list[illegible]. To maintain the required prop[illegible] the drilling fluid. The most importa[illegible]

Density [illegible]

The density [illegible]
As mentioned earlier, fresh water has a density of 8.34 lb/gal, with a [illegible]nt of 0.433 psi/ft. As long as the to[illegible] [illegible]

Since this is [illegible]eight materia[illegible] must be added to the fluid, th[illegible]d hematite.

The drilling [illegible] using a "mud balance". This balance cont[illegible] weight on the[illegible] beam is inscribed with a graduated sc[illegible] a movable rider.

When the cu[illegible]r, steel shot is added to the counter weight conta[illegible] scribe line.

During wells[illegible] checked by filling the cup with drilling [illegible] the level bubble indicates the beam is bala[illegible] using the position of the rider.

Plastic Viscosity [illegible]s)

The plastic v[illegible] is calculated by measuring the shear rate and stress of the [illegible]sing a Fann viscometer, which is a ro[illegible] two speed m[illegible]d electric model. The two speed model [illegible]

The Fann vis[illegible]
When the ou[illegible]own speed, torque is transmitted through the [illegible] where the to[illegible]ar rate is the rotational speed of the sleeve and th[illegible] applied to the bob, measured as [illegible]
[illegible]d to be converted.

Shear rate is the [illegible] ers move past one another per unit distance [illegible] l seconds (i.e. (ft/sec)/ft) and is usually writte [illegible] the dial reading [illegible]

The units of visc [illegible] as follows:

Viscosity (poise [illegible]

where: F = F [illegible]

A = A [illegible]

V = V [illegible]

H = D [illegible]

This produces v [illegible] cosity a [illegible] Dy [illegible] es (sec/cm²) or poise [illegible]

The Fann viscometer reading i [illegible] btain shear stress in lb/100ft²; or mul [illegible] shear rate in second⁻¹ to get Dynes/cm².

Viscosity then becomes:

511 x dial reading / shear rate (sec⁻¹)

since 511 sec⁻¹ = 300 rpm

or (300 x [illegible] ar rpm

The viscometer [illegible] used at 300 rpm [illegible]

For Non-Newto [illegible] hear-stre [illegible] s not constant and va [illegible] With a Bingham plastic [illegible] uid, a finite force is re [illegible] crease of shear-stress with shear-rate. To obtain a value for this constant [illegible] te of increase, readings are tak [illegible] and 600 rpm). The [illegible] slope of the shear-stre [illegible] ity. The "apparent visco [illegible] 2. This is a measure of that [illegible] between solids i [illegible] uids and the shearing layers of the mud itself.

We can see that [illegible] us control over our PV! This leads to "Why a [illegible] Since the viscosity of the mud is one of th [illegible] the mud, the sus [illegible] terials, and pressure surges applied to the fo [illegible] obvious that inc [illegible] may increase the mud density), so a balance must be found in which the correct mud [illegible] are maintained without exerting unnecessary [illegible]

In the mud system, we have solids that are an integral part of the mud (bentonite, [illegible] limestone, [illegible] increased by the addition of barite or [illegible] The PV is also a [illegible] phase of the mud (as temperature [illegible], and the PV will decrease).

Several meth[illegible] of which wil[illegible]

1. **Di**[illegible]
2. **Sh**[illegible] "b[illegible]oid hosing water on the screens as [illegible]
3. **Ce**[illegible] tot[illegible]
4. **Desande**[illegible] sized pa[illegible]

To increase the vis[illegible]ity of [illegible] mud chemicals" can be added. These are [illegible] and gums (Guar or Xanthan) are also used.

The polymer viscosifiers [illegible] Most polymers provide [illegible] allows viscosity to be maintained while circulating pressures are reduced.

Yield Point

This parameter is also obtained from the viscometer. The yield point (YP), as mentioned [illegible] the electro-chemical attractive forces within the m[illegible] positive and [illegible] near or on the particle's surfaces. With this in [illegible] properties of the mud solids, the volume concentration of the solids, and the concentr[illegible] within the fluid phase.

The yield po[illegible] field by eithe[illegible]

YP = 300 rpm reading - PV

[illegible] rpm reading) - 600 rpm reading

This gives a Bin[illegible]nerally higher than the actu[illegible] or true yield.

As stated earlier, at low shear rates, the Bingham model does not give particularly goo[illegible]

High viscosity, [illegible]int is caused by:

1. Introd[illegible]ction of soluble contaminants such as salt, cement, anhyd[illegible]eutralize nega[illegible]ve charges of the clay p[illegible]

2. The b[illegible]aking [illegible] the bit and pipe, w[illegible] crea[illegible] the particles[illegible] causing [illegible]

3. Introduction of inert [illegible]olids causes the particles to be closer together ins[illegible]

4. Drilling of [illegible]atabl[illegible] system, inc[illegible]ing th[illegible]sing the number of charges and by br[illegible]nging the particles closer together.

5. Both insuffi[illegible] chemicals will increase the attr[illegible]

Treatment for increas[illegible]d [illegible]ield [illegible]oint may be controlled by chemical action, but reduction of the y[illegible]cosity.

Yield point may be lowered by[illegible]

1. Broken bo[illegible]valenc[illegible]ption of certain negative ions[illegible]at the edge of the clay particles. These residual val[illegible] such as tannins, lignins, [illegible]hosphates. The attractive fo[illegible]es are [illegible] clay's natural negativ[illegible] so that the particles repel each other.

2. If calc[illegible] occurs, the ion is remov[illegible] thus decreasing the attract[illegible]ve forces and hence the yield point.

3. Water [illegible] solid content is very high, but it is gener[illegible] (i.e., [illegible]ud d[illegible]).

As mentioned earlier, [illegible] chem[illegible] the mud and act as "thinners" [illegible]omm[illegible] These also have a secondary function of a[illegible]

G[illegible] lbs/100 ft^2 (10 sec/10min)

This [illegible] that denotes the thixotropic properties of the mud and is a meas[illegible] the mud while at rest or [illegible] are both measures of flocculation, [illegible] ase together, however a low yield po[illegible]

Gel strength [illegible] speeds for ab[illegible] viscometer off or putting it into neutra[illegible] (low gear if it's a lab model) and waiting the desired period, (i.e., 10 seco[illegible] the "gel stre[illegible] The maximu[illegible] 100 ft^2. With[illegible] the same except a low speed is used. After a[illegible] aken in a similar manner.

Gels are desc[illegible] fragile/weak. For a drilling fluid, the frag[illegible] high but buil[illegible] broken and would req[illegible] re to break circulation.

pH

Drilling mud[illegible] affect viscos[illegible] if the pH is in the range of 7 to 9.5. Above th[illegible] out of propo[illegible] es. For minimizing shale problems, a p[illegible] o give the best hole stability and control over [illegible] problems.

[illegible] ncreased if it comes into contact with an acidic fluid. From this point of view, the higher pH would be desirable to protect pipe and casi[illegible]

[illegible]arbon Diox[illegible] severe pitting and cracks in fatigue areas. If mois[illegible] olves and forms carbonic acid.

$CO_2 + H_2$[illegible]

This causes [illegible] ch makes the water more corrosive to steel.

Fe + H_2C[illegible]

If a high pH [illegible]

Standard treatments for CO_2 are:

1. Kill the source [illegible] circ[illegible] through the [illegible]
2. Re-establish [illegible] proper a[illegible] o[illegible] or caustic s[illegible]

While a high pH will [illegible] to add chemicals to remove [illegible] scale [illegible]

H_2S as a gas is n[illegible] will become cor[illegible] O_2 it becomes extremely corro[illegible] increases, the to[illegible]l amount of sulfides existing as H_2S is reduced. The pH should be maint[illegible] ring formations are to be drilled. A scave[illegible] common scavengers are zinc carbonate, zinc chromate, zinc [illegible] sponge (Fe_3O_4) and copper carbonate. The pH will have to b[illegible] scavengers are added.

pH is commonly measured with pHydrion paper. This paper is impregnated with dyes that r[illegible] dependent. The paper is placed on the surface o[illegible] paper. When the color has stabilized, it is c[illegible]rt. An electronic pH meter may also be used.

Filtrate/Water Loss **[illegible]30 min**
Filter Cake Thickness **1/32 inch**

These two prop[illegible] it is the filtration of mud that causes [illegible] soluble chemica[illegible]tion occurs when the permeability is [illegible] through the pore spaces. As fluid is lost, a b[illegible] This is the filter [illegible]

Two types of fil[illegible] **dynamic**, while circulating and **static**, while the mud is at res[illegible] Dynamic filtra[illegible]n reaches a constant rate when the rate of erosion of the [illegible] circ[illegible] [illegible]ake. Static filtration will cause the cake to grow thicker with time, which results in a d[illegible]crease in loss of fluids with time.

Mud measureme[illegible] filtration. Filtration characteristics [illegible] means of a filter press. The test consists of mon[illegible] is forced from a filter press under specific c[illegible] measuring the th[illegible]posited upon the filter paper.

Excessive fil [illegible] ld up are likely to cause the following pr [illegible]

1. Tig [illegible] t hole, causing excessive drag.
2. Inc [illegible] eter.
3. Differen [illegible] cake.
4. Excessiv [illegible] on problems with wireline [illegible] s.

Most of these pro [illegible] are [illegible] aused by the filter cake and not the amount of filtration because [illegible] cake. A low water loss may not do [illegible] ependent upon solids size and distributi [illegible].

The standard [illegible] The amount of filtrate incre [illegible] uare root of the time. This can be expre [illegible]

Q2 [illegible]

Where: Q2 [illegible]

Q1 [illegible] time T1

Pressure also [illegible] ne the filter cake, reducing its permeability [illegible] he filtrate. Small plate-like particles act as the be [illegible]

Increased te [illegible] viscosity of the liquid phase and he [illegible] factors bei [illegible] g constant, the amount o [illegible] ime.

Proper dispersion of the co [illegible] a good overlap of particles, thu [illegible] giving good [illegible] d mud, which has aggregates o [illegible] The addition of chemicals to [illegible] fficiency of the filter cake.

The standard [illegible] emperature at 100 psi and is recorded as t [illegible] pressure/hig [illegible] The tests ma [illegible] ortable filter press that uses CO_2 cartridges or [illegible]

The high pre [illegible] est is conducted to simulate downhole co [illegible] ditions, since the degree of filtration may vary, depending upon the co [illegible] standard tem [illegible] emperature and 100 psi, or [illegible] pressure will indicate if th[illegible] filter cake is co[illegible]

The primary flu[illegible] loss agent in most water based muds are the clays. These solids should ha[illegible] percentage being under 1 micron. This wi[illegible] low porosity and permeability. The use of centr[illegible] equipment may cause filtration proble[illegible] size solids. Starch is also used as a fluid loss agen[illegible] that it will easily gelatinize and swell. Wate[illegible] acting on the flu[illegible]

Sodium Carbox[illegible] long chain struc[illegible] into different lengths or grades. It is tho[illegible] chains plugging narrow openings in the [illegible] the clay particles with a film. It will however, lose its effectiveness as salt concentrations r[illegible] polyanonic cellulose is used as the fluid loss ag[illegible]

Alkalinity, Mud
Alkalinity, Filtrate

Pf/Mf

Alkalinity or aci[illegible] logarithmic and [illegible] vary considerably without a noticeable chan[illegible] be measured to show the phenol[illegible]

The test for filt[illegible] adding 2 or 3 drops of phenolphthalein indicator solution. [illegible] normal nitric or sulfuric acid solution are then [illegible] just disappears. The alkalinity is measured as the number of milliliters of acid per milliliter of filtrate. The test for mud is similar excep[illegible] mud, 25 to 50 milliliters of water are added for dil[illegible] phenolphthalein are added. The result is measur[illegible]

Salt/Chlorides

ppm or gpg

The salt or chlorides concentration of the mud is monitored as an indicator of contaminatio[illegible] may come from water used to make mud, salt [illegible] The test is conducted on mud filtrate.

One or more mil[illegible] titration dish and 2 or 3 drops of phenol[illegible] acid solution are [illegible] to remove the pinkish color. One gram of pure ca[illegible] added and stirred. Next, 25 - 50 ml of distilled w[illegible]ium chromate solution are added. This m[illegible]y while drops of silver nitrate solution are a[illegible] yellow to orange red and persists for 3[illegible] of silver nitrate used to reach the end[illegible]ed in the equation:

Chlorides[illegible] / ml filtrate

This can be converted to salt (NaCl) ppm by multiplying the chlorides by 1.65, or to grains[illegible] ppm by 0.0583.

Calcium [illegible]ppm

If water cont[illegible] "hard water". The harder the water, the more difficult it is to get bentonite to yield, thus [illegible] bentonite to make a good gel. Excess calcium [illegible] abnormally high water loss and fast gel rates.

Sand Content [illegible]% vol

This is meas[illegible] sand screen set. A measuring tube is filled with m[illegible]orously. The mixture is then poured over [illegible] clean with water. The sand is then washed [illegible] in percent. This will give an indication as to the effectiveness of the mechanical solids control equipment.

Solids Content % vol
Water Content % vol
Oil Content % vol

A retort is us[illegible]tity of liquids and solids in a drilling fluid. A meas[illegible]eated until the liquid portion is vaporized. Th[illegible] a condenser and measured as a percentage b[illegible] then calculated by subtracting the total from 10[illegible]

Funnel Viscosity sec/qt

[illegible] instrument used to measure viscosity. It is [illegible] quart (946 cc) of water will flow through the funnel in 26 seconds. To run a test, the bottom orifice is covered and drilling fluid [illegible] the funnel is full. When the bottom is uncovered, the time required to fill one quart is recorded (in seconds) along with the temp[illegible]

Funnel viscosity [illegible] it is a one point measurement it [illegible] as to why the viscosity has changed, only th[illegible]

Hydraulics

The concept that a fluid cannot maintain a rigid shape is a basic, but important ch[illegible] fluids cannot sustain a shear-stress (a tang[illegible]). Any tangential force will cause the flu[illegible] known as "flow". Fluid flow is [illegible] a conductor. A conductor m[illegible] for drilling fluid or a volcano's sl[illegible]

Generally, fl[illegible] fluid layers sliding past [illegible] surface and [illegible] neighbor with increasing velocity. Thi[illegible] flow pattern is known as **laminar flow**. At higher velocities, th[illegible] with an orde[illegible] the conductor. This flow pattern is kn[illegible]

Laminar Fl[illegible] This type of flow is generally desired in the annulus since it does not lead to hole erosi[illegible] excessive pressure drops. These pressure drop[illegible] according to the type of flow [illegible]

Turbulent Flow is the type of flow regime found inside the d[illegible] during drilling operations. Since high mud velocities are required to achieve turbu[illegible] type of flow is gener[illegible] annulus due to its tendency to cause excessive ho[illegible] circulating densities". However, tu[illegible] mud like a plug, causing the mud to move at app[illegible] provides for better hole cleaning and is somet[illegible] for turbulent [illegible] than mathematically derived.

When a forc[illegible] one another and the fricti[illegible]nal drag that occurs bet[illegible] offers resistance to [illegible]

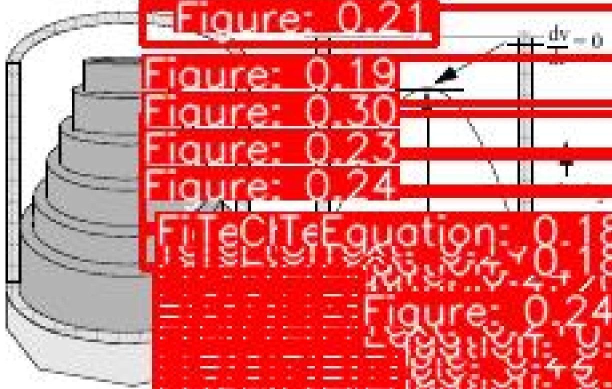
Deforma [illegible]

The magnitude of shear between the layers is represented by the **shear-rate**, which is defined as the difference in the velocities between the layers, [illegible] onship between the shear-stress and [illegible] avior of the fluid.

For some fluids [illegible] if the shear-stress is doubled then the shear-ra [illegible] the pressure req [illegible] known as "New [illegible] ewtonian fluids are water, glycerine and di [illegible] following relati [illegible]

Shear-Stress [illegible] **r-Rate**

The slope of the [illegible] given by the absolute viscosity, this is [illegible] profile for a New [illegible] maximum shear rate at the wall and a minimum (0) at the center.



Drilling fluids are [illegible] n behavior, and are defined by more complex [illegible] stress and shear-rate. When fluids contains colloidal particles (or clays), these particles tend to increase the shear-stress or force necessary to maintain a given flow rate. This is due to electrical attraction between particles and to them physically "bumping" into each other. Long particles, randomly oriented in a flow stream, will display high interparticle interference. However, as shear-rate is increased, the particles will tend to develop an orderly orientation and this interaction will decrease.

In the center of a pipe, the shear-rate will be low and hence particle interaction high, giving it a flattened flow profile. This profile has an improved [illegible] d carrying capacity for larger particles.

As can be seen from the previous examples, the ratio of shear-stress to shear-rate is [illegible] shear-rate.

Various "oil [illegible] describe this non-Newtonian shear-rate/shear-stress curve. In order to arrived at "standard" variables, the [illegible] more shear-r [illegible]

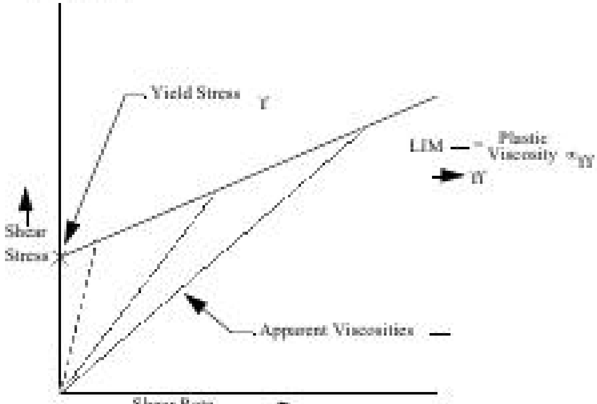
The two most common models used at the wellsite are the Bingham Plastic Model and the Power Law Model.

Bingham Plastic Model

The Bingham model is defined by the relationship;

Shear Stress = Yield Stress + (Plastic Viscosity x Shear Rate)

The major difference between this and Newtonian fluids is the presence of a Yield Stress or "Yield Point" (which is a measure of the electronic attractive forces in the fluid under flowing conditions). No bulk movement of the fluid occurs until this yield stress is overcome. Once the yield stress is exceeded, equal increments of shear stress produce equal increments of shear rate.



Flow Curve for a Bingham Plastic Fluid

Note that the apparent viscosity decreases with increased shear rate. This phenomenon is known as "shear thinning". As shear rates approach infinity, the apparent viscosity reaches a limit known as the Plastic Viscosity. This viscosity is the slope of the Bingham plastic line. The

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commonly used [illegible] ally designed to measure viscosities for th[illegible] e above illustration, this model does not [illegible] luids at low shear rates.

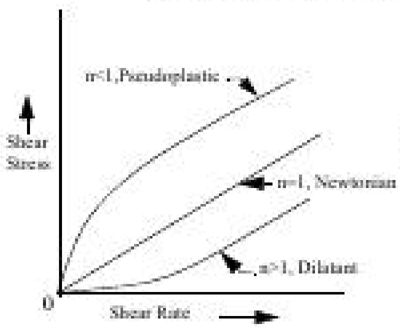
Power Law Model

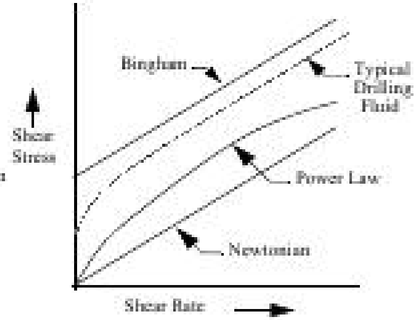
[illegible] relationship:

Shear Stress = Consistency Factor x Shear Rate $^{\text{flow behavior index}}$

[illegible] describes the t[illegible] e fluid, and is somewhat analogous to the [illegible]. The **flow behavior index (n)** indicates the degree of non-Newtonian characteristics of the fluid. As the fluid becomes more v[illegible] **(k)** increases, as a fluid becomes more shear thinning "n" decreases. When "n" is 1 the fluid is Newtonian. If "n" is greater than 1, the fluid is classed as Dilatant (the apparent viscosity increases as the shear rate increases). If "n" is between zero and 1 the fluid is classified as Pseudoplastic, exhibiting shear-thinning; (i.e., the apparent viscosity decreases as the shear rate increases). For drilling fluids, this is a desirable property and most drilling fluids are pseudoplastics.

While the Power Law Model is more accurate then the Bingham Model at low shear rates, it does not include a yield stress. This results in poor results at extremely low shear rates.



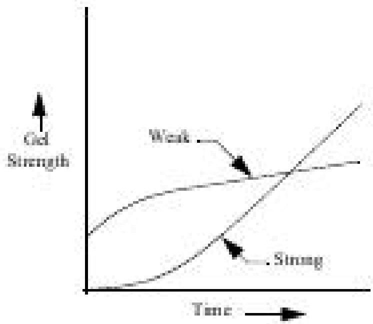


A modification to the Power Law Model, the **OXY Model**, was proposed for use in oil-based muds. The major difference is the viscometer readings used to determine the "k" and "n" values. Power Law uses the 300 and 600 rpm readings, the OXY Model uses the 6 and 100 rpm readings. In addition, other models have been proposed that tend to exhibit behavior between the Bingham and Power Law models at low shear rates.

Non-Newtonian fluids may show a degree of time-dependent behavior. (For example, the apparent viscosity for a fixed shear rate does not remain constant, but [illegible] minimum with the duration of shear.) If the [illegible] flow time, the fluid is termed "Thix[illegible] thixotropic fluid will show an increase i[illegible] apparent viscosity increases with flow time, th[illegible]

The shear str[illegible] is dependent upon the duration of s[illegible] adjustment of shear rate and the stabilizat[illegible] of clay particles at h[illegible] of clay particles when shear rate is [illegible]

"Gel strength[illegible] strength measures the attractive forces of a fluid while under static conditions. If the gel strength increases steadily with time, the gel strength is classed strong or progressive. If it increases slowly with time, it is classed as weak or fragile.



When strong gels occur, excessive pressures may be required to break circulation.

Hydra[illegible]

In the "*Advanced Logging Procedures Workbook*" ([illegible]N 80269H), an introduction to hydraulics illustrates the Bingham m[illegible]thod for hydraulic optimization. Th[illegible]nly used method is the Power Law Model.

This model fits [illegible], although at low shear rates, it wi[illegible]. The model describes a fluid in which th[illegible] shear stress increases as a function of shear rate, raised to some power. As[illegible] the Power Law model is:

Shear Stress [illegible]

"k" is known as [illegible] and is indicative of the pumpability of t[illegible] index, defining the degree of how "non-Newt[illegible]

Both parameters [illegible] be determined from the Fann VG meter. "k" is defined as the vi[illegible]ity of a fluid at a shear rate of 1 sec^{-1}. When "[illegible] 1, the fluid is Ne[illegible]. As the fluid becomes more shear thinning, the "n" value decrea[illegible]

$$k = (1 + 0.[illegible]$$

where: $300_{[illegible]}$ [illegible]g at 300 rpm's
$600_{[illegible]}$ [illegible] Fann VG meter dial reading at 600 rpm's

If the Fann VG [illegible], both "k" and "n" can be determined u[illegible] Point.

$$k = 1.067 \frac{(PV + YP)}{511} [illegible] \quad n = \log \frac{(2PV + YP)}{(PV + YP)} \div \log 2$$

where: PV = Plastic Viscosity (cps)
YP = Yield [illegible]

Once these valu[illegible] pressure losses t[illegible] describe the pres[illegible], using the P[illegible] system, the drill[illegible]ring, and [illegible]he annulus.

Surface Pressure Lo[illegible]

System pressure loss calculations begin with the determination of the type/class of surface [illegible]circulating equipmen[illegible] hose, swivel, an[illegible]

[illegible] ADC as the most common. They are:

Class #1 [illegible]	Class #2 (Coefficient 7)
40 ft & 3 in. [illegible]	40 ft & 3.5 in. I.D. Standpipe
45 ft & 2 in. I.D. Hose	55 ft & 2.5 in. I.D. Hose
4 ft & 2 in. I.D. Swivel	5 ft & 2.5 in. I.D. Swivel
40 ft & 2.25 in I.D. Kelly	40 ft & 3.25 in. I.D. Kelly

Class #3 (Coefficient 4)	Class #4 (Coefficient 3)
5 ft & 2.5 in. I.D. Swivel	6 ft & 3 in. I.D. Swivel
45 ft & 4 in. I.D. Standpipe	45 ft & 4 in. I.D. Standpipe
40 ft & 3.25 in. I.D. Kelly	40 ft & 4 in. I.D. Kelly
55 ft & 3 in. I.D. Hose	55 ft & 3 in. I.D. Hose

When calculating surface pressure losses, choose the class which is closest to the present rig equipment; if necessary, extrapolate. Most modern rigs will have a surface pressure coefficient between 2 and 10. The coefficient is then used in the following formula:

$$P_{ls} = 10^{-5} \times k_s \times MD \times Q^{1.86}$$

where: P_{ls} = Surface Pressure Loss (psi)
k_s = Surface Pressure Coefficient
MD = Mud Density (lb/gal)
Q [illegible]

When extrap[illegible] increased lengths will increase the coefficient, w[illegible] decrease the coefficient.

Pressure Loss in [illegible]

Once passed [illegible] surface equipment, the fluid will flow through [illegible] drillstring. In [illegible] systems are considere[illegible] velocities are in the order of 1000 ft/min [illegible] the fluid is in turbulent flo[illegible].

The pressure [illegible] approximately 1.8 power of th[illegible] increase the pressure drop in the drillstring by approximately 3.5 times. Typically, the pressure losses in the drillstring are about 35 percent of the total pump pressure.

With this in min[illegible] how much pressure will be required to pum[illegible]ing, at a given rate.

Drillstring Pressure Losses

[illegible] laminar flow regime, Power Law Model calculations begin with:

$$P_{ll} = [illegible]$$

where: P_{ll} = Pressure Loss in Laminar [illegible]
L = Length of Section [illegible]
V_P = Velocity in Secti[illegible]
d = Inside Diameter of drill[illegible]
k = Consistency Ind[illegible]
n = [illegible]

Fluid velocity in the drillstring [illegible]

$$v_p = \frac{24.5 [illegible]}{[illegible]}$$

where: Q = Pump flow rate [illegible]
d_1 = pipe I.D. (inche[illegible]

The equivalent v[illegible]

$$\mu = \frac{90000 \cdot P_{ll} \cdot d^2}{L \cdot V}$$

Which, in turn, is used to determine the Reynolds Number.

$$Re = [illegible]$$

Flow behavior, [illegible] value of the fluid. The critical Reynolds Number (Rec) is found using:

3470 - 1370n (from laminar to transitional)

4270 - 1370n (from transitional to turbulent)

If: Re < Rec flow is laminar

Re is between laminar and turbulent, flow is transitional

Re > R[illegible]

If the flow is [illegible] pressure losses will have to be re-calculated [illegible] also require a friction factor (f) to be include[illegible]

$$f = \frac{(\log n + 3.93)}{50} \ [illegible] \ \frac{\log n - 1.75}{7}$$

Pressure losses are then determi[illegible]

$$P_L = \frac{f \ L \ MD \ [illegible]}{[illegible]}$$

Annular Pressure Losses

Hydraulic calculations continue with a de[illegible] pressure lost in the annulus. Assuming laminar fl[illegible] Power Law [illegible] "pressure loss" equation is:

$$P_L = \frac{k \ L}{300(d_1 - d_2)} \left(\frac{1.6 \ V \ G}{(d_1 - d_2)} \right)^n$$

where: k [illegible]
L [illegible]
d_1 [illegible]
d_2 = Pipe or Collar O.D. (inches)
V [illegible]
n = Power Index
G = Geometric Factor

Fluid velocity in the annulus is determined by using:

$$[illegible]$$

where: D_1 = hole or casi[illegible]
D_2 = pipe or coll[illegible]

A "geometric factor" is use[illegible]tion factor (a ratio of the actual shear stress im[illegible] the dynamic pressure imposed on the sy[illegible] dimensionless variables (y [illegible]

$$y = [illegible] \frac{D_2}{D_1}$$

"G" can then be [illegible]

$$G = \left(1 + \frac{[illegible]}{2}\right) \cdot \frac{(3 - [illegible]) \cdot n + 1}{(4 - [illegible]) \cdot n}$$

If flow in the annulus is transitional, [illegible] annulus, then the pressure losses are [illegible] friction [illegible] calculated using:

$$f = \frac{16}{Rec} + \frac{(Re - [illegible])}{800 \ [illegible]} \cdot \left[\frac{\log n + 3.93}{50} \ [illegible] - \frac{16}{Rec} \right]$$

Pressure losses are then determined:

$$P_{sf} = \frac{f \cdot L \cdot MD \cdot V^2}{92894 \cdot (d_1 - d_2)}$$

Reynolds Number a[illegible]

The Reynolds Number, used in the annular Power Law Model calculations is calculated using equivalent viscosity (α):

$$\alpha = \frac{90000 \cdot Pl_a \cdot (d_1 - d_2)^2}{L \cdot V}$$

Reynolds Number is then:

$$Re = \frac{[illegible] \cdot D \cdot V \cdot (d_1 - d_2)}{\alpha}$$

The fluid velocity that will produce the critical Reynolds Number for given fluid properties and pipe configuration is found using:

$$V_c = 60 \cdot \left[\frac{Re_L \cdot k}{185.6 \cdot MD} \cdot \left(\frac{96 \cdot G}{d_1 - d_2} \right)^n \right]^{\frac{1}{(2-n)}}$$

where: Re_L = [illegible]ds Number (3470-1370n).

Cut[illegible]

One of the primary functions of a drilli[illegible] fluid is to bring the drilled cuttings to th[illegible]aning can lead to a number of problems, in[illegible]pipe, and excessive hydrostatic p[illegible] by many fac[illegible] account for a[illegible]e parameters which affect cuttings tran[illegible] eccentricity, [illegible] density, and [illegible]ngs.

If the cutting[illegible]most are) they are subjected to a torque cause[illegible] centrifugal e[illegible] annulus. The[illegible]d because the viscosity of non-Newtonian f[illegible] varies according to the shear rate, and therefore the velocity of th[illegible] are strongly [illegible] and shape, which as stated above, are both irreg[illegible]

The only pra[illegible] velocity) of [illegible]al correlations based on experimental[illegible], there is a wide disparity in the results obtai[illegible]

Cuttings Slip Velo[illegible]

A cutting, tra[illegible]ences a positive upward force due to the dr[illegible] velocity, density and viscosity, and a negative downward fo[illegible] as its "slip ve[illegible]

Several studi[illegible]wing generalizations to be made:

1. Th[illegible] controlling adequate cuttings tra[illegible]
2. An[illegible] typical muds
3. Cuttings transport efficiency increases as fluid velocity increases
4. The[illegible]ansported induces shear th[illegible] tra[illegible]
5. Cu[illegible]y have a moderate influence on cuttings transport

6. Hole size [illegible] cts on cutting transport.

Those who have obse[illegible]d a so[illegible]ds tracer emerging over the shale shaker will realize the l[illegible] Therefore, any calculated estim[illegible]y be an approximation. The reason for this "[illegible] ability to be carried by the drilling fluid. It [illegible] the mud stream and the size of the particle.

Cuttings will tra[illegible]ciently if they travel flat and horizontally. If [illegible] Smaller cuttings [illegible] result in a helica[illegible] motion of the fluid, which will aid transport for those cuttings nearest [illegible]

The rheological [illegible] will affect cuttings transport in as much as th[illegible]wering the "n" value or an increases in the [illegible] the flow profile and increase carryin[illegible]

The slip velocity [illegible]

$$Vs \text{ [illegible]}$$

where: Vs = [illegible]
d_p = [illegible]
pp = [illegible]
MD = Mud Density (lb/gal)
CD = [illegible]

For these calcul[illegible] the particle density is found by multiplying the cuttings density (gm/cc) by the density of fresh water (8.[illegible] coefficient is the frictional drag bet[illegible]

In turbulent flow, the drag coeffici[illegible] 1.5.

In laminar flow, [illegible] this case the slip velocity is:

$$Vs = 175.2 \quad d_p \text{ [illegible]}$$

Equivalent viscosity is calcula[illegible]d as mentioned earlier.

Bit [illegible] Optimization

Jet Nozzles

[illegible] to increase [illegible]ole cleaning in deep wells. Prior to jet nozzles, the fluid course i[illegible]ter of the bit and the [illegible] to the annulus.

These "conv[illegible] the power necessary to lift the cuttin[illegible]

Both roller c[illegible] to install different size jet nozzles in or[illegible] or four jet no[illegible]ually contain six to nine. The flow area of all je[illegible] example, sup[illegible]ose four size 9 jets were being used:

[illegible]

$$= 0.0621 \text{ sq. in.}$$

There are fo[illegible]

Jet nozzles increase the speed of the drilling [illegible] ft/sec, and on many occasions the velocity is much gr[illegible] velocity is so important in hydrau[illegible] when the jets are installed in a bit. The formula is:

$$V_n = \frac{418.3 \quad Q}{d_j^2}$$

where: V_n = Nozzle Velocity (ft/sec)

Q = Flow Rate (gal/min)

d_j = Nozzle Size (32nds)

Note: [illegible] $+ 13)^2$

As mentione[illegible] improved if [illegible] beneath the bit. In soft formations, t[illegible] by the jetting action of the drilling fluid, and the drill [illegible] the loading of th [illegible] rd formations, the drill rate should be propo [illegible] hole cleaning is adequate.

Surface Horsepowe[illegible]

[illegible] ulics program, all aspects concerning drilling fluids and the associated equipment must be considered.

The first compo [illegible] s the surface equipment and the hydraulic ho [illegible] hem. There are two limiting factors on the surface hydraulic horsepower.

The first is the f [illegible] ssed earlier, the flow pattern in the annulus shou [illegible] a Reynolds Num [illegible] ocity in the annulus will be around the colla [illegible] "critical velocity" [illegible] upper range is n [illegible] t always advisable because there will be mo [illegible] tear on the pum [illegible]

The lower limit [illegible] sufficient hole clea [illegible] g. This is determined by u [illegible] the drillpipe and the largest annular section [illegible] A normal range [illegible]

The second fact [illegible] f the mud pumps. Most mud pumps can prod [illegible] with little problem. However, because of the v [illegible] (standpipe, rota [illegible] pressure is usua [illegible] less than the maximum rated pump pressure.

The available "s [illegible]

[illegible] 1714

where: H_{ps} = Surface Horsepower
P = [illegible]
Q = [illegible]

Once the surfac [illegible] ned, the horsepower distributions ca [illegible]

[illegible]

where: H_{ps} = [illegible]
H_{pb} = [illegible]

B[illegible]

[illegible] Cleaning necessary to maximize the [illegible]

1. Hy[illegible]
2. Hy[illegible]

Maximizing [illegible] est flow rate and the [illegible] the highest H_{pb}. However, the "low[illegible] flow [illegible] bottom hole cleaning. To [illegible]pens[illegible] can be increased by using [illegible]aller [illegible] nozzles.

Hydraulic Horsep[illegible]

Hydraulic ho[illegible] from beneat[illegible] power to the bottom of the hole.

The [illegible] at the bit, or bit pressure drop, is essential [illegible] by:

[illegible]

where: M[illegible]

V_n = Nozzle Velocity (ft/sec)

From the bit [illegible] power can be calculated:

$$[illegible] \frac{[illegible]}{1714}$$

To optimize [illegible] necessary to select a circulation rate and nozz[illegible] of the pump pressure to be expended forcing th[illegible] nozzles of th[illegible]

$$H_{hh} = 0.65 \quad H_{pa}$$

Hydraulic Impact [illegible]

Hydraulic (Jet) [illegible] on the theory that cuttings are best removed fro[illegible]

[illegible] the greatest. Impact Force [illegible] determined by:

$$H_i = \frac{MD \quad Q \quad V_n}{1930}$$

where: MD = Mud Density (lb/gal)

Q = Flow Rate (gal/min)

V_n = [illegible]

As can be seen, [illegible] nozzle velocity rather than pressure. [illegible] The emphasis is on a large volume [illegible] force, rather than a small volume [illegible].

This condition is [illegible] rates and bit nozzle sizes are chosen which [illegible] through the jet [illegible]

Fixed Cutter Bit Hydraulics

The hydraulics [illegible] remove cuttings [illegible] to cool the bit. Fluid volume is critical to PDC [illegible] to diamond bit performance.

The major components of fixed cutter bit hydraul[illegible]

1. flow rate - Q (gal/min) and V (ft/min)
2. [illegible]teristics - MD (lb/gal), YP (lbs/100ft²) and PV (cps)
3. pressu[illegible]ce (diamond bit) or through the jet nozzle[illegible]
4. the To[illegible] of nozzle sizes

A very importan[illegible] is "Hydraulic Power Per Square Inch" or HSI. It is calculated using H_{hp} (hydraulic horsepower):

$$[illegible]$$

where: H_{hp} = Hydraulic [illegible]

A = Bit [illegible]

* If the area of [illegible] calculated using:

$$[illegible] \frac{d^2}{4}$$

where: d = bit diameter (inches)

The hydraulic horsepower equation is the same (Eq. 1.7 [illegible]), however in fixed cutter b[illegible]nds, nozzles, flow area restrictions, cuttings and the uneven hole pattern. Pressure losses at the bit are calculated using:

[illegible]

PDC Bit Hydraulics

Since PDC bits are formation specific (best used in [illegible] formation ch[illegible] drilling fluid will dictate the HSI, for water-based [illegible] between 2.5 and 4.5, while for oil-based drilling fluids it will be between 1.5 and 3.0.

The [illegible]le orifices, will have several characteristics which will directly affect hydraulic energy:

1. the [illegible]ly once it leaves the nozzles
2. hig[illegible]ntal velocities are achieved acr[illegible]
3. for[illegible] inc[illegible] HSI

The increased horizontal velocities provide better cuttings removal, better cooling, and [illegible]

Nozzle veloc[illegible] manner as with rollercone bits.

Diamond Bit Hydraulics

The horizontal flu[illegible] performance. It ca[illegible]

$$Vel = [illegible]$$

The fluid courses assist this [illegible] across the bit to cool the diamonds and to remove the cuttings.

The diamond bit [illegible] of two components:

1. **Fluid Course Area** [illegible]
   They are ca[illegible]

2. **Diamond E[illegible]** [illegible]
   formation, [illegible]

The desired TFA is ca[illegible] to the bit by varying the diamond exposure, a[illegible] courses.

Another phenom[illegible]
hydraulic pump-[illegible] of the mud at the bit acts over the bit face [illegible] and tends to lift [illegible] bit off the bottom of the hole. For example, the pump-off force on a 8-[illegible] (having a pressure drop of 900 psi) would [illegible] It will require at least this much bit weight [illegible] contact with the bottom of the hole.

Diamond Bit Flow [illegible]

There are two m[illegible] bits:

1. Cross [illegible]/collector system)

   a) the [illegible] pressure "primary fluid cou[illegible] where "low pressure collectors" draw the fluid across the [illegible]

   b) this ensures that the diamonds towards the outside diameter are [illegible]

   c) The [illegible]

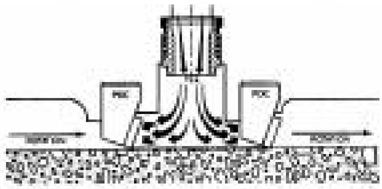
2. Radial Flow [illegible]

   a) provides [illegible] high [illegible] diamond row

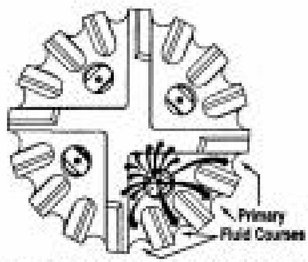
   b) permits fluid to trave[illegible] diamond pad to facilitate cuttin[illegible]

   c) maintains uniform [illegible] by tapering fluid course depth as th[illegible] diameter

   d) The HSI should b[illegible]



PDC TFA (Total Flow Area) determined by nozzle area times number of nozzles.



CONTROLLED RADIAL FLOW WITH NOZZLES

Jet Nozzle Flow Area (inches)

Jet Size	TFA of 1 Jet	TFA of 2 Jets	TFA of 3 Jets	TFA of 4 Jets	TFA of 5 Jets	TFA of 6 Jets	TFA of 7 Jets	TFA of 8 Jets	TFA of 9 Jets
7/32	.038	.075	.113	.150	.188	.226	.263	.301	.338
8/32	.049	.098	.147	.196	.245	.295	.344	.393	.442
9/32	.062	.124	.186	.249	.311	.373	.435	.397	.559
10/32	.077	.153	.230	.307	.384	.460	.537	.614	.690
11/32	.093	.186	.278	.371	.464	.557	.650	.742	.835
12/32	.110	.221	.331	.442	.552	.663	.773	.884	.994
13/32	.130	.259	.389	.519	.648	.778	.907	1.037	1.167
14/32	.150	.301	.451	.601	.752	.902	1.052	1.203	1.353
15/32	.173	.345	.518	.690	.863	1.035	1.208	1.381	1.553
16/32	.196	.393	.589	.785	.982	1.178	1.374	1.571	1.767

Figure 1-1: Nozzle Flow Area

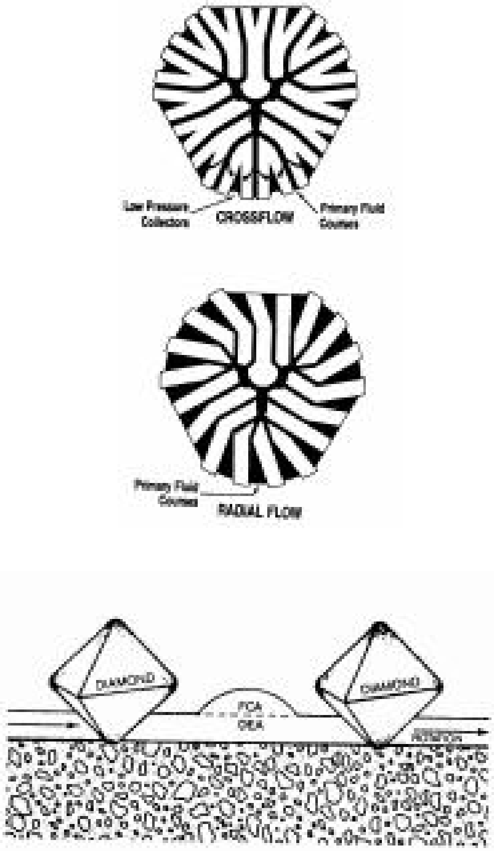

Low Pressure Collectors
CROSSFLOW
Primary Fluid Courses
Primary Fluid Courses
RADIAL FLOW
DIAMOND
DIAMOND

Figure 1-2

Swa[illegible]ssures

Both swab and surge pressures are caused by moving the drills[illegible]ing axially, and can be ca[illegible]lar for calculating a[illegible]nular pressure losse[illegible]ning the fluid flow velocity in th[illegible] distribution [illegible] determined b[illegible]

Two approac[illegible]

The first assu[illegible]he annulus and drillstring remain equal at all ti[illegible]

[illegible]

where: V_a [illegible]

V_p = Drillstring velocity (ft/min)

D = Borehole Diameter (inch[illegible]

d = Drillstring Outside Dia[illegible]

d_i = Drillstring Inside Diam[illegible]

The minus si[illegible]city is in the opposite direction to the fluid velocity.

This average velocity equation [illegible] geometry changes. This method is ea[illegible] oilfield. Its basic premise, t[illegible]g and annulus remain equal, is rarely justifi[illegible] caused by the bit nozzles a[illegible] in the annulus will nearly always exceed that c[illegible] surge pressures are therefo[illegible]

An alternativ[illegible] Tube", as sh[illegible]re. It is clear that the sum of hydrostatic a[illegible] should equal the sum of hydrostatic and frictional pressures in the annulus. Both sums re[illegible]

There is only on[illegible]ulfill this criterion, and it ca[illegible] be found by trial [illegible] the pressure loss equations.

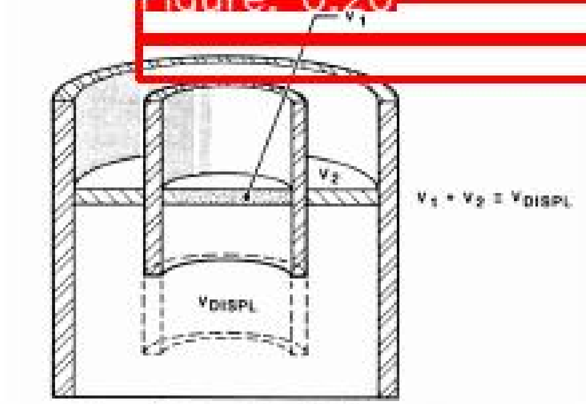


Figure 1-3: Equal Level Displacement

When tripping out of the hole, it may be assumed that both drillstring and annulus are kept full of fluid. The required distribution of flow is that which gives equal frictional losses in the pipe bore and annulus. When tripping into the hole, the fluid level inside the drillstring can drop well below that in the annulus, if small bit nozzles are present. This effect is usually seen as a pit volume be[illegible] string weight lower than expected, and a co[illegible]ped before standpipe pressure builds up while breaking circulation.

When the fluid level in the drillstring is below that of the annulus, a greater hydrostatic press[illegible] and fluid will tend to flow from the annulus[illegible] calculating flow distribution by e[illegible] gives a calculated annular flow and surge pressu[illegible] small and conse[illegible] there is no reliable way of measuring the fl[illegible] the practice of calculating flow distribution by e[illegible] pressure losses is generally accepted.

If the pipe is clo[illegible] the annulus, bec[illegible] by the drillstring passes up the annulus.

Calculating t[illegible] is complicated by the motion of the inner v[illegible]tion is in the opposite direction to the displa[illegible] will be greater than that for the same flowrat[illegible] 1-4). Equations describing th[illegible]ations are usually too complicated [illegible]

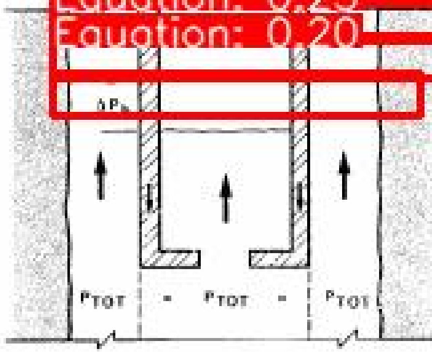


Figure 1-4: U-Tube Analogy for Equal Pressure Displacement

The problem can be solved for a Newtonian fluid in laminar flow, using:

$$\frac{8\mu L}{\Delta P R^2}\left[V_a + \frac{v_p}{2 ln} + \frac{v_p \quad {}^2}{(1 - \quad {}^2)}\right] = 1 + \quad {}^2 + \frac{(1 - \quad {}^2)}{ln}$$

where: v_p = pipe velocity

= d/D

The anal[illegible]s solution is clear. The stationary annulus [illegible]

$$V_{eff} = V_a + v_p\left[\frac{1}{2 ln} + \frac{{}^2}{(1 - \quad {}^2)}\right]$$

The term:

$$\frac{1}{2 ln} + \frac{{}^2}{(1 - \quad {}^2)}$$

is known as the *clinging constant (K_c)*. It represents the proportion of pipe velocity which must be added to fluid velocity in order to find the equivalent or effective velocity, which must be used in the stationary annulus calculation. The effective velocity is numerically greater than the actual fluid velocity, because V_a and v_p are opposite signs and the clinging constant is negative.

For Newtonian fluids, the clinging constant depends only on the annulus diameter ratio. This is not the case for non-Newtonian fluids, in which the clinging constant is also a function of the drilling fluids properties, and of fluid and pipe velocity. Calculation of clinging constants for non-Newtonian fluids is very tedious. Some representative values for Bingham fluids and Power Law fluids are shown in Figures 1-5 and 1-6.

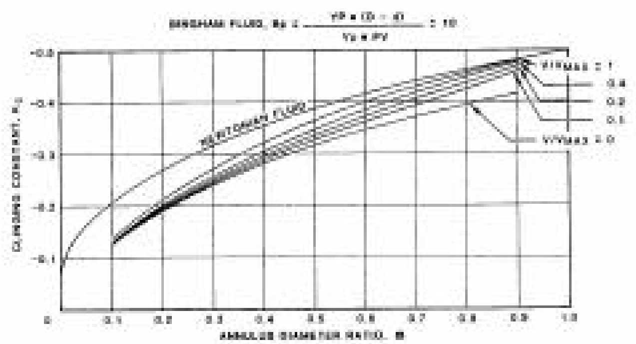


Figure 1-5: Clinging Constants for Bingham Fluid

It is common oilfield practice to assume a clinging constant of -0.45. The two graphs, however, show how much in error this can be. Baker Hughes INTEQ prefers a more exact calculation.

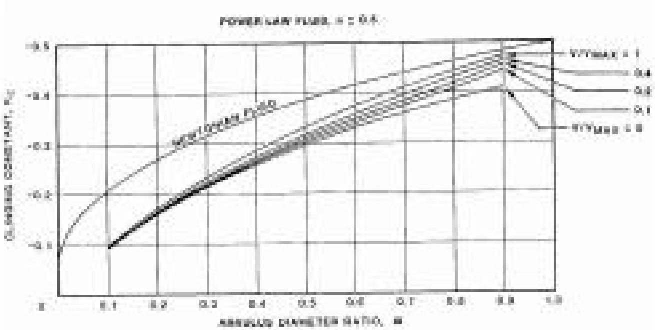


Figure 1-6: Clinging Constants for Power Law Fluid

The possibility of turbulent flow in the annulus must be considered in swab and surge calculations. Assuming that the velocity profile in turbulent flow is flat, the resultant pressure drop can be estimated by summing the pressure drops caused by the velocity at the outer wall and the relative velocity (V_a - v_p) at the inner wall, because V_a and v_p are of opposite signs. With a closed pipe, the turbulent flow clinging constant can be approximated by:

$$K_t \oplus \frac{2 - \left[\frac{4 +}{1 +}\right]^{0.5}}{1 - 2}$$

This function is graphed in Figure 1-7. It is an approximation for closed pipe and it appears to be similar to turbulent flow clinging constants derived by other authors.

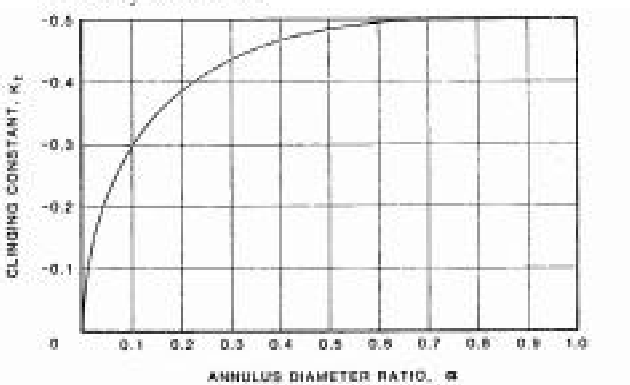


Figure 1-7: Clinging Constants for Turbulent Flow

The point at which transition occurs from laminar to turbulent flow is difficult to determine theoretically, and experimental data is lacking. It is therefore recommended that, for swab and surge pressure calculations, both laminar and turbulent pressure drops be calculated. The flow regime giving the greater pressure drop may then be considered to be correct. This procedure is conservative in that it will give a pressure equal to or exceeding the true swab or surge pressure.

Finally, when calculating swab or surge pressures for Power Law fluids, the calculated pressure loss should be checked against the pressure required to break [illegible] annular section, the gel breaking pressur[illegible]

$$P_g = \frac{4L\tau_g}{(D - d)}$$

where: P_g = Pressure to break gel strength (psi)

L = Section length (feet)

τ_g = Gel strength [illegible]

D = Outer diameter [illegible]

d = Inner diameter [illegible]

If the calculated swab or surge pressure is less than the sum of the gel breaking pressures, the gel bre[illegible] used. This check [illegible] not required if the fluid model incorporates a yield stress.

Swab [illegible] Report

Open Pipe

Input [illegible]

Depth	12000.0 ft.	Mud Density	10.00 lb/gal
Casing Depth	10000.0 ft.	PV	20.000 cP
Leak Off EQMD	15.10 lb/gal	YP	15.00 lb/cft^2
Pore Pressure	9.00 lb/gal	Average Stand	93.0 ft.

Swab and Surge Analysis

Pipe Velocity			Bit at Total Depth			Bit at Casing Shoe		
Stand Time	Average	Maximum	Pressure Drop	Swab EQMD	Surge EQMD	Pressure Drop	Swab EQMD	Surge EQMD
sec/stand	ft/sec	ft/sec	psi	lb/gal	lb/gal	psi	lb/gal	lb/gal
200	0.46	0.70	4	99.9	10.01	3	9.99	10.01
180	0.52	0.77	4	9.99	10.01	3	9.99	10.01
160	0.58	0.87	7	9.99	10.01	4	9.99	10.01
140	0.66	1.00	5	99.9	10.01	4	9.99	10.01
120	0.78	1.16	6	9.99	10.01	5	9.99	10.01
100	0.93	1.39	6	9.99	10.01	5	9.99	10.01
80	1.16	1.74	7	9.99	10.01	6	9.99	10.01
60	1.55	2.33	9	9.99	10.01	8	9.99	10.01
40	2.32	3.49	12	9.98	10.02	10	9.98	10.02
20	4.65	6.97	18	9.97	10.03	15	9.97	10.03
10	9.30	13.95	28	9.95	10.05	24	9.95	10.05
9	10.33	15.50	30	9.95	10.05	26	9.95	10.05
8	11.62	17.44	33	9.95	10.05	28	9.95	10.05
7	13.29	19.93	36	9.994	10.06	31	9.94	10.06
6	15.50	23.25	40	9.94	10.06	34	9.93	10.07
5	18.60	29.90	45	9.93	10.07	38	9.93	10.07
4	23.25	34.87	52	9.92	10.08	44	9.92	10.08
3	31.00	46.50	62	9.90	10.10	53	9.90	10.10
2	46.50	69.75	81	9.87	10.13	69	9.87	10.13
1	93.00	139.50	128	9.80	10.20	109	9.79	10.21

While Bit is in Open Hole
Recommended Maximum Running Speed: 0.67 sec/stand
Maximum Surge EQMD: 10.20 lb/gal
Recommended Maximum Pulling Speed: 0.67 sec/stand
Maximum Swab EQMD: 9.80 lb/gal

While Bit is in Cased Hole
Recommended Maximum Running Speed: 0.67 sec/stand
Maximum Surge EQMD: 10.21 lb/gal
Recommended Maximum Pulling Speed: 0.67 sec/stand
Maximum Swab EQMD: 9.79 lb/gal

80270H Rev. B / December 1995

Mud Hydraulics Analysis Report

Input Data					
Depth	12000.0 ft	Mud Density	12.00 lb/gal	Cuttings Density	2.30 gm/cc
Vertical Depth	12000.0 ft	PV	20.000 cP	Bit Jets	12/12/12 1/32 in
Pump Rate	107 stk/min	YP	15.00 lb/cft^2		
Flow Rate	450 gal/min	Power Law k	0.6217	Total Flow Area	0.3313 in^2
Pump Pressure	3300 psi	Power Law n	0.6521		
Average ROP	20.0 ft/hr				

Table of Results - Power Law Fluid Model @ 450 gal/min

Section		Section Hole		Pipe		Volumes & Capacities			Pressure Loss		Mud Velocity			Reynolds Number Flow		
From	To	Length	Diam	OD	ID	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Annular	Critical	Annular	Critical	Reg
ft	ft	ft	in	in	in	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	ft/min	ft/min			
0.0	900.0	899.0	20.000	5.000	4.276	8	9	180	52	0	683.2	29.6	69.8	421	1769	Laminar
900.0	10000.0	9100.0	12.416	5.000	4.276	1125	169	1176	627	20	683.2	83.6	130.1	1124	1761	Laminar
10000.0	11000.0	1000.0	12.250	5.000	4.276	210	27	180	97	4	683.2	84.2	128.4	1157	1760	Laminar
11000.0	12000.0	1000.0	12.250	8.000	2.750	73	4	42	238	4	1409.4	128.2	103.4	1502	1723	Laminar

Volume Summary

	bbls	Strokes	Minutes	
Annular Capacity	1578	15948	148	<- Lag Time
Pipe Capacity	208	2103	20	<- Down Time
Circulating Volume	1785	18051	168	<- Circulating Time
Pipe Displacement	122			
Total Hole Volume				

Hydraulics Results Using Power Law Fluid Model

Flow Rate	90	162	234	306	378	450	522	594	666	738	810	gal/min
Pump Rate	21	38	56	73	90	107	124	141	158	175	193	str/min
Total Flow Area	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	in^2
Jet Velocity	87.1	156.9	226.6	296.3	366	435	505.4	575.2	644.9	714.6	784.3	ft/sec
Impact Force	48.8	158.8	329.6	563.6	868	1218.9	1608.1	2123.8	2669.8	3270.3	3909.1	lbf
Hydraulic Power	4.3	23.5	76.3	179.8	328	542.4	846.6	1267.8	1798.2	2392.9	3165.3	hp
Pipe Loss	65	188	337	521	738	976	1242	1533	1847	2185	2548	psi
Bit Loss	82	244	498	842	1458	2058	2742	3503	4464	5482	6603	psi
Percentage of Total	19.1	46.4	52.8	60.3	65.6	65.8	67.3	68.8	69.8	70.7	71.3	%
Annular Loss	12	18	22	27	31	34	38	42	48	57	65	psi
Cutting Loss	248	138	96	73	59	50	43	38	34	30	28	psi
Total Loss	427	578	1008	1503	2283	3098	4065	5143	6392	7751	9238	psi
Hydrostatic Pressure	7479	7479	7479	7479	7479	7479	7479	7479	7479	7479	7479	psi
Circulating Pressure	7736	7658	7596	7576	7568	7562	7558	7557	7559	7563	7570	psi
ECD @ Vertical Depth	12.02	12.03	12.04	12.04	12.05	12.06	12.06	12.07	12.08	12.09	12.10	lb/gal
ECD with Cuttings	12.42	12.25	12.19	12.16	12.14	12.13	12.13	12.13	12.13	12.14	12.15	lb/gal

Minimum Recommended Flow is 159 gal/min to maintain laminar flow in section with Diameter 12.250 and Pipe OD 8.00 in
Minimum Recommended Flow is 302 gal/min to maintain cuttings transport in section with Diameter 20.000 and Pipe OD 5.000 in

Bit Hydraulics Optimization Report - Input Data

Previous Bit			
Nozzle A diameter	12 1/32 in	Mud Density	12.00 lb/gal
Nozzle B diameter	12 1/32 in	PV	20.000 cP
Nozzle C diameter	12 1/32 in	YP	15.00 lb/cft^2
		Flow Rate	450 gal/min
Total Flow Area	0.3313 in^2	Pump Pressure	3300 psi

Optimization Limits	Maximum		Minimum
Flow Rate	800 gal/min		300 gal/min
Pump Pressure	3000 psi		

Calculated From Previous Bit

Jet Velocity	435.7 ft/sec
Parasitic Pressure	1262 psi
Bit Pressure Drop	2038 psi
Parasitic Exponent	1.6271

Calculated Optimum Bit Hydraulics

	Hydraulic Power	Impact Force
Parasitic Pressure	1142 psi	1654 psi
Bit Pressure Drop	1858 psi	1346 psi
Optimum Flow Rate	423 gal/min	531 gal/min
Flow Rate Used	423 gal/min	531 gal/min
Hydraulic Power	465.0 Hp	423.0 Hp
Impact Force	1094.5 lbf	1169.7 lbf
Jet Velocity	416.0 ft/sec	354.1 ft/sec
Total Flow Area	0.3263 in^2	0.4815 in^2
Recommended Bit Nozzles	11/12/12 1/32 in	14/14/15 1/32 in

Self [illegible]e

1. What are the three basic components of a drilling fluid?

   a________________________

   b________________________

   c________________________

2. What are three m[illegible]

   a________________________

   b________________________

   c________________________

3. What ma[illegible]al is [illegible] oil phase in an invert emulsion [illegible]

   ____

4. What criteria is used to express the stability of an oil-based mud's emulsion strength?

   ____

5. The fric[illegible]al dr[illegible] flowing fluid slide past ea[illegible]

   ____

6. Bingham's [illegible]ship of shear stress and shear rate inc[illegible] from the Newtonian Mode[illegible] What is that feature?

   ____

7. If a gel s[illegible] what is it's classific[illegible]

   ____

8. What mathe [illegible]

____

____

____

____

9. What type of gel stru [illegible] ling fluids?

____

10. What two g [illegible]

a____

b____

11. What is the [illegible]

____

12. Calculate the amoun [illegible] e resulting volume increase if you raise [illegible] Give this answer in s [illegible] cks and barrels.

Given: [illegible]

sacks/bbl = 14.9

answer____

13. Calculate slip veloci [illegible] ormation.

Given: Dril [illegible] @ 2.4 g/cc
Parti [illegible]
Visc [illegible] 55 cps
Ann [illegible] lar Ve [illegible]
Gravity: 32.2 [illegible]
Flow Regi [illegible] e: Lami [illegible]

answer____

14. Calculat[illegible] readings from the Fann Meter.

Given: RPM_{600} = 40 RPM_{300} = 30

answer ______________________________

15. From the data in question #14, calculate n and k.

answer ______________________________

16. In hard formations, what must be efficient for the drill rate to be proportional to w[illegible]

____

17. What tw[illegible] when determining surface hydraulic[illegible]

a ______________________________

b ______________________________

18. What w[illegible]er, with a pump pressure [illegible]/min?

____

19. Using 3200 psi, w[illegible] hydraulic horsep[illegible]?

Hhh = ______________________________

Hif = ______________________________

20. What fu[illegible] of f[illegible] PDC and diamond bits?

PDC Bits: ______________________________

Diamond Bits: ______________________________

21. What are th[illegible]cs in the following drilling flu[illegible]

Water-Based Drilling Fluids: ______________________________

Oil-Based Drilling F[illegible] ______________________________

22. What two componen[illegible]

a ______________________________

b ______________________________

23. What are the two types of diamond bit flow patterns?

a ______________________________

b ______________________________

24. Turbulent f[illegible]arrying capacity than laminar flow. Why is it not normally the flow regime of choice?

____

____

•Notes•

Casing And Cementing

Upon completion of this chapter, you should be able to:

- Understand the limitations of various casing strings.
- Calcul[illegible] cementing operation.
- Calcul[illegible] slurry volumes, job times, and mud returns.
- Trouble-shoo[illegible]g cementing operat[illegible]

Additional [illegible]

Petroleum Extension Se[illegible]
University of Texas at [illegible]

Bourgoyne Jr., Adam, et al, *Ap*[illegible]
Series, Vol. 2, 1986

Moore, Preston, *Drilling Practices Manual*, PennWell Publishing Co., Tulsa, 1986

Rabia, Hussain, *Oilwell Drilling Engineering: Principles and Practice*, Graham & Trotman Limited, 1[illegible]

Cas[illegible]

Casing has several important functions during the drilling and completing of a well. I[illegible] caving in during the drilling of the [illegible]lling fluids encountered while drilling [illegible] to be produced, and to protect or iso[illegible] of a well. Casing is also one of th[illegible]ound 20% of the cost of a completed w[illegible]

Casing is us[illegible]pes.

Conductor [illegible]

Conductor p[illegible] drive pipe if it is hammer-driven to depth, is the first string of casi[illegible] from 10 ft to around 300 ft. The n[illegible] pipe is from 16 to 36 inches (outside dia[illegible] other casing [illegible] of conductor pipe are to:

- rai[illegible]d so that fluid returns are pos[illegible]
- pr[illegible] normally unconsolidated for[illegible]

Surface Cas[illegible]

The amount [illegible] unconsolidat[illegible] competent fo[illegible]etween 20 inch and 13-3/8 inch [illegible] corrosive fluids tend to increase with depth, different grades of casing will be required to handl[illegible] casing are to:

- protect fre[illegible] water formations
- sea[illegible] lost circulation zones
- pr[illegible]
- pr[illegible]ted wells
- pr[illegible]k-off" test to be conducted

Intermediat[illegible]

Intermediate [illegible]rmally to seal off a problem form[illegible]g, will depend on the size of the surfac[illegible] conditions. Nom[illegible]/8 inch (outside diameter).

Production Casing

Production casi[illegible]pe set in a well. These strings are run to [illegible] formations and provide for selective production in m[illegible]e size of production casing will depend on t[illegible]her the barrel per day production rate, [illegible] of the pipe. Common sizes are between 3 a[illegible]

Liner

A liner is a string[illegible] "hung" (attache[illegible] using an arrangement of packers and slip[illegible] from the base of the intermediate casing and reach to the bottom of the ho[illegible] reduced, as are r[illegible] times. During the course of the well if the liner has t[illegible] making it another string of casing), the strin[illegible] surface is known as a "tie-back" string.

Casing Standards

The American P[illegible] has developed certain standards and specificatio[illegible] common standa[illegible] used:

- Nomi[illegible]retical calculated weight per foot fo[illegible] casing joint.
- Plain [illegible]: The weight of the joint of casing without the [illegible]plings.
- Threa[illegible] weight of a casing joint with thread[illegible] at one end.

The Plain End W[illegible] calculated using [illegible] in API Bulletin 5C3.

API standards include three length ranges, which are:

- R-1: Joint len[illegible] 16 to 25 feet, and 95% must have leng[illegible]
- R-2: Joint len[illegible] 95% must hav[illegible]

- R-3: Joint [illegible] % must have lengths greater [illegible]

The API grade of ca[illegible]ng de[illegible]otes the steel properties of the casing. The grade has a le[illegible] designates th[illegible] of API casing grade[illegible]

API Grade	Yield Strength (min), psi	Tensile Strength (min), psi
H-40	40,000	60,000
J-55	55,000	75,000
K-55	55,000	95,000
C-75	75,000	95,000
L-80	80,000	100,000
N-80	80,000	100,000
C-90	90,000	105,000
C-95	95,000	105,000
P-110	110,000	125,000

Casing properties are defined as:

- Yield Strength: The tensile stress required to produce a total elongation of 0.5% per unit length
- Collapse Strength: The maximum external pressure or force required to collapse the casing joint
- Burst Strength: The maximum internal pressure required to cause a casing joint to yield

Casing dimensions are specified by its outside diameter (OD) and nominal wall thickness. Normal wellsite conventions specify casing by its OD and weight per fo[illegible]uld specify which weight one is referring to, t[illegible]minal weight.

Casing Couplings

Couplings are short [illegible] They are normally m[illegible] as the casing. Through their strength co[illegible] API has specifications for four types of [illegible]

- Short [illegible]ound threads and couplings (CSG)
- Long [illegible]ound th[illegible]
- Buttress threa[illegible]
- Extremeline [illegible]reads [illegible]

The CSG and LCSG ha[illegible] threads have a rounded shape, with eig[illegible] referred to as API 8-rou[illegible] two is that the LCSG has a longer thread run-out [illegible] connection. LCS[illegible]s.

Buttress (BCSG[illegible] are also longer c[illegible]ding longer thread run-out.

The XCSG (Ext[illegible] different from the other three connectors in th[illegible]ctors, meaning the coupling has both box and pi[illegible]

Coupling thread[illegible] are made up. A [illegible]lt in a leaking joint. An over-tight connection will [illegible]gain, will cause leaking. Proper make-up is moni[illegible] using torque make-up tables and the number of required turns.

A special thread[illegible] type of coupling[illegible]und.

Many companie[illegible] have their own couplings, in addition to the API standards, which [illegible] available on the API couplings.

Cementing

Introduction

[illegible] is the process of mixing and displacing a slurry down [illegible] annulus, behind the casing, where is allowed to "set", thus bonding [illegible] additional functions of [illegible]

- Pr[illegible]
- Pr[illegible]
- Pr[illegible] the casing from corrosion
- Se[illegible]
- Protecting [illegible]

The main ingredient [illegible] limestone and clay. [illegible] ture resembling the rocks quarried o[illegible]

All cement is manu[illegible] calcareous and argillaceous materia[illegible] ground and mixed i[illegible] dry condition (dry processing) o[illegible] the upper en[illegible] iform rate. The kiln is heated to temperatures [illegible] the mixture [illegible] occur between the raw materials. When the mi[illegible] with a contr[illegible] portland cem[illegible]

The principl[illegible] Tricalcium S[illegible] 2S), Tricalcium Aluminate(C[illegible] ite(C4AF). Table 2-2 contains mo[illegible] materials are [illegible] their hydrous form, which is then called a "cement slurry".

The Americ[illegible] ablished a classification system for th[illegible] must meet sp[illegible] chemical and [illegible] their applica[illegible] under various temperature [illegible]

Cem[illegible]

[illegible] cause hydration and to make a pumpable slurry. To be use[illegible] be known: the yield per [illegible] required (gallons per sack), and its de[illegible]

Another importa[illegible] absolute volume". This is the actual volume o[illegible] spaces between [illegible]he cement particles). For example, one sack (94 lbs) of cement has a bu[illegible]e open spaces between the particles were re[illegible]

With dry materi[illegible] absolute volume is used along with the w[illegible]ter requirements to determine the slurry. For ex[illegible] absolute volume [illegible] (5.18 gal/sk or 0.693 ft^3) yields a slurry volume of 1.171 ft^3 (0.478 + 0.693).

The absolute vol[illegible]ents are normally found in tables (see Table[illegible]sing:

$$AbsoluteVol[illegible] = \frac{[illegible]}{8.34 lb/gal} \times \frac{1}{SG\ of\ component}$$

For components [illegible]m chloride, etc.), since they do not occupy as much space as the specific gravities would indicate, the absolute volume[illegible]erimental data and placed in reference tables.

Slurry density is also determined. Since one sack of cement weighs 94 lbs, and 0.693 ft^3 of water weighs 43.2 lbs, which [illegible] slurry. The slurry's density is then calculated b[illegible] slurry volume, 137.2 lbs / 1.171 ft^3 equals 117.1 lbs/ft^3 (15.7 ppg).

Yield is converted to cubic feet per sack by us[illegible] the con[illegible] [illegible]805 (62.[illegible] lbs/ft^3 / 8.34 lbs[illegible]

Fly ash, a synth[illegible] constituent of cements. A fly ash/cement [illegible]he ratio of fly ash to cement (expressed as 5[illegible] [illegible] first number is t[illegible] [illegible] cement (94 lbs/sack). A sack of fly ash and a sack of cement have the same absolute volume[illegible]

If other additive[illegible] the mixture is expre[illegible]t of both cement and fly ash. The slurry is then [illegible]

Example pro[illegible]

Using the informat[illegible] r requirement.

Cement Blend:

35: 65 : 2% GEL C[illegible]

	Bulk Weight lbs/ft^3	Absolute Volume gal/lb
Class H	94	0.0382
Fly Ash	74	0.0487
Gel (Bentonite)	60	0.0453
Water	X	0.1199

Material	lb/ft3		gal/lb		gal/ft^3
Class H	61.1	x	0.0382	=	2.33 (65% of 94)
Fly Ash	25.9	x	0.0487	=	1.26 (35% of 74)
Subtotal	87.0				3.59
Gel	1.74	x	0.0453	=	0.08 (2% of 87)
Water	X	x	0.1199	=	0.1199X

$$88.74 + X = 13.5(3.67 + 0.1199X)$$

$$88.74 + X = 49.545 + 1.61865X$$

$$39.195 = 0.61865X$$

$$63.35 = X$$

Water = 63.35 lb/ft^3 x 0.1199 gal/lb = 7.60 gal/sack

Yield = (3.67 gal/ft^3 + 7.60 gal/sk)/7.4805 gal/ft^3 = 1.52 ft^3/sk

Typi[illegible]

[illegible] calculating the annular volume between [illegible] essing this value in [illegible] casing below the plugs must be ad[illegible]

The annular vol[illegible] ned ($d_1^2 - d_2^2$ x 0.000971 x L) and the conversi[illegible]

From carbide da[illegible] If it isn't known, [illegible] to the volume (anywhere betw[illegible] ume). Once the annular volume is determined, then a minimum excess factor is applied (normally 10% to 15%) to [illegible]

This quantity w[illegible] casing.

Example Field Cal[illegible]

Well Informatio[illegible]

13 3/8" casing ([illegible] feet
12 1/4" open ho[illegible]

9 5/8" casing (3[illegible] ID 8.921", to be run to TD
Float Collar 42 [illegible]
Cement [illegible] casing

Slurry: Class G (25% excess) neat, with 1.3% FL-50 at 14.2 ppg
20 bbl[illegible]) ahead of cement

High Pressure [illegible]
10 minutes for p[illegible]
Displacement R[illegible]

Volume Calcul[illegible]

Volume 1: [illegible]

([illegible] 971 x 300 = 19.37 bbls

[illegible] 19.37 x 5.6146 = 108.8 ft³

Volume 2: [illegible] hole w/25% excess

([illegible]

226.51 x 5.6146 = 1271.8 ft³

Volume 3: [illegible]

([illegible]

Total Slurry Volume: [illegible] 271.8 + 18.22 = 1399 ft³

Cement and Water Requirements:

Material	[illegible]	gal/ft	gal/ft³
Class G	[illegible]	[illegible]	[illegible]
FL-50 (1.3%)	[illegible]	[illegible]	[illegible]
Water	[illegible]	[illegible]	[illegible]

[illegible] 60.73 = X [illegible]

Water = 60.73 lbs/ft³ x 0.119 [illegible]

Yield = (3.7016 gal/ft³ + 7.2 [illegible]

Sacks of Cement: 1399 ft³/1.47 ft³ [illegible]

Mix Water Required: (7.28 gal/sk x 954 sks)/42 gal/bbl = 165 bbls

Total Water: [illegible]

Amount of FL-50: 1.3% of 952 sa[illegible] = 12.4 sacks

Weight: 952 [illegible] = 89388.0 lbs

12.4 sks of FL [illegible]

Total Weight [illegible]

Displacement Volume: (8.921²) x 0.000971 [illegible]

Job Time:

Pumping of [illegible] @ 2.5 bbl/min = 8 min

High Pressure [illegible]

Displacement Time [illegible]

Time to Dr[illegible]

Total Time [illegible]

Mud Returns [illegible]

(9.625² - 8.921²) x 0.000971 [illegible] = [illegible] bbls

Pre-flush = 20 bbls

[illegible] 250 bbls

Mud Returns = 333 bbls

Removal of [illegible]

For cementing operations to be successful, all annular spaces must be filled with cement, and [illegible] previous casing and formation [illegible] drilling fluid must be displaced by the cement sl[illegible] easy matter, because there are several factors w[illegible]:

- washo[illegible] fluid a[illegible]
- crooked holes making casing centralisation difficult and drilling fluid not bein[illegible]
- poorly treated drillin[illegible]

Good drilling practices [illegible] they may help prevent a failure. The ide[illegible] operations should have:

- a low gel stre[illegible]
- a low density
- a low [illegible]
- a chem[illegible] the cement

Since these con[illegible] very seldom met, fluid washes and spacers are usually pumped [illegible] drilling fluid as possible.

Cementing Nomenclature

Casing Centralizers

Centralizers assist in the removal of filter cake and displacement of drilling fluid by providing a m[illegible] slurry. Close scrutiny of the mudlog and wireline logs will help in the placement of centralizers. Zon[illegible]ity, doglegs and areas of key seating, should b[illegible] around the casing.

Wall Scratcher[illegible]

These are most useful when running casing through a high fluid-loss drilling fluid. Th[illegible]pes of wall scratchers, rotating scratchers [illegible]tated (normally in vertical wells), and reciprocating scratchers used when the pipe is reciprocated (moved up and down). When the[illegible] in 15 to 20 foot intervals, overlapping cleaning occurs.

Wiper Plug[illegible]

Both top and [illegible] [illegible]ting operations. They are used to separ[illegible] [illegible]her.

The red botto[illegible] [illegible] rubber, and has a hollow core. It is us[illegible] ahead of the cement slurry to prevent cement/drilling fluid contaminatio[illegible] [illegible]er cake. After the bottom plug comes i[illegible] [illegible] psi) causes th[illegible] [illegible]e, allowing the cement slurry to flow through[illegible]

The black to[illegible] [illegible] core. It is dr[illegible] [illegible] has been pumped, to prevent contaminatio[illegible] [illegible] fluid. The top plug also signals the end of displa[illegible] [illegible] pressure incr[illegible]

Chemical W[illegible]

Chemical wa[illegible] [illegible]g surfactants and mud thinners, designed to t[illegible] from the casi[illegible] [illegible] are available for water-based and oil-based dri[illegible] [illegible]gned to be used in turbulent flow conditions.

Spacers

Spacers are f[illegible], density and gel strength used to form a buffe[illegible] [illegible] drilling fluid. They also help in the removal of d[illegible] [illegible]e.

Cement Additives

Accelerator[illegible]

An accelerat[illegible] [illegible] reaction betw[illegible] [illegible] the cement, i[illegible] [illegible]h of cement, and saves time on the drilling rig. C[illegible] [illegible]te shallow, low-temperature formations r[illegible] [illegible]n the time for "waiting-on-cement". Mo[illegible] [illegible] strength of 5[illegible] [illegible]rilling operations. When using accelerators, [illegible] to use accele[illegible] [illegible] [illegible]ure 1 or 2 days to develop a 500 psi [illegible]

Common acc[illegible] [illegible]ate, sodium chloride, sea water, anhydrous ca[illegible] [illegible]hloride and gypsum.

Retarders

Neat cement slurries set quickly at a BHT greater than 110°F. A retarder is an additive used to increase the thickening time of cements. Besides extending the pu[illegible]ers affect the viscosity to some degree. [illegible] use of retarders are temperature and [illegible]

Common retard[illegible] organic material[illegible]

Extenders

Extended cemen[illegible]ce the hydrostatic pressure on weak formations[illegible] of slurries. Extenders work by allowing the add[illegible] to lighten the mixture and to keep the solid[illegible] additives change the thickening times, compress[illegible]

Common extend[illegible] and diatomaceous earth.

Pozzolans

Pozzolans are n[illegible]s materials added to portland cement to reduc[illegible] volcanic ash or [illegible] silica in the pozzolans combines with the free lime in dry cement, which means a soluble constituent is removed from th[illegible]

Common pozzo[illegible] earth and fly ash.

Table 2-2:

PRINCIPLE COMPOUNDS IN PORTLAND CEMENT
Tricalcium Silicate $3CaO:SiO_2$ = C_3S 1. The major compound in Portland cement 2. Contributes to strength development, especially during the first 28 days 3. Hydration equation: $2(3CaO:SiO_2) + 6H_2O \dashrightarrow 3CaO:2SiO_2:3H_2O + 3Ca(OH)_2$
Dicalcium Silicate $2CaO:SiO_2$ = C_2S 1. A much slower hydrating compound than tricalcium silicate 2. Contributes to a slower, gradual increase in strength, over an extended period of time 3. Hydration equation: $2(2CaO:SiO_2) + 4H_2O \dashrightarrow 3CaO:2SiO_2:3H_2O + Ca(OH)_2$
Tricalcium Aluminate $3CaO:Al_2O_3$ = C_3A 1. Promotes rapid hydration of cement 2. Controls the initial set and thickening time of the cement 3. Regulates resistance to sulfate attack (HSR - High Sulfate Resistance) 4. Gypsum is added to retard hydration and flash setting 5. Produces most of the heat observed over first few days 6. Hydration equation: $3CaO:Al_2O_3 + 12H_2O + Ca(OH)_2 \dashrightarrow 3CaO:Al_2O_3:Ca(OH)_2:12H_2O$ $3CaO:Al_2O_3 + 10H_2O + CaSO_4:2H_2O \dashrightarrow 3CaO:Al_2O_3:CaSO_4:12H_2O$
Tetracalcium Aluminoferrite $4CaO:Al_2O_3:Fe_2O_3$ = C_4AF 1. Promotes low heat of hydration in cement 2. Hydration equation: $4CaO:Al_2O_3:Fe_2O_3 + 10H_2O + 2Ca(OH)_2 \dashrightarrow 6CaO:Al_2O_3:Fe_2O_3:12H_2O$

Table 2-3:

API Class	Application
A Neat	- [illegible] ft. - [illegible]°F - Used when special properties are not required [illegible] - Economical when compared to premium cements * Normal Slur[illegible] * Normal Mixi[illegible] (5.19 gal/sk & [illegible] ft^3/sk) * Normal Slur[illegible]
B Neat	- Used at depth[illegible] [illegible] - Used when [illegible] to high sulfate resistance is required - Used when w[illegible] - Economical when compared to premium cements * Normal Slurry Weight is 15.6 ppg * [illegible] 46% (5.19 gal/sk & [illegible] ft^3/sk) [illegible]
C Neat	- Used at depth ranges of 0 to 6000 ft. - Used at temp[illegible] - Used when hi[illegible] - Used when it[illegible]required - High in trical[illegible] [illegible] * Normal Mixing Water Requirement - 56% (6.31 gal/sk & 0.844 ft^3/sk) * Normal Slur[illegible]
D,E Neat	- Class D used at depths from 6000 to 10000 ft. and at temperatures from 170 - 260°F [illegible] ft. and at temperatures from 170 - 290°F - Both used at [illegible]es and high pressures - Both availabl[illegible]ate - Both are retar[illegible]d, chemical composition and grind - Both are more[illegible]d cement * Normal Slur[illegible] [illegible] (4.28 gal/sk & 0.572 ft^3/sk) * Normal Slurry Yield - 4.29 ft^3/sk

Table 2-3: continued

API Class	Application
F Neat	[illegible]0000 to 16000 ft. [illegible]m 230 - 320°F - U[illegible]d when extremely high temperatures and pressures are [illegible]ncountered [illegible]rate and high resistance to sulfate - Retarded with an organic additive, chemical composition and grind[illegible] * Normal Sl[illegible] * Normal M[illegible] * Normal Sl[illegible]
G,H Neat	- Used at de[illegible] [illegible]ithout modifiers [illegible] compatible with accelerators or retarders Usable ove[illegible] Additives [illegible]n be blended at bulk station or at well site - Class H is a coarser grind than Class G [illegible] [illegible] (4.96 gal/sk & [illegible]66[illegible] ft³/sk) * Class G sl[illegible] * Class H sl[illegible]o 16.4 (deep) ppg * Class H A[illegible] (4.3 gal/sk & 0.57 ft³/sk) * Class H sl[illegible]allow) to 1.05 ft³/sk (deep)
J	- Used at de[illegible] 16000 ft [illegible]d pressure: 170 - 320°F [illegible] Usable wit[illegible] Will not se[illegible] at temperatures less than 150°F when used a[illegible] Water requ[illegible]

Table 2-4: Physical Properties of Cement Additives

Material	Bulk Weight, lbs/ft^3	Specific Gravity g/cc	Absolute Volume gal/lb	ft^3/lb
Sodium Chloride	71.0	2.17	0.0553	0.0074
Calcium Chloride	56.0	1.96	0.0612	0.0082
Potassium Chloride	64.9	1.984	0.0604	0.0081
Gypsum	75	2.7	0.0444	0.0059
Cement	94	3.14	0.0382	0.0051
Attapulgite	40	2.89	0.0415	0.0053
Barite	135	4.23	0.0284	0.0038
Hematite	193	5.02	0.0239	0.0032
Diatomaceous Earth	16.7	2.1	0.0572	0.0076
Pozzolan	40	2.43	0.0493	0.0066
Diesel Oil (1)	51.1	0.82	0.1457	0.0195
Diesel Oil (2)	53.0	0.85	0.1411	0.0189
Fly Ash	74	2.46	0.0487	0.0065
Bentonite	60	2.65	0.0453	0.0060
Gilsonite	50	1.07	0.1122	0.0150
Nut Plug	48	1.28	0.0938	0.0125
Silica Flour	70	2.63	0.0456	0.0061
Sand	100	2.63	0.0456	0.0061
Water (fresh)	62.4	1.00	0.1200	0.0160
Water (Sea)	63.96	1.025	0.1169	0.0153
Lignosulphonate	35.1	1.36	0.0882	0.0118
Polymer (FL-50)	35	1.34	0.0895	0.0119

Table 2-5: Absolute Volume of NaCl (Dissolved)

%NaCl	gal/lb
2	0.0371
5	0.0381
8	0.0390
10	0.0394
12	0.0399
15	0.0405
17	0.04095
20	0.0412
23	0.0422
25	0.0426
28	0.0430
30	0.0433
33	0.04375
35	0.0440
37	0.0442

Table 2-6: General Problems Encountered During A Cementing Operation

PROBLEM	PROBABLE CAUSE	CORRECTION
Cannot receive [illegible] fluid from the rig	a. [illegible] b. Hooked to wrong line c. [illegible]k empty d. [illegible]n in line	a. [illegible] b. Trace out supply lines and tank c. [illegible] d. [illegible]
Cannot pu[illegible]mp out of displacem[illegible] tank	a. Valve closed or b[illegible] b. Obstruction in su[illegible] c. No air pressure on the unit d. Air lock in pumps	a. [illegible]ves b. [illegible] c. Check air system d. Prime pumps
Leaks or b[illegible] discharge [illegible]	a. [illegible] b. [illegible]n f[illegible] c. Improperly made up d. Washed-out pipe	a. [illegible]d repair b. [illegible] repair c. Take apart, inspect and repair d. Take apart, inspect and replace
Cannot pu[illegible] through cement mixer	a. [illegible] disengaged b. Valve closed or b[illegible] c. Obstruction in suction d. Screen or jet plug[illegible] e. Obstruction in mix[illegible]	a. Check pump for rotation b. [illegible] c. Back-flush d. [illegible] and tube e. [illegible] and tube
Cannot obtain proper slurry or control the density	a. Starving mixing pump b. Obstruction in jet, bypass [illegible] c. [illegible]ixer bowl	a. Check out pump, jet, bypass, [illegible] b. Check out pump, jet, bypass, [illegible] hopper c. [illegible]p, jet, bypass, tube, bowl or hopper

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
No cement r[illegible] to surface	[illegible] b. Loss to formation [illegible] from pipe	[illegible] b. Use lost-circulation material [illegible] job [illegible]
Sudden pressure drop while displacing	a. Pumps lost pr[illegible]	[illegible] e and re-prime pumps
	b. Split pipe	b. [illegible] volume, locate hole in pipe and squeeze
	c. Lost circulation	c. Check well returns
	d. Packer failure	d. Check annulus pressure. Reverse out and reset packer
	[illegible] between [illegible]	e. Check annulus pressure. Reverse out and reset packer
[illegible]	a. Differential pressure too great	a. Slow pump rate. Use low density slurry. Displace with a heavy fluid. Open bleeder valve and allow pipe to settle back in place. Chain down pipe
	b. Hole caved in.	b. Slow pump rate. Use low density slurry. Displace with a heavy fluid. Open bleeder valve and allow pipe to settle back in place. Chain down pipe

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
Find no cement [illegible] the shoe joint	a. [illegible] wall by top plug b. [illegible]oned fr[illegible] of top plug [illegible]nt to [illegible]	a. [illegible]n pre-flush b. [illegible]arge valve after [illegible]t of the pipe
Top plug [illegible] bump	a. Sh[illegible] joint off or casing weight quoted wrong. b. Plug still in head c. [illegible]d to seal d. [illegible]ession	a. Recheck calculations and weight of casing. Check with measuring line b. Check cement head. Check with measuring line c. Stop pumping; check with measuring line d. Allow for compression in mud. Check with measuring line
Top plug bumps but pressure fails	a. Surface leak b. Shoe joint off c. Baffle broken d. Plug failed to seal e. Surface leak	a. Check for surface leaks b. Stop pumping; check float c. Stop pumping check float d. Stop pumping; check float e. Check leak
Cement plug in place; pipe on a vacuum	a. Underdisplaced b. Formation broke down c. Oversized hole	a. Recheck calculations b. Recheck calculations; allow to equalize c. Recheck calculations; allow to equalize
Cement pl[illegible] place; pre[illegible]ure on pipe	a. [illegible] b. Undersized ho[illegible]e c. We[illegible] fluid out of balance d. Pre-flush and after-flush not in balance e. Slurry lighter than well	a. Recheck calculations b. Allow to equalize c. Circulate fluid to condition before cementing d. Pull it wet e. Overdisplaced

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
Cement plug [illegible] place; cannot pull pipe	[illegible] closed [illegible] eat in bore [illegible] aved in [illegible]	[illegible] dditives for proper percentages [illegible] d. Circulate or reverse-circulate [illegible]
Canno[illegible] cemen[illegible] plug [illegible]r plug too low	a. [illegible] not se[illegible] b. Hole washed [illegible] c. Lost to forma[illegible]on d. Moved downh[illegible]	[illegible] minate [illegible] c. Use low density [illegible]lurry [illegible] rs
Locati[illegible] plug to[illegible]	[illegible] isplaced [illegible] undersiz[illegible] [illegible] ed [illegible] d. Swabbed up th[illegible] pulling pipe e. Bottom joints [illegible] [illegible] pi[illegible]	[illegible] ons [illegible] condition [illegible] ty [illegible] lowly; condition [illegible] condition mud densit[illegible] [illegible] condition [illegible] lowly; condition mud de[illegible]sity
Pluggi[illegible] for lost circulation	a. W[illegible]eak zone, fr[illegible] caverns	[illegible] enting materials for gel strength. Use granular or [illegible] materials to bridge. Low [illegible] d head low [illegible] ts

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Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
Squeeze cemen[illegible] or treating below packer; su[illegible] or pressur[illegible] annulus	[illegible] seated [illegible]ation outside casing [illegible] [illegible]per[illegible] [illegible] manifold [illegible] annulus	[illegible]ol. Check lines and valve to annulus [illegible]wnhole tool. Check [illegible]alve to annulus c. Check lines and valve to [illegible]us Set packer above upper perforations d. Pull drill pipe [illegible]sure test
Squeeze cementing or treating below packer. Sudden pressure loss in the annulus	a. Casing split above [illegible] perforations above [illegible] b. BOP leaking	[illegible]side pressure to safe [illegible] or pull pipe [illegible]OP
Displacing cement to packer [illegible] depth, los[illegible] displacing [illegible]	a. Not reading strok[illegible] [illegible] tank	a. Reverse out Reverse slurry back to top of tubing; then measure displacement back [illegible] out. Reverse [illegible] to top of [illegible] displacement back down
Squeeze c[illegible] place; pac[illegible]	[illegible] pa[illegible] [illegible]w pack[illegible] [illegible] d. BOP closed [illegible] differen[illegible] packer too high	[illegible]rse-circulate [illegible]-circulate c. Not enough pressure was held on back side; go fishing d. Check BOP [illegible]ve pressure differential

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	[illegible]
Zone to be squeezed ac[illegible] well fluid but not cement[illegible]	a. Tight formation b. Pressure limitation too low [illegible] sensitive zone	a. Spot acid or other break-down [illegible] b. Spot acid or other break-down [illegible] [illegible] slurry
Mixing [illegible] bulk de[illegible] and ca[illegible] fixed i[illegible] time to finish	[illegible]	a. Calculate volume of slurry mixed if sufficient for proper job, continue. If not, circulate out and start over
Slurry [illegible] pumpi[illegible] becom[illegible]	[illegible]	a. Displace with the rig pump
Operat[illegible] complains of trouble [illegible] top rubber plug in large-[illegible] casing	[illegible] with bit	a. Place a few sacks of cement on top of the plug

Casing [illegible] Report

Depth 14500.0 ft

Casing Shoe Depth [illegible]

[illegible]

From	Section To	Length	Hole Diam	Casing Section	Average Joint	Casing OD	Casing ID	[illegible] Total	Displ. Joint	Casing Total	Capacity Joint	Annular Volume	Annular Volume
ft	ft	ft	in		ft	in	in	bbls	bbls	bbls	bbls	[illegible]	bbl/ft
0.0	500.0	499.8	20.000	3	94.7	5.000	4.000	4	0.828	8	1.472	380	1.190
500.0	762.8	262.8	12.416	3	94.7	5.000	4.000	2	0.828	4	1.472	33	0.122
762.8	8707.9	7945.2	12.416	2	38.9	9.625	8.835	113	0.552	682	2.951	475	0.196
8707.9	10000.0	1292.1	12.416	1	39.2	9.625	8.921	16	0.497	108	3.029	77	0.196
10000.0	14036.8	4036.8	12.250	1	39.2	9.625	8.921	51	0.497	312	3.029	235	0.181
14036.8	14500.0	463.2	12.250	1									

Summary

Total Steel Displacement	187 bbls
Total Casing Capacity	1026 bbls
Total Casing Displacement	1213 bbls
Total Annular Volume	998 bbls
Total Hole Volume	2271 bbls

Weights and Hookload

								Casing Hook Load		
Casing Section	Length	Number of Joints	Average Joint	Casing OD	ID	Casing Weight Steel	Per Joint	In Air	In Mud Empty	Full
	ft	ft	ft	in	in	lb/ft	klb	klb	klb	klb
1	5328.8	136	39.2	9.625	8.921	36.00	0.14	19.56	1.88	18.86
2	7945.2	204	38.9	9.625	8.835	36.00	0.14	29.17	1.61	24.83
3	757.8	8	95.3	5.000	4.000	76.80	0.75	5.97	5.26	5.72
	-------	-----						------	-----	-----
	14031.8	348						54.70	7.95	47.50

Hookload Summary

Block and Hook Weight	99.00 klb
Empty Casing in Air	153.70 klb
Empty Casing in Mud	106.95 klb
Full Casing in Mud	146.50 klb

Cementing Analysis **Cement Pump Capacity 0.119 bbl/stk**

Cementing Operation	Circulating Depth	Cement Top	Position Base	Length Cement	Mud Density	Cement Density	Volume Cement		Mud Volume to Position Cement		Cement Back Pressure
	ft	ft	ft	ft	lb/gal	lb/gal	bbl	stk	bbls	stk	psi
1	14050.0	11000.0	14000.0	3000.0	9.08	12.00	169	35219	1026	577153	472
2	9000.0	7000.0	8000.0	1000.0	9.08	11.50	60	50130	686	385372	130
3	5000.0	3000.0	4500.0	1500.0	9.08	11.00	90	45706	363	183802	156

Self [illegible]

1. What do the "threaded and coupled weight" standards refer to?

____

____

____

2. Three common A[illegible] associated tensile strengths are:

a._______________________________________

b._______________________________________

c._______________________________________

3. After the initial c[illegible]s cement materials are mixed and baked [illegible] the resulting mixture is known as:

____

4. What formula is used to calculate the absolute volume of cementing [illegible]

____

5. An example of a slurry mixture is 60:40:2. What do these three numbers refer to?

60:______________________________________

40:______________________________________

2:_______________________________________

6. What are the idea[illegible] of a drilling fluid that should be used during ceme[illegible]

____

____

____

Co[illegible]H Rev. B / December 1995

7. Most operators wait on cement to reach a minimum compressive strength of [illegible] g operations.

8. Why are Pozzolans [illegible]

9. Given the following [illegible] with an excess facto[illegible]

Diameters and Lengths	Material	Specific Gravities
Casing OD = 13 3/8"	[illegible]	[illegible]
Casing ID = 12.415"	Bentoni[illegible]	[illegible]
Casing Shoe = 40'	[illegible]Cl_2	[illegible]
Hole Size = 1[illegible]	[illegible]	[illegible]

Objective [illegible] nt of high-st[illegible] low-density [illegible] feet of annulus.

Tail Slurry: [illegible] $CaCl_2$ flake (b[illegible] a [illegible] sk.

Lead Slurry: Class H cement mixed with 16% Bentonite and 5% NaCl (by [illegible] r/cem[illegible]

answer

10. What is a casing coupling?

•Notes•

Bit Technology

Upon completion of this chapter, you should be able to:

- Describe the components of roller cone and fixed cutter bits and understand why these variations are advantageous in certain situations.
- Determine [illegible] given the previous bit [illegible]
- Describe the various [illegible]
- Explain why running procedures are different for fixed cutter bits.

Additional Review/Reading Material

Rabia, Hussain, *Oilwell* [illegible] *Practice*, Graham & Trotman, 1985

SPE, *Applied Drilling E*[illegible], Vol 2, 1986

Moore, Preston, *Drilling Practices Manual, 2nd Edition*, Pennwell Publishing Company, 1986

Hughes Tool Co.; Video Tape, *Tri-Cone Bit Design*

Hughes Tool Co.; Video Tape, [illegible]

Hughes Tool Co.; Video Tape, *Dull Bit Grading*

Hughes Tool Co[illegible] Bits

Bit Technology

The *Advanced Logging Procedures* workbook contains information on drill bits, IADC classifications and bit grading, and should be re[illegible] before begin[illegible]

Rolling Cutter Ro[illegible]

The first suc[illegible] into the oil field [illegible]r. in 1909. Over the next fifteen years, the rolling cutter bit was used primarily in hard formation areas. This rolling cutter bit was a two-co[illegible]sh, consequently, the bit had a tendency to[illegible]es. The bit was redesigned with meshing teet[illegible] in the early 1930's, the tri-cone bit was [illegible]designed for hard and soft formations.

The primary [illegible]ling cutter bits is intrusion, which means [illegible] the rock by the weight-on-bit, and pulled th[illegible] For this reason, the cutter and teeth of [illegible]made from specially, case hardened ste[illegible]

One advanta[illegible] rolling cutter bits is the three bearing design located around the jo[illegible] most of the l[illegible]ear. Middle bearings are ball bearings, wh[illegible] direction. Th[illegible]f a special case hardened bushing pressed into [illegible] male piece, hard faced with a special mate[illegible]

Although roc[illegible] three develop[illegible]ments remains outstanding: (1) the change in water course design and th[illegible], (2) the introduction of the tungsten carb[illegible]re, and (3) the development of sealed journal beari[illegible]

Journal Angle

One of the b[illegible] of rolling cutter rock bits is the journal angle[illegible] from one rock bit type to the next, in each [illegible] all identical.

The journal a[illegible] is the angle at which the journal is mounted, relative to a [illegible] (cones) outsi[illegible] The journal angle also controls the cutter profile[illegible] the bottom o[illegible]

Journal angle [illegible] formation:

Soft Formation:

Journal angle (3[illegible] profile which accentuates cutter action and permi[illegible]

Medium Forma[illegible]

Journal angle (34° to 36°), to decrease cutter action.

Hard Formatio[illegible]

Uses a large jou[illegible] cutter [illegible]

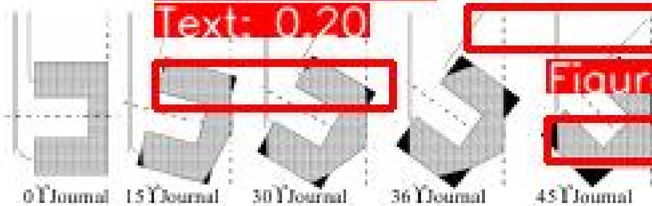


Figure 3-1: Journal Angles in Roller Cone Bits

Interfitting Teeth and Cone Offset

The idea of interfitting teeth (Figure 3-2a), makes it possible to have large bit parts, and allows the inner row of teeth to cut new formation on each rotation. Interfitting also offers some degree of self-cleaning. One result of this interfitting is that each of the three c[illegible]

Cone offset (Figure 3-2b), is caused by the journal centerline not intersecting the bit cent[illegible] distance that the journal centerline misses the bit cent[illegible] to the journal centerline [illegible] is the offset.

[illegible] from the bit center to the [illegible]

The skew direct[illegible] This permits the tips [illegible] "Negative" skew would hav[illegible]all, increasing gauge wear.

As with the i[illegible]rent in each type of formation. In soft formation bits, the maximum offset (3° skew angle) is used to incre[illegible] action. Medium formation bits add a limited offse[illegible]lon cutter action. While hard formation bits have no offset, to mini[illegible]ng.

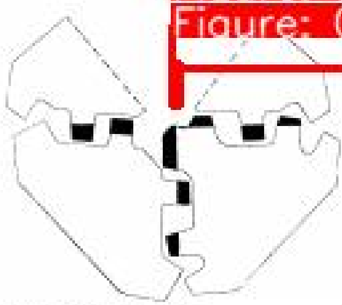


Figure 3-2a:Interfitting Teeth

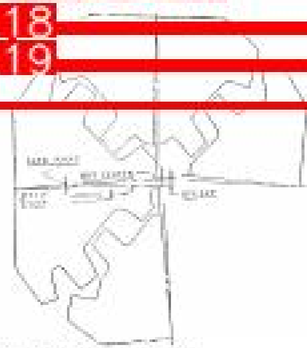


Figure 3-2b:Cutter Offset Skew Angle

Circulation Systems

The first hydraulic features incorporated into drilling tools dated back to the original use of hollow drillpipe with direct circulation of drilling fluids. As the first fishtail bits became popular, around the turn of the century, circu[illegible]ses was used for the first time. T[illegible] rollin[illegible] introduced a central water cou[illegible] whic[illegible]rs.

In 1[illegible]re introduced to the oil [illegible] "jet bit" concept is [illegible] to be the major hydraulic design [illegible]bits and remains state-of-the-art.

Further impr[illegible]systems include extended nozzle bits, seven to[illegible]and the various water courses in diamond bits[illegible]

Regular Cir[illegible]

Regular circu[illegible] have one to three holes drilled in the dome of the [illegible] bore of the bit, through the drilled ho[illegible] to the bottom of the hole, to flush away th[illegible]

Jet Circulation

Jet circulation bits (Figure 3-3b) are manufactured with smooth, streamlined, flui[illegible]ne of the bit. Drilling fluid passes through the bore [illegible]h minimum pressure losses, through the jet n[illegible]ole bottom to flush cuttings away from the bit and [illegible] flows up and ar[illegible]

Figure 3-3a: Regular Circulation

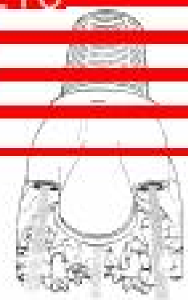


Figure 3-3b: Jet Nozzle Circulation

Air or Gas Circulation Bits

A third type of circulation medium is compressed air or gas, and can be used with either regular or jet circulation bits. Bits manufactured for air or gas circulation have special passageways from the bore of the bit to the bearings, through which a portion of the air or gas is diverted to keep the bearings cool and purged of dust or cuttings. From the special passageways t[illegible]gas passes through a number of strategically located ports or holes in the bearing journal, flows through the bearing structure and exhausts at the shirttail and gauge of the bit, to flow up the annulus.

Jet Nozzles

There are essent[illegible]zzles used in tri-cone bits. Shrouded nozzl[illegible] retainer ring erosion, excessi[illegible]d drilling periods. Standard jet nozzles are easi[illegible] erosion is not a [illegible] designated for d[illegible]

Nozzle sizes pla[illegible] hydraulics. The benefits of the correct selection [illegible]leaning and cuttings removal, faster drill rates[illegible]

[illegible] with the most common being between [illegible] bit jets are available in sizes from 1[illegible]

Cutting Structures

[illegible] ere introduced into the oilfield, the drag bit was replaced by the roller cone's steel tooth cutting structure. These steel (milled) teeth [illegible], number per cone, and thickness, to [illegible] formations.

When harder [illegible] up" the steel teeth, a different cutting struct[illegible] Introduced b[illegible] nicknamed the "The Chert Bit", it brought on [illegible] Many of the [illegible] insert bits.

Steel Tooth Cut[illegible]

There are th[illegible] d in steel tooth cutting structures, te[illegible] ooth angle (Figure 3-4). Using variati[illegible] types.

[illegible] Bits

Soft Formati[illegible]

[illegible] few in number, widely spaced and placed in a few broad rows. They tend to be slender, with small tooth angles (39 to 42). They are dressed with hard metal.

Medium Formation Cutting Structures

Teeth on medium formation bits are fairly numerous, with moderate spacing and depth. The teeth are strong, and are a compromise between hard and soft bits, with tooth angles of 43[illegible] gauge rows are hardfaced.

Hard Formation Cutting Structures

There are many teeth on this type of bit. They are closely spaced and are short and blunt. There are many narrow rows with tooth angles of 46° to 50°. The inner rows have no hardfacing, while the gauge row is hardfaced.

Tungsten Carbide Cutting Structures

Since most of the basic design features of the mill tooth cuttings structures have been incorporated into insert bits, the main variations occur in insert shape (Figure 3-5).

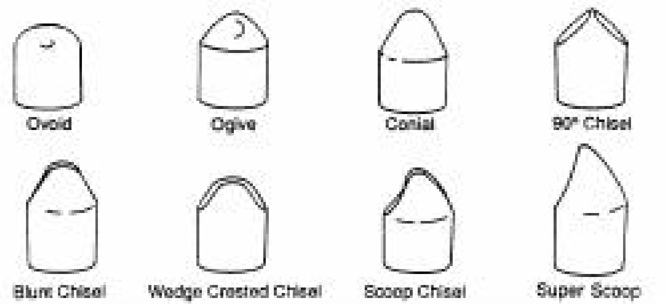


Figure 3-5: Tungsten Carbide Tooth Shapes

Historical shapes of milled teeth have built up a mystique about insert tooth shape. Many people in the oil field thought that chisel shaped teeth significantly affected the drill rate in all formations. This was because early drilling practices used light bit weights, causing the relatively sharp chisel shaped inserts to have a higher unit loading on the formation, hence faster drill rates. When heavier bit weights are used, it tends to nullify the advantage of the chisel shape. Even the steel milled teeth break down under heavy weights. In fact, most bits drill 75% of the hole in a 1/2 to 3/4 dull condition. With this in mind, many "blunt" insert tooth designs were made, and seem to drill efficiently. Nowadays, most insert teeth have this blunt, conical shape.

Gauge Protection

Protection of the gauge surface is vital to the effectiveness of any bit. The gauge surfaces constantly ream the hole, and thus are subject to continuous abrasive wear.

Applying tungsten carbide in a steel matrix through a welding process, called "hardfacing", provides the best resistance to this type of wear. Gauge protection is improved as the amount of hardfaced surface area increases.

The configur[illegible] the available surface area. The "A" type [illegible] bits, resulting in minimum ga[illegible] hard formations. The "T" type teeth pr[illegible] of surface area for the application of hard meta[illegible] bit types.

For work in [illegible] flat-top tungsten carbide insert is pressed into the gauge surface for additional protection.

Gauge protec[illegible] cone bits by adding a "G" to the IADC code.

Bearing Systems

The first typ[illegible] roller cone bits was a non-sealed, roller[illegible] bearing arrangement, utilizing rollers on the heel of the journa[illegible] or stress was exerted on these rollers, and [illegible] ubricate the bearings. Bearing size was maximized, since room for a seal was not required. The bearing surfaces were machin[illegible] tolerances to ensure dependable service. This [illegible] available with modifications for air circulatio[illegible] (Figure 3.6a).

The next gen[illegible] sealed roller bearing system having a seal[illegible] bearings. The bearing system is co[illegible] roller-ball-roller bearings, 2) the seal, w[illegible] drilling fluid and abrasive cutt[illegible] bearing cavities, 3) the shirttail is designed and[illegible], 4) a lubricant, an elasto-hydro[illegible] the reservoir, [illegible] the lubricant to the bearings, and 6) the vented br[illegible] plug, which transfers downhole fluid pressure against the lubricant fill[illegible]lize pressures surrounding the bearing seal [illegible]

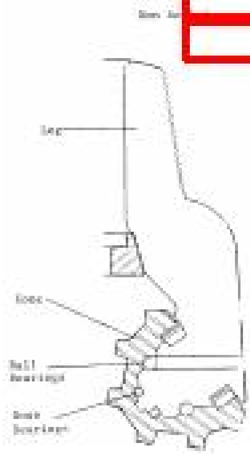


Figure 3-6a

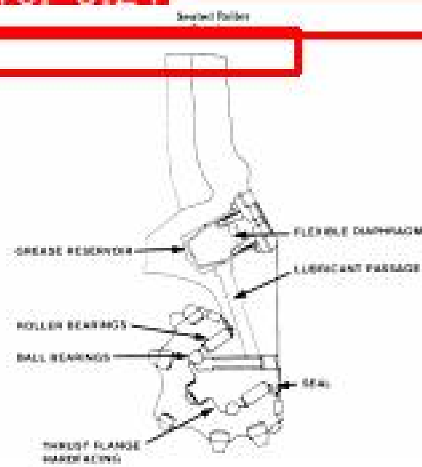


Figure 3-6b

There is, however, one serious drawback to the roller-ball-roller bearing system. The primary cause of roller bearing failure is journal spalling, which causes destruction of the rollers and the locking of the cone.

To remedy this, instead of the standard roller bearing assembly, the "journal bearing" system utilizes solid metal bushings for direct cone to journal contact. This offers a distinct mechanical advantage over roller arrangements in that i[illegible]a at the load bearing point. This distributio[illegible]chief cause of roller bearing assembly fai[illegible]e load portion of the bearing face.

Journal bearing [illegible]arbide insert bits features a metal bearing surface [illegible]d journal and a lubricant. Specialized seal[illegible] drilling fluid an[illegible] of bearings, and positively seals the graphit[illegible] Precision fit of the journal and con[illegible] perfect arc. Bea[illegible] a carefully controlled surface texture to ensur[illegible]

The manufactur[illegible] journals either [illegible]pending on the bit company) to accommodate [illegible]gs are inlaid on the journal. Once the cone i[illegible] machine pro[illegible] seal between the cone and the journal, s[illegible]oped.

Seals

The first and [illegible] the radial seal (used mainly on the sealed roller [illegible]s a circular steel spring encased in rubber, wh[illegible]he shank and the face of the cone. The ne[illegible]d the most effective seal. The major proble[illegible]ng is tolerance, which must be precise in order to m[illegible]

An understan[illegible] successful dr[illegible]ing systems are essentially the same, and ar[illegible]l equalizer located under the bit or on back of the s[illegible] with some sort of expandable diaphragm to distribute the grease, and some sort of distribution system to the bearings. [illegible]essure relief valve to release any trapped press[illegible]

Pressure surg[illegible] sealed systems. As pressure and temperature [illegible]ubricant increases. As a result, the system c[illegible] for abrupt changes in pressure due [illegible] making connections, etc.) and small quanti[illegible]. With the close tolerance necessary fo[illegible] can be damaging.

Adequate cle[illegible] drilled cuttin[illegible] and prematu[illegible]ult. Gauge protection is also important to [illegible] shirttail wear[illegible]uge protection.

Any time a s[illegible]e seals and shirttail should be carefully che[illegible] grooving.

To complete [illegible]y, a positive seal is required to keep drilling fluid [illegible] bearings from overheating. The positive seal requires a relief valve to allow escape of exc[illegible] overload the seal and cause seal failure.

Material Requiremen[illegible]

The rock bit [illegible] rock it is to drill. The measurement of hard steel [illegible]ll" hardness tester scale (Rc). The tester uses a diamond pyramid indenter with a load of 150 kilograms. The deeper the in[illegible] softer it is.

The degree of h[illegible]ced in steel is determined by its carbon content, [illegible]bon (up to 0.7%), the harder the steel. [illegible] Rc. Alloying ele[illegible] and cause the st[illegible]m response to heat treating. The steel must also [illegible] or "toughness" [illegible] metal, the less d[illegible]e more ductile). Alloying elements impro[illegible] toughness, and resistance to failure from imp[illegible]

Heat Treating

The desired met[illegible]ysical strengths are developed through heat tre[illegible] increasing the c[illegible] essential for the t[illegible]th on milled tooth bits, [illegible] for strength and wear resistance on the bearing surfaces. [illegible]k propagation) is attained by [illegible]aving the inne[illegible]unchanged.

The overall phy[illegible] are achieved by [illegible] them in oil. The[illegible]he carbonized section gets about 60 - 64 Rc[illegible] - 40 Rc, remaini[illegible]

Mill Tooth Bit [illegible]

The teeth on a m[illegible] carbide. This hard-facing can be on the gauge teeth (for hard formations), the inner teeth ([illegible] both rows. Hard-facing is applied in such [illegible] self-sharpening [illegible]

Insert Bits

Over the past te[illegible] in rolling cutter bits has been made in the desi[illegible] bits has long been accepted, it was not until recently that bit manufacturers obtained enough[illegible]ide material and design to make it possible to cons[illegible] formations - sof[illegible]

The chief advan[illegible] virtually no change in the configuratio[illegible] due to wear. In addition, any bit often finds good[illegible] factor on perfor[illegible] formation chang[illegible]).

The basic pri [illegible] signs are the same as those applied to mi [illegible] ooth interfit, insert extension, co [illegible] and gauge requirements.

Of primary i [illegible] proper grade of carbide material used in the inserts. Much [illegible] placed on the [illegible] shown the need for carbide materials of various gr [illegible] structure.

At present, th [illegible] function closely parallels the mechani [illegible] (gouging/sp [illegible] (crushing/fra [illegible] turing). For this reason, the composition as well as the configuration [illegible] being subjected to constant evaluation an [illegible] ultimate in both areas has not been determi [illegible]

Polycrystalline Diamond Compact Bits

In the early days of oilwell drilling, fishtail/drag bits were used extensively throughout the o[illegible]alized that these drag bits would not penet[illegible]ch overlay deeper oil and gas reservoirs, a[illegible]roller cone bits.

General Electri[illegible] the absence of m[illegible] the early 70's th[illegible] testing of new cutting structures for these drag bits. Since their introductio[illegible] polycrystalline [illegible] with the conven[illegible]

PDC Drill Blanks

These drill blan[illegible]lycrystalline diamond bonded to a laye[illegible] using a high-temperature, high-pressure b[illegible] wear resistance [illegible]f diamond which is complemented by the strength and [illegible]sten carbide.

PDC blanks are self-sharpening in the sense that small, sharp crystals are [illegible]epeatedly expos[illegible]because they are [illegible]olycrystalline t[illegible]y weak cleavage planes, which can resul[illegible] diamonds in the [illegible]

The blanks are t[illegible]rbide studs, which are then press-fitted into holes [illegible] the bit. The cutters are positioned in a [illegible] an equal distribu[illegible]tion of weight-on-bit, and a redundant shearing action. The result being[illegible].

The bit body is [illegible] of tri-cone bits, [illegible]er of tungsten carbide, to resist fluid er[illegible]

Bit Design

PDC bits featur[illegible] there are no bea[illegible]nes to have to fish out of the hole. The bit ha[illegible] wear pads to he[illegible]rent stabilization in the bits extended ga[illegible]

The face of th[illegible] gauge and nose cutters to attack the ro[illegible]ization while decreasing the potential [illegible]

Jet nozzles v[illegible] interchangeable, and are strategically [illegible] of the cutters and the bottom of th[illegible]

The cutters a[illegible]terns.

- an [illegible]
- a r[illegible] less than one-inch above the [illegible]
- a bladed p[illegible], more than one-inch from the [illegible]

All three types prov[illegible] a consistent bottomhole pattern. [illegible]ne bo[illegible] combination of scrib[illegible] and round cutters to enhance the scraping and shearing action of th[illegible]

Without moving part[illegible], the [illegible] crushing as do the ro[illegible]er co[illegible]e bits.

PDC Bit Operating [illegible]

PDC bits do [illegible]e self fluid-cleaning action between rows of teeth [illegible] to flush the c[illegible] accomplished with strategically positioned converging-diverging nozzles which maxim[illegible]g eros[illegible] of the body near the nozzle area. [illegible] 2.0 to 4.0 hydraulic horsepower p[illegible] jet nozzles come in standard size[illegible]

[illegible] the PDC cutting elements provide a self-sharpening edge with the wear resistance of diamonds. Th[illegible]ffective in soft to m[illegible]dium formations such as shale[illegible]. These formations h[illegible] between 10[illegible] of 85 to 140 [illegible] has also been achieved with rotary speed[illegible] diameter usi[illegible]

High rotary s[illegible] deviation. O[illegible]th formation hardness. A soft, [illegible] [illegible] [illegible]m; a hard formation, lower rpm. Most application[illegible] [illegible]ess than 120 rpm.

Lighter weight-[illegible]-bit means lower stress on the drill string, with increased string life as a r[illegible] [illegible] drill collars are [illegible] [illegible] stuck pipe.

These bits have [illegible] oil and water base muds. Oil base muds and [illegible] PDC bit perform[illegible] sticky.

Formations whi[illegible] and clays, abras[illegible]ations which are very hard. In sticky formation[illegible] ball up; in abrasive formations or ha[illegible] PDC bits cannot drill as broad a range of formations as roller cone bits, but have shown to b[illegible]nd bits. Thus, care must be taken when selecting b[illegible]When properly applied, most PDC bits can be [illegible]

PDC bits cost b[illegible]0, and savings are measured in terms of trip tim[illegible] fewer rig hours [illegible]

PDC Bit Drilling Par[illegible]

Even though PD[illegible]ognition as a viable tool for improved drillin[illegible] met in order that the bit run be as efficient and economical as possible.

1. When [illegible] should be inspected for any damag[illegible] the ho[illegible]
2. When picking up a PDC bit, take all the precautions normally [illegible]ndling a diamond bit, and some additional ones
   a. When removing the bit from its box, handle it carefully. Do not [illegible]r. If the bit is [illegible]mped on the floor and [illegible]hipped, the bit's life will be red[illegible]
   b. The [illegible] debris is left inside.
   c. The prop[illegible] up the bit.
3. The bit is one solid p[illegible] flexibility of roller co[illegible]its. H[illegible] can damage the gauge cutters.

4. If it is [illegible] ck up the kelly and run the [illegible] rotary speed should be about 6[illegible] and go [illegible] wly.

5. When ne[illegible] at full flo[illegible]

   a. To locate the [illegible] weig[illegible] PDC [illegible], it is [illegible] sudden increa[illegible]

   b. After the bott[illegible] be lifted a foo[illegible] and rotate slowly for about [illegible] e bottom of the hole is cleaned[illegible]

6. When ready to st[illegible] approach bottom. [illegible] in order to [illegible] a new hole pattern.

   a. At least 1 foot [illegible] looking for optim[illegible]

   b. In sof[illegible] and t[illegible] d until [illegible] he bit is drilling at its [illegible]

   c. In ha[illegible] foot. Adding [illegible] eight too quickly will damage the cutters. Once the bott[illegible] added, watch [illegible] roblems.

7. There is no limit [illegible] possible without damaging the res[illegible]

8. The on-bottom to[illegible] roller cone bits. [illegible] the penetration rate does not incr[illegible] be suitable for PDC [illegible]

9. After making a co[illegible] be washed back down to bottom. Droppi[illegible] can cause the bit [illegible] to pipe stretch.

10. PDC bits respond dra[illegible], if the rate of penet[illegible] change in [illegible] ed should help.

11. When th[illegible] will not drill, the bit should b[illegible]

will be a sudden dec[illegible]nd torque, and an increase in standp[illegible]uge portion, there will be [illegible] little weight-on-bit and a decrease in the penetration rate.

Dia[illegible]

Diamond core bits were in[illegible]roduced into the oilfield in the early 1920's and were used to [illegible]ese early diamond bits were very ex[illegible] times the price of the roller bits. Since perfor[illegible] for coring, very little consideratio[illegible]

By the 1940[illegible] manufacture [illegible]monds were cast in a matrix of tungsten carb[illegible] This change [illegible] setting patte[illegible]ed in the improved performance of diamond bits[illegible] roller cone b[illegible]ere ten to fifteen times the cost of roller bits, a[illegible]

Regardless o[illegible] diamond bits[illegible] drill for long[illegible] the late 1950's several major oil companies b[illegible] diamond bits, and these studies provided a m[illegible] drilling and t[illegible]s on the penetration rate. This, plus subsequent d[illegible] more erosion resistant matrix materials, led to performance [illegible] basis.

The Diamonds

There are th[illegible]

1. Si[illegible] ge[illegible] and come in geometrically regular sh[illegible] te[illegible]

2. Co[illegible] or [illegible]nish or grayish in color, and does not pe[illegible] light. They are balas (rounded) in sh[illegible]

3. [illegible](Black Diamond): So termed because the majority [illegible] and do not transmit light. The majority of these dia[illegible]lline or amorphous structure.

Diamonds u[illegible] as 15 stones [illegible]er ca[illegible] stone. Diamonds are resistant to a[illegible]

[illegible] ength and have high thermal capacity. The lo [illegible] to withstand impacts.

The terminology used to describe diamond quality is quite varied, and "quality" is roug [illegible]

1. Surfac [illegible] better quality.

2. Transl [illegible] to transmit light is [illegible] when non-c [illegible] alline diamonds and coated diamonds are being evaluated.

3. Internal Structure: T [illegible] actures, inclusions, [illegible] grow [illegible] high quality.

4. External Shape: A b [illegible] diamond is stronger and hence [illegible]

The Diamond Bit

A diamond bit (either [illegible] drilli [illegible] diamonds, matrix and [illegible] The diamonds are held in place by the matrix which is bonded to th [illegible] powdered tungsten carbide infiltrated wi [illegible] carbide is used for its [illegible] sive [illegible] properties (but far from a diamond in thi [illegible] spect [illegible] s to attach the bit to the drill string.

Diamond bits are sold by the carat weight (1 carat = 0.2 grams) of the diamonds in the [illegible]. The price will vary depending [illegible] The setting charge is to cover the manufacturing c [illegible] is generally returned to salvage the diamonds an [illegible] materially decre [illegible] s frequently as much as 50% of the original b [illegible]

Uses of Diamond Bi [illegible]

As with any bit [illegible] a diamond bit should be based on a detailed co [illegible] analysis. There are, however, certain drilling situations which indicate t [illegible] bits.

- Very short [illegible] e bit life is very short due to bearing fai [illegible] increase o [illegible] bits have no bearings and each di [illegible] trength of 1,261,000 psi (approxima [illegible] tungsten carbide). The [illegible] re[illegible]s that of tungsten carbide.

- Low penetration rates with roller cone bits: Frequently, when roller cone bit[illegible] due to high mud weights or [illegible] bits can provide a savings. The "pl[illegible]ing" [illegible] bits generally produces higher p[illegible] since the drilling fluid is distribu[illegible] and the formation in a smooth uniform sheet, [illegible] per square inch to clean under a d[illegible]
- Deep, small ho[illegible] limited life due [illegible] on the bearing, cone shell thickness, etc. [illegible] piece often last much longer in very [illegible]
- Directio[illegible] "sideways" [illegible]cking off" in directional drilling situatio[illegible]
- Limited [illegible] with less weigh[illegible] cone bits in the same size range.
- Downho[illegible]erally have bearing failures on mot[illegible] Diamond bits will have a very [illegible]nditions.
- Cutting casing windows: Window cutting through casing using diamond [illegible] older we[illegible] directional drilling techniques, or t[illegible] speciall[illegible] and longer windows are cut when sidetracking.
- Coring: [illegible] operations is essential for smooth, whole [illegible] possible with increased on-bottom time an[illegible]ause of the cutting action of diamond bits a[illegible]

There are so[illegible] diamond bits:

- Very ha[illegible] brok[illegible]ormations can cause severe shock lo[illegible] short bit life.
- Formations co[illegible]hert and pyrite tend to break apart in large p[illegible] diamond bit, causing diamond damage.

- Reaming [illegible] the "nozzles" of a diamond bit are [illegible] and the bit matrix on the other [illegible] are extremely poor during reamin[illegible] "burning" or breakage in the ga[illegible]

Diamond Bit Operating P[illegible]

Hydraulics

[illegible] rate and [illegible] lean under the [illegible]odification, but a good [illegible] are inch of hole are[illegible]s if the hole or operating condi[illegible] is designed for such conditions.

Each diamond c[illegible]om, continually doing work, therefore the en[illegible] must be kept cle[illegible] the cutting actio[illegible]st be kept cool; excessive heat is one of th[illegible] cutting action, h[illegible] prevented with adequate flow rates. Other factors being equal, better performance ma[illegible]r rates of fluid flow.

Pressure is requ[illegible] high enough to [illegible]ng. When the bit is off bottom, the flui[illegible] must pass throu[illegible] hole itself (clear[illegible] bit matrix and the formation). This [illegible] pressure difference in a range of 100 to 1,000 [illegible] conditions (mud [illegible]ressure, etc.).

Weight-on-Bit

The weight on d[illegible] bits. A good ave[illegible] to 750 pounds per square inch of bit area.

Hole conditions [illegible] more weight, but caution should b[illegible]ssive weight-on-bit will shorten its life. [illegible] impact load agai[illegible] increments of 2.[illegible]t does not show a comparable incr[illegible] should be decre[illegible] was obtained.

Rotary Speed

Rotary speed [illegible] 100 rpm being average, although 200 [illegible] en downhole motors are used. Penetra[illegible] at high speeds if hydraulics are good and no rough[illegible]

Drill rate, wi[illegible] straight line function of rotary speed. Drilli[illegible] increased. Th[illegible] for the drill pipe.

Torque

Torque indic[illegible] absolute valu[illegible] steady torque is an indication that the previous three factors are well coordinated.

Bit Stabiliza[illegible]

A diamond is [illegible]sion, but relatively weak in shear, and ne[illegible] bottom. The bit is designed and the rake of th[illegible] keeps an eve[illegible]monds, and even distribution of coolant fluid over the bit face. If there is lateral movement or tilting of the bit, an uneve[illegible] on the oppos[illegible]

Any of the st[illegible]ed hole assemblies are suitable for stabilizati[illegible]s. It is recommended that full gauge stabili[illegible] 10 feet and 40 feet from the bottom.

General Diamond [illegible]

Prior to runn[illegible]ole by running a junk basket on the last roller[illegible]

Running a D[illegible]

Place the bit [illegible] the collar, to the same torque [illegible]ction.

Use care goi[illegible] ledges and pushing through tight places which [illegible]

Although dia[illegible] taken, especi[illegible] first time a diamond bit is run. Remember, diamond [illegible]ucted and have no "give" as do roller cone bits. In a reaming situation, most of the drilling fluid escapes through the junk slots [illegible] gauge zone. Du[illegible] absorb all applied weight and may become ov[illegible]

When reaming, [illegible]e bit weight of about 2,000 to 5,000 pounds maximum should be used [illegible] and the rotary speed should be [illegible] considerable reaming in hard, abrasive formati[illegible] the diamond bit should be pulled and repla[illegible] specifically designed for reaming.

Starting a Diam[illegible]

It is recommend[illegible] prior to reaching bottom and that extreme car[illegible] be used to find bottom. The bit should be rotated slowly to bottom, or if [illegible] no rotation. Then circulate with full volume [illegible] at a point about one foot or less off bottom for a pe[illegible] to clean the bottom of the hole.

After circulating[illegible] minimum bit weight and full [illegible] hole to form a new bottom hole contour. This is [illegible] get proper cleaning and cooling acti[illegible] hole exactly fits the bit profile.

Under some con[illegible] dictate touching bottom with full pump force but [illegible]o rotation in order to try to crush any irregular large foreign particle[illegible] of bit damage. This procedure, [illegible] be used several times before rotating the drill[illegible]

Drilling

After the bit has [illegible] should be increased to the practical limit i[illegible] The drill pipe, hole condition and depth shoul[illegible]deration.

Weight should b[illegible] in 2000 pound increments. Observations of [illegible] weight increase should be made to avoid overloa[illegible] rate continues to increase with weight, the[illegible] However, if additional weight does not [illegible] then the weight should be reduced back 20[illegible]0 to 3000 pounds, to avoid packing and balling-up of the space between t[illegible] be continued at this reduced weight.

After making a [illegible]culate just off bottom for at least five minutes, as [illegible] damage the bit. The time spent here may length[illegible] many hours.

Diam[illegible]

[illegible] quality can mean the difference be[illegible] costly bit run.

Some format[illegible] these formati[illegible] and their drillability change from area to area. Diamond bits normally [illegible] formations, because it is easier to keep the bit clean, [illegible] plowing acti[illegible] and tearing.

Diamond bits [illegible] equivalent to, or greater than other bits in order to stay [illegible] the diamond [illegible] because of hydraulics. Since the cu[illegible] very close to the formation, the cuttings [illegible] the outside o[illegible] the greater amount of cuttings to be [illegible] of the flow a[illegible] tration rate unless hydraulics are maintained a[illegible]

Special Desi[illegible]

Standard bit [illegible] es. Special designs, or standard bits with spe[illegible] example:

1. Lo[illegible]
2. Fl[illegible] do[illegible] nhole motors
3. De[illegible] n for whipstock j[illegible] s or side[illegible]
4. Co[illegible] to most styles where cone wear is a pr[illegible] are desired
5. De[illegible] bu[illegible] the cone ap[illegible]. In [illegible] the formation [illegible], leaving a plug in the bit cone. Thereafter the form[illegible] splintered away beneath the bit f[illegible] indu[illegible] In fractu[illegible] type [illegible], a shallower cone angle of about 90Υor 1[illegible]

Selection Guide [illegible]

Because formations [illegible] position change in character, with depth, and [illegible] bit selection guide can be prepared. Howe [illegible]

Soft formations [illegible]

Sand, shale, salt [illegible] require a bit with a radial fluid course set with [illegible] rats each are used, depending on fo [illegible] single row of di [illegible] gned to handle mud velocities ranging from 30 [illegible] ing.

Medium forma [illegible]

Sand, shale, anh [illegible] radial style bit with double rows of diamon [illegible] diamond sizes range from 2-3 stones per carat. [illegible] velocity. Good [illegible] can be expected in interbedded sand and shale formation [illegible]

Hard, dense fo [illegible]

Mudstone, silts [illegible] e a crowsfoot fluid course design. This pro [illegible] cleaning and cooling and allows a higher concent [illegible] average about 8 [illegible]

Extremely hard [illegible] **nations**

Schist, chert, vo [illegible] quartzite require a bit set with small diamonds [illegible] se to permit a high concentration of diamonds. Th [illegible] carat) are set in concentric "metal protecte [illegible] nment diamond exposure and protection f [illegible]

Diamond Bit Salvag [illegible]

When returning [illegible] report on the bit. The manufacturer can then inspect the bit with a better understanding o [illegible] on with its condition.

Salvage, or reco [illegible] The binder mate [illegible] atrix, which allows the tungsten carbide particles [illegible] out of the result [illegible] eaned.

When brought t [illegible] screened for sizing, then each stone [illegible] by an expert.

Self-Check Exercises

1. What are the types of bearings used on all roller cone bits?

   a. ______________________________

   b. ______________________________

   c. ______________________________

2. The "skew" direction [illegible] d always be in a ____________ directi[illegible] gauge.

3. What too[illegible] ne bits for these typ[illegible]:

   Hard [illegible] ______________________________

   Medium Form[illegible] ______________________________

   Soft Formatio[illegible] ______________________________

4. Steel mi[illegible] teeth [illegible] weights. In fact, most rol[illegible] cone [illegible] of the hole in a __________ to ________ conditi[illegible].

5. What type of teeth on [illegible] amount of surface are[illegible] ns?

   ____

6. In mill t[illegible] advantage in that it utilizes [illegible] arger contact area at the load bearing [illegible].

7. Insert drill bits have a distinct advantage in th[illegible] there is virtually no change in ____________ [illegible].

8. What are the [illegible]gard to its steel head feature?

a.____

b. _______________________________________

c.____

9. PDC bits are sensitive to the amount of RPM used to optimize the drill rate. A soft, plastic formation would require a ________ RPM, while a harder formation would require a ________ RPM.

10. What three types of natural diamonds are used in diamond bits?

a.____

b. _______________________________________

c.____

•Notes•

Drillstring Basics

Upon completion of this section you will be able to:

- Explain how drill pipe grades define the yield strength and tensile strength of steel.
- Explain ho[illegible]
- Calculate t[illegible] of drill pipe.
- Explain the [illegible]string.
- Calculate the buoyed weight (or hookload) in a vertical hole.
- Explain the [illegible] the drilling process.
- Explain ov[illegible]ermitted pull.
- Calculate [illegible] to be run i[illegible]
- Calculate [illegible] when runn[illegible]
- Explain ca[illegible]uckling.
- Explain ne[illegible] neutral poi[illegible]
- Explain th[illegible] fatigue.
- Describe s[illegible]e of [illegible] drag and torque, and the effect of d[illegible]

Tub[illegible]

In[illegible]roduction

[illegible] designed to satisfy certain operational [illegible] downhole tubulars must have the capability to withstand the [illegible]ue, bending stresses, [illegible]ssure. Operational capabilities of different s[illegible] collars are tabulated in the API RP 7G [illegible] a given drill[illegible] the presence of H_2S, must also be [illegible]

Drill Pipe Yield St[illegible] Strength

If drill pipe i[illegible] deformation. [illegible]ching force is removed, the drill pipe will return to [illegible]. The upper limit of this elastic deformation [illegible] [illegible]ists a region of plastic deformation. In this region, the drill pipe becomes permanently elongated, even when the stretching force is removed. [illegible] is called the **Tensile Strength**. If t[illegible], the drill pipe will fail.

Tension failu[illegible] pulling on stuck drill pipe. As the pull exceeds [illegible] thinning in th[illegible] weakest area of the drill pipe (or the smallest cross secti[illegible] area). If the p[illegible] the tensile strength, the drillstring will part. Su[illegible] near the top of the drillstri[illegible] because the [illegible]ed to the upward pulling force a[illegible] well as the d[illegible] weight of the drillstring.

Drill Pipe Grades

There are fou[illegible] and tensile st[illegible].

	[illegible]	[illegible]	G-105	S-135
Minimum Yield Stren[illegible] (psi)	[illegible]	[illegible]000	105,000	135,000
Minimum Tensile Strength (psi)	[illegible]	[illegible]000	115,000	145,000

Grade E [illegible] times referred to as "mild" steel, bec[illegible] ength per unit area. As such, mild steel is gen[illegible] yield strength of less than 80,000 psi. As c[illegible] has a lower yield strength in psi than the high[illegible] once the yield strength is exceeded, it c[illegible] of stretch or "strain" prior to parting. [illegible] resistant to corro[illegible] n utilized in medium depth wells (10,[illegible]

In the 1980's, as [illegible] ation extended reach wells and deep hole d[illegible] strength drill pip[illegible] ations for high strength drill pipe to be u[illegible] ized in the upper portion of the string to keep the tension load within the c[illegible] , such as those encoun[illegible] horizontal wells. High strength drill pip[illegible] bending stresses. In high inclination and h[illegible] drill pipe is also commonly run in compress[illegible] grades of steel is that they are generally less re[illegible] (H_2S). Limited [illegible] the higher cost.

The yield and te[illegible] per square inch of the cross-sectional area" [illegible] o calculate yield strength in pounds, this cro[illegible] known. This leads to a discussion of drill pipe clas[illegible]

Drill Pipe Classificat[illegible]

Drill pipe class [illegible] pipe in terms of dimension, surf[illegible] pipe class is indicated by paint bands on t[illegible] according to the following code:

CLA[illegible]	[illegible]
1 (New[illegible]	[illegible]
Premi[illegible]	[illegible]
2	One Yellow
3	One Orange
4	[illegible]
Scrap	[illegible]

Class 1 drill pip[illegible] is new and therefore the strongest. As pipe is used, the wall thickness w[illegible]

[illegible] results in a lower **Total Yield Strength** in pounds. This yield strength [illegible] the following formula:

```
YIELD STRENGTH = Yield Strength x π/4 (OD² - ID²)
  (in pounds) (in psi)
```

Example 4.1

5" grade G-105, [illegible] nal weight of 19.5 lb/ft and [illegible]

```
Minimum [illegible] ,000 x π/4 x (5² - 4.276²)
    = 553,83[illegible]
```

This [illegible] the **API RP 7G**. This publication contains data on the properties of drill pipe and tool joints for all common sizes in class [illegible] interest is in[illegible] "New Drill Pipe Torsional and Tensile Data" (Table 2.2). [illegible] yield states the maximum twisting force (torque) in foot pounds the drill pipe can withstand before permanent damage can [illegible] yield refers to the maximum stretch force (yield s[illegible] the pipe can withstand before plastic or permanent [illegible]

Tool Joints

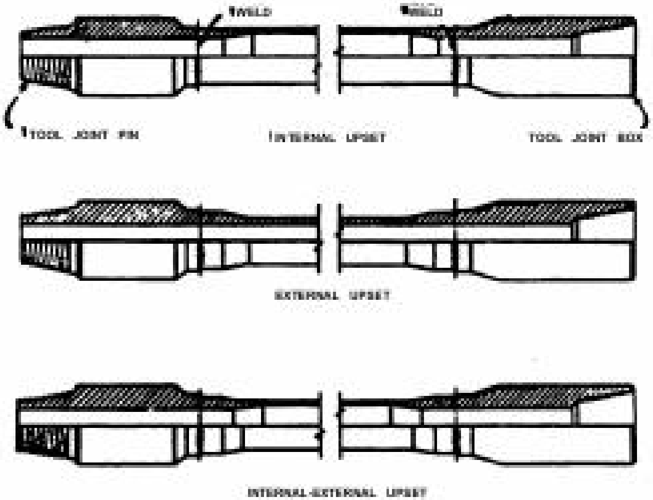
Tool joints a[illegible] that are attached to the tubing portion of drill pipe [illegible] threaded tool [illegible] the externally threaded tool joint if the "pin".

API specific[illegible] joints:

- Minimum Yield Strength = 120,000 psi
- [illegible] Tensile Strength = 140,000 psi

Because tool joints are added to drillpipe, the weight of given to pipe in many tables [illegible] exact weight will require adding the weight of [illegible] ing portion. Since two joints do not weigh the sa[illegible] and so an "ap[illegible] d in many calculations.

The tool join[illegible] in internal and/or external upsets. An upset is a decrease in the ID and/or an increase in the OD of the pipe which is used to str[illegible] the pipe and the tool joint. It is important to note that under tension, the tool joint is stronger than the tubular.



Make-Up Torque

Part of the strength of the drillstring and the seal for the fluid conduit are both contained in the tool joints. It is very important therefore, that the correct make-up torque is applied to the tool joints. If a tool joint is not torqued enough, bending between the box and pin could cause premature failure. Also, the shoulder seal may not be properly seated, resulting in mud leaking through the tool joint, causing a washout. Exceeding the torsional yield strength of the connection by applying too much torque to the tool joint could cause the shoulders to bevel outward or the pin to break off the box. Recommended make up torques for drill pipe and tool joints are listed in the API RP 7G.

Buo[illegible]

In[illegible]roduction

[illegible] air due to a fluid property [illegible] Therefore, what is seen as the hookload is actually the buoyed weig[illegible] principle states that the [illegible] id displaced. Another way of saying this is [illegible] pressure at the bottom of the string multip[illegible] the fact that [illegible] force such as gravity, but a surface force[illegible]

For example, [illegible] inch x 2-inch drill collars in a 700 ft vertic[illegible]

Hydrostatic [illegible]

= 0.0519 x (12) x (700)

[illegible] si

Cross Sectio[illegible] (OD² - ID²)

= π/4 x (7.5² - 2²)

= π/[illegible]

[illegible]

Buoy Force [illegible] x 41.04

[illegible] pounds

By looking a[illegible] mined tha[illegible] these 7.5-inch drill collars is 139 pounds per foot. If w[illegible] have 700 feet of collars, the to[illegible] 0 pounds.

Total Air W[illegible] h

= 139 x 700

= 97,300 pounds

The buoyed weight of the collars, or the **Hookload**, is equa[illegible] to the air weight minus[illegible]

Hookload = Air Weight - Buoy Force

= 97,300- 17,925

[illegible]

This method for [illegible] not normally used. Instead, the follo[illegible]rates a buoyancy factor, is used and recom[illegible]

$$\text{Buoyancy Factor} = 1 - \frac{MW}{65.5}$$

$= 1 -$ [illegible]

$= 0.817$

MW=Mud Density (ppg)

Hookload = Air Weight x Buoyancy Factor

= 97,300 x 0.817

= 79,494 pounds

Buoyancy Factors [illegible] be found in the API RP 7G (Table 2.12).

Note: *The fo[illegible] acc[illegible]unt axial drag. Hookload, as determine[illegible] form[illegible] that would be displayed by the weight indica[illegible] vert[illegible]ing the weight of the trav[illegible]*

In practice, hook[illegible] Pick-Up Load refers to the hookload when pull[illegible]ds. The highest hookload normally encountered w[illegible] pick up the string. Slack-Off Load refers to [illegible] the drillstring. Drag Load refers to the hookloa[illegible] mode. Other references to hookload are Rotatin[illegible] rotary) Drilling Load.

Overpull

In tight holes or stuck pipe situations, the operator must know how much additional tensio[illegible] string before exceeding the yield strength of[illegible] as Overpull, since it is the pull force over th[illegible] in a vertical hole with 12 ppg mud, a d[illegible] of 7.25-inch x 2.25-inch drill collars and 6,00[illegible] drill pipe with a nominal weight of 19.5 l[illegible]

First, the hoo[illegible]

Hookload = [illegible]

[illegible] (600 x 127[illegible] 0.817

[illegible]

Referring to [illegible]e API RP 7G, the yield strength in pou[illegible] class, size and nominal weight of drill pipe is 395,59[illegible] pounds. Therefore:

Maximum O[illegible]ounds - Ho[illegible]kload

[illegible]4,658

= [illegible] pounds

The operator [illegible]r the hookload before reaching the limit of e[illegible] increases, ho[illegible]kload increases, at a certain depth the h[illegible] the yield stre[illegible] thought of as the maximum depth that can be reached without causing permanent el[illegible]regarding h[illegible]le drag as a consideration[illegible]uld never i[illegible] limit. A cons[illegible]s included to allow for overpull caused by ex[illegible]

In practice, s[illegible] of pick-up lo[illegible] prediction of pick-up load is best obtained[illegible]gram, as well as including the capacity for [illegible] basing their [illegible]ld strength values quoted in API RP7G.

Example 4.2

For a horizon[illegible] calculated us[illegible]rogram assuming that 5-inch drill pipe will be [illegible] end of the bu[illegible]ion are:

8.5-[illegible]	[illegible]
[illegible]	[illegible]
T[illegible]	[illegible]

Using 90% of the [illegible] P7G and including a margin of 100,000 lbs o[illegible]nsile loads which can be applied to 5-inch, 19.5 l[illegible]e (worst case) are:

Drill Pipe Grade	E75	X95	G105	S135
RP7G	[illegible]	342,548	[illegible]	[illegible]
90% of RP7G Value	243,389	308,293	340,745	438,100
less 100,000 lbs	143,389	208,293	240,745	338,100

In this [illegible] drill pipe [illegible] tensil[illegible] yield strength for b[illegible]h the cur[illegible] and the h[illegible]rizontal s[illegible]ctions. Th[illegible] reco[illegible]ent w[illegible] drill pipe [illegible] should be used.

Maximum Hookload When Two Grades Of Drill Pipe Are Used

When two grade[illegible]he higher grade (i.e. the pipe with the higher load c[illegible] the lower grade pipe. The maximum tensi[illegible] yield strength o[illegible]ulations similar to those already dealt wi[illegible] may be used to determine the maximum length of both grades of pipe.

[illegible] the maximum hookload which can be applied [illegible] the higher grade [illegible]ction, maximum hookload (pick-[illegible] the "air weight" [illegible]s is because the surface hookload includ[illegible] (since it is supp[illegible]es not act on the top joint of lower grade pip[illegible]

Maximum Hook[illegible] + Weight [illegible]

When a sufficie[illegible] condition will b[illegible] the higher grade pipe.

The air weight [illegible]d because the buoy force acting on the dr[illegible] The hydrostatic [illegible] (vertical) sectio[illegible] resultant force acting upwards.

Example

A directional well has been drilled vertically to the kick-off point at 3,000 ft. Premium [illegible] nominal weight 19.5 lbs/ft) is used [illegible] at point the pipe used is premium clas[illegible] weight 19.5 lbs/ft.

Calculate the [illegible] en all the pipe above the kick-off poin[illegible]

Solution

From API R[illegible]
(nominal we[illegible] is 21.92 lbs./ft.

Weight of 3,[illegible] 65,760 lbs
Yield streng[illegible] lbs
90% of yield [illegible] 80

maximum [illegible]
i.e. approx. = 346,000 lbs

(For compari[illegible] the X95 pipe is 394,612 [illegible]
90% of that [illegible]

Higher Grade Pipe [illegible] Well

The previous [illegible] simple case when the higher grade pipe is [illegible] pipe is used through a build-up section, [illegible] difficult. A r[illegible] length as a st[illegible] using the average inclination of that course length[illegible]

Weight acti[illegible]

[illegible] ch may be significant.

[illegible] constant, the [illegible] be the air-weight of the pipe [illegible] particular ca[illegible] ancy factor. This is because although the [illegible] acting on the [illegible] and affects the weight pulling down on the [illegible] pe from below, but not the weight of the joints of [illegible]

It must be em[illegible] part of the w[illegible] use of "Torq[illegible]

[illegible] Rev. B / December 1995

BHA [illegible]-Bit

One important consideration in designing the BHA is determining the number of drill [illegible]red to provide the desired weight-[illegible]s, standard practice is to avoid putting [illegible] (recommended by Lubinski in 195[illegible] sure that the "buoyed weight" of the d[illegible]pipe exceed the maximum weight-on-bit. T[illegible] directionally dri[illegible]

In other types of [illegible] acts vertically, [illegible]ole" component of the BHA elements will co[illegible] The problem this creates is that if high WO[illegible] long (and expensive) BHA would be needed to prevent putting the drillpipe into compressio[illegible]ination wells, it is common practice to use a[illegible] low inclination wells.

On highly devia[illegible] running drillpipe in compression for[illegible] a number of rese[illegible] and Paslay), has shown that drillpipe can tol[illegible]pression in small diameter, high inclination [illegible] "low-side" of th[illegible]

Drillpipe is alw[illegible] horizontal wells, without apparently causing damage to the drillpipe.

Required BHA Weig[illegible]emblies

When two conta[illegible]pe and the borehole wall) are in relative motion, [illegible] sliding force on each surface will act along a [illegible] motion. Therefo[illegible]d, most of the frictional forces will act circumf[illegible]que), with only a small component acti[illegible]

Measurements o[illegible] the BHA is rota[illegible]eduction in WOB due to drag. This reduction is[illegible] "safety factor".

[illegible]

Consider a short element of the BHA which has a weight "W" (see following figure). Neglecting drag in the hole:

Effective weight in mud = W (BF)

Component of weight acting along borehole = W (BF) cos
... where is the borehole inclination

Extending this discussion to the whole BHA,

$$W_{BIT} = W_{BHA} \text{ (BF) cos}$$

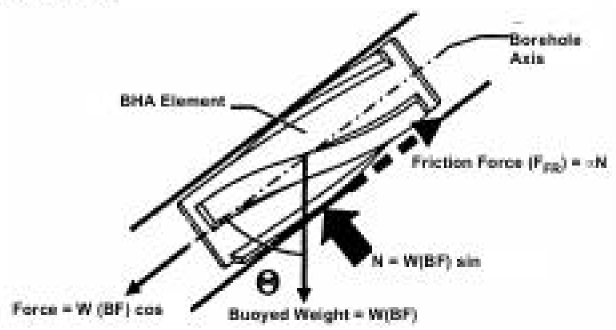
... where W_{BHA} is the total air weight of the BHA and W_{BIT} is the weight on bit.

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

$$\text{Required air weight of BHA} = \frac{\text{Maximum WOB x safety factor}}{\textit{buoyancy} \text{ factor x cos}}$$

$$\text{where the safety factor} = 1 + \frac{\text{percentage safety margin}}{100}$$

For example, to allow a 10% safety margin the safety factor in the formula would be 1.1



Example 4.4

A. Drilling 17.5-inch hole with a roller cone bit, we want to use 45,000 lbs WOB in the tangent section at 30° inclination. What air weight of BHA is required to avoid running any drill pipe in compression? The m[illegible]fety margin.

$$\text{Required air weight of BHA} = \frac{[illegible] \times 1.1}{0.847 \times \cos 30°} = 67,500\,lbs$$

B. Sup[illegible] 9.5-inch tubulars w[illegible] lbs per foot, a 9.5-inch MWD tool weighing 3,400 lbs [illegible] tubulars weighing 154 lbs per foot. How many joints [illegible] HWDP wo[illegible]xample 4.4A.

Total weight of drill collar section = [illegible] x 2[illegible]

Required air weight of HWDP [illegible]

Weight of one 30 ft joint of 5-i[illegible]

$$\text{Therefore, numb[illegible]quired} = \frac{10,640}{1,480} = 7.2$$

Therefore a mi[illegible]red.

Running Drill Pipe In Compressio[illegible]

Example 4.5

Prior to drilling [illegible]n a hard formation using an insert bit, the directional driller estimates that they expect to use 50,000 lbs WOB. The hole inclination is 60° and the mud density is 11 ppg.

What air weigh[illegible] avoid running any drill pipe in compres[illegible]n.

$$[illegible] = \frac{[illegible]0,000 \times 1.15}{0.852 \times \cos 60°} = [illegible]\,lbs$$

This is roughly the weight of ten stands of 8-inch drill collars, or attentiv[illegible]y, six s[illegible]us 44 joints of HWDP!

This is just not [illegible]ng, stiff and expensive BHA.

Critical [illegible]

Daw[illegible] formula for critical buckling forc[illegible] in drill [illegible]

$$F_{CR} = 2\sqrt{\text{[illegible]}}$$

where E is Young's modulus.
I is axial moment of inertia.
W is buoyed weight per unit length.
[illegible]
[illegible] is borehole inclina[illegible]
r is radial clearance between the pipe tool joint and the borehole wall.

If the compressive load reaches the F_{CR}, then sinusoidal buckling occurs.

This sinusoidal buckling formula can be used to develop graphs and tables (see pages 4-18 through 4-23). If [illegible] en inclination lies below the graph, [illegible] The reason that pipe in an inclined ho[illegible] the hole is supporting and constraini[illegible] low side of the hole tends to form a trough that resists even a slight displacement of the pipe from its initial straight configuration.

The graphs a[illegible] s section are for specific pipe/hol[illegible] configuratio[illegible] k up the critical buckling force. The following ex[illegible]

Calculating Crit[illegible]

Calculate the [illegible] grade E drill pipe with a nominal wei[illegible] 6.375 inches [illegible] in an 8.5-inch hole at 50° inclination.

1. Young's modulus, E, for steel is 29 x 10 psi

2. I [illegible]

4.5 inch drill pipe w[illegible] as an ID of 3.826 inches. This information can be found under *"New Drill Pipe Dimensional D[illegible]"* in the API RP-7G. (Table 2.1)

$$I = \frac{\pi}{64}(4.5^4 - 3.826^4) = 9.61\,in^4$$

3. The approximate air weight [illegible] also be found in the API RP 7G [illegible]

Air weight [illegible]

Buoyancy factor for 14 ppg [illegible]

W = 1.498 x 0.7 [illegible]

4. SIN 50° = **0.766**

5. Radial cle[illegible]

Note: *The values obtained in steps 1 through 5 may now be substituted in the formula* [illegible]

$$FCR = 2\sqrt{\frac{[illegible]}{1.062[illegible]}}$$

Critical Buckling [illegible]

Calculating BHA Weight With D[illegible]

This means that on high-angle w[illegible] weight on bit can safely be provided by havin[illegible] is suggested that 90% of the [illegible] maximum contribution to the weight on bit [illegible]

Denoting the total air weight of the BHA by [illegible] the w[illegible] W_{BIT} and the critical buckling [illegible] F_{CR}, we have:

$$W_{BIT}\,(SF) = W_{BHA}\,(BF)\,COS \;\; + 0.9F_{CR}$$

Therefore,

$$W_{[illegible]} = \frac{W_{BIT}(SF) - 0.9F_{CR}}{(BF)\cos}$$

Note: *This* [illegible] *account of drag.*

Continuing [illegible] of the BHA required (assuming so[illegible]ssion).

Suppose we [illegible]re using New 5-inch Grade E drill pipe with 4.5-inch IF connections. [illegible]

Referring to [illegible] the critical b[illegible]ckling load at 60° inclination is approximately 26,000 lbs.

Our formula [illegible]

$$W_{BHA} = \frac{[illegible]26,000}{0.832 \quad 0.5}$$

[illegible]

Thus, a total [illegible]ir weight of 82,000 lbs [illegible] feasible than the value of 138,[illegible]

BHA Requirements When The Drill[illegible] is Not Ro[illegible]ed

As stated earlier, when the drillstring is rota[illegible] friction (drag) [illegible] in BHA weig[illegible]c[illegible]on for rotary assemblies will mainly affect [illegible] motor system [illegible]in the oriented mode) axial drag can become very significant and drillstrin[illegible]

A pr[illegible] account [illegible]

BHA Weig[illegible]

In practice, [illegible] wells is not [illegible]g reasons.

- The WO[illegible]ially when a PDC bit is used.
- When th[illegible]d, the drill pipe is not subjected to the cyclical [illegible] Therefore, sinusoi[illegible] drillstri[illegible]ever, must be avoided.

Helical buck[illegible] [illegible] F_{CR}, where F_{CR} is the compressive force at which sin[illegible]

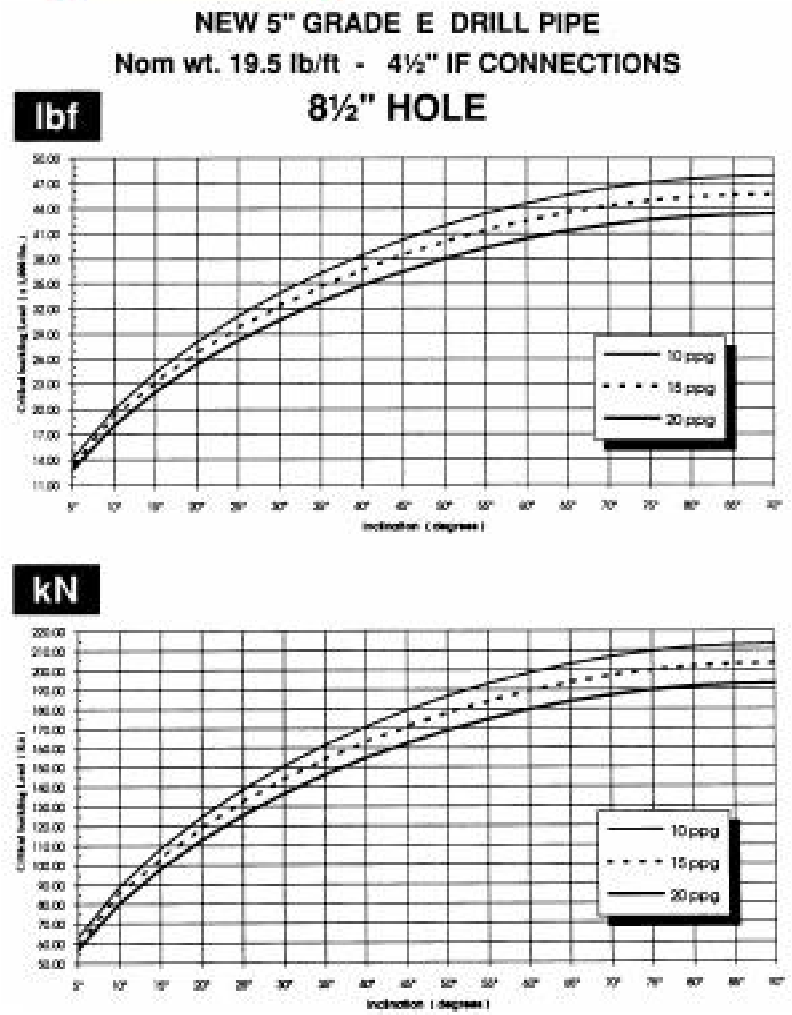
Ther[illegible] the results should be valid for steerable systems in the oriented mode exce[illegible]t for un[illegible]reate exceptionally high values of axia[illegible]

The standard pr[illegible]d weight for steerable assemblies has [illegible]ease in the incidence of drillstring failur[illegible] drilled in the oriented mode.

Summary

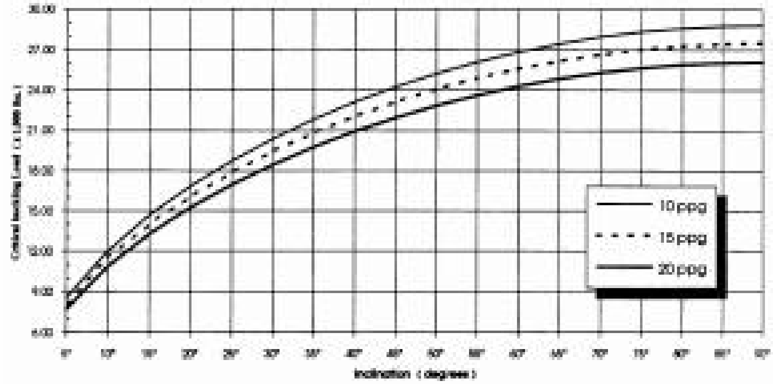
- [illegible]cal wells, ordinary drill pipe must NEVER be run in compression, in any hole size. Therefore, sufficient BHA weight must be use[illegible]n bit with an acceptable [illegible]ations.
- In large hol[illegible]sizes [illegible] should not be run in compressio[illegible]
- In smaller hole siz[illegible] drill pipe may be run in compressio[illegible] to contribute to the weight on bit, provided the maximum [illegible]ckling force. This critical buck[illegible] force which will cause s[illegible]usoi[illegible]
- A safety ma[illegible]sed in the calculation to allow for some dr[illegible]owever, axial drag *is* not a major facto[illegible] when [illegible]

The majori[illegible]ty of th[illegible] rotary assemblies. However, it would [illegible] systems used in the rotary mode, with [illegible]rilling anticipated, the required BHA wei[illegible]ght could be calculated the same way. If a significant [illegible] hole should [illegible] Drag computer programs. In this type of situ[illegible] requiremen[illegible]t is ad[illegible]

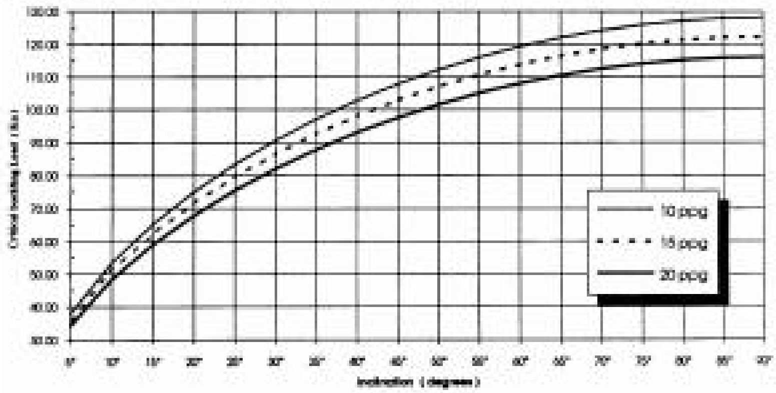

NEW 5" GRADE E DRILL PIPE
Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS
8½" HOLE
lbf
10 ppg
15 ppg
20 ppg
Inclination (degrees)
kN
10 ppg
15 ppg
20 ppg
Inclination (degrees)

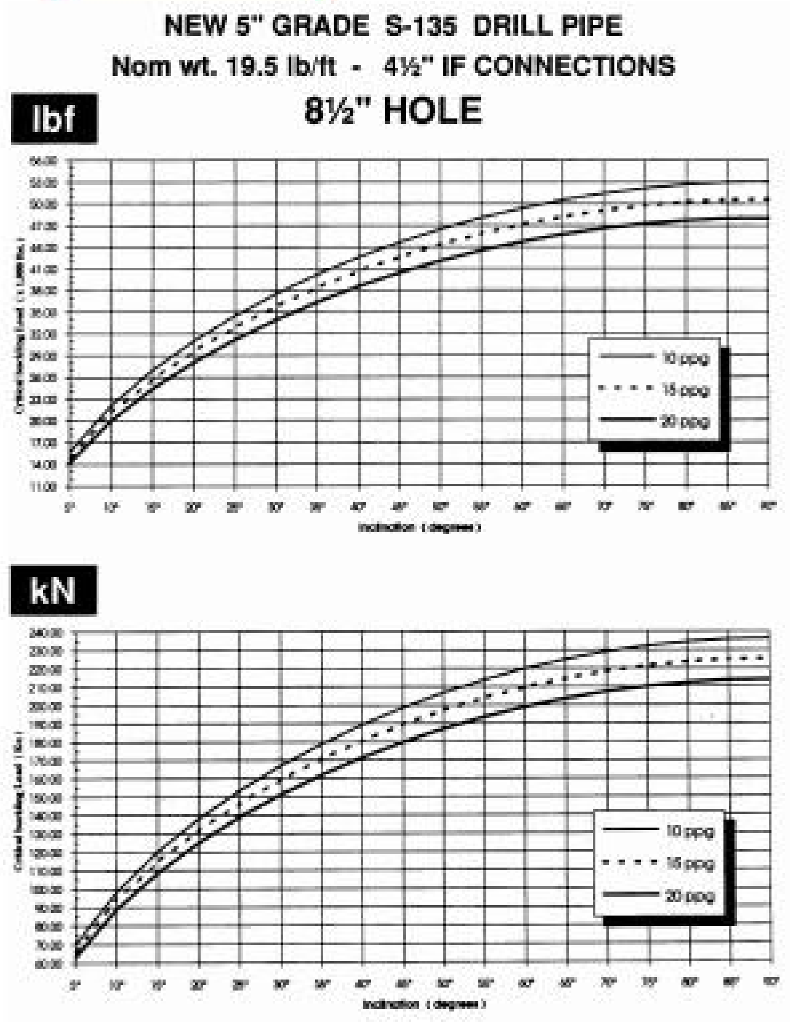
NEW 5" GRADE E DRILL PIPE
Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS
12¼" HOLE

lbf



kN



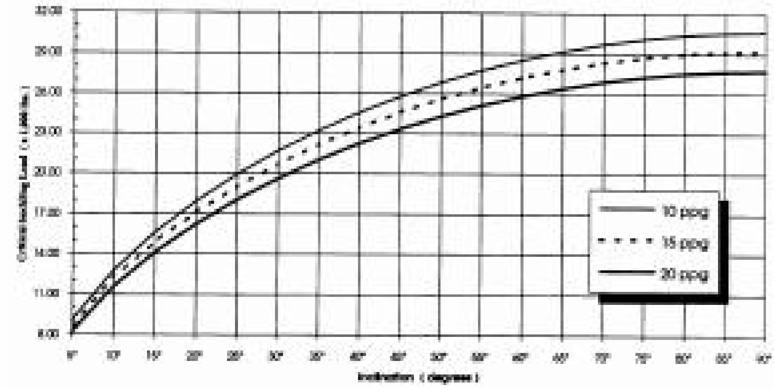

NEW 5" GRADE S-135 DRILL PIPE
Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS
8½" HOLE
lbf
10 ppg
15 ppg
20 ppg
Inclination (degrees)
kN
10 ppg
15 ppg
20 ppg
Inclination (degrees)

NEW 5" GRADE S-135 DRILL PIPE

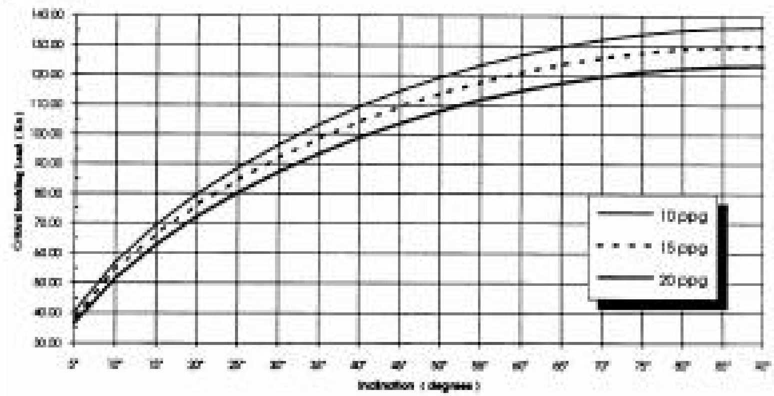
Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS

12¼" HOLE

lbf



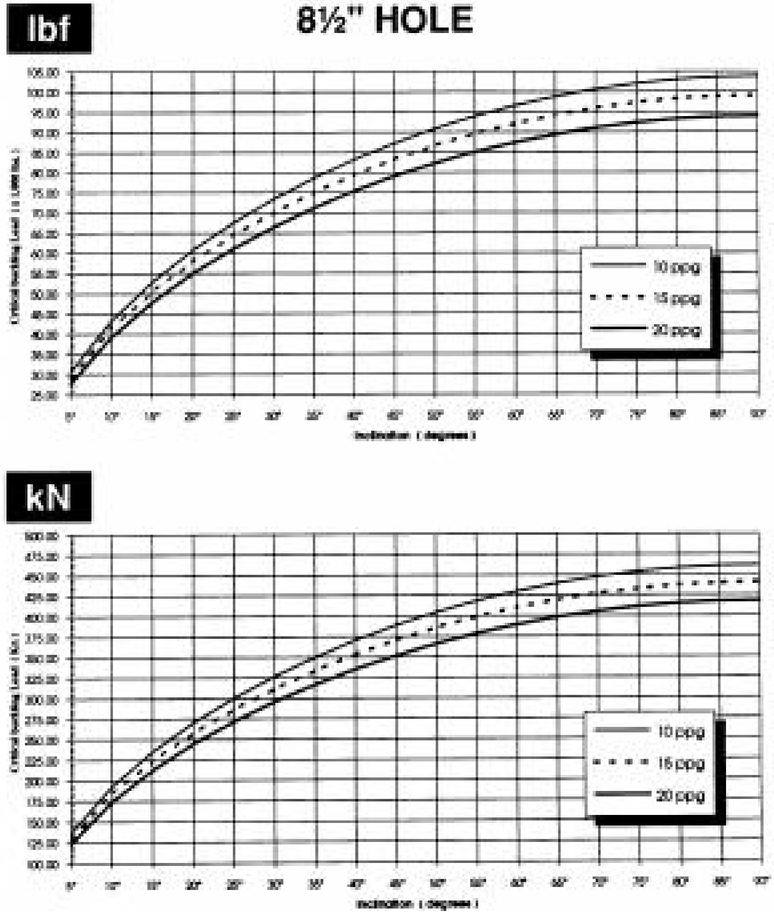
kN



NEW 5" HWDP DRILL PIPE

49.3 lb/ft - 4½" IF CONNECTIONS

8½" HOLE



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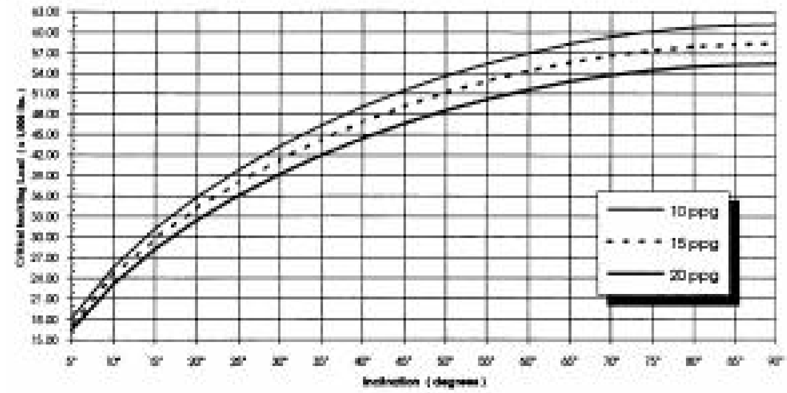
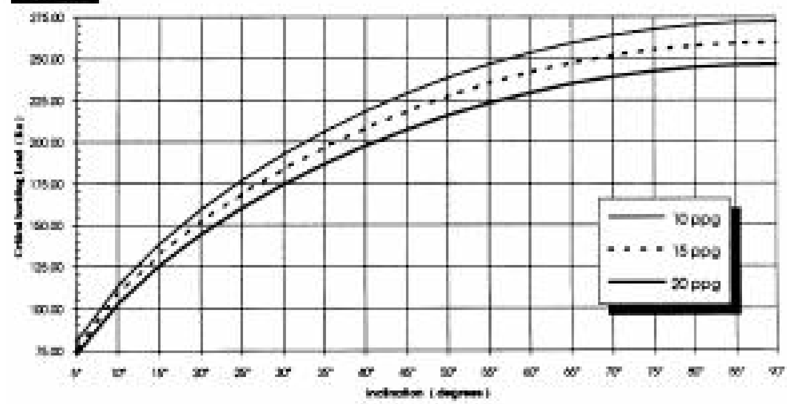
NEW 5" HWDP DRILL PIPE
49.3 lb/ft - 4½" IF CONNECTIONS
12¼" HOLE

lbf



kN



Neu[illegible]

The neutral point is usua[illegible]y defined as the point in the drillstring where the axial stress c[illegible]. The location of this neutral point [illegible]he buoyancy factor of the drilling fluid[illegible]es, the position of the neutral point [illegible] common to refer to a "transition zone" as the [illegible]s changes from compression to tension.

Drillstring co[illegible] transition zone" may, therefore, alternately ex[illegible] can damage [illegible] drilling jars, whose life may be drastically shortened if the jars are located in the transition zone. It is also impor[illegible] run in compr[illegible]portant to know the location of the neutral point[illegible]

Calculation [illegible]

Case 1: Vert[illegible]

where:

[illegible] to the neutral point.

W_{dc} [illegible] per foot of the drill collars.

BF is the buoyancy factor of the drilling mud.

Example: Determine the neutral point in [illegible] if the weight-on0bit is 30,000 lbs a[illegible] ppg.

[illegible] 127 0.832

therefore:

L_{np} is 284 feet up into the[illegible]

Case 2: Vertica[illegible] weight drill pipe

If drill collars an[illegible] location of the n[illegible] First, you should use the previous for[illegible] than the length [illegible] point is in the collars. If L_{np} is more than the [illegible] to determine ho[illegible] far up in the heavy weight the neutral point is located.

$$L_{n} [illegible]$$

where:

L_{nphw} is the distance from the botto[illegible]

WOB is weight on bit

W_{DC} is weight per foot of the collars

L_{DC} is length [illegible]

W_{hw} is weigh[illegible]

BF is Buoyan[illegible]

Example: Determin[illegible]

Mud density = 1[illegible] ppg

Weight-on-Bit = 40,00[illegible]

400 of 7-inch x 2.25-in[illegible]

600 of 5-inch heavy we[illegible]

$$L_{np} = [illegible]$$

[illegible]

Since L_{dp} is 426 feet and w[illegible] the neutral point must be [illegible]

$$L_{npdw} = \frac{W([illegible] B - W_{[illegible]} L_{[illegible]} (BF)}{W_{dw} (BF)}$$

$$= \frac{40,000 - (117 \; [illegible]}{50 \quad 0.8[illegible]}$$

$$= 61.51 \text{feet}$$

Thus, the neutral point is 62 feet up [illegible] drill pipe.

Case 3: Directional Well, Neutr[illegible]

When the neu[illegible] section [illegible]nd the collars are all of one diameter[illegible]

$$L_{np} = \frac{WOB}{[illegible] (BF) \cos I}$$

where:

L_{np} = [illegible] to neutral point in feet

W_{DC} = weight per foot of the drill collars

BF = Buoyancy Factor

WOB = weight on bit

I = borehole inclination

Case 4: Directional well with heavy weight drill pipe

When the neutral point is in the HWDP but all the drill collars are of the same diameter, the following formula can be used:

$$L_{nphw} = \frac{WOB - W_{DC}L_{DC}(BF)\cos I}{W_{hw}(BF)\cos I}$$

where:

L_{nphw} is the distance from the bottom of the HWDP to the neutral point.

L_{DC} is the total length of the drill collar section.

W_{hw} is the weight per foot of the HWDP.

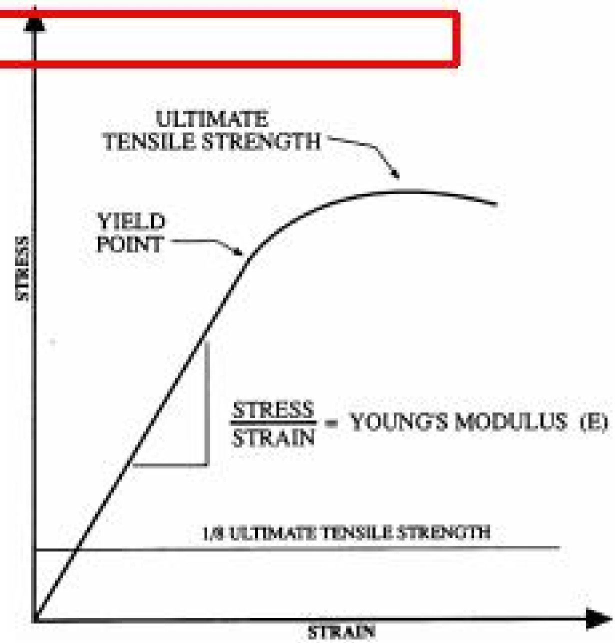
General Formula for Directional Wells

The last formula can be expanded in the case of a directional well with drill collars of more than one diameter. For example, if there were two sizes of drill collars but the neutral point was in the HWDP, the formula would become:

$$L_{nphw} = \frac{WOB - (BF)\cos I(W_{DC1}L_{DC1} + W_{DC2}L_{DC2})}{W_{hw}(BF)\cos I}$$

where W_{DC1} and L_{DC1} are the weight per foot and total length of the first size of drill collars, and W_{DC2} and L_{DC2} are the weight per foot and total length of the second section.

Drillpipe Fatigue Failure



Bending Stress

$$SIGMA = \frac{ED}{2R}$$

where **E** is Young's modulus (psi)

D is Diameter of tubular (inches)

R is Radius of curvature (inches)

Pipe Grade	SIGMA Ultimate	SIGMA Min Tensile Yield
E	100,000 psi	75,000 psi
X	120,000 psi	95,000 psi
G	130,000 psi	105,000 psi
S-135	160,000 psi	135,000 psi
S-165	175,000 psi	165,000 psi

Fatigue Damage

Note: *Fatigue damage will ultimately lead to pipe failure.*

Case 1

Sigma < 1/8 Sigma Ultimate

- Fatigue damage should not occur.
- Life should be infinite.

Case 2

1/8 Sigma Ultimate < Sigma < 1/4 Sigma Ultimate

- Fatigue damage may occur.
- Life may be as low as 1,000,000 cycles [illegible]

Case 3

1/4 Sigma Ultimate < Sigma < 0.42 Sigma Ultimate

- Fatigue damage will occur.
- Life will be l[illegible]

Case 4

Sigma [illegible] 0.42 Sigma Ultimate

- Fatigue damage will occur.
- Do not rotate.

Tor[illegible]g

Several factors affect hole dr[illegible], including hole inclination, dogleg severity, hole conditio[illegible]llstring component types, sizes and pla[illegible]lier, in drilling situations where the dr[illegible] system is used in the oriented [illegible] significant and should be evaluated us[illegible]ter program. Torque and Drag programs ca[illegible].

Along Hole Comp[illegible]

Consider a s[illegible] element of a BHA which has a weight W

Effective we[illegible]ght in drilling mud = W(BF)

[illegible]**ing along borehole** = W(BF)cos

If the BHA is not rotated, [illegible] borehole on the BHA [illegible]

[illegible] is the coefficient of friction

N is the norm[illegible]l reaction force between the BHA element and the borehol[illegible] wall. If this [illegible] element itself, then:

N = W[illegible]

F_{FR} = [illegible]

The net co[illegible]s therefore

W_{BIT} = W (BF) (cos - [illegible]sin)

Computer Models[illegible]tion

Proper evalu[illegible] requires the use of a computer program. Th[illegible] friction for rotary drilling as well as drilli[illegible]g with no drillstring rotation.

These mathe[illegible]atical models [illegible]ake a number[illegible]ons and consider [illegible] as composed of [illegible]. Using these models, it is possible to solve equations for [illegible]ng/ well bore contact at the bottom drillstring [illegible] force deriving from th[illegible]nd th[illegible]ad condition at the upper end of the drillstring element. Such methods, r[illegible]ated for each drillstring element over the [illegible]

- Surface [illegible]

[illegible]

- Normal force [illegible] each drillstring element
- Average torsional and tensile load acting upon each drillstring element

The E*C TRAK Torque and Drag [illegible]

This program, developed at the Drilling Research Center in Celle, [illegible] torque and drag when a friction factor (coefficient of sliding friction) is known or estimated. It will calculate the friction factor w[illegible] load is known.

[illegible] and outputs han[illegible].

General Uses

The program may be used to:

- Optim[illegible] minimum torque and drag
- Analyze problems either current or post-well
- D[illegible] design limitations
- Determine rig size requirements

Inputs Required

- Drillstring co[illegible] material composition)
- Survey data ([illegible])
- Friction facto[illegible] friction factor calculation)

Outputs

Informat[illegible] torques and stresses are calculated for discrete [illegible] to the bit. These values are output in both tabular (summary or detailed) and graphical formats:

- Drag load (pick-up [illegible]
- Pick up load
- Slack off load
- Rotating off bottom load
- Drilling load

- Rotating [illegible]
- Rotary torque (drilling and off bottom)
- Maximum [illegible] yield)
- Drillstring [illegible]
- Bit to neu[illegible]
- Drillstring twist
- Axial stre[illegible]
- Torsional [illegible]
- Bending stress
- Total equi[illegible]

Typical Drillstring - We[illegible]

Well Environment	[illegible]	[illegible]
Casing	[illegible]	[illegible]
[illegible]	0.23 - 0.44	0.13 - 0.26

Use Of Torque & Drag Programs For BHA Weight Evaluation

[illegible] used to evaluate drillst[illegible] horizontal wells or complex, unusual directional wells. [illegible] program can be use[illegible] directional wells. T[illegible] assembly and also calculates the position of the neutral point in the drillstring. In addit[illegible] and will "flag" any [illegible] compressive load which [illegible] buckling force for the drill pipe.

Self-C[illegible]

1. Determine the static hookload of a drill[illegible]tring consisting of 9,000 ft of 4.5-inc[illegible]nal weight of 16.6 lbs/ft (appr[illegible] 600 feet of 5 inch heavy-w[illegible]ght d[illegible] eight 2.5-in[illegible] collar[illegible] Disregard effects of [illegible]t the drillstring is full of fluid.

   A. What is the air [illegible]

   B. What is the bu[illegible]

   C. What is the net [illegible]

2. Allowing for a safe[illegible] pound overpull before reaching the drill p[illegible]hat can be drilled with the [illegible]

3. In all the following [illegible]mple[illegible] run in compression [illegible] ign[illegible]re drag in the calculation. Find the air weight r[illegible]

   A. Desired weight [illegible] 13 ppg; hole angle 20°; sa[illegible] mar[illegible]QUIRED =

      ____

   B. Desired weight 40,000 lbs; mud weight 13 ppg; hole angle 20°; sa[illegible]HT REQUIRED =

      ____

   C. Find the numbe[illegible] needed to get the air weight. 62,000 lbs air w[illegible] collars are avai[illegible]eavy weight are need[illegible]

      ____

4. Calculate the critical buckli[illegible] for the drill pipe sp[illegible]cified in the following case.

   A. 3.5-inch new, high stre[illegible] with an approximate wei[illegible]t[illegible] joint) in a 6 inch hole w[illegible] ppg.

5. In the fo[illegible] y be run in compression but [illegible] eed 90% of the critic[illegible] buckli[illegible] new, S-135 drill pipe with 4.5[illegible] being used. Find the BHA air weight r[illegible]

A. Desired ma[illegible] s:
Borehole In[illegible]
Mud Densit[illegible]
Hole Size = [illegible]
Use a safety [illegible]

B. Suppose you have [illegible] weighing 160 lbs/ft and 93 feet of [illegible] 9 lbs/ft. How many joints o[illegible]

Drill Collar Weights
(pounds per foot)

OD/ID	1"	1-1/4"	1-1/2"	1-3/4"	2"	2-1/4"	2-1/2"	2-13/16	3"	3-1/4"	3-1/2"	3-3/4"
3" OD	21	20	18									
3-1/8"	22	22	20									
3-1/4"	26	24	22									
3-1/2"	30	29	27									
3-3/4"	35	33	32									
4" OD	40	39	37	35	32	29						
4-1/8"	43	41	39	37	35	32						
4-1/4"	46	44	42	40	38	35						
4-1/2"	51	50	48	46	43	41						
4-3/4"			54	52	50	47	44					
5" OD			61	59	56	53	50					
5-1/4"			68	65	63	60	57					
5-1/2"			75	73	70	67	64	60				
5-3/4"			82	80	78	75	72	67	64	60		
6" OD			90	88	85	83	79	75	72	68		
6-1/4"			98	96	94	91	88	83	80	76	72	
6-1/2"			107	105	102	99	96	91	89	85	80	
6-3/4"			116	114	111	108	105	100	98	93	89	
7" OD			125	123	120	117	114	110	107	103	98	93
7-1/4"			134	132	130	127	124	119	116	112	108	103
7-1/2"			144	142	139	137	133	129	126	122	117	113
7-3/4"			154	152	150	147	144	139	136	132	128	123
8" OD			165	163	160	157	154	150	147	143	138	133
8-1/4"			176	174	171	168	165	160	158	154	149	144
8-1/2"			187	185	182	179	176	172	169	165	160	155
9" OD			210	208	206	203	200	195	192	188	184	179
9-1/2"			234	232	230	227	224	220	216	212	209	206
9-3/4"			248	245	243	240	237	232	229	225	221	216

Heavy Weight Drill Pipe - Range II

Nominal Size (in)	ID	Connection Type & OD	Approximate Weight/Joint (lb)	Make-Up Torque (ft/lb)	Capacity bbl/100ft	Displacement (bbl/100ft)
3-1/2"	[illegible]	[illegible]	25.3	9,900	0.421	0.921
4"	[illegible]	N.C.40 (4 F.H.) / 5-1/4"	29.7	13,250	0.645	1.082
4-1/2"	[illegible]	N.C.46 (4 I.F.) / 6-1/4"	41.0	21,800	0.743	1.493
5"	3"	N.C.50 (4-1/2 I.F.) / 6-1/2"	49.3	29,400	0.883	1.796

Directional Drilling

Upon completion of this chapter, you should be able to:

- Describe the general aspects involved in well planning.
- Describe [illegible] common well patterns and list [illegible]
- State the two [illegible] give a simple explan[illegible]
- Explain what [illegible] importance of this in dire[illegible]
- List the main [illegible] and disadvant[illegible]
- Explain what [illegible] mea[illegible]
- Define and ex[illegible] Side Tool Face", an[illegible]
- List the main [illegible] behavior of rotary assemb[illegible]
- Explain the Fulcrum[illegible]
- Explain what [illegible] mea[illegible] by the terms "steerable motor" and "Navigation [illegible]
- Explain the co[illegible] "Theoretical [illegible] of a Navigation System.
- Explain the d[illegible] "Navigational[illegible]

Additional Review[illegible]

Baker Hughes INTEQ, [illegible] *Operations Manual*, P/N 80319H

Baker Hughes INTEQ, [illegible]

Bourgoyne Jr., Adam, [illegible], SPE Textbook Series, Vol. 2, 1986

Moore, Preston, *Drillin[illegible] Practices Manual*, PennWell Publishing Co., Tulsa, 1986

App[illegible]onal Drilling

Definition of Directional Drilling

Directional drilling can generally be defined as the science of directing a [illegible] designated sub-surface target[illegible]

Applications

Multiple wells from offshore structures

[illegible] directional drilling techniques is in offshore drilling. Many oil and gas deposits are situated well beyond the reach of land based ri[illegible]s. Drilling a large number of vertical wells from indiv[illegible]ractical and uneconomical. The obvious approach for a large oilfield is to install a fixed platform on the seabed, from [illegible] be drilled. The bottomhole loca[illegible] for optimum recovery.

Figure 5-1: Multiple wells from offshore structures.

In conventional development, wells cannot be drilled until the platform has been constructed and installed. This can mean a delay of several years before production begins. Such delay scan be considerably reduced by pre-drilling some of the wells through a subsea template while the platform is being constructed. These wells are directionally drilled from a semi-submersible rig and tied back to the platform once it has been installed.

Relief Wells

Directional techniques are used to drill relief wells in order to "kill" blowouts. Relief [illegible]s as close as possible to the uncontrolled we[illegible] the reservoir to overcome the pressure and [illegible]ntrol.

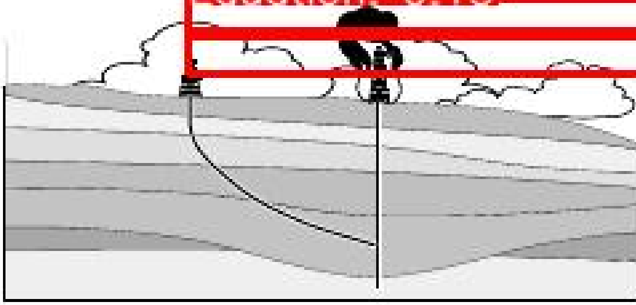


Figure 5-2: Relief wells.

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.

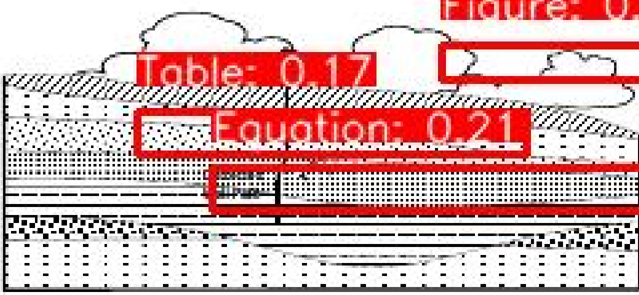


Figure 5-3: Controlling vertical wells.

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.

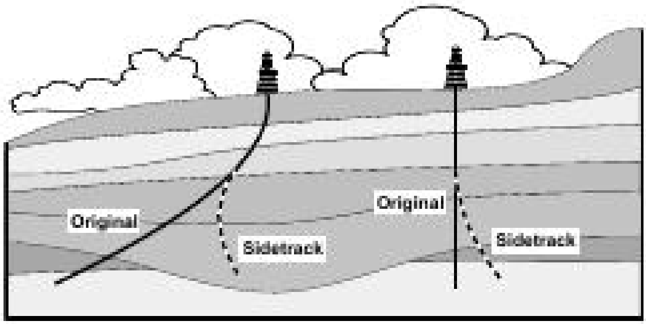


Figure 5-4: Sidetracking.

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.

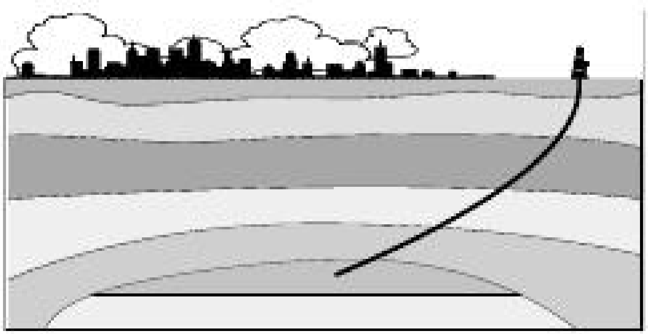


Figure 5-5: Inaccessible locations.

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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.

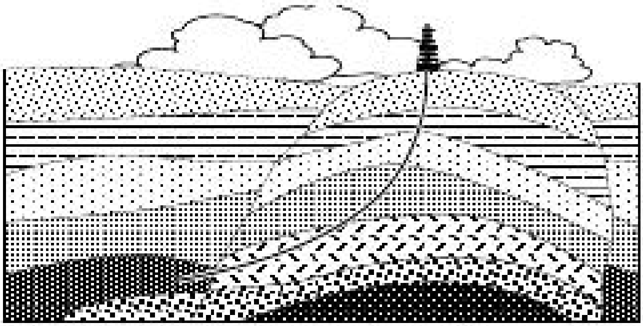


Figure 5-6: Fault drilling.

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.

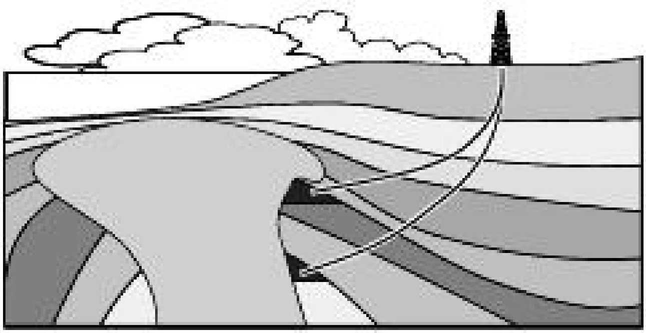


Figure 5-7: Salt dome drilling.

Shoreline Drilling.

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

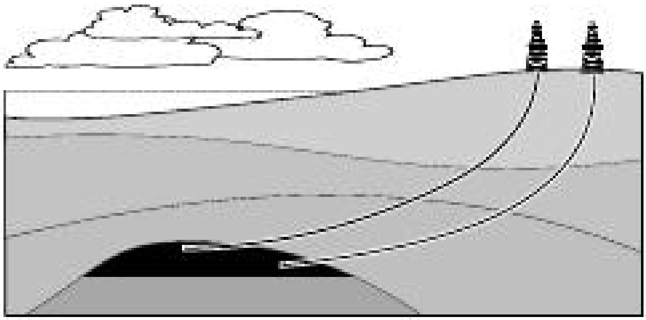


Figure 5-8: Shoreline drilling.

These are only some of the many applications of directional drilling. Although it is not a new concept, one type of directional drilling, horizontal drilling, is the fastest growing branch of drilling, with major advances occurring in tools and techniques. As with directional drilling, there are numerous specific applications for horizontal drilling.

Well P[illegible]

Introduction

[illegible] well planning, and many individuals [illegible] are involved in designing various programs for the [illegible] program, drill string design, [illegible] ell planning is one where the service contract[illegible] in their area of expertise.

This section wil[illegible] of well planning which have always been the [illegible]

Reference Systems [illegible]

With the excepti[illegible] ems, all survey systems measure inclinat[illegible] measured "along hole"). These measurements are tied to fixed reference systems so that [illegible] include:

- Depth [illegible]
- Inclin[illegible]
- Azimu[illegible]

Depth References

During the cour[illegible] ere are two kinds of depths:

- Measured [illegible] course of the borel[illegible] point to the survey point. This [illegible] ample, pipe tally, wireline dep[illegible] ter.
- True Vertical Dep[illegible] the depth reference level to [illegible] ep h is always calculated from the deviat[illegible]

In most [illegible] elevation is used as the working depth reference. The abbreviation BRT (below rotary table) and RKB (rotary [illegible] e depths measured from the rotary table. T[illegible] ick floor elevation. For floating drilling rigs the [illegible] hence a mean rotary table elevation h[illegible]

In order to comp[illegible] same field, a common depth reference [illegible] well into a blow-out we[illegible] en the [illegible], mean sea level (MSL) is sometimes us[illegible]om MSL can be read from tide tables or [illegible]

Inclination References

The [illegible] is the angle (in degrees) between the vertical and the well bore axis at a particular point. The vertical reference is the direc[illegible] be indicated by a plumb bob.

Azimuth Refere[illegible]

For direction[illegible]

- Ma[illegible]
- [illegible]
- [illegible]

All "[illegible]on) referenced to Magnetic North. Ho[illegible]es are always referenced to [illegible]

True (Geographic) [illegible]

This is the direction [illegible]e Earth's axis of rotation. Dir[illegible]ongitude.

Grid North

Drilling oper[illegible] the surface of the Earth) but when cal[illegible] coordinates a flat surface is assumed. Since it is no[illegible] on a flat well[illegible] this, differen[illegible]ch can be used.

UTM Syste[illegible]

One example[illegible] System. In tr[illegible] chosen to rep[illegible]ch touches the spheroid alo[illegible] the Earth pas[illegible]uth geographic poles.)

These meridi[illegible] produce a re[illegible]d lines on a map form the rectangular g[illegible] one specifie[illegible] be identical t[illegible] meridian.

The relationship between True North and Grid North is indicated by the angles 'a' in Figure 5-9. Convergence is the angle difference between grid north and true north for the location being considered.

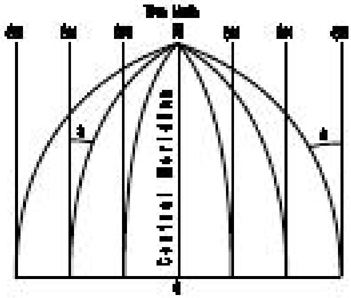


Figure 5-9: Relationship between True North and Grid North

The reference meridians are 6 degrees apart, starting at the Greenwich meridian, which means the world is divided into 60 zones. The zones are numbered 0 to 60 with zone 31 having the 0 degree meridian (Greenwich) on the left and the 6 degree East on the right. Each zone is then further divided into grid sectors - a grid sector covering 8 degrees latitude starting from the equator and ranging from 80° South to 80° North. The sectors are given letters ranging from C to X (excluding I and O).

Therefore, each sector is uniquely identified by a number from 0 to 60 (zone number) and a letter. For example, sector 31U shown in Figure 5-10, is the Southern North Sea.

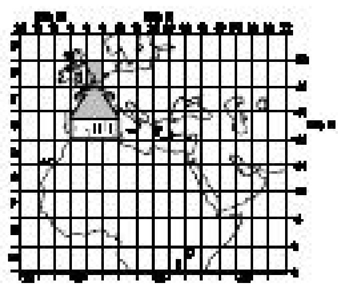


Figure 5-10: Sector Identification

Coordinates i[illegible] meters. North coordinates being measu[illegible]ern hemisphere, the equator is tak[illegible] Southern hemisphere the equator is 10[illegible] numbers). East coordinates [illegible]red from a line 500,000m west of the central meri[illegible]er words, the central meridian on each zone is [illegible] avoids negat[illegible]

So UTM coo[illegible]hings and Eastings, and are always positive num[illegible]

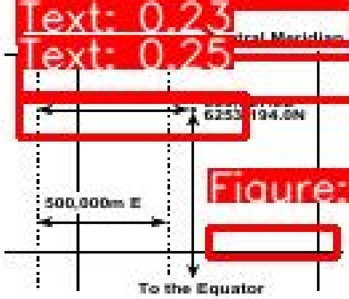


Figure 5-11: Northings and Eastings

Lambert Projection.

Another projection system, used in s[illegible]al projection or LAMBERT system. A [illegible]s the spheroid under consideration. Th[illegible]presentation with meridians as convergent lines and parallels as arcs of circles.

Further discussion of the coordinate systems and map projections is beyond the scope of this text.

Field Coordinates

Although the coordinates of points on a wellpath could be expressed as UTM coordi[illegible]actice. Instead, a reference point on the platform or rig is chosen as the local origin and given the coordinates 0,0. On offsh[illegible]he center of the platform. The Northing[illegible] the wells drilled from the platform are reference[illegible] positions of [illegible]llision analysis.

Direction Measurement

Survey tools measure the direction of the wellbore on the horizontal plane with respect to North, either True or Grid North. There are two systems.

Azimuth.

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

Figure 5-12: The Azimuth System

Quadrant Bearings

In the quadrant system (Figure 5-13), the directions are expressed as angles from 0°-90° measured from North in the two Northern quadrants and from

South in the Southern quadrants. The diagram in Figure 5-14 illustrates how to convert from the quadrant system to azimuth, and vice versa.

Figure 5-13: The Quadrant System

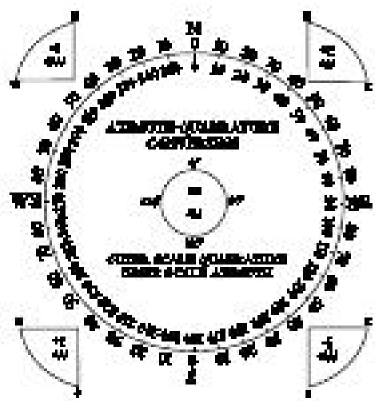


Figure 5-14: Conversion from Quadrant to Azimuth Systems

Plan[illegible]

[illegible] are closely involved is the p[illegible], this [illegible] not as simple a [illegible] multi-well platform. There [illegible] must be carefully considered before calculati[illegible]

The Target

The target is usu[illegible] specified by the geologist, who will not merely define a certain point [illegible] circle of [illegible] target as its center). Target zones should be selected as large as possible to achieve the objective. If multiple zones a[illegible] to be p[illegible] so that the planned pattern [illegible] without causing drilling problems.

Types of Direction[illegible]

The advent of st[illegible] wells that are planned and drilled with com[illegible] This is particularly true [illegible] drilled to new ta[illegible]

These complex well paths are harder to drill and the old adage that "the simplest [illegible] holds true. Therefore, most directional wells ar[illegible] patterns which have been in use for many years. Common patterns for vertical projections are shown on the following pages:

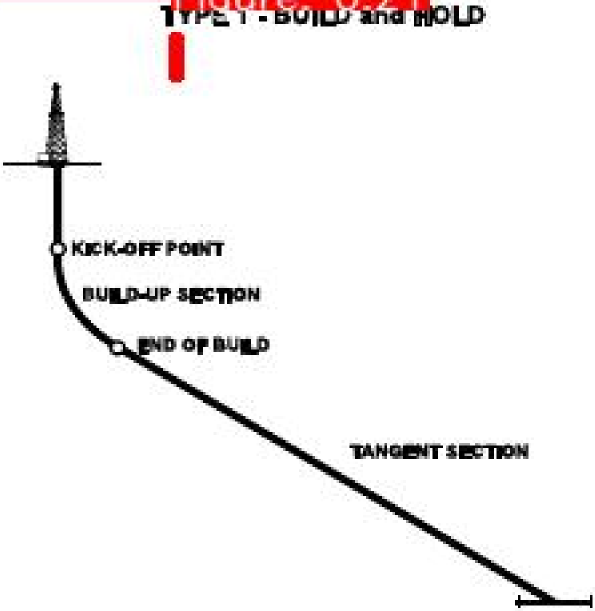


Figure 5-15: Type 1 (Build and Hold)

Features:

Shallow kick-off point (KOP)

Build-up section (which may have more than one build up rate)

Tangent section

Applications:

Deep wells with large horizontal displacements

Moderately deep wells with moderate horizontal displacement, where intermediate casing is not required

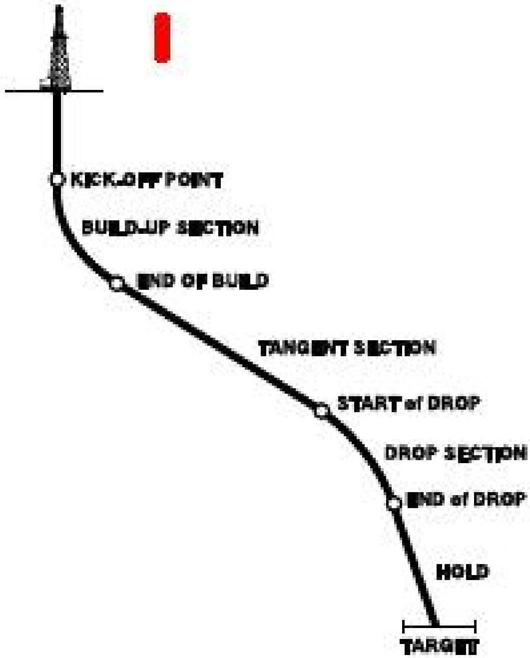


Figure 5-16: Type 2 (S Type Well)

Features:	**There are several variations:**
Shallow KOP	- Build, hold & drop back to vertical
Build-up section	- Build, hold, drop & hold (illustrated above)
Tangent section	- Build, hold & continuous drop through reservoir
Drop-off section	

Applications:	**Disadvantages:**
Multiple pay zones	- Increased torque & drag
Reduces final angle in reservoir	- [illegible]
Lease or target limitations	- Logging problems due to inclination
Well spacing requirements	
Deep wells with small horizontal displacements	

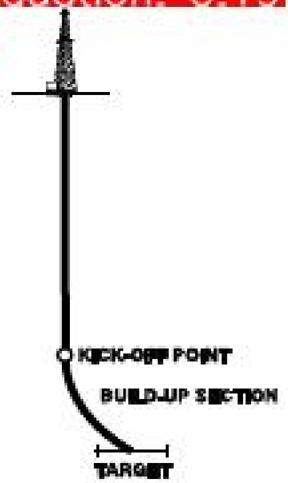


Figure 5-17: Type 3 (Deep Kickoff and Build)

Features:

Deep KOP

Build-up section

Short tangent section (optional)

Applications:

Appraisal wells to assess the extent of a newly discovered reservoir

Repositioning of the bottom part of the hole or re-drilling

Salt dome drilling

Disadvantages:

Formations are harder so the initial deflection may be more difficult to achieve

Harder to achieve desired tool face orientation with downhole motor deflection assemblies (more reactive torque)

Longer trip time for any BHA changes required

On multi-well pl[illegible] deep kick-off points, because of the s[illegible]y of keeping wells vertical in firme[illegible] shallow kick-off points to reduce conges[illegible] and to minimize the risk of collisions.

Catenary Curve W[illegible]

One suggestion [illegible] well path for directional wells would be to plan the [illegible]h curve, all the way from KOP to target. This is the catenary method. A catenary curve is the natural curve that a c[illegible] weight assumes when suspended betw[illegible]ension of drill string would also form a cate[illegible]

Proponents of th[illegible] drilled wellbore, [illegible]duced and that there is less chance of key se[illegible]cking. However, in practice it is hard to pick BH[illegible] of build. It is in [illegible]tenary curve well plan than a traditional well plan. Also, the catenary curve method produces a higher maximum inclin[illegible] patterns.

Although the ca[illegible]ried, with some success, it is not widely used and[illegible] this type of well[illegible]

Horizontal wells

For many applic[illegible] is built to 90° or[illegible]

Allocation of slots to targets

Even this is not [illegible]om a directional driller's viewpoint, slots [illegible] East side of the platform [illegible] used for wells w[illegible]ose targets are in a North Easterly direction. Unfortunately th[illegible]ons (e.g. water injection wells) may have to be grouped together for manifolding requirements). Also, as more wells are drilled and the reservoir model is upgraded, targets can be changed[illegible]

Inner sl[illegible] i.e. targets with the smalles[illegible] horizon[illegible] and these wells will be given slightly de[illegible] targets which are furthest from the platform. These wells will be given shallow [illegible] build-up rates to keep the maximum inclinati[illegible]

Kick-off [illegible]

The selection of both the kick-off point and the build-up rate depends on many factors [illegible] program, mud program, required [illegible] inclination. Choice of ki[illegible] requirements to keep the well path at a safe [illegible] higher the bu[illegible] maximum inclination.

Build-up rate[illegible]/100' M.D. to 4.0°/100' M.D. for normal direc[illegible]ermissible dogleg severity must be considered w[illegible]

In practice, w[illegible] rates and the [illegible] safe clearanc[illegible]eeps the maximum inclination within desire[illegible]

Tangent Sectio[illegible]

During the ei[illegible] completed. I[illegible] (up to 80°), the area which can be cover[illegible] covered whe[illegible] However, hig[illegible] inclination angles can result in excessive torque and drag on the drill strin[illegible] hole cleaning, logging, casing, cementing and prod[illegible] technology.

Experience [illegible]ctional control problems are aggravated w[illegible] there is more [illegible]alk (i.e. change in azimuth) so more time is spent [illegible]. As such, most run-of-the-mill directional w[illegible]

Drop-off sectio[illegible]

On S-type we[illegible] selected to ease casing problems and avoidance of [illegible] to drilling be[illegible]n in the drill pipe that is run through deeper dogle[illegible]s and less time spent rotating below the dogleg.

The horizontal [illegible]

On many we[illegible]ction is just a straight line drawn from the slot to th[illegible] necessary to [illegible]t direction to avoid other wells. Once clear of these [illegible] the target. This is a 3-dimensional turn, but on t[illegible]

The path of the [illegible] horizontal projection by plotting total No[illegible] versus total East/West coordinates (Eas[illegible] calculated from surveys.

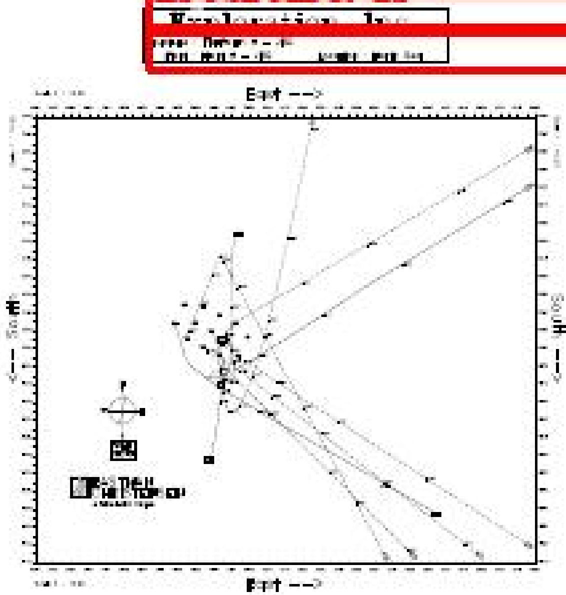


Figure 5-18: This is a 3-dimensional turn on the horizontal plan.

Lead angle

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

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

Nudging

The technique of "nudging" is used on platforms in order to "spread out" conduct[illegible] the chance of a collision.

Basically, [illegible]lled, some angle is built at a low rate (e. [illegible]

In addition t[illegible] "spreading things out", other reasons for "nudging" are:

- to drill [illegible]ide of the platform from the targe[illegible]
- to keep [illegible] direction as far apart as possible[illegible]
- if the re[illegible] the total [illegible] build angle right below the surface con[illegible]

Techniques for [illegible]

When formations ar[illegible] the best technique to use. The most co[illegible]mon [illegible]otor of 9.5" OD or greater with a 17.5" [illegible] and [illegible] gives low build rates and hence a lo[illegible]. The hole is then opened to the requ[illegible]otor run. Occasionally the job is performed with a large mud motor and a 26" bit from the start. In this case either a 1.5° or 2° [illegible]

Planning a nudg[illegible]

The direction[illegible] maximum se[illegible]sarily be nudged in their target directions.

Nudges will [illegible] individual well plans for each well, but a structur[illegible] surface casin[illegible]

Proximity (anti-co[illegible]

On multi-well projects (particularly offshore) there are small distances betw[illegible]irectly beneath the platform, the [illegible] existing and other proposed we[illegible] calculated at [illegible]s. These calculations can be performe[illegible]

Survey unce[illegible] the proposed well and the existing [illegible]panies have established criteria for the minim[illegible] wells, which are usually linked to "cone of e[illegible]" calculations.

Down[illegible]

The idea of using downhole motors to directly turn the bit is not a new one. One of the first [illegible]en. The first patent for a turbodrill exist[illegible] efforts in developing downhole motor[illegible] continued to use motors extensively in th[illegible]5, the West focused efforts more on rotary [illegible]ions for downhole motors has increased specta[illegible]

A turbine consis[illegible] rotor and stator section, a bearing section, [illegible] rotor and stator [illegible]tators are stationary, locked to the turbine body, an[illegible] locked to the dri[illegible] also forced to tu[illegible] bit to rotate

Positive Displaceme[illegible]

A positive displa[illegible]draulically driven downhole motor that uses [illegible] rotate the bit, independent of drill string rotation. [illegible]

- By-pa[illegible]
- Motor [illegible]
- Universal joint or connecting rod section.
- Bearin[illegible]

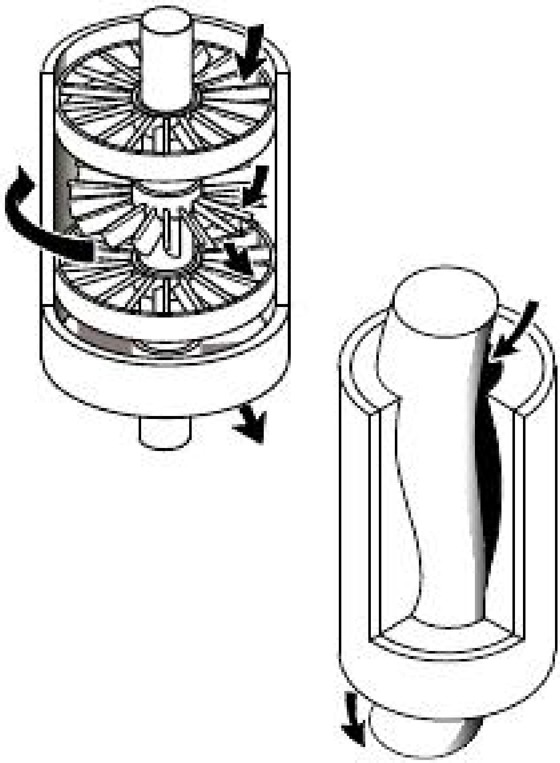


Figure 5-19: Differences between the turbine motor (left) and positive displacement motor (right) designs.

By-Pass Valve

The by-pass valve allows fluid to fill the drill string while tripping in the hole and to drain while tripping out. When mud is pumped, the valve closes causing fluid to move through the tool. Most valves are of a spring piston type which closes under pressure to seal off ports to the annulus. When there is no downward pressure, the spring forces the piston up so fluid can channel through the ports to the annulus. (Figure 5-20).

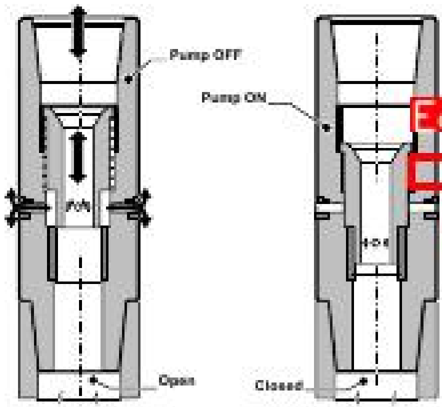


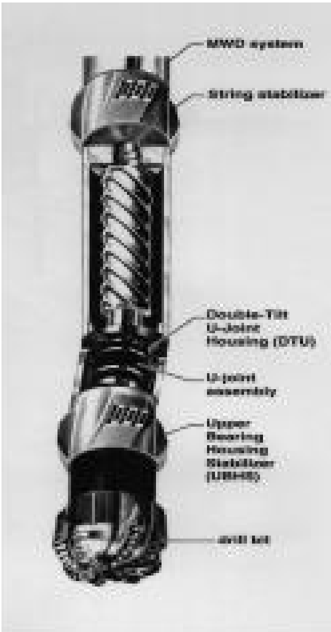
Figure 5-20: Bypass Valve.

Motor Section

This is a reverse application of Rene Moineau`s pump principle. The motor section consists of a rubber stator and steel rotor. [illegible] helical rotor which is continuous and round. This is the single lobe type. The stator is molded inside the outer steel housing and is an elastometer compound. The stator will always have one more lobe than the rotor. Hence motors will be described as 1/2, 3/4, 5/6 or 9/10 motors.

Both rotor and stator have certain pitch [illegible] length is equal to the ratio of the number [illegible] number [illegible]

As mud is pumped through the motor, it fills the cavities between the dissimilar shaped [illegible] rotor is forced to give way by turning or, in [illegible] hence the name). It is the rotation of the rotor shaft [illegible] transmitted to the bit.



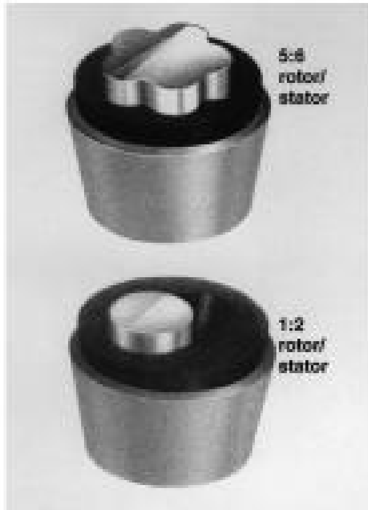


Figure 5-21: Parts of Downhole Motors

Connecting rod assemblies

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

Universal-joint

U-joint assemblies (Figure 5-22a) have been utilized by the industry and are still used in most positive displacement motors. The assembly consists of two universal joints, each grease filled, and sealed with oil-resistant reinforced rubber sleeves to [illegible]ination. A drawback of the U-joint assembly is the lack of sufficient strength for high[illegible] those encountered with recent gene[illegible] particularly when used with PDC bits.

This inherent weakness is a result of the manufacturing process whereby the U-joint is "flame-cut" rather than machined.

Flex rod

A recent development in connecting rod assembly technology has been the utilization of flexible steel or titanium "flex rods" (Figure 5-22b). While flex rods are limited by the degree of allowable lateral bending, they have the advantage of low maintenance, since they do not require lubricants or rubber sleeves. Flex rods are now standard on most smaller Navi-Drills. One recent approach has been to mount the flex rod inside the hollow rotor of a short, high torque steerable PDM, rather than connecting it to the bottom of the rotor. By connecting a long flex rod to the inside of the top end of the rotor and extending it through the rotor, to connect to the top of the drive sub assembly, the overall rate of bend is decreased due to its increased length.

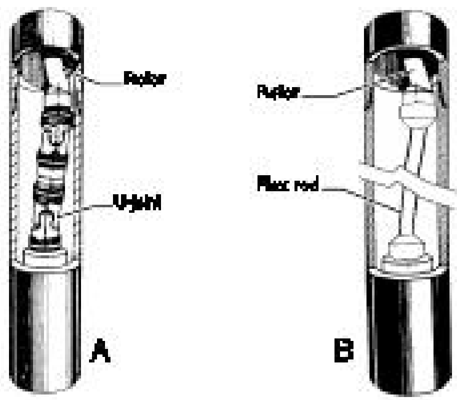


Figure 5-22: Type of Connecting Rod Assemblies

Bearing Section

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

The axial thrust bearing section supports the on and off bottom loading and hydraulic thrust. It consists of a series of ball bearings stacked one on top of the other, each set being contained in its own race (groove). The number of these bearings will vary, depending on the size of the tool.

The upper ar[illegible]h tungsten carbide inserts. These bearin[illegible]g drive shaft against lateral loads. [illegible] amount of fl[illegible] This diversi[illegible]10%, depending on motor and bit pressure dro[illegible] in the drive s[illegible] bearings are [illegible]0% of the flow to be diverted, depending u[illegible] illustrates typical bearing sections found in PD[illegible]

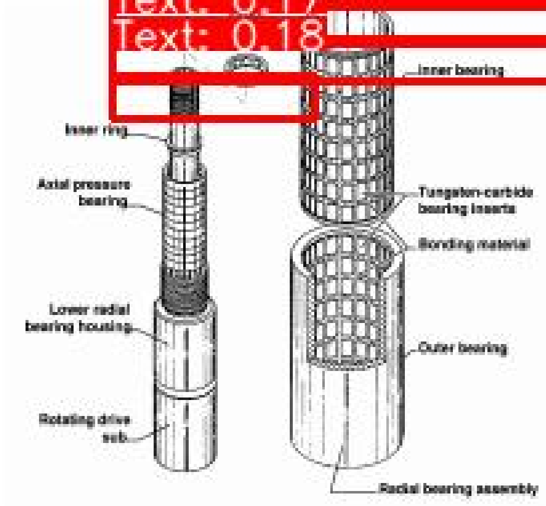


Figure 5-23: Various bearings in PDMs.

Types of Positive Displacement Motors

PDMs come in various configurations. As has been mentioned previously, the stator will have one more lobe than the rotor. The first types of PDMs, and the simplest, are 1/2 motors. These generally give medium to low torque output and medium to high rotary speed. Torque output is directly proportional to pressure drop across the motor. The 1/2 motors have good applications in performance drilling with a PDC, diamond, or TSP-type bits. Some shorter models are used for directional purposes.

Multi-lobe moto[illegible]ively slow speed. Therefore, they [illegible]one bits and for coring. Such motors are [illegible], especially the large cutter types whi[illegible]output to be efficient. These tools being fairly sho[illegible]nal applications with bent subs as the deflection de[illegible] with a hollow rotor and a nozzl[illegible] allows for high [illegible]y-passing the excess flow from the m[illegible] exit through the bit.

PDM Observations

- Motor stall[illegible]ease in surface pressure. Motor stall[illegible]ng should be avoided as it erodes the service life of the motor.
- LC[illegible] The system should not be [illegible]lugged.
- Sand conte[illegible] in th[illegible] kept to a minimum.
- Temperatur[illegible] limits [illegible], but higher temperature stators have been developed.
- Pressure dr[illegible]ng is typically around 50 psi to 800 p[illegible].
- Allowable [illegible]ear o[illegible], depending upon tool si[illegible].
- The tool shou[illegible]water prior to laying down.

In general, drilli[illegible]ge the rubber stator. As a rule, [illegible] 150°F (60°C). U[illegible]ally, this is related to the aromatic content which should be equal to or le[illegible] supplier if there is any doubt.

If a by-pass noz[illegible]e is fi[illegible]ed to a multi-lobe [illegible] carefully to allo[illegible]power. Any variation in flow[illegible]mpromise the motor's performance.

Characteristics

- Torque is di[illegible]motor's differential pressure. This makes[illegible]rate.
- RPM is di[illegible] by torque o[illegible]

- Hydraul [illegible]) √ 1714}, where P is the pressure drop ([illegible] rate (gpm).

Navi-Drill Mach 1C

The [illegible] placement motor that develops high torque at the bit at relatively low speed ranges (80-340 rpm). This makes it ideal for directional ap [illegible] weight-on-bit, navigation drilling with [illegible] r PDC bits, and coring operations.

The motor ha [illegible] /stator configuration, which generates hig [illegible] on-bit and in [illegible] low speeds, [illegible] can improve bit performance without accelerating wear on the bearings [illegible]

A unique bea [illegible] stator have in [illegible] ulic horsepower and extended operating life [illegible] to be run at [illegible] exceeding m [illegible] speed. The additional mud passes throug [illegible] interchanging [illegible] hydraulics.

Although pri [illegible] nance drilling motor, the Mach 1C can also be u [illegible]

Tables 5-1 a [illegible]

Confidential

Table 5-1: Mach 1C Specifications (US Standard)

Tool Size (OD) (in)	3¾	4¾	6¾	8	9½	11¼
Length (ft)	16.1	17.4	19.8	22.9	24.6	26.5
Weight (lbs)	440	710	1720	2430	4080	6070
Recommended Hole Size (in)	4¾ - 5 7/8	6 - 7 7/8	8 - 9 7/8	9⅞ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (gpm) minimum maximum	 65 185	 80 185	 185 475	 315 685	 395 740	 525 1135
Bit Speed Range (rpm)	120 - 340	100-300	100-260	85-190	100-190	80-170
Operating Diff.Pres. (psi)	800	725	725	580	800	655
Operating Torque (ft/lbs)	890	1180	2800	4500	6870	9770
Maximum Torque ** (ft/lbs)	1420	1890	4480	7200	10,970	15,570
Horsepower Range (hp)	20-58	22-67	53-139	73-163	131-240	149-316
Efficiency (max%)	67	68	70	70	72	73.5%
Thread Connection By-Pass Valve Box-Up Bit Sub Box Down	 2 7/8" Reg 2 7/8" Reg	 3 ½" Reg 3 ½" Reg	 4 ½" Reg 4 ½" Reg	 6 5/8" Reg* 6 5/8" Reg	 7 5/8" Reg 7 5/8" Reg	 7 5/8" Reg 6 5/8" Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life.**

Table 5-2: Mach 1C Specifications (Metric)

Tool Size (OD) (in)	3¾	4¾	6¾	8	9½	11¼
Length (m)	5.1	5.3	6.1	7.0	7.5	8.1
Weight (kgs)	200	320	781	1100	1850	2750
Recommended Hole Size (in)	4¾ - 5 7/8	6 - 7 7/8	8- 9 7/8	9⅞ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (lpm) minimum maximum	 250 700	 300 900	 700 1800	 1200 2600	 1500 2800	 2000 4500
Bit Speed Range (rpm)	120 - 340	100-300	100-260	85-190	100-190	80-170
Operating Diff.Pres. (bar)	55	50	50	40	55	45
Operating Torque (Nm)	1200	1600	3800	6100	9300	13,200
Maximum Torque ** (Nm)	1920	2560	6080	9760	14,880	21,120
Horsepower Range (kW)	15-43	17-50	40-103	54-121	97-185	109-235
Efficiency (max%)	67	68	70	70	72	73 5/8
Thread Connection By-Pass Valve Box-Up Bit Sub Box Down	 2 7/8" Reg 2 7/8" Reg	 3 ½" Reg 3 ½" Reg	 4 ½" Reg 4 ½" Reg	 6 5/8" Reg* 6 5/8" Reg	 7 5/8" Reg 7 5/8" Reg	 7 5/8" Reg 6 5/8" Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life**

Navi-Drill Mach 2

The Navi-Drill Mach 2 is a positive-displacement motor that can improve drill rates in both straight-hole and directional applications.

The Mach 2 has a multi-stage, 1/2 rotor/stator configuration, which generates low to medium torque at medium speeds for higher penetration rates with less weight-on-bit. This makes it a good choice for drilling straight and directional holes in difficult formations. The motor is particularly suited for long-interval performance drilling with natural diamond, TSP, or PDC bits.

Mach 2 motors also come in 1-3/4", 2-5/8" and 4-3/4" ODs for slimhole applications.

Tables 5-3 and 5-4 list the Mach 2 specifications.

Table 5-3: Mach 2 Specifications (US Standard)

Tool Size (OD) (in)	1¾	2 5/8	3¾	4¾	6¾	8	9½	11¼
Length (ft)	8.9	13.1	21.5	17.8	26.7	26.5	33.0	32.1
Weight (lbs)	49	190	840	710	2160	2810	5220	7300
Recommended Hole Size (in)	1 7/8 - 2¼	2 7/8 - 3½	4½ - 5 7/8	6 - 7 7/8	8 - 9 7/8	9½ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (gpm) minimum maximum	20 50	25 80	65 250	80 265	185 530	240 685	385 790	525 1135
Bit Speed Range (rpm)	800-2100	550-1600	250 - 500	195-650	190-550	155-410	200-400	156-310
Operating Diff.Pres. (psi)	580	870	725	725	725	580	870	580
Operating Torque (ft/lbs)	33	95	480	740	1600	2000	4750	5500
Maximum Torque ** (ft/lbs)	49	135	750	1100	2950	3030	7610	8850
Horsepower Range (hp)	8.7-12	10-30	23-75	27-92	67-190	71-206	131-262	163-307
Efficiency (max%)	71	38	83	80	86	89	90	90
Thread Connection By-Pass Valve Box-Up Bit Sub Box Down	AW Rod AW Rod	BW Rod BW Rod	2 7/8" Reg 2 7/8" Reg	3 ½" Reg 3 ½" Reg	4 ½" Reg 4 ½" Reg	6 5/8" Reg* 6 5/8" Reg	7 5/8" Reg 7 5/8" Reg	7 5/8" Reg 6 5/8" Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life.**

Table 5-4: Mach 2 Specifications (Metric)

Tool Size (OD) (in)	1¾	2 5/8	3¾	4¾	6¾	8	9½	11¼
Length (m)	2.7	4.8	6.3	6.5	8.2	8.1	10.0	9.8
Weight (kgs)	21	80	210	380	900	1250	2360	3310
Recommended Hole Size (in)	1 7/8 - 2¼	2 7/8 - 3½	4½ - 5 7/8	6 - 7 7/8	8 - 9 7/8	9⅞ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (lpm) minimum maximum	75 190	100 340	250 600	300 1000	700 2000	900 2600	1500 3800	2000 4000
Bit Speed Range (rpm)	810-2100	510-1650	250 - 900	195-1600	190-510	155-450	200-400	156-330
Operating Diff. Pres. (bar)	40	60	50	58	50	40	60	40
Operating Torque (Nm)	41	130	650	1080	2500	3250	6450	7500
Maximum Torque ** (Nm)	66	220	1040	1600	4000	3280	10,120	12,000
Horsepower Range (kW)	3.0-8	7.5-22.5	15-54	20.3-60	50-144	51-151	118-278	122-240
Efficiency (max %)	71	10	61	53	66	38	90	90
Thread Connection By-Pass Valve Box-Up	AW Rod AW Rod	BW Rod BW Rod	2 7/8" Reg	3 ½" Reg	4 ½" Reg	6 5/8" Reg*	7 5/8" Reg	7 5/8" Reg
Bit Sub Box Down			2 7/8" Reg	3 ½" Reg	4 ½" Reg	6 5/8" Reg	7 5/8" Reg	6 5/8" Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life**

Navi-Drill Mach 1 P/HF

The Navi-Drill Mach 1 P/HF (High Torque/High Flow) is a positive displacement motor that develops high torque at the bit at relatively low to medium speed range (80-310 RPM). This makes it ideal for directional applications, drilling with high weight-on-bit, or in areas where formations require high torque due to specialized PDC bits.

The Navi-Drill Mach 1 P/HF motor has a multi-lobe rotor/stator configuration which generates more torque than other motors.

A unique bearing assembly and improved elastomer compounds have increased the Mach 1 P/HF's hydraulic horsepower and extended its operating life. The rotor/stator design allows a larger than normal flow rate to be pumped through the motor, generating the higher torques. There is a rotor nozzling system that allows the motor to run over the higher maximum flow [illegible] commended motor speed. These hig[illegible] cleaning and bit hydraulics.

The Navi-Drill [illegible] which is rig floo[illegible] 2.75°, giving a BUR up to 12°/100 ft. Inclu[illegible]que U-joint assembly which allows the highe[illegible] the motor section through the bearing asse[illegible]

Although primar[illegible] drilling motor, the Navi-Drill Mach 1 P/[illegible]

Table 5-[illegible]: Specifications for Mach 1 P/HF

Tool Size (OD) (in)	[illegible]	[illegible]	[illegible]	8	9½
Flow rate (lpm) minimum maximum	[illegible]8	606	1308	2008	2501
Bit Speed Range (rpm)	155-310	[illegible]	[illegible]	[illegible]	[illegible]
Diff. Pres. (bar)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Max. Torque (N[illegible]	[illegible]	[illegible]	[illegible]	11,700	16,690
Power Output ([illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Efficiency (max[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rotor/Stator	[illegible]	[illegible]	[illegible]	9/10	9/10

Navi-Drill [illegible]

The N[illegible] Mach 1/AD motor is [illegible] specif[illegible] use in [illegible] drilled [illegible] and mist. With an AKO, the steerable motor drilling system combines directional and straight hole drilling capabilities to provide precise directional control. Generally, in one run it can establish the desired direction and inclination for the surface interval of a directional well.

The AKO places the bend close to the bit, and can be adjusted so the motor housing tilt angle can be configured on the rig floor to settings from 0° - 2.5°. The resulting dogleg capability can be as high as 12°/100 ft. The unique AKO design requires no shims to adjust the bent housing angle, so a single motor can achieve a variety of build rates.

This mo[illegible]rm directional work when oriented in a particul[illegible] of drilling straight ahead when the drillstri[illegible] is rota[illegible]ed by tilting the bit relative to the motor [illegible] while maintaining a minimum amount of bit of[illegible] the motor.

When an ali[illegible] the top of the motor and used in conju[illegible]nfiguration can be used for building ang[illegible] orientation of the motor and drillstrin[illegible] not rotation. The maximum b[illegible]ation is approximately 20°/ 100 ft.

Motor Orientatio[illegible]

All direction[illegible] wells require steering during initial kick offs, correction runs, [illegible]. Once the desired direction in which the tool shou[illegible]d, the next step is to actually face the tool in that direction in order to drill the predetermined course.

For the Mach[illegible] data transmission (CDT) system has been develop[illegible] direction, wh[illegible] with drillstring rotation. This CDT system uses [illegible]ring tool which provides continuous surface read[illegible] orientation while drilling ahead.

A "hard wire[illegible] through the drillstring to the surface, relays the inf[illegible] equipment. Data transmitted f[illegible]dated and converted instantly to information [illegible] any necessary corrections to the motor.

Tab[illegible]

Tool Size OD (in)	4¾	6¾	8
Flow rate (lpm) minimum maximum	[illegible]	5000 [illegible]	4250 [illegible]
Bit Speed Range (rpm)	[illegible]	[illegible]	[illegible]
Diff. Pres. (bar)	[illegible]	[illegible]	28
Max. Torque (Nm)	[illegible]	[illegible]	[illegible]
Power Output (kW)	[illegible]	[illegible]	[illegible]

Turb[illegible]

[illegible]n of several sections:

- Drive [illegible] section.
- Axial [illegible]ust b[illegible]ings.
- Bit drive sub[illegible]

As stated earlier, the dr[illegible] stag[illegible] of a series of stators and rotors of a b[illegible] form a stage. Turbines [illegible] The number of stage[illegible] Each stage, theoretically, ap[illegible] to [illegible]e control shaft and it is the sum of those[illegible]

The drive sub is[illegible] bearings protect[illegible]ding and the thrust bearings support the dow[illegible] pumped through the tool and the [illegible] Theoretically, w[illegible] to equalize the hydraulic thrust, which un[illegible] the bearings and prolongs their life.

Drive Section

This will consis[illegible]rs, fixed to the outer tool housing and bladed roto[illegible] at a pre-determi[illegible]ades to hit the rotor blades and cause the shaft [illegible] blades will affect the torque and speed output of [illegible]

Bearing Section

Usually[illegible]e up of rubber discs (Figure 5-24) which are non-[illegible] steel dis[illegible] shaft. Long bearing sections known [illegible] cartrid[illegible] in tangent or straight hole drilling sections. These [illegible] If the bearings wear past the maximum point[illegible]n be inflicted as the steel rotors will crash into th[illegible]

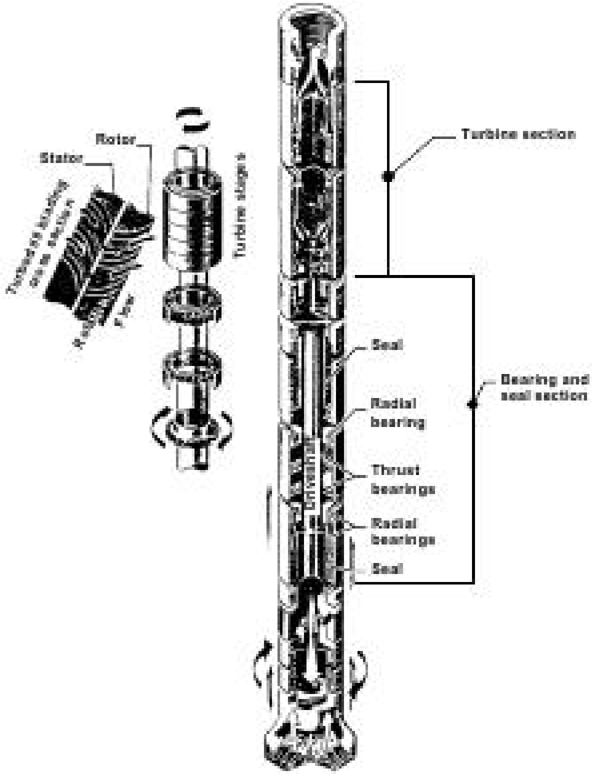


Figure 5-24: Cross-section of a turbine motor

Directional Turbine

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

Turbine Ob[illegible]

- There is minimal surface indication of a turbine stalling.
- Tu[illegible] of LCM.
- Sand conte[illegible] kept to a minimum.
- Due to min[illegible]
high tempe[illegible]
- Pressure d[illegible] and can be anything from 500 p[illegible]
- Turbines d[illegible] not re[illegible] a by-pass valve.
- Usually, the[illegible] ear is of t[illegible] order of 4mm.

Turbine Character[illegible]ics

- Torque and[illegible] (i.e. as RPM incre[illegible]ses, torque decreases a[illegible]
- RPM is dir[illegible] constant torque).
- Torque is a[illegible] functi[illegible] of flow rate, mud density, blade angle and the nu[illegible] s if weight-on-bit varies.
- Op[illegible] bearings are balanced.
- Ch[illegible] to shift.
- Off bottom[illegible] he tu[illegible]ine RPM will reach "run away speed" and torque is zero.
- On bottom, and ju[illegible]
RPM is zer[illegible]
- Optimum p[illegible]rform[illegible]
runaway sp[illegible]ed, th[illegible] turbine then achieves maximum horsepower.
- A stabilized[illegible] ally cause the hole to "wa[illegible]

Def[illegible]chniques

Whipstocks

[illegible] standard [illegible] used nowadays, but it has not disappeared completely. Whipstocks [illegible] re-entry work. There are 3 [illegible]rectional drilling:

Standard remov[illegible]

The Standar[illegible] can also be u[illegible]ed for sidetracking. It consists of a long inverted steel wedge which [illegible] to hold and guide the drilling assembly. It is also [illegible] turni[illegible] from the hole. It will usually b[illegible]sisting of a bit, a spiral stabili[illegible]stock by means of a s[illegible]

The whipsto[illegible] bottom of the hole and orientated. W[illegible] is then drille[illegible] hole" is drill[illegible]ock and the assembly is then pulled out of [illegible] open the rat [illegible] tripped out a[illegible]embly run in hole to "follow up"the initial deflec[illegible] may have to be repeated several times in the [illegible]

It is obvious [illegible]he standard whipstock is the number of "t[illegible] important disadvantage is that the whipstock pr[illegible] dogleg - whi[illegible] problems with the hole. The advantages a[illegible]ece of equipment which requires relatively lit[illegible]

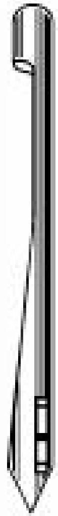


Figure 5-25: Standard removable Whipstock.

Circulating Whipstock

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

Permanent Casing Whipstock

The "Permanent Casing Whipstock" (Figure 5-2[illegible]) is designed to remain permanently in the well. It [illegible] "window" is to be cut in casing for a sid[illegible]e set using a Baker Model "D" Packer. A special stinger at the base of the whipstock slips into the packer assembl[illegible], and a [illegible] the packer locks the whipstock's anchor-[illegible]nt during drilling.

The normal proc[illegible] then set the packer. After this, the st[illegible] whipstock and the whole assembly run slo[illegible]

Although the [illegible], it is good practice to orientate the [illegible] packer. This will ensure that a faster [illegible] endangering the shear pin.

After the whi[illegible] circulation a[illegible] cut through t[illegible]ximately 2 feet of the window. The lug that held [illegible]

This assemb[illegible] diamond spe[illegible]est of the window. Once the window has been cut, [illegible] hole. Next, a [illegible] This is done [illegible] bottom of the window. Finally, another trip i[illegible] to drill ahea[illegible]

The advanta[illegible]d of the normal method of milling a sec[illegible] time. The ma[illegible] casing whips[illegible]ended if there is a considerable distance to d[illegible] when trying [illegible] window. On [illegible]he other hand, if there is only a short distance to be drilled below the si[illegible] whipstock is well worth considering.

In recent yea[illegible]f the system have eliminated the need for [illegible]

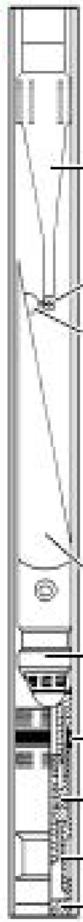


Figure 5-26: Permanent casing Whipstock.

Je[illegible]

Jetting (or badgering) is a technique used to deviate wellbores in soft formations. [illegible]ped in the mid 1950s and superseded the use of w[illegible]tion technique.

Although jet[illegible]n supplanted by downhole motor deflection as[illegible] it is still used frequently and offers several advantages w[illegible]

A special jet[illegible] standard soft[illegible]ith one very large nozzle and two smaller ones.

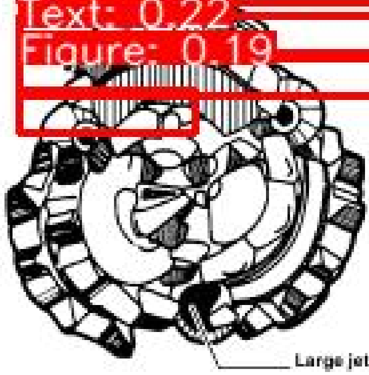


Figure 5-27: Bit set-up for jetting

Requirements for jetting

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

Jetting Ass[illegible]

A typical [illegible] $12^1/_4$"pilot hole is:

1) $12^1/_4$" [illegible]et bit,
2) extension sub,
3) $12^1/_4$"stabilizer,
4) UBHO sub,
5) 3 x 8" Drill Collars,
6) 12-1/4" stabil[illegible]
7) a Drill Collar[illegible]
8) HWDP as re[illegible]

This is essential[illegible]ssembly with a suitable bit for jetting. The [illegible]ften omitted.

Nozzling the Jettin[illegible]

There are three [illegible]

1. Use a [illegible]nded nozzle in place of one of [illegible]
2. Fit on[illegible]
3. [illegible] through the other two.

Flow th[illegible]ole sizes (e.g. 17-1/2") because of the l[illegible]near bit stabilizer. Both (A) an[illegible]ich are commonly jet drilled. [illegible] is th[illegible] standard bits and noz[illegible] and [illegible]sults in a bit dressed in such a way as to be suitable for both jettin[illegible]

A 12-1/4" bit dressed [illegible] of 26/32" or 28/32" a[illegible]

Procedure for Jetting

The assembly w[illegible]rvey is taken and the l[illegible]ge jet nozzle (the "too[illegible]

Maximum circu[illegible] in 12-1/4" hole) and a controlled wash[illegible]

The drill string [illegible]dically, but not rotated, until several fee[illegible] the bit and near bit stabilizer have been force[illegible] string 5 to 10 fe[illegible]t off bottom and then let it fall, catching it with the brake so that the stretc[illegible] on bottom rather than the full weight of th[illegible]

[illegible] table a few degrees (15°) right and left [illegible]

Having jette[illegible] 5 to 8 feet of hole (the exact distance depending on required build rate an[illegible] The circulation rate is now reduced [illegible] considerations are ignored while drilling the [illegible] on bit (40 - 45 Klb) and low rotary speed [illegible] to bend the assembly and force it to follow th[illegible] while jetting. Progress may be difficult at fi[illegible] the stabilizer and the irregularly sh[illegible]

After approx[illegible] drilled, the pump rate can be increased to [illegible] rate originally used while jetting. High WOB a[illegible] The hole is drilled down to the next su[illegible]

A survey is t[illegible] section shou[illegible] survey taken.

At the start o[illegible] every single until about 3° of angle has be[illegible] drilling each [illegible] be re-orientated to the desired tool face setting before jetting again. The operation is repeated until sufficient an[illegible] in the desired direction.

The principle [illegible] during the initial spudding and washing process, a pocket is pro[illegible] WOB is then [illegible] being rotated, the bit and near bit stabilizer wo[illegible] The collars above [illegible] the low side of the hole. This causes [illegible] stabilizer which acts as a pivot or fulc[illegible] direction in w[illegible] was originally orientated).

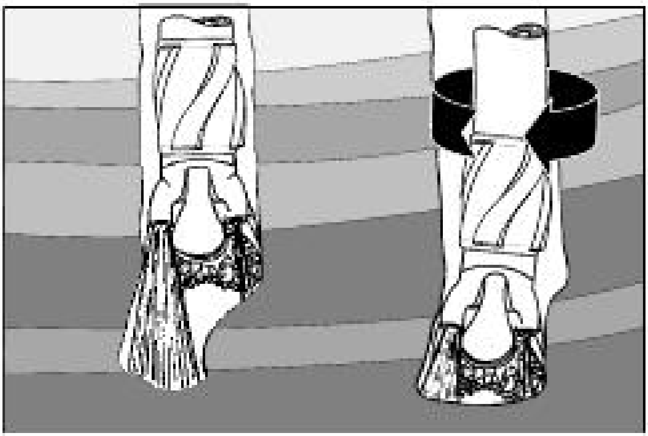


Figure 5-28: Jetting and drilling actions

Advantages of Jetting

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

Disadvantages of Jetting

The technique only works in soft formation and therefore at shallow depths. For this reason, jetting is mainly used to kick wells off at shallow depths.

In jetting, high dogleg severities are often produced. Deviation is produced in a series of sudden changes, rather than a smooth continuous change. For this reason, it is normal practice to jet an undergauge hole and then open it out to full gauge, which smooths off the worst of the doglegs.

D[illegible]

A [illegible] hole motor and a bent sub. A [illegible] sub is placed directly [illegible] assembly. Its lower thr[illegible] from the axis of the sub body.

The bent sub [illegible] well as down[illegible] force at the bit gives the motor a tend[illegible]ncy to drill a curved path, provided there is no rotation of the drill string. T[illegible] sub angle an[illegible] and drill collars in relation to the diameter [illegible]

A downhole [illegible] wells, and fo[illegible]

Notice the a[illegible] Usually ther[illegible] least 90 feet above the bent sub. In fact, it is [illegible] and bent sub [illegible]

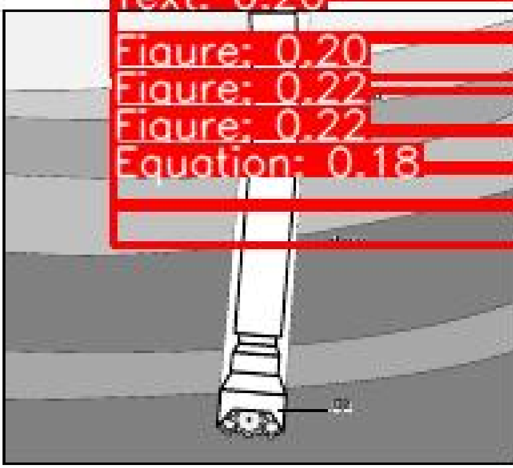


Figure 5-29: Downhole motor and bent sub assembly.

Reactive to[illegible]

Reactive torque is created by the drilling fluid pushing against the stator. Since the stator [illegible] the effect of this force is to twi[illegible] As weight-on-bit is increased, the d[illegible] the motor increases, and reactive torque increases[illegible] simplistic, way [illegible]lling torque generated at the bit is the "[illegible]orque on the motor housing is the "r[illegible] drilling torque.

Reactive torque [illegible] using a motor a[illegible] well-bore. The twisting of the BHA caused by [illegible] bent sub. If they [illegible] surveys, the directional driller has to estimate how much turn to the left they will get du[illegible] set the tool face that number of degrees roun[illegible]ool face, so that the reactive torque will bring[illegible] while drilling.

Drill string desig[illegible] concept is impo[illegible] face orientation [illegible]twisting becomes more critical at greate[illegible] using smaller OD drillpipe.

When drilling is [illegible]de to keep the drilling parameters cons[illegible] face setting. Re[illegible] Obviously, high torque motors produce higher reactive torque.

Factors Affec[illegible]

The reactive tor[illegible]te will be in direct proportion to the differential p[illegible]

- Motor[illegible]
- Bit ch[illegible]
- Forma[illegible]
- Weigh[illegible]

Estimation of re[illegible] drillers. Several charts and rules of thumb have evolved. One is:

EXPECTED RE[illegible] 10° - 20° / 1000 ft M.D.

Note: *Use[illegible] hig[illegible]otors (Mach 1).*

Running [illegible]

1. The motor is inspected and tested using standard procedures.
2. Before [illegible] motor and bent sub assembly, the bent [illegible] in the desired direction [illegible]
3. The pipe is work[illegible] Best results are obtained by u[illegible] movement. It is recommended that the bit be kept a minimum of 5 feet fr[illegible]
4. Make a reference [illegible] table and take a s[illegible] orientation.
5. Turn the pipe to a [illegible] orientation. This orientation should [illegible] reactive [illegible] lower torque [illegible] for higher torque motors (Mach 1) [illegible] function of WOB and differential pressure across the motor.
6. When or[illegible] less the turn is less than 90° left of th[illegible] so that the turn re[illegible]ly.
7. Lock the rotary t[illegible]

PDMs vs Turbines with a Be[illegible]

For directional work with a [illegible] turbines. When drilling with a PDM, the directional driller can use pump pressure as a weig[illegible] constant, the differential pressure across [illegible] constant. It is also much ea[illegible]lled because there will be an immedi[illegible] life than turbines because of the slower rotary speed. They can tolerate LCM whereas turb[illegible] a bent sub, a PDM with a small bend at the U-j[illegible] to the bit, a smaller angle of bend will have the same effect as a larger bent sub a[illegible] of the bit riding the side of the hole while tripping in and out.

The only real [illegible] at they can operate at higher temperatures [illegible] Years ago, s[illegible]uld handle higher flow rates than PDMs, but th[illegible] it is quite rare to use a turbine with [illegible]

Downhole [illegible] on

A downhole motor and bent sub combination will drill a smooth continuous curv[illegible] predictable than with other de[illegible] since there is no[illegible] is possible to use a wireline "steering tool" f[illegible] MWD system c[illegible]

One drawback o[illegible] face when drilli[illegible] y also make it difficult to keep a steady tool face.[illegible]

PDM with Kick-Off [illegible]

An alternative to[illegible] a PDM with a single bend in the universal joint h[illegible] in the case of a Navi-Drill and a bent housing by some other PDM manufacturers. Historically, these "single tilt[illegible] sidetrac[illegible] of hole into hard formation. Since the bend is closer to the bit than when a bent sub is used, a smaller tilt angle can be used but [illegible] on tendency.

Nowadays, sing[illegible] steerable motors. If the drill string is rot[illegible] he motor rotates, then a fairly straight path is [illegible] is orientated in a desired directio[illegible] drill a controlle[illegible]

Too[illegible]

The "Toolface" of a deflection tool, or a ste[illegible]able motor system, is the part (usually mark[illegible]nted in a particular direction to [illegible] wellbore. There are two ways of expr[illegible]

Magnetic or [illegible] direction on [illegible] a "magnetic" type survey tool, it is call[illegible]d magnetic toolface; whereas if it is measured by a gyroscopic s[illegible] measured an[illegible] low inclinations, generally less than 5Y.

High Side T[illegible] of the boreho[illegible]

It must be po[illegible] version of "t[illegible]netic or gyro toolface reading can be converted [illegible] reading using:

High side too[illegible] = mag/gyro toolface [illegible]

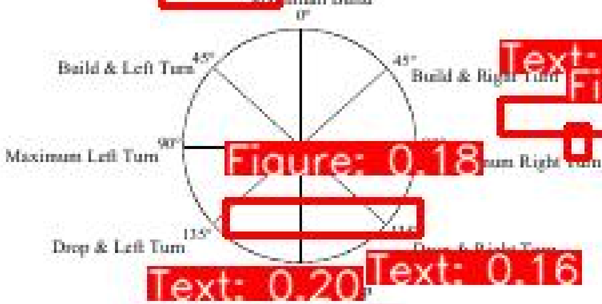
A negative a[illegible] me[illegible] high side. The above formula is based on [illegible]he fact that the high side direction is t[illegible]e.

The followin[illegible] deflection to[illegible]hart is applicable to steerable systems in m[illegible] sub assembli[illegible] soft formatio[illegible]s.I[illegible]nges in inclination and azimuth whi[illegible]

It should be noted [illegible]ed on the high side of the hole.

Hole Direction

(High Side)



Rule of thumb for orientation of ToolFace (at low inclinations, less than 30°).

Dir[illegible] Rotary Assemblies

An important aspect of directional drilling is the BHA design which is to drill the plan[illegible]ll concentrate on the basic principles us[illegible]g with rotary assemblies, and the typic[illegible] The effects of drilling parameters ([illegible]anisotropy) will be considered.

Historically, [illegible] the angle (inclination) of directional [illegible]ect design of the assembly and use of su[illegible] drilling parameters. However, the control of hole direction has [illegible] right, and dir[illegible]erly limited to using well-stabilized assemblies t[illegible] practice to g[illegible]left of the proposal to compensate for this right [illegible]

Side Force and Ti[illegible]

Directional t[illegible] direction of the resultant force at the bit. It has[illegible] tilt (the angle between the bit axis and the hole [illegible] bit is designe[illegible] In rotary assemblies where there is a near bit stabilizer, the bit tilt angle is small causing the magnitude of side force at [illegible] be a key factor.

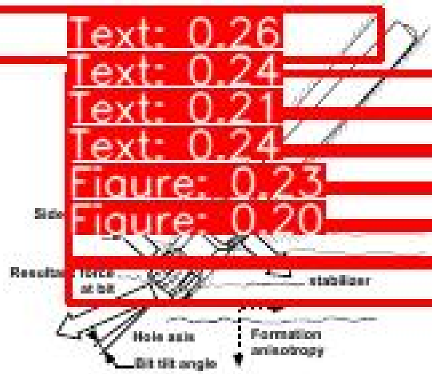


Figure 5-30: Forces acting at the bit which influence the direction of the borehole.

Factors Affecting Directional Behavior

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

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

Many of these factors are interrelated.

Basic Directional Control Principles

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

The Fulcrum Principle

An assembly with a full-gauge near-bit stabilizer, followed by 40 to 120 feet of drill collars before the first string stabilizer, or no string stabilizer at all, will build angle when sufficient WOB is applied.

As illustrated in Figure 5-31, the collars above the near-bit stabilizer bend, partly due to their weight and partly due to the applied WOB. The near-bit stabilizer acts as a fulcrum or pivot point and the bit is pushed to the high side of the hole. The bit therefore drills a path which is gradually curving upwards (the assembly builds angle).

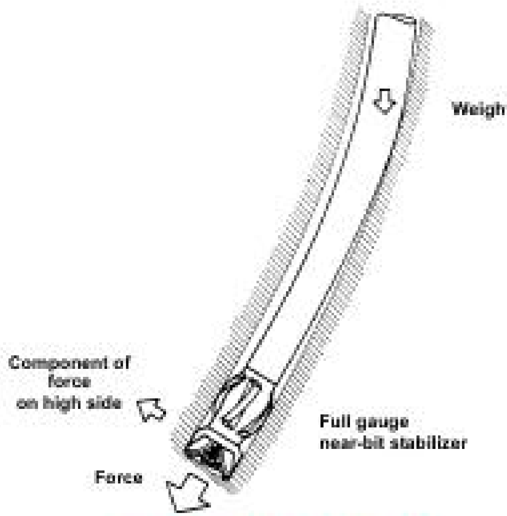


Figure 5-31: BH[illegible]

The rate of build will be **INCREASED** by the following:

- Increasing the distance from the near-bit stabilizer to the first string stabilizer
- Increase in hole inclination
- Reduction of drill collar diameter
- Increase in weight on bit
- Reduction in [illegible]
- Reduction in flow rate (in soft formations)

The distance from the near-bit stabilizer to the first string stabilizer is the main design feature in a fulcrum assembly which will affect the build [illegible] The build rate increases as this distance is increased, because a longer fulcrum section will [illegible] fulcrum effect and the side force on high side. [illegible] upper stabilizer is more than 120 [illegible] depending on hole size, collar [illegible] the low side of the hole and any fur[illegible]ve no additional effect on build rate.

The rate of buil[illegible] increases because there is a larger compone[illegible] weight causing them to bend. The mechanics invol[illegible] of build should increase in direct proportion to the [illegible]lity, the situation and the actual response [illegible] strong build assembly which built at a [illegible] was only 15° might build at 4°/100' [illegible]

Drill Collar Di[illegible] collar is proportional to the fourth power of [illegible]uction in the OD of the drill collars used in t[illegible] increases their limberness and hence the ra[illegible] drill collar diameter according to build rate requirements. Usually, standard collar sizes for the given hole size are used.

Weight-on-Bit: [illegible] will bend the drill collars behind the near-[illegible] of build will increase.

Rotary Speed: [illegible]d to 'straighten' the drill collars and henc[illegible] this reason, low rotary speeds (70 - 100[illegible]

Flow Rate: In s[illegible] the bit is washing out the formation ahead of the bit which reduces the build tendency.

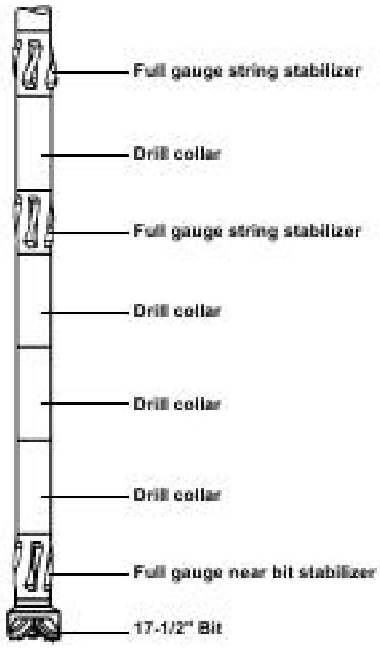


Figure 5-32: 90 ft Build Assembly
17½" bit / 17½" NB stab 3 x 9½ x 30' DCs / 17½" stab / 9½" x 30' DCs as needed / etc. This assembly will build angle rapidly, typically at 2.0° - 3.5°/100', depending on the inclination and the drilling parameters.

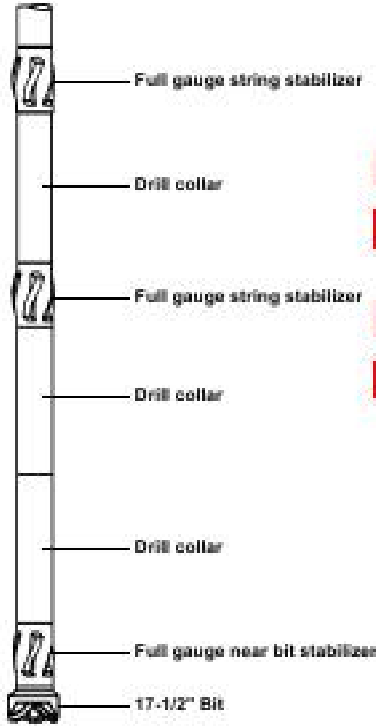


Figure 5-33: 60 ft Build Assembly
17½" bit / 17½" NB stab 2 x 9½ x 30' DCs / 17½" stab / 9½" x 30' DCs as needed / etc. This assembly will build angle at the rate of 1.5° - 2.5°/100', depending on the inclination and the drilling parameters

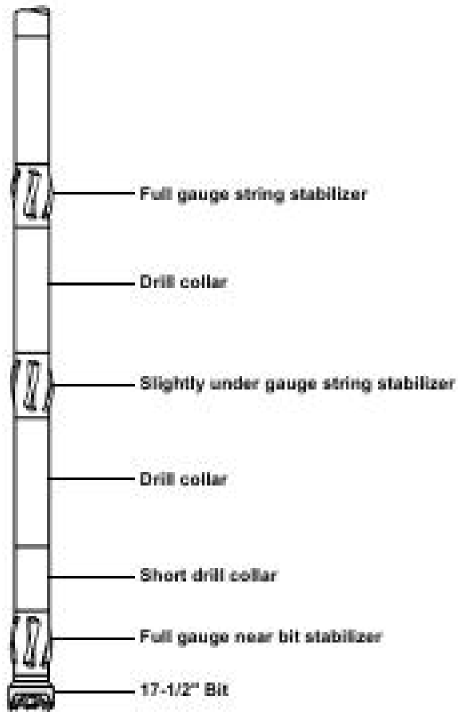


Figure 5-34: Gradual Angle Build Assembly
17½" bit / 17½" NB stab /9½ x 12' DC / 9½ x 30' DC / 17½" stab / 9½" x 30' DCs as needed / etc. This assembly will build typically at 0.5° - 1.5°/100', depending on the inclination and the drilling parameters

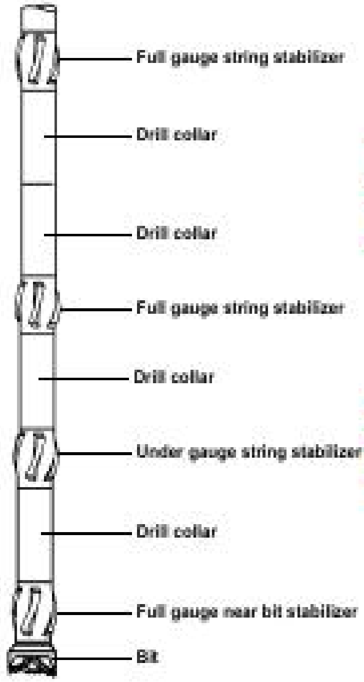


Figure 5-35: Gradual Angle Build Assembly
12¼" bit / 12¼" NB stab / 8" x 30' DC / 12¼" stab / 8" x 30' DCs as needed / etc. This assembly would be used in the tangent section when it was necessary to build angle gradually. It would build typically at 0.5° - 1.0°/100'

The Stabilization (Packed Hole) Principle

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

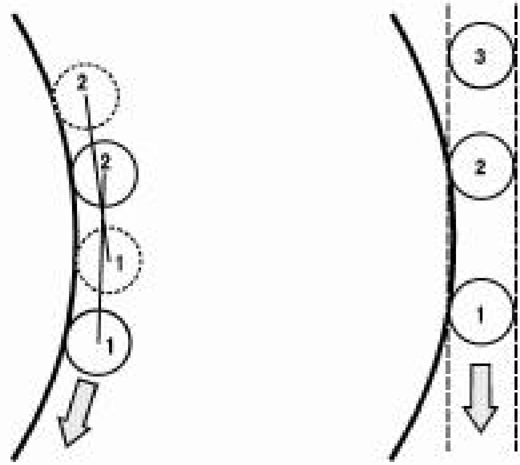


Figure 5-36: Packed Hole (Stabilization) principle

Assemblies which utilize this principle are called packed hole assemblies and are used to drill the tangent sections of directional wells, maintaining angle and direction. High rotary speed (120-160+) will assist the tendency to drill straight.

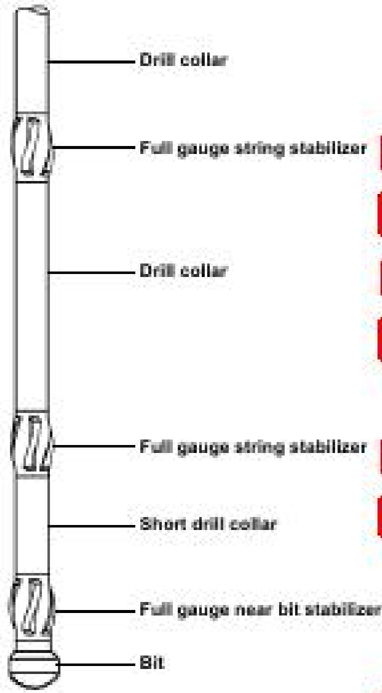


Figure 5-37: Rate equals 0.1° - 0.5°/100' depending on various factors such as formation characteristics, WOB, RPM, bit type, etc.

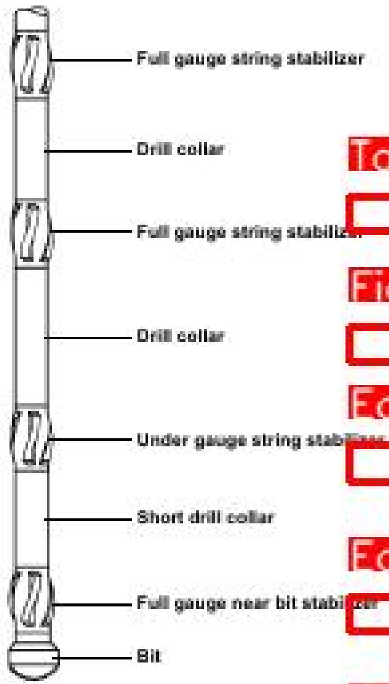


Figure 5-38: This assembly should hold angle depending on the exact gauge of the first string stabilizer.

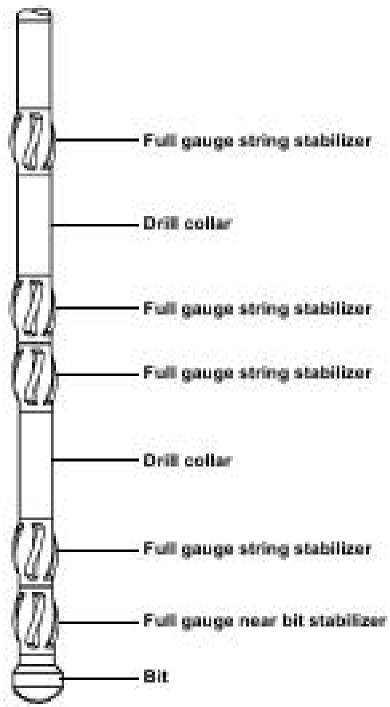


Figure 5-39: The tandem stabilizers make this assembly very rigid. In the past it was more common to use tandem stabilizers to control the bit walk of roller cone bits. Presently, its use is limited to areas where extreme bit walk is common. Rotation of an assembly such as this will generate high rotary torque. Generally, as the number of stabilizers in the BHA increases, so does the possibility of hole sticking.

The Pend[illegible]

This [illegible] be formulated and was originally ana[illegible] straight holes. We shall conc[illegible] [illegible]iated wells.

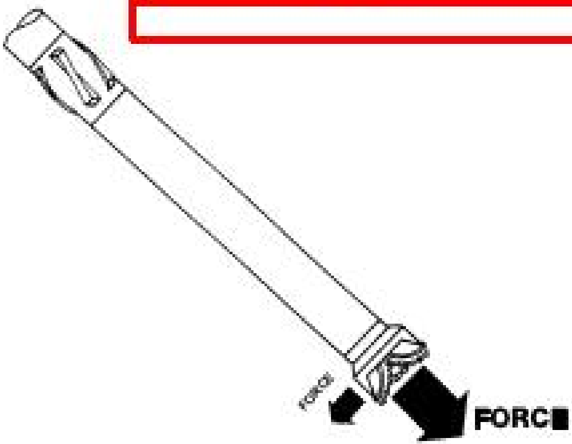


Figure 5-40: The pendulum principle.

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

If the collars make contact wi[illegible] Figure 5-41, then the effective length of the pen[illegible]w side are both reduced. This situation is also [illegible] tilted upwards in relation to t[illegible]e hole axis which will reduce the dropping tendency.

Careful selec[illegible] required to prevent this. High rotary speed [illegible] above situation [illegible] be used, again to avoid bending the pend[illegible] hole. Once the dropping trend has been e[illegible] used to achieve a respectable pend[illegible]

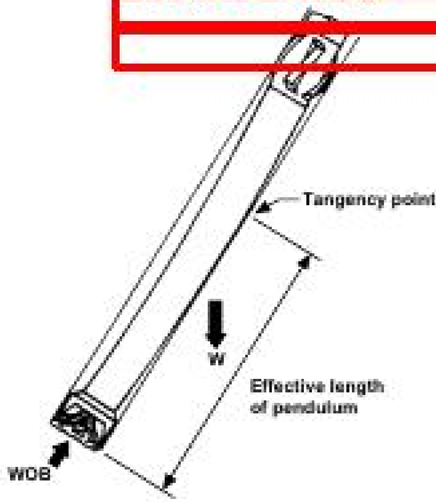


Figure 5-41: Reduction of pendulum force due to wall co[illegible]

Some elementary texts on directional drilling depict the pendu[illegible] shown in Figure 5-42. The implication being that part of the dropping tendency is produced by a downward tilt of the bit axis. It is interesting to note that if this picture [illegible] endency would be increased by increasing [illegible] speed, the precise opposite of what is recommended.

Figure 5-42 is possible [illegible] lengths of pendulum when there is no near-bit stabilizer and only one string stabilizer. The collars above the upper stabilizer will sag towards the low side of the hole causing a fulcrum effect about th[illegible] ing the upper portion of the pendulum towards the high side of the hole.Experienced has shown instances of pendulum assemblies dropping faster with high WOB and low rotary speed.

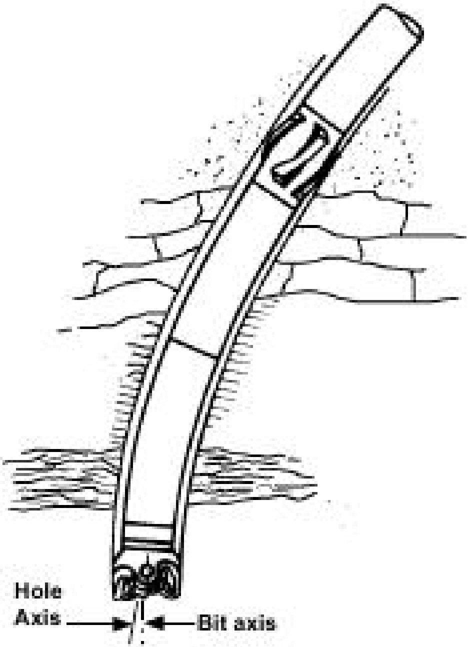


Figure 5-42: One possible interpretation of the pendulum effect.

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

Summary and Recommended Practices.

- The safest approach to designing and using a pendulum assembly is to concentrate on producing a side force at the bit on the low side of the hole. This is achieved by running an assembly where the pendulum portio[illegible] as possible. It is also desirable that the section immediately above the first string stabilizer be stiff and straight and that a second string stabilizer be within 30 feet of the first.
- Omit the [illegible] azimuth control is not a concern or when dr[illegible] drilling with a roller cone bit, use

an under-gauge ne[illegible] a consideration. Typ[illegible]nly be 1/4" to 1/2" undergauge in [illegible]y.

- The assembly sho[illegible] stabilizer n[illegible]
- Initially use low [illegible] gradually i[illegible] penetration rate is achieved.
- Use high rotary sp[illegible]
- If possible, [illegible] not [illegible]mation.

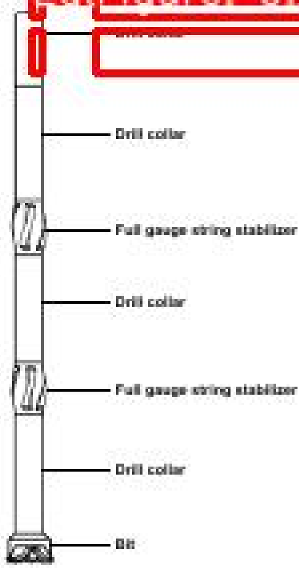


Figure 5-43: 30 foot Pendulum Assembly.
The rate of drop depends on the wellbore inclination and the diameter and weight of the bottom drill collar, as well as the drilling parameters. At 45° inclination, this assembly would typically drop at 1.5° - 2.0°/100'.

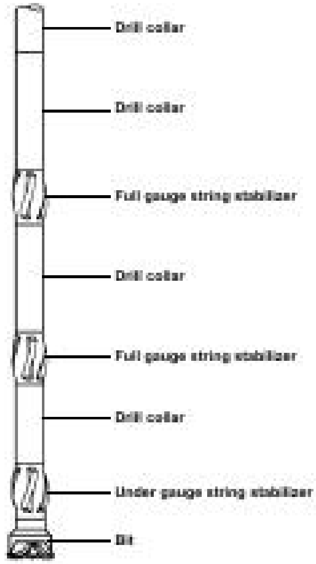


Figure 5-44: 30 foot Pendulum Assembly with under-gauge near bit stabilizer. This will give a slightly lower rate of drop than the previous BHA, but should reduce bit walk and thereby give better azimuth control.

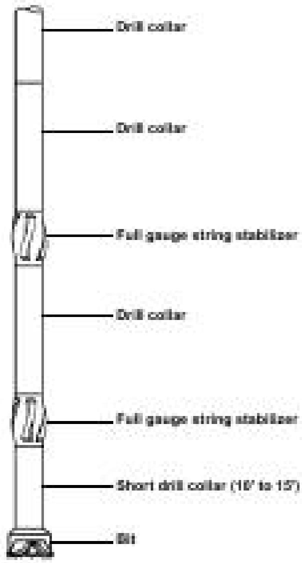


Figure 5-45: Gradual Angle Drop Assembly.
This short pendulum hook-up would give a more gradual drop rate approximately 1°/100' depending on inclination, etc.

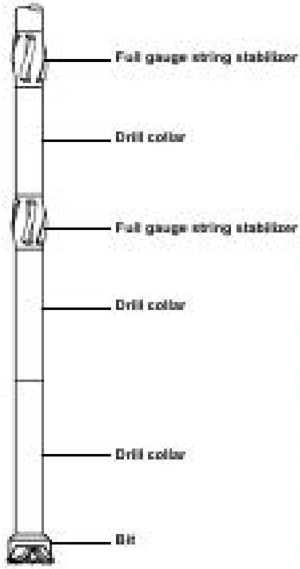


Figure 5-46: 60 foot Pendulum Assembly
used to drill vertical wells. This is too strong a dropping assembly to use on directional wells, except perhaps low angle wells. It is commonly used to drill vertical wells through soft to hard formations.

Bit Type Effects on Rotary Assemblies

Roller Cone Bits

When rotary drilling with roller cone bits, the type of bit makes very little difference to whether an assembly builds, holds or drops angle. Mainly because directional control is determined by the configuration of stabilizers and collars and by varying [illegible]

However [illegible] fluence on walk rates. Conventi[illegible] alk in normal rotary drilling. Generall[illegible] give a g[illegible] formation. This [illegible] larger cone offset and cut the rock by [illegible]

PDC Bits

During [illegible] mmon practice to use PDC bits for rotary drilling, with low WOB and high rotary speeds. When rotary drilling with PDC bits, it has [illegible] urs (the assemblies hold the [illegible] at inclination angle is affected by PDC [illegible] angle drop assembly is used.

The gauge lengt[illegible] rotary assembly [illegible] greater than that [illegible] a tri-cone bit. On the other hand, a longer gauge sta[illegible] low WOB typic[illegible] collar flexure de[illegible] WOB. When used with packed assemblies, long[illegible] and direction du[illegible] e bit.

When used with [illegible] C bits can reduce the drop rate previously obtai[illegible] enerally, the longer the gauge length, the lowe[illegible] similar to a full [illegible] ort gauge length PDCs can be used effectively [illegible] h a suitable PDC bit is used in a rotary pendu[illegible] most PDC bit ap[illegible] opping angle.

Stiffness of drill coll[illegible]

The behavior of [illegible] pendulum assem[illegible] y by the stiffness of the drill collars used in t[illegible]

It is generally ac[illegible] are considered as thick walled cylinders. Their [illegible] modulus of elast[illegible]

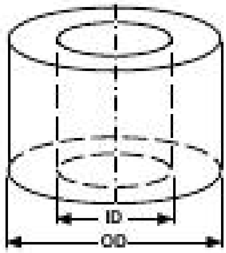


Figure 5-47: Collar strength determination

A collar's axial moment of inertia I, is determined by:

$$I = (\pi \sqrt{} 64) \times (OD^4 - ID^4)$$

The weight per unit length, W, is calculated from:

$$W = (\pi \sqrt{} 4) \times (OD^2 - \text{[illegible]}$$

where is th[illegible]

Notice that th[illegible] diameter, wh[illegible]le the collar weight is proportional to the [illegible] outside diam[illegible] on collar stiff[illegible]ect on collar weight.

Table 5-7: Relative [illegible]

Collar OD (in)	Mome[illegible]	[illegible]
4.75	[illegible]	[illegible]
6.5	[illegible]	100
8.0	[illegible]	160
9.5	[illegible]	[illegible]

For example, the moment of inertia of a 9-1/2" collar is double that of an 8" col[illegible] that of a 6-1/2" collar.

The component of weight/unit length tending to bend the drill collars and contributing to the [illegible]

$$W_x = W (BF \text{[illegible]}$$

where W = weight/foot of the drill collar in air

BF = buoy[illegible]

= inclination of the wellbore

For example, if [illegible] density was 10 ppg then the value of W_x for 8-inch drill collars w[illegible]

$$W_x = 160 \times 0.847 \times \sin 50°$$

$$W_x = 160 \times 0.847 \times 0.\text{[illegible]}$$

(Buoyancy factor for 10 [illegible]

The following table give[illegible]ity for various metals which can be used to manufacture drill collars.

Table 5-8: Modulus of Elasticity and density of Various Metals

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

The thing to notice is that most types of steel and monel which are actually used in drill collars have about the same modulus of elasticity and density. So in practice the stiffness of a drill collar depends almost entirely on its outside diameter and is proportional to the fourth power of the OD. However, aluminum drill collars would be more limber than steel drill collars of the same dimensions whereas tungsten collars would be much stiffer.

In general, it is recommended that standard drill collar diameters should be used for each hole size.

Effects of Drill Collar O.D.

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

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

When using [illegible] the pendulum portion be as stiff as pos[illegible] diameter collars. Reducing co[illegible] the collars will bend towards the [illegible] the pendulum effect and the rate o[illegible] reduces the weight of the bottom colla[illegible] and the rate of drop.

Formation Effects

The nature a[illegible] hardness of the rock being drilled can have a pronounced [illegible]al tendencies, although in many cases the importance may be exaggerated. [illegible] or behaves in th[illegible] direction. Most sandstones are [illegible] the same propert[illegible]

Most oilfield[illegible] rocks. Due to the nature of their deposit[illegible] most sedime[illegible] degree of anisotropy. Drilling into dipping (tilte[illegible] that the drill bit is forced towards a preferential [illegible] The trends a[illegible] medium to hard drilling especially in formations with pronounced structure.

A number of [illegible] have been proposed over the years to explain th[illegible] theory. Lubinski and[illegible]bility model which related an index of the rock s[illegible] rock strength[illegible] formation. They produced tables of anis[illegible]tion classes which could be used as a guide in sele[illegible] collar size or weight on bit.

Another theo[illegible] into hard layers, the hard layer will fracture [illegible] which guides the bit to drill into the dip.

Another expl[illegible] Lamore and others, is that of preferential [illegible] single tooth. [illegible] preferential planes of failure. As it impacts th[illegible] a compressive stress in a direction per[illegible] occur more [illegible] planes. When the bit is drilling an anisotropic [illegible] rapidly on one side of the bit and smaller chips [illegible] will therefor[illegible] a bit tooth.

Using Figure 5-48 as an example, the forces between the bit tooth and the rock will be greater on the right side of the tooth. Therefore, there will be a resultant force on the bit acting to the left. This is Fd, the deviation force. It follows that the deviation force will depend on the angle of dip.

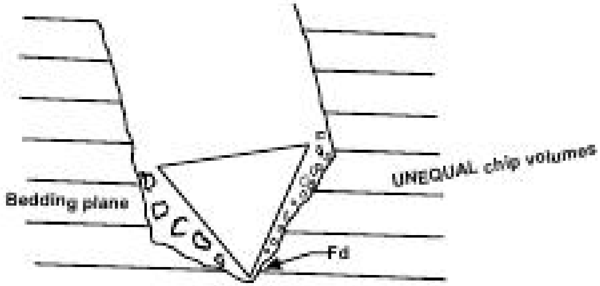


Figure 5-48: Generation of drill cuttings in a directional well

Relationship Between Dip Angle and Deviation Force.

Based on the preferential chip formation theory, the graph shown below has been derived from experimental work.

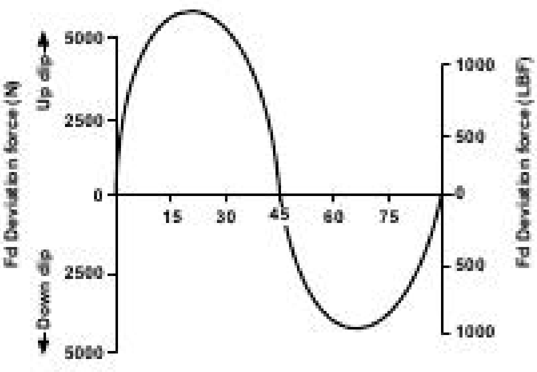


Figure 5-49: Maximum deviation force as a function of formation dip.

The effective dip angle is the angle at which the bit strikes the bedding plane. The graph predicts that when the effective dip angle is less than 45°, the direction [illegible] en the effective dip angle is greater tha [illegible] force is down-dip.

The meaning of up-dip and down-dip is illustrated in Figure 5-50. In practice, it ha [illegible] up-dip tendency is observed at [illegible]

Figure 5-50: Up-dip versus down-dip.

The unwanted deviation in vertical wells has borne out the predictions of the graph sho [illegible] alternately hard and soft formations w [illegible] lized bit and weights high enough to cause collar flexure, usually results in a course perpendicular to the bedding planes.

Figure 5-51 illustrates the tendency of the bit to deviate in the up-dip direction when the formation [illegible]

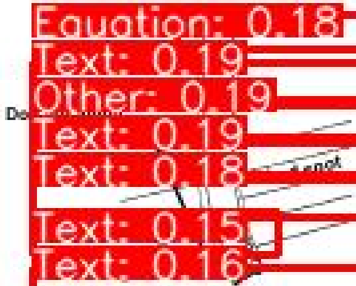


Figure 5-51: At low dip angles, deviation tendency is up-dip.

The formation attitudes will have a similar effect on directional tendencies. For dip angles less than 45°, if the direction is up-dip, the bit will tend to maintain direction, but build angle. If the borehole direction is left of up-dip, the bit may tend to walk to the right; whereas if the direction is right of up-dip the bit tends to walk [illegible] ena are just special cases of the up-dip tendency.

When the formation dip angle is greater than 60°, the usual tendency of the bit is to drill parallel to the bedding plane or down-dip.

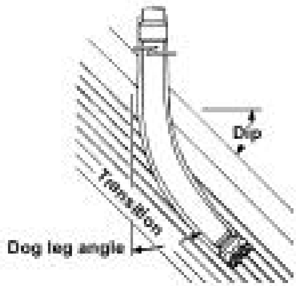


Figure 5-52: At high dip angles, deviation tendency is down-dip.

In cases where the dip angle is greater than 60°, if the hole direction is right of down-dip direction then the bit tends to walk to the left. If the hole direction is left of down-dip direction, the bit tends to walk to the right. Again, these are simply special cases of the down-dip tendency.

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

Effective Dip Angle in a Deviated Hole

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

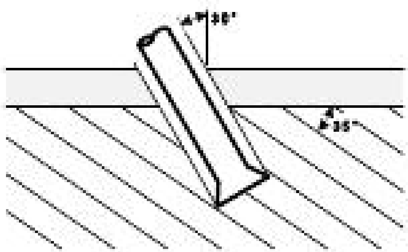


Figure 5-53: Hole inclination = 30°;
Real dip angle = 35°; Effective dip angle = 30° + 35° = 65°;
There will be a down-dip deviation force.

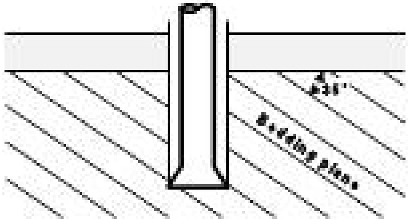


**Figure 5-54: Hole inclination = 0°;
Effective angle of dip equals real dip angle (35°);
There will be an up-dip deviation force.**

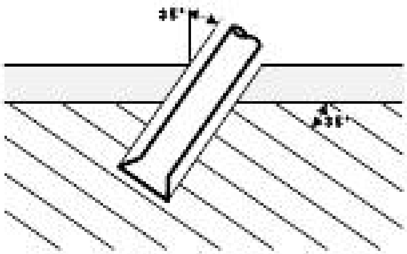


**Figure 5-55: Hole inclination = 35°;
Real dip angle = 35°; Effective dip angle = 0;
There will be no deviation force.**

Formation Hardness

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

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

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This can be [illegible] reducing flow rate. If anticipated befo[illegible] to run a mild build assembly.

BHAs tend to re[illegible] formations. This [illegible] more likely to be in gauge. In medium to ha[illegible]ies are more responsive as maximum bit we[illegible] the required build. The main directional [illegible] hard formations is getting a pendulum assem[illegible] speaking, the harder the formation, the le[illegible]. There may also be a conflic[illegible] WOB to get the dropping trend establishe[illegible] maintain an acceptable penetration rate. [illegible] in hard formatio[illegible]led in hard formation, the use of large [illegible]nted.

Summary of Form[illegible]

It should be emp[illegible]ns, the rock properties have a minimal effect o[illegible]nse.

In soft to mediu[illegible] has little influence on directional respo[illegible] directional behavior.

In medium to ha[illegible] have an appreciable degree of anisotropy, directio[illegible]nificantly affected by formation attitude and in particular by the effective dip angle of the bedding planes. If the effectiv[illegible] dip ang[illegible] tends to drill up-dip. When the effe[illegible] down dip. When the effect[illegible] 0°, there is no tendency to deviate.

Unwanted devia[illegible] formation can best be reduced by pack[illegible] gauge near-bit stabilizer definitely reduc[illegible] formation effects have been observed o[illegible] area, the BHA design should be suitably mod[illegible].

Nav[illegible]stems

Most conventional directional drilling operations will require extra trips to change the B[illegible]on, bit performance can be reduced by t[illegible]techniques.

Several meth[illegible] directional drilling using "steerable d[illegible] axis of the bi[illegible] the bit. If the[illegible] of the motor, is rotated at the surface, the b[illegible] is not rotated[illegible]rved path determined by the orientatio[illegible]

Most steerab[illegible] displacement[illegible] respect to the[illegible]ajority of directional drilling companies u[illegible] or at the con[illegible] Nowadays this single bend is typically adjustable on the rig floor, enabling the tilt angle [illegible]ween zero and some maximum.

There are als[illegible]

Advantages of [illegible]

- Elimina[illegible] changes, saving rig time
- More c[illegible]ed
- Wells a[illegible]plan at all times
- Smaller directional targets can be hit

Steerable Turbine[illegible]

Stee[illegible]ce method by having an eccentric (or offse[illegible] bottom end) of the turbine body, quite close to the bit. The three blade version shown below is the [illegible]le blade version exists and is used [illegible]

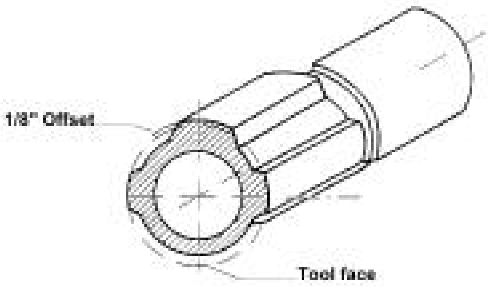

Figure 5-56: Three blade steerable turbine

As illustrated in Figure 5-56, one blade is larger in surface area and is offset by 1/8-inch. When the drill string is rotated, the offset stabilizer has no effect on the well path. When it is desired to deflect the well path, the toolface (the point opposite the center of the offset blade) is orientated using an MWD tool. Drilling continues with no rotation from surface and the turbine drills a curved path.

Steerable turbines have been used to perform various types of deflections including kick-offs. Their most successful applications have been tangent section drilling and performing correction runs as required to keep the well on course.

The DTU Navigation Drilling System

This drilling system consists of the following:

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

Modes of Operation

The capability to drill either oriented or rotary with the same tool is made possible by incorporating a Double-Tilted U-joint housing (DTU) and a longer U-joint assembly on a standard Mach 1 or Mach 2 PDM. The DTU creates a small tilt much closer to the bit than a conventional bent sub assembly, producing a lower bit offset.

Bit tilt and of[illegible] (or inclination) changes to be performed[illegible]

The low bit t[illegible]t and offset produced by the sub, means the string can be rotated when[illegible] of the drillstring negates the b[illegible] drill a straight path.

DTU Basic Com[illegible]

- By[illegible] Valve with box connection
- [illegible]ction - Mach 1 or 2
- Double tilted U-joint housing
- Upper bearing housing with stabilizer (UBHS)
- Drive sub[illegible]

Only the DTU hous[illegible] housing components will be [illegible] standard Navi-Drill parts. Navi-Drill per[illegible] by the addition of these [illegible]ble motor is shown in Figure 5-5[illegible]

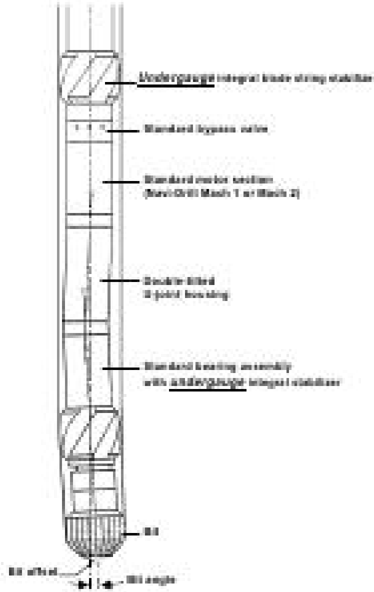

Figure 5-57: DTU Configuration

The double tilted universal joint housing:

- Replaces the straight universal joint housing on a standard Navi-Drill. The universal joint is slightly longer than the straight housing and universal joint.
- Is available in various tilt angles and identified by the ti[illegible] which is the mathematical resultant [illegible] two opposing tilt angles.
- Produces a desired bit tilt angle w[illegible]cing actual bit offset.
- Allows for extended rotation of the motor with a low eccentricity as compared to convention[illegible]es with c[illegible]ion of the drill string negate[illegible]sembly theoretically drills a straight, slightly [illegible]
- Is avai[illegible]4" to 11-1/4".

With the exceptions of the 8" and the 9-1/2" tools, each diameter has three standard tilt angles designed to provide approximately 2°, 3° and 4° per hundred feet theoretical dogleg rates when configured with a Mach 2 motor. TGDS is theoretically higher when using the shorter Mach 1.

As illustrated in Figure 5-58, the concept behind the double tilt is that by having the two tilts in the same plane but opposed (at 180°) to each other, the bit offset is minimized. Bit offset is the distance from the center of the bit to the axis of the motor section (extrapolated down to the bit).

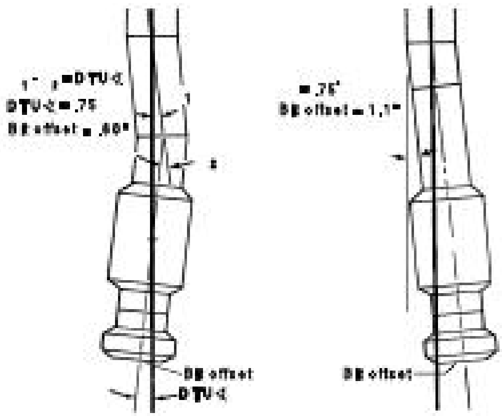

Figure 5-58: DTU and Bit Offset

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

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

The design of the UBHS includes:

- A double taper or watermelon-shape profile with rounded edges to reduce stabilizer hangup and drag.

- Blade widths [illegible] ploughing action by [illegible] the oriented mode.
- Blade wraps [illegible]ying from straight ribbed to a maximum of 30° to reduce contac[illegible]
- Gauge lengths varyi[illegible] length being [illegible]s tha[illegible] or equal to bit gauge length.
- Three blades [illegible]-1/2" hole sizes, or four blades at ¼-i[illegible]

UBHS with 5 straight b[illegible]des a[illegible] now the preferred design.

Theoretical geometric dogleg s[illegible]

This angle is defined b[illegible]hree [illegible]oints on a drilled arc:

1. The bi[illegible]
2. The [illegible] or Upper Bearing Housing Stabilizer
3. [illegible]

TGDS([illegible]

Tilt angle = Bit [illegible]lt in [illegible]

L = length between th[illegible]

Note: *The abov[illegible] formula[illegible] Dogleg S[illegible] is based on a system which contains full gauge sta[illegible]*

Adjus[illegible]or

This is [illegible]

- Is [illegible]
- Incorpo[illegible]ng which can be set to achieve [illegible] 20°/30m [illegible]bilizer configuration
- Allows single [illegible]
- Allows [illegible] from the rig, a particular advantage for remote locations

Adjustable Kick Off [illegible]

The NaviDri[illegible]d with an adjustable U-joint housing drilling mo[illegible] directional drilling [illegible] rotary and oriented mode) opera[illegible]n of [illegible] requ[illegible]um radius directional drilling operations.

The tilt angle of the AKO can be adjusted from 0° to the maximum design angl[illegible]. The m[illegible]n 2° to 2.75° depending on tool size [illegible] because the internal connections [illegible] a tilted pin thread which screws into a tilted b[illegible] determines th[illegible] position of the High Side. The AKO angle is rig f[illegible]

Maximum Adjustment of AKO Motors

On the adjus[illegible] is infinitely adjustable from 0° up to[illegible]

- 3-3[illegible]
- 4-3[illegible]
- 6-3[illegible]
- 8" [illegible]
- 9-[illegible]
- 11-[illegible]

The addition [illegible]gle, above the motor section allow[illegible] rates up to 24°/100 ft. This is the Double Adju[illegible] components include:

- Standar[illegible] bearing and drive sub assembly with short gauge, straight [illegible]

- Rig floor [illegible]
- Standard Mach 1 or Mach 2 motor section.
- Standard by[illegible]
- String stabi[illegible]ntegral blades (optional).

Dogleg Capabilitie[illegible]

The dogleg capa[illegible]lity f[illegible]r the AKO is variable and is a function of the adjustable U-joint hous[illegible] housing [illegible]leg capability for both oriented-only and steerable (mixed mode) operation, are detailed in the NaviDrill Operati[illegible]s hand[illegible]

Using lower [illegible] steerable motor. [illegible]

The AKO motor [illegible]

- partially st[illegible] housing stabilizer
- fully stabilized system with bearing housing and top stabilizer
- slick system [illegible] where a wear protection hard-banding rin[illegible] tool inside the hole.

Maximum allow[illegible] the AKO sub may be limited when contact of [illegible] limitations. Thi[illegible]mended Maximum Angle".

The NaviDrill A[illegible]ations in 3-3/4", 4-3/4", 6-3/4", 8[illegible] 26". Mechanica[illegible]cteristics for the AKO are identical to t[illegible]se fo[illegible]

Tilt Angle

The proper tilt a[illegible] dependent upon [illegible]acteristics of the well plan.

When kicking o[illegible] recommended. [illegible] severity in the o[illegible]iented mode than the rate of change specified in the well plan.

By getting highe[illegible] can "get ahead" [illegible]quirements and begin utilizing the practice of d[illegible] rotary modes. The directional dr[illegible] increasing the percentage of footage dr[illegible]

Typically, th[illegible] oriented mod[illegible] should theor[illegible]f 1.25 times the maximum dogleg sever[illegible] keep in mind that the [illegible]metric Dogleg Severity) assumes that tool face orie[illegible] in high torqu[illegible] orientation, t[illegible]ould be less than expected.

- When a [illegible]l with a higher dogleg capability can increase [illegible]ucing oriented drilling requirements.
- When t[illegible] drilling, a lower tilted tool may be more [illegible] depends on the extent to which orientation may be necessary and the anticipa[illegible]

First String Stabilizer

It is normal p[illegible] directly above the motor or with a pon[illegible] Reasons for [illegible]ing th[illegible]

- It defines the t[illegible] assembly
- It produces a p[illegible] directional response
- It [illegible]

Placement

The stabilize[illegible]directly above the motor. According to the 3-poin[illegible] stabilizer hig[illegible] the Theoretical Geometric Dogleg Severity. Thi[illegible] does not always work in practice. It has been found that moving the s[illegible] a kick-off. H[illegible]eved, the rate of build is ofte[illegible] increasing "I[illegible]ory predicts.

Size and D[illegible]

The diamete[illegible] of the [illegible] than the diameter of t[illegible] It should have preferably the same physical design as the UBHS.

First string stab[illegible]

If the first string stabilizer diameter is decreased to less than the UBHS and an upward toolf[illegible]riented dogleg rate is increased. This [illegible]

Figure 5-59: Upward Toolface

If the first string stabilizer diameter is decreased to less than the UBHS and a downward toolface orientation is present, then the oriented dogleg rate is reduced.

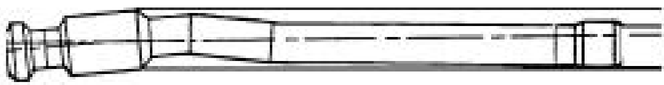

Figure 5-60: Downward Toolface

In either of the above cases, the more undergauge the first string stabilizer, the greater the effect. The same basic effect is seen with both the AKO and the DTU steerable systems.

First string stabilizer size - rotary mode

Field results have shown that an undergauge first string stabilizer is required to produce a holding tendency when NDS is run in the rotary mode. The requirements for the first string stabilizer gauge diameter will be a function of formation trends and hole inclination.

The following table can be used as a general guideline for determining the required diameter for the first string stabilizer so that inclination is maintained.

Table 5-9: Required Diameter for First String Stabilizer

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

Table 5-10 [illegible] determining first string stabilizer cha[illegible]icant change (minimum of 0.25°/100') i[illegible]

Table 5-10: [illegible] Gauge of First String Stabilizer

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

These guidelines apply to both AKO and DTU steerable systems.

Kicking-Off

Bottomhole Assemblies

During kick-[illegible]l determine general NDS assembly design.

- [illegible]
- Expected length of run

The [illegible] 17-1/2" hole is designed to have a [illegible]

- [illegible]
- 11[illegible] BHS
- 16-[illegible] String Stabilizer
- Flo[illegible]
- 9-1[illegible]
- 9-1[illegible]
- 16-[illegible]
- 2 x[illegible]
- Cr[illegible]
- 2 x[illegible] (Supplied)
- Jar[illegible]
- 8" Steel Drill Collar
- Crossover
- HWDP (sufficient amount to provide weight on bit)

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The following [illegible] is designed to have a rotary build tend[illegible]

- 17-1/2" PDC Bit
- 11-1/4" Mach [illegible]
- Crossover
- 12-1/4" First S[illegible] [illegible]ilizer
- Float Sub
- 9-1/2" NMDC
- 9-1/2" MWD
- 16-1/2" Non-[illegible]
- 2 x 9-1/2" NM[illegible]
- Crossover
- 2 x 8" Steel D[illegible]
- Jars
- 8" Steel Drill C[illegible]
- Crossover
- HWDP (suffic[illegible]

This assembly is design[illegible] build tendency. A good estimate would be [illegible].

The following example [illegible]gned to have a rotary hold tendency.

- 12-1/4" Bit
- 9-1/2" Mach 1[illegible]
- Crossover
- 12" First String Stabil[illegible]
- 8" NMDC
- 8" MWD
- 12" Non-magnetic Stabilizer
- 2 x 8" NMDC
- Jars
- 8" Steel Drill Collar
- Crossover
- HWDP (sufficient amount to provide weight-on-bit)

The followin [illegible] signed for a rotary build tendency.

- 12- [illegible] /4" Kock Bit
- 9-1 [illegible] 2" Ma [illegible]
- Crossover
- 11" First S [illegible] ng S [illegible] ilizer
- 8" NMDC
- 8" MWD
- 11-3/4" No [illegible] magn [illegible] etic Stabilizer
- 2 x 8" NM [illegible]
- Jars
- 8" Steel D [illegible] Coll [illegible]
- Crossover
- HWDP (su [illegible] on-bit)

Recommended Guideli [illegible]

- When beginni [illegible] have the first string stabilizer in op [illegible] hole and [illegible] up in the casing to prevent hanging up or any other an [illegible]
- When using a s [illegible] r vertical holes, the actu [illegible] TGDS.
- [illegible] observe the actual oriented dogleg severity [illegible] subsequ [illegible] vals.
- Minimiz [illegible] ng ro [illegible] practice [illegible] an re [illegible] ervals.
- During the initi [illegible] l stage of a kick-off from vertical, stabilizer hangup can occ [illegible] re is inclined and/ or the first strin [illegible]
- Conside [illegible] begin [illegible] ning the kick-off early; this can reduce oriented drilling [illegible] nation of the wellpath.

Interval drilling

An estimate of the r [illegible] ented mode can be determined using:

% Footage O [illegible]

where:

DL = required [illegible] (°/100')

DLO = actual [illegible] ('/100')

DLR = actual dog[illegible] (°/100')

Example:

Planned build-up [illegible]

Build-up rate [illegible]

Build-up rate [illegible] 0.5°/100'

% Footage O[illegible] - 0.5) √ (3.5 - 0.5)] x 100 = 67%

Tangent Section Drilli[illegible]

Tangent or hold sec[illegible]nomical using NDS, although NDS perfo[illegible] motor performance [illegible]rilling. Long sections of hole can be drilled faster th[illegible] with conventional [illegible] [illegible]course. Basic design principles include:

- An undergauge first string stabilizer is required to maintain inclination [illegible]S.

  [illegible] an acceptable dogleg rate to allo[illegible]riented intervals.

- Decreasing [illegible] stabilizer versus increasing "L" is pref[illegible] limits the [illegible] OD of the first string stabilizer.

A typical BHA [illegible]tion is:

- 12-1/4" PDC [illegible]
- 9-1/2" [illegible] motor, AKO or DTU, 12-1/8" UBHS
- Crosso[illegible]
- 11-3/4" string [illegible]
- 8" NM[illegible]
- 8" MWD tool
- 11-3/4" non-m[illegible]
- 2 x 8" NMDC
- 2 x 8" DC
- Jars
- 8" DC

- [illegible]
- HWDP as [illegible]

When drilling a tang[illegible] should be observed:

- After ob[illegible] a minimum of 200 ft of rotary [illegible] for drilling long distances between orientat[illegible] number [illegible] penetration rate.
- Oriente[illegible] drillin[illegible]ed. Oriented drilling in a tangent [illegible] hold [illegible] and to compen[illegible]
- Never le[illegible] because [illegible]ificantly more expensive. As surveys are o[illegible] horizon[illegible] and [illegible] there must be a feasible course t[illegible] drill [illegible]

Drop Sections

When a drop [illegible] increased to [illegible]ency in the rotary mode. The recommended diam[illegible]UBHS. Increasing the diameter of this stab[illegible]

Typical rotary drop [illegible] to 0.75°/100 ft comm[illegible] required, then oriented drilling will be mandatory.

The following is a general design for a drop assembly while rotary drilling.

- 12[illegible]
- AK[illegible]
- Cr[illegible]
- 12"[illegible]
- 8" [illegible]MDC
- 12"[illegible]
- 8" [illegible]
- Etc[illegible]

The following [illegible] drilling drop sections.

- Except in [illegible] the drilled wellpath can be positioned [illegible] will usually reduce the oriented dr[illegible]
- In hard to [illegible] toolsets should be minimized or avoided.
- Actual dog[illegible] with an oriented system is usually [illegible]
- The NDS assembly should be designed such that the TGDS is at least 125% of th[illegible]
- Stabilizers should [illegible] achieving [illegible] or produces a neutral tendency.

Azimuth Control

Rotary Mode

Rotary drilling with ND[illegible] tendency.

The dip and strike of the formation will affect the tendency of the NDS assembly to walk.

The con[illegible] an asse[illegible]

Oriented Mode

Changes in azim[illegible] rmed in oriented mode.

Due to the stabil[illegible] orientated 90° ri[illegible] imum turn without dropping inclination (a ty[illegible] formations).

A reduction in T[illegible] d for a turn due to the effect of the und[illegible]

Self Check Exercises

1. List six applications of directional drilling.

(a) ____________________

(b) ____________________

(c) ____________________

(d) ____________________

(e) ____________________

(f) ____________________

2. Define the following terms for "north".

(i) True North:

____

(ii) Magnetic North:

____

(iii) Grid North:

____

3. Convert the following quadrant bearings into azimuth.

Quadrant Bearing	Azimuth
S64-1/2°E	
N 35°E	
S 88-3/4°W	
N 66.5°W	
S 22.25°E	
N 35.5°W	
S 89°E	
N 71 1/2°E	
S 25.5°W	
N 3-3/4°W	
S 11.5°E	

4. State one ad[illegible]d removable whipstock[illegible]

Advantage: [illegible]

Disadvantages:

a. ______________________________

b. ______________________________

5. Explain what is mea[illegible] done.

____

____

____

6. What is me[illegible] by "[illegible]" PDM's?

____

____

____

7. State the relationship betw[illegible] in PDM's

____

____

8. What is the relationship b[illegible]es?

____

____

9. Explain wh[illegible]nhole motors and why it causes pr[illegible]

____

____

10. List three advantages of a [illegible]eflection tool.

1. ______________________________

2. ______________________________

3. ______________________________

11. How can [illegible] be drilled in an oriented mode [illegible]

____

____

12. List six factors which [illegible] a fulcrum assembly.

a. ____

b. ____

c. ____

d. ____

e. ____

f. ____

13. Explain the effect of [illegible] rate of a pendulum assembly [illegible]

____

____

____

____

____

14. What are the guid[illegible] kicking off with a NDS?

____

____

____

____

15. Describe how the plac[illegible] affects the response of an NDS assembly.

____

____

16. How does th [illegible] t NDS assemblies when dri [illegible]

17. What are the guidelines to be followed when drilling the tangent section with a NDS?

•Notes•

Horizontal Wells

Upon completion of this chapter, you should be able to:

- Understand the general classifications of horizontal wells and the major factors which dictate a well's profile.
- Appreciate the recent developments that have made horizontal wells f[illegible]
- Unders[illegible] may be an option and when they [illegible] may not the ideal option.
- Provide information [illegible] removal of cuttings.
- Use drilling a[illegible] when the zone of i[illegible] and when the bit has left this zone.

Additional R[illegible]

AAPG, *Geological Aspects of Horizontal Drilling*, Course Note #33, Tulsa, OK., 1991

World Oil, *Handbook of Horiz[illegible]nology*, Gulf Publishing Company, 19[illegible]

Brochure:

Oil & Gas Journal - Horizontal Wells- December 30, 1990

Innovative Horizontal Drilling Technology - EC - x-229

Self-Check Exercises

1. What are the typical build rates for the following types of horizontal w[illegible]

   Short Radius: ____________________

   Medium Radius: ____________________

   Long Radius: ____________________

2. What are some of the de[illegible] drilling that have improved the over[illegible] the last decade?

   ____

   ____

   ____

   ____

3. What are four major [illegible] drilling horizontal wells?

   a. ____________________

   b. ____________________

   c. ____________________

   d. ____________________

4. What are the [illegible] horizontal wells?

   Short Radius: ____________________

   Medium Radius: ____________________

   Long Radius: ____________________

5. What are three param[illegible] remain within a rese[illegible]ly?

   a. ____________________

   b. ____________________

   c. ____________________

6. What are three reasons why drill rate is not a sure indicator of lithology?

   a. ______________________

   b. ______________________

   c. ______________________

7. Why is it a bad si[illegible] than the theoretical lag in [illegible]

   ____

   ____

   ____

8. What type of carbide s[illegible] in horizontal wells and why is it nec[illegible]

   ____

   ____

   ____

9. When th[illegible] reservoir, a large increase in [illegible] the reservoir. A small increase likely means the bit is penetrating ______________.

Stuck Pipe

Upon completion of this chapter, you should be able to:

- Understand the importance of preventing stuck pipe.
- Unders[illegible]ms of stuck pipe can be prevented.
- Recognize the [illegible]
- Calculate the [illegible]
- Calculate the stuck p[illegible]
- Understand th[illegible] remedial actions taken when stuck pipe problems arise.

Additional Review [illegible]

Adams, Neal, *How to C[illegible] Part Series*, Petroleum Engineer, Se[illegible] 77 - [illegible]

BP Research, *Guidelin[illegible]pe*, Sudbury Research Cent[illegible], Aug[illegible]

Baker Hughes INTEQ, *[illegible]rillin[illegible] Fluids Manual*, 1991

Kemp, Gore, *Oilwell Fishing Operations: Tools and Techniques*, Gulf Publishing Company, 1986

Moore, Preston, *Drilling Practices Manual, 2nd Edition*, PennWell Publishing Company, 1986

Stu[illegible]s

Introduction

Baker Hughes INTEQ personnel can be valuable members of the drilling team in [illegible]potential stuck pipe problems. Having access to the drilling infor[illegible]work), the geological data (from the logging [illegible] analytical approach, INTEQ personnel ca[illegible]ng stuck pipe problems to a minimum.

Effective co[illegible] directional d[illegible]event many stuck pipe situations.

The types an[illegible] causes of stuck pipe have been mentioned and described in the "*Advanc*[illegible] section will [illegible]g unit's analysis of the information [illegible] potential stuck pipe situations.

The followin[illegible] factors that c[illegible] stuck pipe/borehole problems.

DRILLBYTE INSTRUMENTATION	BORE[illegible]	[illegible] PERSONNEL RESPON[illegible]
Lithology Identification and Description	a. Forma[illegible]on Related b. Diffe[illegible] c. Ceme[illegible] d. Unde[illegible] e. Poor [illegible]	a. Identification of Rock Types and Characteristics [illegible] [illegible]cation of Cement in Cuttings Samples [illegible] [illegible]
Depth and Drill Rate Recorder	a. Forma[illegible] b. Wellb[illegible] c. Poor [illegible] Cleaning	a. Identification of borehole problems from drill rate b. Reduced drill rate due to [illegible] c. Reduced drill rate due to poor transfer of WOB
Monitor Calculations	All Types of Borehole Problems	Monitor trends in hole conditions, and relating trends to lithology, hole deviation and BHA configuration
Pump St[illegible] Counter[illegible]	[illegible]	[illegible] adequately cl[illegible]
Pore Pr[illegible] Evaluati[illegible]	[illegible]	a. Detecting abnormal [illegible] normal pore pressure [illegible]
Lag Ti[illegible] Determi[illegible]	[illegible]	[illegible]

[illegible]. Response[illegible] Conditi[illegible]

INDICATOR CAUSES	Cuttings	Drag	Shale Density	Gas	Flowline Temperature	Shale Swelling	Shale Factor (CEC)
REACTIVE (HYDRATING) FORMATIONS	Large Quantities	No Indication	No Indication	No Indication	No Indication	Good Indication	High Values
GEOPRESSURED FORMATIONS	Large Quantities	Decrease in Trend	Decrease in Value	Increase in Value	Increase in Trend	Some Indication	High Values
FRACTURED & FAULTED FORMATIONS	Not Present	No Indication	No Indication	Increase if Present	No Indication	No Indication	No Indication
MOBILE (SALT) FORMATIONS	Small Quantities	No Indication	No Indication	No Indication	No Indication	No Indication	No Indication
UNCONSOLIDATED FORMATIONS	Not Present	Large Decrease in Trend	No Indication	Increase if Present	No Indication	No Indication	No Indication

Table 7-2: Indicators Available to the Field Personnel.

Recognizing Problem Situations

During the course of a well, many drilling and non-drilling operations can potentially cause stuck pipe. Careful observation of the various parameters monitored by DrillByte can pin-point many troublesome zones. Several of the more common operations are listed below.

During Connections and Surveys

The major indication of a potential problem will be increased drag, when the drillstring is moved.

Questions to Answer	Response
1. Are problem formations exposed?	1. Check lag time
2. Was the borehole adequately cleaned before the connection/survey?	2. Check drill rate before connection/survey
3. Are there indications of sticking?	3. Check lithology
	4. Check annular velocities
	5. Check filter cake thickness
	6. Check hydrostatic overbalance
	7. Check if permeable formations are exposed

Tripping Out

During trips out of the hole, the common indication of stuck pipe problems will be increased drag and overpull.

Questions to Answer	Response
1. Are problem formations exposed above the bit?	1. Review records of previous trips. Is there a trend which can be related to a possible cause?
2. Are high swab pressures resulting in hole instability?	2. Check if the proper lag time was completed when circulating bottoms up?
3. Was the hole adequately cleaned prior to the trip?	3. Check swab pressures, should the trip speed be reduced.
4. Were similar conditions experienced on previous trips? If so, is the hole getting worse?	4. Check the lithology
1. Can the problem be related to deviation or the BHA?	1. Check if overpulls are increasing on each trip
2. Is a keyseat developing?	2. Check the nature of any interbedded sequences.
3. Are there sequences of hard/soft formations which may result in ledges?	3. Relate doglegs to BHA configuration
	4. Check if conditions exists which would encourage keyseating

Reaming Operations (Reaming In & Reaming Out)

During reaming operations, the primary indication of hole problems will be increased torque.

Questions to Answer	Response
1. Are problem formations exposed?	1. Check the BHA configuration. How does it compare to the last assembly?
2. Can the problem be related to deviation and BHA?	2. Check for hard/soft interbedded sequences.
3. Can the problem be related to ledges?	3. Check for problem formations
4. It is possible that a cuttings bed has formed on the low side of the borehole?	4. Correlate trends from previous trips. Is the problem still occurring?
5. Was the hole adequately cleaned?	5. Correlate deviation with BHA configuration.
	6. Check annular velocities during circulation.
	7. Check the drill rate prior to reaming
	8. Check lithology and location of problem formations.

Drilling Operations

Though few stuck [illegible] drilling, it is wise to keep in mind that they c[illegible]ly monitored drilling parameters whic[illegible] drill rate. Chang[illegible]ed with known data (i.e. cuttings lith[illegible] stuck pipe and o[illegible]

Several problem[illegible] correlations are listed in the following table:

INDICATOR PROBLEM	[illegible]	[illegible]URE	DRILL RATE
Poor Hole Cleaning	Increase	Increase	Gradual Increase
High Overbalance & Permeable Sands	Gradual Increase	No Change	Gradual Decrease
Mobile Formations	Gradual Increase	Increase	Gradual Decrease
Fractured and Faulted Formations	Sudden Erratic Increase	May Be Unaffected	Sudden Increase
Geopressured Formations	Increase	Increase	Initial Increase with a Gradual Decrease
Reactive Formations	Gradual Increase	Increase	Gradual Decrease
Unconsolidated Formations	Increase	Increase	Decrease
Junk	Sudden Increase	No Change	Sudden Decrease
Cement Blocks	Sudden Increase	No Change	Sudden Decrease

Table 7-3: Stuck Pipe Indicators During Drilling Operations

Mechanics of Differential Sticking

Even when all precautions are taken, stuck pipe may occur. Should this situation develop, there are still ways in which the INTEQ personnel can be of assistance.

To free a differentially stuck drillstring, the driller must overcome the restraining force of the drilling fluid, which is pushing the drillstring [illegible] against a [illegible] string (drillpipe or collars) will soon become [illegible] the permeable zone if corrective ac[illegible] situation is noticed.

The force ne[illegible] proportional to the area of contact and [illegible] with time because of filter cake bu[illegible] up, the area of contact can double by th[illegible]

The force ho[illegible] can be calculated very quickly. [illegible] be exceeded to free the drillstring. If the force is g[illegible] the tensile strength of the drillstring, th[illegible] "black magic", etc.) [illegible] friction between the drillstring an[illegible]

The equation[illegible] force is:

[illegible]

where: [illegible] or the total pulling force that would be required to free the pipe (lbs)

[illegible] differential between the drilling fluid and the formation (psi)

A = The area of co[illegible] cake (in²)

f = The coefficient of friction between the drillstring [illegible]

Determining the Variables in the Stuck Pipe Equation

Pressure Differential (ΔP)

The pressure differential between the drilling [illegible] formation is determined using the hydrostatic pressure of the drilling fluid (0.0519 x MD x TVD) and the esti[illegible] the formation.

Area of Contac[illegible]

The effective are[illegible] of the imbedded portion of the drillstring m[illegible] of th[illegible] permeable formation. The most acceptable [illegible]

[illegible]

where P_C is the [illegible] formation (inch[illegible]), T_F is the thickness of the formation [illegible] pipe (feet) and 12 [illegible]

Coefficient of Friction (f)

Though very sel[illegible] normally vary b[illegible] solids native mu[illegible]. As the mud density increas[illegible] the amount of solids (barite, sand, be[illegible]es, which increases the coefficient of friction.

The coefficient [illegible]cialized [illegible]ud test apparatus called a "stickom[illegible] a filter cake at [illegible]ate is rotated using a torque wrench [illegible] measured.

The coefficient [illegible] sliding of the pl[illegible]te to the normal force on the plate. The core face of the stickometer is 3[illegible] differential pres[illegible]use of the geometry of the core face the torque i[illegible]

$$f$$ [illegible]

Preventing Stu[illegible]**k Pipe**

If the driller is u[illegible] the force necessary to free the pipe is great[illegible] other remedial [illegible]lubricating fluid is "spotted" in the [illegible] Spotting proced[illegible] "*Advanced Log*[illegible]dditional Volume Calculations".

These equ[illegible]ti[illegible]y pin-pointing the depth at which the pi[illegible]- stuck point location) can be calculated [illegible] taken on the rig floor. With referen[illegible]termine the variables is as follows:

1. An [illegible] pipe. This must be greater tha[illegible] in tension.

2. A [illegible] the surface, no[illegible]to[illegible]

3. A greate[illegible] upward force "F2" is applied, causing the free portion of the dr[illegible] the stretch is measured above [illegible]

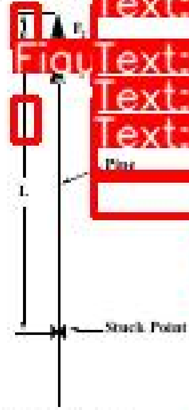

Figure 7-1Determination of Stuck Pipe Variables

Once the measurements have been taken, they are use[illegible] following equation:

$$SPL = (735 \quad 10^3) \quad \frac{(w) \quad (e)}{(F_2 - F_1)}$$

where: SPL = Stuck Pipe Location

735 x 10^3 = Derivation of Youngs Modulus for steel

w = Drillpipe weight (lbs/ft)

e = Length of stretch (inches)

F_1 = Force applied when pipe is in tension (lbs)

[illegible] pipe to ... (lbs)

The stuck pipe [illegible] will be a best guess value for a coup[illegible]s are crooked to some extent, there can [illegible] between the borehole and drillpipe, an[illegible] it will be very difficult to place [illegible] without it coming into contact with the borehol[illegible]

However, this c[illegible] and is much better than the industry's nomo[illegible] equation will als[illegible] provide a "near-enough" depth for a starting point when a free-point indi[illegible]string.

Preventing Stuck Pi[illegible]

During the cours[illegible]ns or items within those operations [illegible] problems are ev[illegible] there are generally ways to prevent the drillstring [illegible]n will list the most common causes of stuck pipe, [illegible] and the operatio[illegible]sures fail.

Differential Sti[illegible]

Much has been [illegible]ntial sticking. It should be remembered tha[illegible] (1) a permeable [illegible] (due to a high water loss), (3) the drillstrin[illegible] filter cake, (4) an overbalance situation exists, [illegible] circulation betw[illegible] filter cake. Preventive measures include:

1. Movi[illegible]ossible
2. Rotat[illegible]
3. Alwa[illegible]ard direction
4. Ensur[illegible] pills
5. Use g[illegible]
6. Minin[illegible]lized drill collars
7. Minin[illegible]
8. Use u[illegible] possible
9. Consi[illegible] placing the jar(s) in the heavy-weight pipe section
10. Use s[illegible] that are of short duration

There are basically th[illegible]llstring becomes differentiall[illegible]ck. [illegible] the drilling [illegible] apply right-hand torque. Secondly, [illegible] be an option (well control consideration [illegible] operation involves spotting a fri[illegible] zone.

If these meth[illegible] must be considered. The fish can then be recovered using washover pipe, or a DST too[illegible] pressure followed by the washover [illegible]

Geopressure[illegible]

These format[illegible] exceed the hydrostatic pressure of th[illegible] (for example, sha[illegible] will "cave" into the borehole. Pr[illegible]

1. Cl[illegible] when not drilling
2. Ob[illegible] large and convex/ co[illegible]
3. Inc[illegible] ble
4. Re[illegible]m on each connection
5. Perform [illegible]
6. Monitor [illegible]
7. Control the drill [illegible]
8. Minimize the time in the open hole when tripping
9. Recogni[illegible] the hole
10. Monitor [illegible]

If geopressured fo[illegible] care must be taken to e[illegible] develop. The first step in correcting the situation [illegible] possible, pipe movement should [illegible] these applied forces. Once full c[illegible] unrestricted, an in[illegible]e.

Reactive Form[illegible]

These are natura[illegible] generally known as "gumbo shales". [illegible] with the mud filtrate and hydrate. The hy[illegible] into the borehole. When drilling, the bit [illegible] these clays. When tripping, the BHA can becom[illegible] borehole. Preve[illegible]

1. Avoid [illegible] circulation
2. Be pr[illegible]
3. Plan t[illegible]
4. Caref[illegible]
5. Be prepare[illegible]
6. Carefully m[illegible]

If the drillstring is stu[illegible] established. Concentr[illegible]nwards. Rotation may help dislodge th[illegible]king [illegible] density, if possible, m[illegible]

Unconsolidated For[illegible]

These naturally occur[illegible] into the borehole when d[illegible] form a bridge ar[illegible]easures include:

1. Contr[illegible]
2. Use a[illegible]
3. Be pr[illegible]
4. Use vi[illegible]
5. Ream [illegible]
6. Avoid excessive swab/surge pressures
7. Avoid excessive circulation opposite those zones

If sticking does occur, establish circulation first. Then concentrate on working the drillstring downwards to disturb the bridge/mound. Once the drillstring is free, ensure the material is circulated out before drilling. Increase the mud density if possible.

Mobile F[illegible]

These are na[illegible] Most commonly shales and salt. Wh[illegible] into the borehole. Preventive m[illegible]

1. Re[illegible]ciated with these for[illegible]nations
2. Re[illegible]ular [illegible]
3. Conditio[illegible] the mu[illegible]
4. Use "ec[illegible]
5. Increase the mud [illegible]ble
6. Minimiz[illegible]

If the drillstring be[illegible] the annulus may become packed-o[illegible] on establishing circulation. The d[illegible], if possible.

If circulation is po[illegible]ble, in [illegible] should be pumped[illegible]re used, a water/ detergent spacer s[illegible] every 2 hours[illegible]e.

Once the dril[illegible]ould be considered.

Fractured/F[illegible]ulted Formations

These are na[illegible]hen the fractured or faulted formation is [illegible] fall into the b[illegible] vary from pebbles to boulders. Th[illegible] Preventive m[illegible]

1. Cl[illegible]
2. Mi[illegible]
3. Pla[illegible]e the jar in the heavy-weight pipe section
4. Be[illegible] tripping in
5. De[illegible]ge
6. Us[illegible]e

If it is determ[illegible]d formations are the cause of the sticking, the [illegible] down to try and break up the pieces of [illegible] acid (HCl) pill [illegible] limestone. The pill should be spotted with a la[illegible]

Key Seating

Key seats are th[illegible] wearing an additional hole into the side of the boreh[illegible] of the drillpipe's tool j[illegible] not pass through this extra hole when trippi[illegible]s include:

1. Minim[illegible]
2. Use w[illegible]
3. Minimize dogleg severity
4. Carefully design the BHA
5. Minimize t[illegible]
6. Have a surf[illegible]
7. If the probl[illegible] ahead

If the drillstring beco[illegible] worked upwards gradually, th[illegible] if the BHA is not jammed [illegible] try to be rotated up and out of [illegible]

Borehole Geometry

The borehole is seldo[illegible] are common, especia[illegible] formations are drilled. Problems with b[illegible] operations. Rem[illegible] drillstring is in compression making it more [illegible] making it more [illegible]s include:

1. Minim[illegible]
2. Reduce the number of BHA changes
3. Ream [illegible] changed
4. Do no[illegible]
5. Be pr[illegible]

If borehole geo[illegible] tripping in, a gradual upwards workin[illegible] curs when tripping out, upwards forces [illegible] further jamming [illegible] downward force [illegible] the ledge.

Underga[illegible]ge

When drilling [illegible], the gauge protection on the bit and st[illegible]omes ineffective. Any additional ho[illegible]. Preventive measures include:

1. Pr[illegible]after each run
2. Re[illegible]m back to bottom if an undergauge hole is suspected
3. Never fo[illegible]
4. Select bi[illegible] roller cone bits[illegible]
5. Carefull[illegible]s

If the new bit is r[illegible] jarring forces sho[illegible]

Inadequate Hole [illegible]aning

Inadequate hole cl[illegible]highly deviated or horizontal wel[illegible] the formation of a cuttings bed on the low si[illegible] measures include:

1. Co[illegible] hole is cleaned
2. Ci[illegible]culate bottoms-up until shakers are clean
3. Al[illegible]f cuttings coming over the shaker
4. Ma[illegible]g fluid properties
5. Co[illegible]
6. Re[illegible]ll
7. Al[illegible] reciprocate and rotate pipe while circulating
8. Us[illegible] viscous sweeps
9. Recogni[illegible]oles
10. Plan to u[illegible]
11. On float[illegible] use t[illegible] booster pumps

If the annulus bec[illegible] circulation must be attempted. In a[illegible] until circulation be[illegible] the drillstring should be rotated t[illegible] further [illegible]

In low angle holes[illegible] to "float out" the cuttings. I[illegible]d to disturb the cuttin[illegible]ghted pills to carry the cuttings out of the hole.

Junk in the Borehole

Junk is a foreign [illegible] s not meant to be there. Since the clearan[illegible]tabilizers is not great, even a small piece of [illegible] Preventive measures include:

1. Ensur[illegible]
2. Inspec[illegible]
3. Be ca[illegible]
4. Leave [illegible]
5. Install drillp[illegible]

If junk sticking is sus[illegible]g and jarring should commence to [illegible] these forces should be gradually increase[illegible]

Cement Blocks

After a leak-off test h[illegible] resumed, the large sized collars or st[illegible] fall into the bore[illegible]n easily jam against the drillstring. Preve[illegible]

1. Minim[illegible]low the casing shoe.
2. Alway[illegible] before drilling ahead.
3. Be ca[illegible] through the casing shoe.

If jamming occu[illegible] break up the obstructions by using alternating[illegible]ing and jarring. These freeing forces sh[illegible] until the drillstring is freed and, if available [illegible] cement.

Green Cement

A rare occurren[illegible] "green" cement. This occurs when the ceme[illegible] incorrect additives an[illegible]ts, the cement does not set properly. After [illegible] the drillstring is tripp[illegible]t equipment, the cement can "flash set" [illegible] include:

1. Pre-tr[illegible]
2. Know[illegible]

3. Begin ci[illegible]

4. Monitor cement returns at the shale shaker.

5. Realize [illegible]

6. Restrict [illegible]

If problems devel[illegible] from setting. Upw[illegible]uld commence as soon as possib[illegible] to try and dis[illegible]

Self-C[illegible]

1. What should be the response of INTEQ personnel if borehole problems n[illegible]?

2. How can Shale Factor [illegible] problems?

3. What is the most com[illegible] en the rig is performing rea[illegible]?

4. When using [illegible] ermined?

5. What piece of mud te[illegible] "friction coefficient"?

6. What is [illegible] in geopressured, reactive or uncon[illegible]

____

____

____

7. What two operatio[illegible] [illegible]lstring becomes stuck in a faulted l[illegible]

____

____

____

8. What type of pill[illegible] [illegible] high angle hole due to i[illegible]

____

____

____

9. What is meant by [illegible]

____

____

____

Well Control

Upon completion of this chapter, you should be able to:

- Understand [illegible] knowledge to assist in preventing [illegible] occurring.
- Recognize the warning signs of kicks.
- Understand [illegible] kill methods on different [illegible]
- Calculate the nece[illegible] proper kill procedures.
- Adapt to the corre[illegible] problems occur.

Additional [illegible]

Adams, Neal, *W[illegible]*, [illegible] Publishing Co., Tulsa, 1980

INTEQ Video Tape #3[illegible]

Moore, Preston, [illegible] Publishing Co., Tulsa, 1986

Rabia, Hussain, *[illegible]well Drilling: Principles and Practice*, Graham & Trotman Limited, 1985

Petroleum Extension Service AV [illegible], *[illegible] Prevention Of Blowouts, Part I. Causes*, The [illegible]

Petroleum Exten[illegible] *[illegible]es And Prevention Of Blowouts, Part I[illegible]*, The University of Texas at Austin

Petroleum Extension Service AV #106, *Causes An[illegible] Blowouts, Part I[illegible] Equipment*, The University of Texas at Austin

Intr[illegible]

A kick is defined as an undesirable influx of formation fluid into the borehole. If k[illegible] into a blowout (an uncontrolled [illegible] borehole).

While kicks [illegible] non. However, the penalty for failing to [illegible] the loss of th[illegible]

Well control [illegible] company, bu[illegible] considered.

Rig Control: [illegible] responsibility of the driller, and any [illegible] the driller.

Mud Control: This involves the addition of weighting material (most commonly bari[illegible] but also includes the correc[illegible] em and chemical additi[illegible] of the mud enginee[illegible]

Choke Control: This includes the [illegible] relationships, as we[illegible] the choke and monitoring the pump rate. The[illegible] e the best trained man on the rig in k[illegible] quired to give guidance during t[illegible]

Supervision: This is the final ele[illegible] will normally be assigned to the ri[illegible] supervise the previ[illegible] l control operations.

Decisions made under kick situatio[illegible] and judgement of the supervisor. T[illegible] crew change problems and the divided responsi[illegible] toolpusher and the oil company rep[illegible] eer. One of the most important elements of a well [illegible] of policies and procedures outlined in[illegible] known to Baker Hughes INTEQ p[illegible] It is the responsibility of the senior person or Field Supervis[illegible] tion as soon as possible.

Kicks

Causes of Kicks

There are 5 major reasons why kicks occur:

Failure To Keep [illegible]: [illegible] kicks occur when the bit is off bottom, while [illegible]. When the pumps are shut down prior to tripping, there is [illegible] pressure losses. If the equivalent circulating density and the pore [illegible] are nearly equal, [illegible] stops. As pipe is removed, the m[illegible] a reduction in hydrostatic press[illegible] be converted into pump strokes so [illegible] the hole is known.

Swabbing of Fo[illegible]rehole: When pipe is pulled it acts like a pisto[illegible] above the bit. Both gel strength and viscosity of the [illegible] increased if the mud cake [illegible] up, the nozzles are blocked, or a ba[illegible] string. The speed at which pipe is pulled al[illegible].

In INTEQ loggi[illegible] units, [illegible] program [illegible] a range of pipe pulling speeds a[illegible] and surge pressures. If swabbing does [illegible] back to bottom and the invading fluid c[illegible], when running into the hole (pipe or casing), [illegible]ed the fracture pressure of a weak formation. The [illegible], and the pipe run at a spe[illegible] pressure below the minimum fracture pressur[illegible]mber that this is necessary anywhere in bo[illegible] to the open hole even when the bit is i[illegible].

Insufficient Mu[illegible]: [illegible] result from too low a mud density than the previo[illegible] occurs while drilling, due to insufficient mu[illegible] has occurred or that poor engineerin[illegible] any event, pressure trends and plots will h[illegible] and a geopressured formation witho[illegible] unconformity m[illegible] also changes in lithology or drilling practices may h[illegible].

Poor Well Plan[illegible]: [illegible] have a great bearing on well control. [illegible] progressively d[illegible] set; otherwise a situation may arise where it is [illegible] kicks or lost circulation. Well control is [illegible] it should not be overstated to the point [illegible] reduced.

Lost Circulation: Raising the mud density to a value that exceeds the lowest fractu[illegible] was in the 40[illegible] likely to be d[illegible] pore pressure than an abnormally p[illegible] setting casing after drilling through a ge[illegible] density is kept high to balance these formations. I[illegible] pressured for[illegible] the fluid leve[illegible] due to lost circulation and the resulting loss [illegible] may allow an influx of formation fluids, result[illegible] zone and a lo[illegible] same hole section are ingredients for a kick. The [illegible] observation are necessary to successful[illegible]

Recognition of Ki[illegible]

The only tim[illegible]rning is when drilling offshore and there is [illegible] the wellhead and the rig. However, th[illegible] occurring. In[illegible] the borehole and mud pits are a closed circul[illegible] the formation will result in a ch[illegible] during lost circulation. The annulus is not full and cannot be filled. When the rate of loss is grea[illegible] pumped into the hole, it [illegible]ls. A major influx may occur and it will not be d[illegible] such an event occurs, the well should be shut in, a[illegible] made by stri[illegible] and the hole can be filled using the choke and ki[illegible]

Sequence of Ever[illegible]

In most case[illegible] can lead to a kick while drilling[illegible] while others may be accentuated. [illegible] remedial act[illegible]mizing the potential hazards and costs.

1. Th[illegible] need not ne[illegible] in porosity, permeability and pr[illegible]me that it does. The magnitude of [illegible] on the formation

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characteristics. Rega[illegible]nt drilling break should [illegible]

This is done by: (1) picking up the kelly so the kelly bushings are about 10 ft above the [illegible] pumps, and (3) observing the fluid l[illegible] if the well is flowing. This may be [illegible] as the level will fluctuate with the he[illegible]stances the flowcheck should co[illegible]tes, or be conducted by circula[illegible] and the trip tank volume observed for [illegible] it should be shut-in and any resul[illegible]

2. The second indicatio[illegible]mation that a kick is taking place, [illegible]rate at the flowline. Flow of for[illegible] return flowrate to inc[illegible]urrently with, or shortly after the drill break. The invading fluid is normally lighter than [illegible] column and [illegible] this, in turn, allows the influx rat[illegible] rate of increase wi[illegible] prop[illegible]ation into the formation.

3. Hookload may be se[illegible] the lower density invading fluid and fl[illegible] fluid is great enough [illegible] in hookload, as the drillstring is lifte[illegible]

4. An increase in pit vo[illegible] separate mechanisms: (1) the [illegible] increase in mud volu[illegible] expansion in the ann[illegible]e and pit volume.

5. A pump pre[illegible]e increase becomes no[illegible]ck fluid has been displaced some dista[illegible]

6. A reduction in flowli[illegible] invading fluids reach the surface. Th[illegible] may be large or unnoticeable with a water kick (depending on the mud density[illegible]ved in the kick fluids and as the kick[illegible] will occur.

During drilling operations, it i[illegible] on as many sensors as possible. However, [illegible] unwise to depend on only one [illegible]events. For example, co[illegible]tem may mask a volume increase, or p[illegible]of flowrate and volume increases, wh[illegible]ficult.

During Connections

[illegible]between equivalent circulating density and pore pressure), flow into the annulus may occur when the pumps are shut off. This is ca[illegible]he annular pressure loss, which increases the [illegible]ile circulating. When the kelly is lifted, swab p[illegible]ce bottomhole pressure. An increase in hookload [illegible]d has invaded the hole as the less dense invadi[illegible] effect on the drillstring, hence the higher ho[illegible]

A kick taken [illegible] the same as [illegible]

1. Th[illegible]mps are first shut off. This can be mo[illegible]w sensor and a PVT (Pit Volume To[illegible]
2. An[illegible]ced only after the co[illegible]pumps are shut off, some of the mu[illegible] will flow back into the active pit. When the levels have stabilized, after the pumps are restarted[illegible]connection indicates that[illegible]ud from the surface equipment should[illegible]rt of each new job and re-established pe[illegible] increase on a connection may be normal, while a 3 bbl increase may be s[illegible]
3. Pump pressure a[illegible]those experienced while drilling ma[illegible]nnections. However, the flo[illegible]onnection.
4. Mud density redu[illegible] while drilling.

Recognition of kicks during[illegible]monitoring of the return flow sensor. After th[illegible] should indicate an absolute[illegible]ver, on some rigs a long sloping flowline may [illegible]ter the pumps have been shut dow[illegible] trickle will indicate a kick. [illegible]e mud density will disclose small mud cuts ca[illegible]ccompanied by connection gases, but co[illegible] of a kick during a conn[illegible]

While T[illegible]

[illegible] are greatly simplified when the bit is near the bottom of the ho[illegible]erations have the [illegible] standing on the rig floor, it is impossible to ge[illegible]m of the hole. During trips, the same annular pr[illegible]

When the drill p[illegible] mud regularly. I[illegible]me volume of mud to replace the volume of pi[illegible]e withdrawn, it is an indication that formation fluid is displacing mud [illegible] common while [illegible]lly circulate through a trip tank while tripping o[illegible] decrease in trip tank volume, against the calcu[illegible]s required so discrepancies can be noticed. In INT[illegible]onitor program provides comparison vol[illegible] log" provides a [illegible]ons and fill up during trips.

Older rigs may [illegible] on monitoring o[illegible] strokes. PVT monitoring provides a nece[illegible] of the large surface area of the active pits, p[illegible] efficient displac[illegible]s and stroke-rates, and pump strokes are ofte[illegible] of fluid displaced, while tripping out. It i[illegible] volume of the pi[illegible] removed, due to static filtration into the formation.

If a kick occurs [illegible], every effort must be made to run back in the h[illegible] annular prevent[illegible]e bit to be run back to TD.

Kick Tolerance

Kick tolerance i[illegible] be encountered i[illegible] density and the [illegible]ownhole fracturing occurring.

During drilling, [illegible]be exceeded because if a kick occurs there is a considerable chance that an underground blowout will occur when the [illegible]

A complete desc[illegible] calculations can [illegible]*Pressure Evaluation*" manual (P/N 80824H).

Kick [illegible]

Within the oil industry, there are three recognized kick control procedures. 1) Driller's, [illegible] selection of which to use will depend [illegible] uids that have entered the well, the rig's [illegible] fracture pressure in the open hole, a[illegible] well control policies. Determinatio[illegible] ethod (assuming their company po[illegible] determined by the demands of [illegible]

- Th[illegible]
- Su[illegible] flu[illegible]
- Do[illegible]nhole stresses are applied to formations during kill op[illegible]ration
- The comp[illegible] implemen[illegible] experience

It is the responsibili[illegible] of th[illegible] representative to decide which metho[illegible] Under no circumstance should INTEQ perso[illegible]on.

Each of the previou[illegible] oints[illegible] relative importance to the kick situation [illegible] before implementing the selected kill method. In the follo[illegible] points will illustrate the reasoning beh[illegible]ividual situations.

The Time Factor

The total am[illegible] is important, [illegible]as. This is because the "gas bubble" will percolat[illegible]

There may al[illegible] mud system [illegible] may cause the mud cake to flocculate,[illegible] danger of sticking.

Considerable[illegible] mud, but more importantly i[illegible] the time for the kill operation to be completed. The strains and pressure[illegible] of safety and cost. Therefore, depending on the kick situation, the decision as to which method to use must be based on these prioriti[illegible]

The kill procedu [illegible] initial waiting time are the two circulati [illegible] the concurrent method. In both of these [illegible] after the shut-in pressures are rec [illegible] taken to weight up the mud is less than one cir [illegible] rculation, method may be preferred. In [illegible] time required for the two circulation meth [illegible] cause excessive [illegible]

Surface Pressures

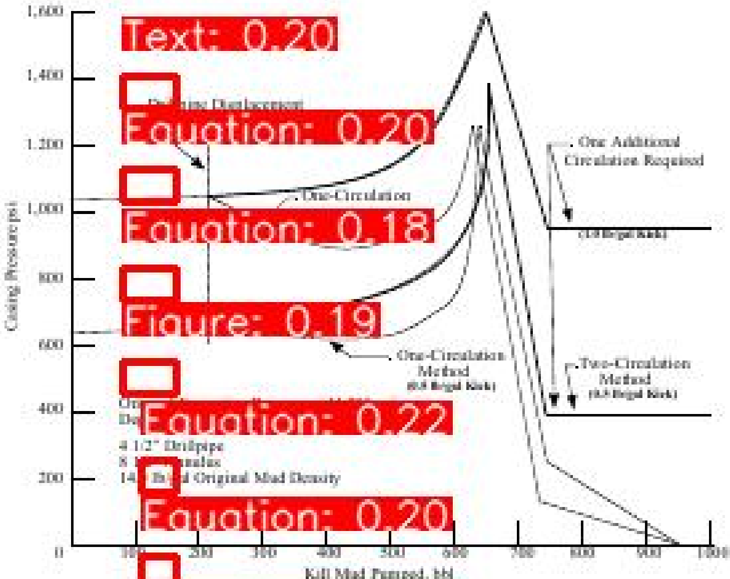
If a gas kick is t [illegible] during the cours [illegible] expansion as it [illegible] expansion is not all [illegible] wed to occur, seve [illegible] placed on the annulus and surface equipment. For [illegible] procedures utilize a constant drillpipe pressur [illegible] rough a variable choke) during c [illegible]

The kill procedu [illegible] must be used if the kick toleranc [illegible] shows the different surface pressure require [illegible] and two circulat [illegible]

The first differe [illegible] with kill mud. W [illegible] ssure constant (with the constant pump r [illegible] begins to decrease as a result of the kill mud hydros [illegible] procedure.

This initial decr [illegible] method, since the mud density has [illegible] casing pressure increases as the [illegible] The second pressure differe [illegible] s the surface. The two circulation meth [illegible] which is the result of circulating the o [illegible]

Also, after one c [illegible] the one circulation method has kille [illegible] ero surface pressure, whereas the two circulation [illegible] equal to that of the shut in drillpipe [illegible]



F[illegible] produced during the one and two circulation kill methods

Downhole Str[illegible]

Downh[illegible]stresses are prime concern during kill operations. If the extra stresse[illegible]posed by the kick are greater than the minimum fracture pressure i[illegible]

Similarly, procedures which through its implementation, places high stresses o[illegible]he wellb[illegible] hould [illegible] e use[illegible] prefer[illegible] to others which impose lower stresse[illegible]bove points illustrates that the one[illegible]mum stresses on both the wellbore and[illegible] maximum stresses oc[illegible] wells with higher pres[illegible]ures. At any point in the borehole, the maximum [illegible]n when the top of the kick fluid reaches [illegible]

Generally, if [illegible] not occur on initial shut-in, they will [illegible] kill process (if the correct procedure is chosen and [illegible]

Formulas that ar[illegible] to be calculated and predicted are pre[illegible]

Procedural Complex[illegible]

[illegible] is dependent on the ease with which it may be reliably executed. If a kill procedure is difficult to comprehend and implement, its re[illegible]

The one and two[illegible]le in both theory and execution. Choi[illegible]on the other points (time factor, sur[illegible] and any other limitations[illegible] relatively compl[illegible]lity may be reduced through its intricacy. Bec[illegible]

It is important t[illegible]ulated on deviated wells must use vertica[illegible]h. Measured lengths are used for ECD calcula[illegible] the hydrostatic p[illegible]

Situations may a[illegible] approaching or slightly exceeding the actual or estimated minimum fracture pressur[illegible]not be shut-in, and an alternate method of kill co[illegible] Maximum pressures at the surface are determined b[illegible]

1. The m[illegible]head will hold
2. The m[illegible] the casing will hold (burst pressure)
3. The m[illegible] will hold

Table 1: Formu[illegible] Kill Procedures

Hydrostatic Pres[illegible] [illegible] x 0.0519

where: M[illegible]
TVD = True Vertical Depth (ft)

Circulating Press[illegible] [illegible]

where: P_{la} = A[illegible]

Initial Circulating Pre[illegible] (psi) [illegible] SPR + SIDP

where: SPR = [illegible]
SIDP= S[illegible]

Final Circulating Pres[illegible] (psi) [illegible] (KMW / MW) x SPR

where: K[illegible]

Kill Mud Weigh[illegible] [illegible] MW + (SIDP / (TVD x 0.0519))

Formation Pressure (psi): SIDP + (MW [illegible]

Density of influx (ppg): MW - [(SICP - SIDP)/(L x 0.0519)]

where: SICP= Shut in casing pressure (psi)
L = Leng[illegible]

Length of kick around drill col[illegible]

Pit Gain (bbls)/ Annular Volume around collars (bbls/ft)

Length of kick, drill collars and drill pipe (ft):

Collar Length + [[illegible] Volume) / (D_1^2 - D_2^2 x 0.00[illegible])

where: D_1 = hole diameter (inches)
D_2 = drillpipe diameter (inches)

Gas bubble migration rate (psi/hr): ∅Pa / (0.0519 x MW)

where: ∅Pa = pressure change o[illegible] interval (hr)

Barite required (sk/100 bbls mud):

1490 x (KMW - MW) / ([illegible] - KMW)

Volume increase caused by weighting up:

100 x (KMW - MW) / (35.8 - KMW)

The drill pipe pressure can be used as [illegible] while the casing pressure is affected by the type and amount of fluid influx. When the density of the kick fluid is known, the [illegible]d;

Influx Density (psi/ft)	**Influx Ty**[illegible]
0.05 - 0.2	gas
0.2 - 0.4	combination of gas/oil and or seawater
0.4 - 0.5	oil or seawater

Kick Control Meth[illegible]

All kill proce[illegible] drillstring geometry, hole geometry, m[illegible] pressure losses, and fracture pressure. Important da[illegible] initiating kill procedures include:

1. Ci[illegible]
2. Su[illegible] (in strokes and minutes)
3. Bit to s[illegible]
4. Maxim[illegible]
5. Formu[illegible]
6. Formu[illegible]ing the cha[illegible] heavier mud

7. The clients [illegible]

For a well to be killed successfully, the pressure in the formation must be kept under contr[illegible]tion. The only exception is in cases when the [illegible]. The simplest me[illegible]l the drillpipe pressure by running the kill [illegible] regulating the c[illegible]

The three main [illegible]

1. The D[illegible]

2. The W[illegible]

3. The C[illegible]

The EAP Kick and Ki[illegible]r programs provides printou[illegible]plots a record of progress du[illegible]

Th[illegible]

Wh[illegible]dures is as follows:

1. Pic[illegible]e position of tool joints in relation to the[illegible]
2. Sto[illegible]
3. Open th[illegible]oke l[illegible]e.
4. Close th[illegible]
5. Close th[illegible]
6. Record t[illegible]
7. Record [illegible]stabilize[illegible]

Once the well is s[illegible]d density, initial and final cir[illegible] If the kick fluid is gas, the b[illegible]his will cause a slow rise i[illegible]nd casing). If the pressures begin to[illegible]ed from the choke, to release this "tra[illegible] repeated until the drillpipe pres[illegible]

The first circ[illegible] mud. The ch[illegible] the same time the pumps are started up to the kill[illegible] manipulated [illegible]ting Pressure (ICP) on the drillpipe. As [illegible] rise drastical[illegible] will drop slig[illegible]

When the ini[illegible]out, the pumps are stopped and the choke closed. At this time, the two surface pressures (SIDP & SICP) should be the[illegible]

During the fi[illegible]sed to the kill mud density. [illegible]has been achieved, the kill mud is circulated. A[illegible] speed increas[illegible]annulus pressure kept constant). The annular [illegible]manipulating the choke until the kill mud has [illegible] drillpipe pres[illegible]initial circulating pressure to the final circulat[illegible]).

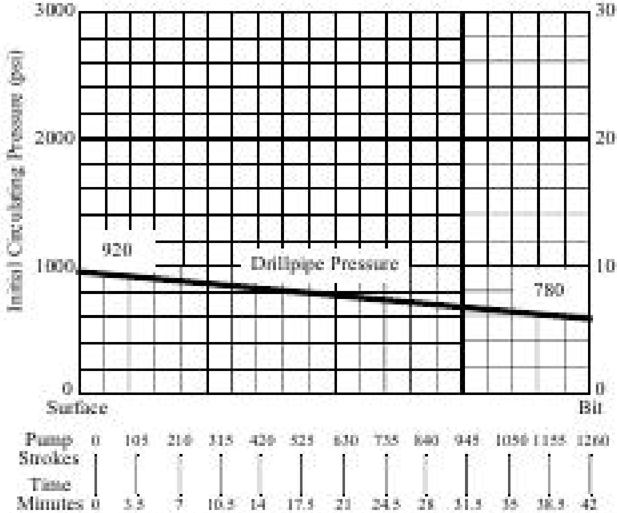
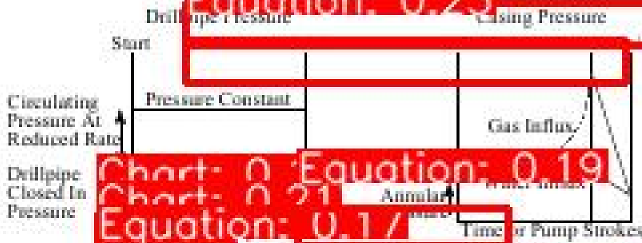


Figure 0-2Drillpipe/pressure plot of kill mud being pumped down the drillpipe

When kill mud reaches the bit, it is good practice to shut-in the well. The drillpipe pressure should fall to zero; if it doesn't, a few more barrels should be pumped to ensure that the kill mud has reached the bit. If the drillpipe pressure is still greater than zero when the pump is stopped and the choke closed, the kick control figures should be rechecked. When satisfied, pumping is restarted, but now the drillpipe pressure is kept constant as the kill mud displaces the mud in the annulus. When the kick fluids and original mud have been displaced, the choke should be wide open. The pump should be shut down and both SIDP & SICP should read zero. If so, the well should then be observed for flow. The kick is now killed and mud should be circulated to condition the hole, and at the same time the trip margin (if any) should be added.

Figure 8-3 ... behavior as the first and second circul...



Figu...

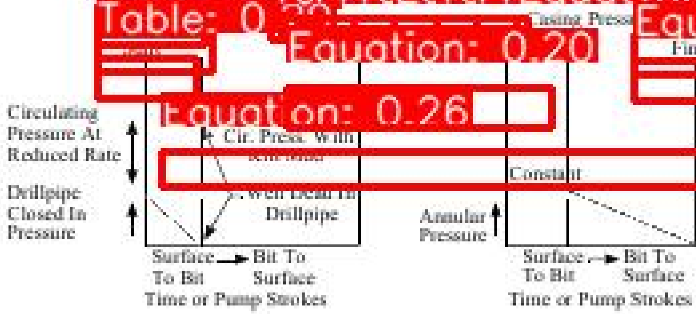


Figure 8-4Second circulation during the drillers method.

The Engineer's Method

This is usually a more effective method of killing a kick than the driller's method, if time is not a prime concern (Figure 8-5). Kill mud is pumped into the drillpipe as soon as it is ready, which tends to reduce the high annular pressures associated with gas kicks. The same shut-in procedures are used as outlined in the previous section.

When all the calculations have been performed, the mud density is raised immediately to the calculated kill mud density. When the kill mud volume is ready, the pumps are started and the choke slowly opened, while keeping the annular pres... ...ached kill rate. The choke is then regulated in such a way as to decrease the drillpipe pressure ... the bit, at which point the final circulating pressure is reached.

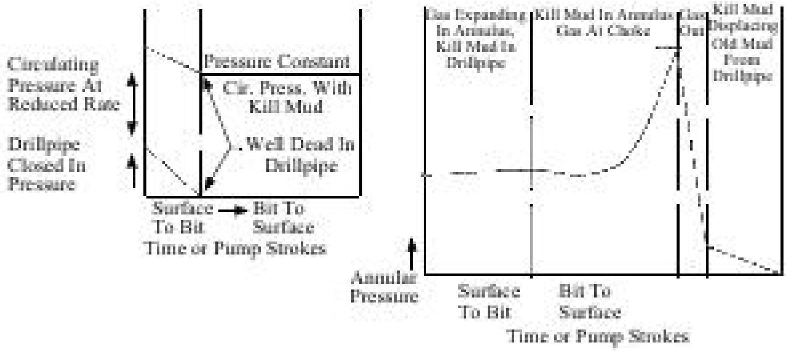


Figure 0-5Drillpipe and annular pressure curves during the engineer's kill method

Pumping is continued, holding the drillpipe pressure constant by adjusting the choke. When the kick fluids have been displaced, and further volume has been displaced equal to the pipe volume, the SIDP should be zero. The kick should be killed and the well checked for flow. Further circulations can be performed to condition the hole and to add any trip margin. Figure 8-6 shows the variations in drillpipe and casing pressures as the kill procedure is implemented.

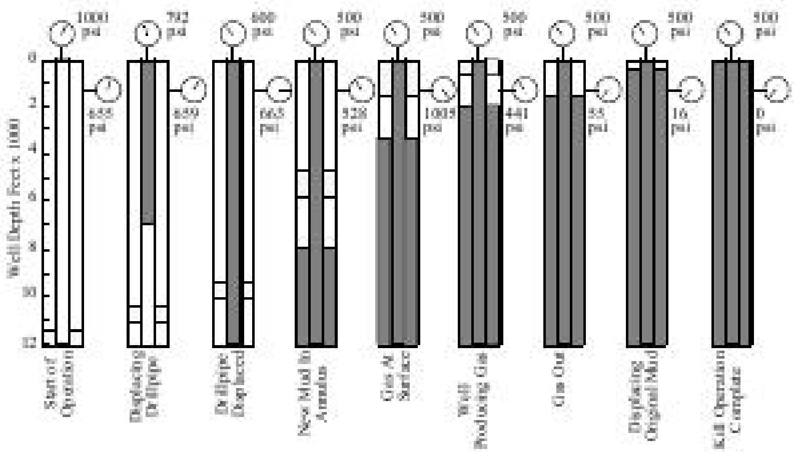


Figure 0-6Shows diagrammatically the displacement of the original mud with kill mud, with example pressures, using the engineers method.

The C[illegible]

[illegible] ble method of the three. Its main value li[illegible] riller's and engineer's [illegible] mmediately upon receipt of the shut-in [illegible] all the surface mud has been weighte[illegible] is pumped d[illegible] ed. The rate at which the mud density is rai[illegible] g facilities available and the capability of [illegible] drillpipe can [illegible] of the bottom [illegible] d drillpipe pressure) difficult.

Provided the [illegible] communication, and the method is co[illegible] can be a very effective way of killing a kick [illegible] with kill mud [illegible] different densities of the mud. The shut-in proce[illegible] is the same as that outlined previously. When all the kick information [illegible] initial circula[illegible] ched at the designated kill rate. The mud should b[illegible] changes in th[illegible] tor is informed. The total pump strokes are c[illegible] e chart when the new density is pumped and [illegible]

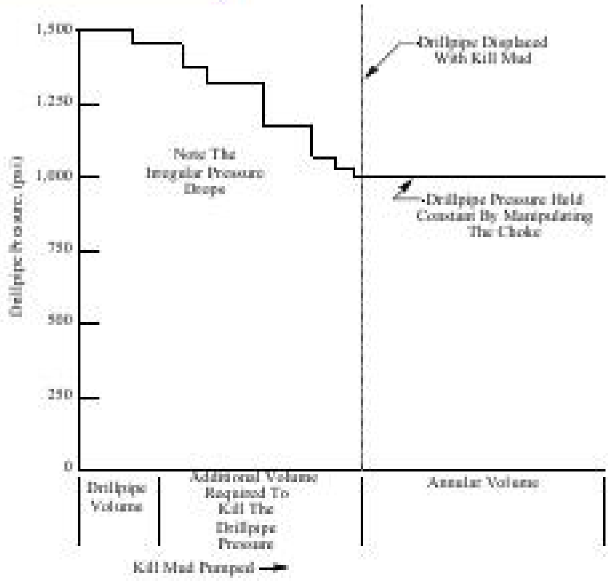


Figure 0-7Typical irregular drillpipe pressure reductions during concurrent method

When the final kill mud reaches the bit, the final circulating pressure will be reached and from this point on the drillpipe pressure should be kept constant until the operation is completed.

Pre[illegible]eory

S[illegible]ut-in Procedures

[illegible] are noticed, steps [illegible] If tripping, under no circumstances should the pi[illegible] the annular preventer open and [illegible] is to kill the well, any concerns about stuck p[illegible]s should be secondary. Two types of shut-in are p[illegible]

Hard Shut-In[illegible]

Soft Shut-In: [illegible]
The choke is then closed.

One argumen[illegible] water-hammer effect of abru[illegible] of well contr[illegible]l should the casing pressure become excessive. The primary argument aga[illegible] occurs while the shut-in procedures are execute[illegible]

Within the in[illegible]ustry, there is stil[illegible] d[illegible] which shut-in method should be use[illegible] no has not be[illegible]oke method is unreliable. In any case, it is the[illegible] what method should be used.

Shut-in proc[illegible] operations. T[illegible]res are dependent upon whether the rig is flo[illegible] in procedure[illegible]

Drilling on [illegible]

These includ[illegible] platforms.

1. On[illegible] kick have been observed, the kelly sho[illegible] all[illegible] an[illegible]ular preventer also develops a better seal around drillpipe tha[illegible]
2. Th[illegible]
3. Th[illegible]
4. Re[illegible]

Tripping on a fixed rig:

Once the warning [illegible], the top tool joint should be set in [illegible]

1. An op[illegible] pipe. [illegible] up the pipe [illegible]llation (a float valve [illegible]ow stripping back to bottom).

2. The safety valve sho[illegible]enter is closed.

3. Pick up, and make u[illegible]

4. Open the sa[illegible]

5. Record the SIDP, SI[illegible]

Drilling on a floating rig:

These are semi-subme[illegible]

The major difference [illegible]k is on the seafloor and pipe movement r[illegible]ve to [illegible] compensator). To sol[illegible]o a set of closed rams and the w[illegible]ms. With the BOP stack so far [illegible] the [illegible] interfering with the cl[illegible]g of [illegible]e preventers always e[illegible] for this problem[illegible] is performe[illegible]rior to the possibility of tak[illegible]closed and th[illegible]rill string lowered until a tool joint [illegible] recorded.

1-3 These [illegible] fixed rig.

4. Close [illegible]

5. Reduc[illegible] preventer.

6. Lowe[illegible] supported entirely by the rams.

7. Recor[illegible]

Tripping on a f[illegible]

1-4. These [illegible]

5. Open [illegible]

6. Close [illegible]

7. Reduc[illegible] pressure on the annular preventer.

8. L[illegible]wer th[illegible]ned by the rams.

9. Record the SIDP, SICP and the pit gain.

Diverter procedu[illegible]

During initial spud[illegible]g and early drilling, a s[illegible]wout is difficult to contr[illegible] and ma[illegible] effort must b[illegible] the rig. Care must be taken to ensu[illegible] the diverter lines are opened.

1. As[illegible]
   joi[illegible]

2. Sh[illegible]

3. Op[illegible]

4. Cl[illegible]ter[illegible]

5. Start pu[illegible]ng at [illegible] fast rate.

When kicks occur [illegible] sometimes becomes necessary to lower the strin[illegible] proper surface pressures [illegible] The correct procedure is to either strip [illegible]P closed.

The difference bet[illegible]ship between the string weight and [illegible] upward force exer[illegible] greater than the weight of the [illegible] That is, pressure will [illegible]ing to run it in. If the string weight is greater tha[illegible]

Drillpipe Fl[illegible]

If a kick occ[illegible]talled in the drillstring, both fluid and pressure movement up the string will be prevented. It is therefore impossible t[illegible]

If the slow ci[illegible] SIDP as foll[illegible]

1. Sh[illegible]

2. St[illegible]hem at the SCR.

3. As[illegible]oke to regulate the SICP at the [illegible] shut-in.

4. Af[illegible] the kill rate and the casing pr[illegible] the pressure on the drillpipe wh[illegible]orded.

5. The pumps [illegible]

SIDP = Circulating pressure - SCR pressure

If the SCR is not known the SIDP can be [illegible]

1. Shut i[illegible]
2. Line u[illegible] stand pipe.
3. Start pump[illegible]
4. Gradually increase th[illegible] the pumps begin to move fluid down the drill pipe.
5. The SIDP is [illegible] the fluid movement. It is assum[illegible] the amount needed to overcome t[illegible] of the valve.

Floater Operations:

In shallow water oper[illegible] that on land, with resp[illegible] water depths increases, it becomes increasin[illegible] pressures (initial circulating pr[illegible] pressure) due to the small choke line I.D. from th[illegible] thorough understanding of cho[illegible] loss) is an important aspect of subsea well co[illegible]

Choke line fricti[illegible] through 8-8c):

The choke line f[illegible] pumping down the choke and up th[illegible] rate (Figure 8-8a).

Figure 8-8a

The choke line f[illegible] circulating pressures recorded while circulating down the drillpipe and up the choke an [illegible] up the riser (Figures 8-8b and 8-8c).

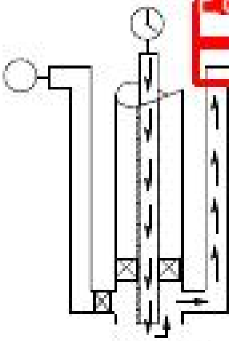


Figure 8-8b

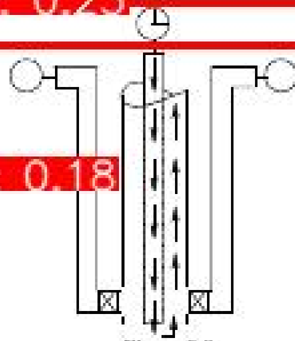


Figure 8-8c

The difference between t[illegible]tion pressure.

Having calculated the pr[illegible] the riser and choke line, it is necessar[illegible]g the initial and final circulating pres[illegible] kick will be done through the choke, [illegible] the ICP and FCP is that derived from the slo[illegible]circulation up the riser, not the choke!

It is importan[illegible] because this pressure is imposed on a[illegible]OP stack, even back up to the drillpipe [illegible]

With a surfa[illegible] pressure loss[illegible]

1. Pr[illegible]

2. Pr[illegible]

3. Pr[illegible]sure loss through the drill collars

4. Pr[illegible]

5. Pr[illegible]

The annular [illegible] When killing a well from a floater, the annular pressure loss will include the choke lin[illegible]e well must be killed using the choke and th[illegible]o the list:

6. Pressure loss through the choke line.

The deeper t[illegible]e wa[illegible] pressure loss, and the more significa[illegible]

In summary, the [illegible] added to the annular pressure loss wh[illegible]m of the hole to the surface, through[illegible]

For example:

Using a slow cir[illegible] of 1500 psi, and a slow circulating press[illegible] psi up the riser, the choke line pr[illegible]ssure loss can be calculate[illegible]aken and the following pressures are re[illegible]

S[illegible]00 psi

All of the neces[illegible] to circulating. If the standard proced[illegible] brought up to sp[illegible], maintaining the casing pressure constant, the gauge would read 300 psi.

However, this w[illegible] The 300 psi read[illegible] is only valid while shut-in. Once fluid move[illegible] casing pressure. [illegible]lating, the kill line must be used as [illegible]ple, an extra 300 psi would have been impo[illegible]

What should hap[illegible] is that the choke should be [illegible]he pressure to drop to zero. The casing press[illegible] pressure will be [illegible]d ICP. The choke line friction pressure drop of [illegible] for the SICP of 300 psi.

In another exam[illegible] (Figure 5-9):

S[illegible]00 psi

C[illegible]oke line pressure drop = 300 psi

The casing press[illegible]ile the pumps are brought up to speed. The de[illegible] or 100 psi while[illegible]uld be opened up and adjusted to 100 psi, the cho[illegible] retain the [illegible] and 8-9b show the shut-in and initial cir[illegible]

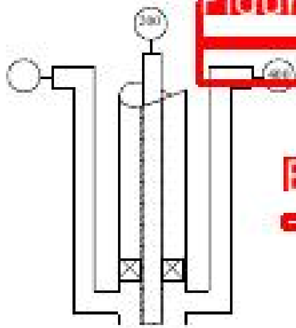


Figure 8-9a

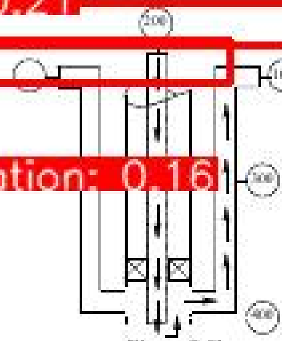


Figure 8-9b

As the water depth increases, the pressure drop through the choke line increases. For example:

SIDP = 200 psi   SICP = 300 psi

Choke lin[illegible]

Note that the choke line [illegible]essure drop is greater than the SICP. In this instance, it is impossible [illegible] open the choke to substitute all of the choke pressure loss [illegible] surface choke pressure will read zero but 100 [illegible]low the BOP stack. This is in effect an "ov[illegible] result in the drilpipe pressure increasing by [illegible] as the choke [illegible] still already open. F[illegible] illustrate this overkill. To reduce the "overkill", [illegible]

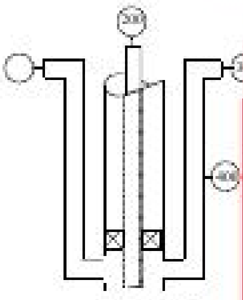


Figure 8-9c

Figure 8-9e

reduced. This is accomplished by either reducing the slow circulating rate [illegible] gure 8-9c, illustrates circulating with [illegible]

If the SICP is gr[illegible] than the choke line friction pressure loss, it is possible to circulate out t[illegible] the choke frictio[illegible] the old mud is in the choke line, the p[illegible] measured by the slow circulating rate. [illegible] the choke line, the choke line friction pressure [illegible] ratio of the kill mud density to the original mud. Fo[illegible]

S[illegible] ough choke 1300 psi.

S[illegible] through the riser 1000 psi.

This gives a cho[illegible] friction pressure loss of 300 psi. If the old mud density was 10 p[illegible] choke friction pressure loss wi[illegible] become:

300 x 11/10 = 330 psi

This will occur when the kill mud [illegible] pressure can be [illegible] a slower rate or by using both the choke and kill li[illegible] optimum rate wi[illegible] necessary to use the cementing pump to circula[illegible] be taken with th[illegible] cementing unit prior to this!

As stated earlier [illegible] kicks occurring while [illegible] rig will usually give hig[illegible] also, only a small por[illegible] required to completely fill the choke line and b[illegible] length of the kic[illegible] mportant to detect kicks as rapidly as possi[illegible] return flow sensors be [illegible]

In deep water su[illegible]

1. It is al[illegible] pressure.
2. The m[illegible] nd mud weight decreases with water [illegible]
3. "Gas [illegible]
4. The ki[illegible]
5. Circul[illegible]
6. Slow [illegible] choke [illegible] using the mud pumps and the cementing pump.

7. Formati[illegible] choke line.

8. Diverter [illegible] mud.

Well Control Equipment

[illegible] n the [illegible] ell ca[illegible] sed by a kick is stopped by using the [illegible] preventers. Multiple blowout preventers used in a series is [illegible] uld be capable of terminating flow under al[illegible]

A BOP stack [illegible] preventers, s[illegible] ter.

Annular pr[illegible]

Commonly referred to as a bag type or spherical preventer, it [illegible] ntracts aro[illegible] nd the drill pipe. The [illegible] bore hole. It is operated hydraulically, utilizing a piston acting on the packer. Once [illegible] pward [illegible] preventers are avail[illegible] ssures, ranging from 2,000 [illegible] be used without pip[illegible] element will be red[illegible] self.

The initial recommended hydrauli[illegible] annular preventers is 1,500 psi. On[illegible] should be reduced slightly to reduc[illegible] packer. One special feature of the [illegible] will allow stripping operations to be carried o[illegible] as the tool joints pass through the preventer. [illegible] be moved slowly through the prev[illegible] acking element.

Some of the m[illegible] preventers are manufactured by Hydril. These p[illegible]ents for different applications:

Packing Type	[illegible]	[illegible]
Natural rubber	[illegible]	[illegible] greater than [illegible]
Synthetic ru[illegible]	[illegible]	Oil bas[illegible] mud w/ aniline [illegible]ints between 165° and 24[illegible] [illegible]peratures >20°F
Neoprene	green	Oil based mud, operating temperatures between 20°F and -30°F

All of the above are suitable for H_2S use.

Both NL Schaffer and Cameron Iron Works also make annular preventers.

Ram Preventers:

Ram type preventers have two opposing packing elements that are closed by moving them together. Rubber p[illegible] elements again, form the seal. A major difference b[illegible] th[illegible]er is that they are desi[illegible] s[illegible]e designed for a certai[illegible] size of pipe and will only work on that type of pipe. Also, [illegible] t[illegible] seal in only one direction. T[illegible] T[illegible]us they will not func[illegible] will n[illegible] that they may accept a[illegible] of ram elements.

Pipe rams: These hav[illegible] that match the diameter of the pip[illegible]prising different pipe sizes, su[illegible] would require two sets[illegible]te both sizes of pipe. These ar[illegible] close around the tubing[illegible]

Blind rams: These are[illegible] no pipe is in the hole. I[illegible] flatten the pipe, but no[illegible]w.

Shear rams: These ar[illegible] designed to cut drill pi[illegible]e when closed. This will result in the dropping of the drillstri[illegible] stack is designed in su[illegible] pipe rams below the shear rams o[illegible] They will stop the flow [illegible] only used as a last r[illegible]nular preventer have faile[illegible]

The ram preventers will have a ma[illegible]ual screw-type locking device that can be used in th[illegible]

Other Comp[illegible]

In addition t[illegible] components, the BOP stack must contain some[illegible] stack to allow [illegible]choke and kill lines.

The BOP sta[illegible] string via a "casing head". This casing/[illegible] of the BOP [illegible]

In certain ca[illegible] controlled m[illegible]his is common in shallow sections due [illegible] a **diverter sy**[illegible] relatively low pressure system, often using t[illegible] line. The div[illegible]ter line will then be opened below the annular preventer to allow the flo[illegible]

The BOP sta[illegible] Additional va[illegible] within the drillstring. These valves inclu[illegible]

Kelly cocks a[illegible] valves may b[illegible] kick occurs. [illegible]ually controlled and they consist of subs with [illegible]ring loaded ball type, a flapper valve type, or dart [illegible] below closin[illegible] drawback of [illegible]eventing a blowout up the string they prevent [illegible]

A manual va[illegible] valve", is us[illegible]ally installed onto the drillpipe after a kick occurs. They usually cont[illegible] through a ho[illegible] off flow completely. Rotating the [illegible] that wireline [illegible] them.

Control of th[illegible] using a **choke**[illegible] must be able to work under a variety of conditions[illegible] capable of w[illegible] the kick flui[illegible]capable of controlling the well using one of [illegible] areas, such as [illegible] since vibrations occur during kill opera[illegible] anchored down, with as few bends as [illegible] high pressure flow conditions.

The system used [illegible] **accumulator**. Hy[illegible]draulic fluid is stored under pressure, the pressure being provided by sto[illegible] is forced into the accumulator by [illegible] en is compressed, sto[illegible] the pressured oil is [illegible] pumps replenish [illegible] the amount of fluid that was used to operate [illegible] also be equipped to allow varying pressur[illegible] constant pressur[illegible] tool joints pass through the packing element[illegible] have minimum working pressures of 120[illegible] and 3000 psi.

Spe[illegible]ms And Procedures

The majority of problems which occur during well control operations are caused by e[illegible]akdown or improper operating procedures.

Excessive Casing [illegible]

Mechanical [illegible] Mechanical failure at the surface can be catastrophic, while formation breakdown can lead to lost circulation, an underground [illegible] fracturing. A "maximum allowable cas[illegible]ined and if casing pressure rises to this maxim[illegible] the well, a decision must be made whe[illegible]

If excessive [illegible] following alternatives may be considered:

1. Th[illegible]

2. Tu[illegible]

3. Close in the well and consider bullheading

With the co[illegible]ment selection and frequent testing of the surface e[illegible] failures are greatly reduced.

Formation b[illegible] if the last casing shoe is shall[illegible]bility of fractures reaching the surface.

If the maximum c[illegible] a kick the decision must be made whether to:

1. Controll[illegible] pressure while all[illegible] me[illegible] and/or formation breakdown.

2. Ad[illegible]imum allowable casing pressure and [illegible] until the well can be shut in. However, the control of a high volume gas flow using the low cho[illegible]

3. Clo[illegible] kick back down the annulus to reduce casing pressure or spot a pill of heavy mud or cement. Th[illegible] breakdown.

If the casing [illegible] the possibility of surface fracturing due to casing or formation failure exists, the we[illegible] the alternatives i[illegible] procedure, pumping a barite pill, pump[illegible] flow until pressure is reduced. If the s[illegible] exceeded and fracturing to the [illegible]ideration can be given to shutting in the well and a[illegible]down to occur.

The Low Choke [illegible]ting and weighting up the mud at its maxi[illegible] maximum allowable casing pressure [illegible] until the mud ha[illegible]nd this may take several circulations. The [illegible] drillpipe pressur[illegible]pon initial closure. After some heavier fl[illegible] well may be shut-in and an estimate of the [illegible]

When using the [illegible] to the mud syste[illegible] applying the maximum allowable casing [illegible]r pressure drop will aid this method. The hig[illegible] (except in the ca[illegible] the choke line friction will be excessive. In these cases, the returns should be circulated up both the choke and kill li[illegible] will not cause s[illegible] imposed choke and kill line friction pressure[illegible]

Low Choke Pr[illegible]

1. Circul[illegible]

2. Start [illegible] kill fluid density.

3. Begin [illegible] maximum allowable casing pressu[illegible] Care must be taken, and observe for los[illegible]

4. Circul[illegible]uces the choke opening in order [illegible] maintain the maximum allowable casing pressure.

5. Shut-i[illegible]-in drill pipe and shut-in casing [illegible]ight (engineers) method or the concu[illegible]rent [illegible]

   To obtain [illegible] prerecorded[illegible]esent fluid density to th[illegible] add it to the [illegible]

6. If the casing pressur[illegible] to be safely shut-in, [illegible]ed, preparations must be made for ei[illegible] plug to seal the kicking form[illegible]

Ki[illegible]sing or Liner

Running liner

Kicks that occur while running line[illegible] manner to a kick that oc[illegible]ar bottom, an attempt should be ma[illegible]an then be circulated out, the hole cond[illegible] be necessary [illegible] casing shoe to prevent the liner from sticking[illegible] drilling fluid[illegible] running of m[illegible]e some of the heavy fluid and may star[illegible]ation, pumping high density fluid into the [illegible] is killed, the [illegible]d the hole conditioned for rerunning th[illegible]n run to the shoe, an attempt should be ma[illegible]

Running cas[illegible]

A kick that o[illegible] extreme problems. Stripping the [illegible] within a few [illegible]t section of casing is in the hole, the annular p[illegible] it upwards, in which case the casing will need to b[illegible] long section of casing, it becomes more likely that the combination of tensional forces, the annulus pressur[illegible] the BOP's (in su[illegible] preventers sh[illegible]e wide open. Due to the small annulu[illegible]asing, pump rates will tend to be slower and th[illegible] will take much longer. Gas entering[illegible] complicate p[illegible] lost circulation and an underground[illegible] resort to gain[illegible] not at bottom[illegible]

Parted or Washe[illegible]

If the drill st[illegible] to preventing[illegible] movement sh[illegible]ully to minimize the chances of the string parting[illegible] parted string, a washed out string, or [illegible] The followin[illegible]

1. Lo[illegible]rted or washed out.

2. Observe the [illegible] ntly lower than the SICP [illegible] e washout or bit (if the bit is off bottom) [illegible]

3. If the influx is below [illegible] percolate up[illegible] purpose in [illegible] upwards it will expand and th[illegible] carefully to prevent further in[illegible]

4. When the influx rise[illegible]) the SICP will be higher than the SID[illegible] circulated out conventionally and [illegible] can be calculated using the following equation:

KMD (ppg) = SIDP / [illegible] 0.0519

The well will not have been s[illegible] drillstring is run back to bottom and all influx f[illegible] replaced with a suitable drilling fluid to maint[illegible]

Stuck Pipe

An influx of formation fluid or [illegible] may cause the drillstring to bec[illegible] Pipe movement (if possible) should be made [illegible] kick, the well must be controlled first. [illegible] under control should drillstring recov[illegible]

Plugged or Packed [illegible]

If one or more bit jets become plugged, the SIDP will increase suddenly while a constant [illegible]. The choke should not be opened to maintain a co[illegible] as this will allow the influx of more fluid. The [illegible] and the well shut in. The SPR should be redete[illegible] e maintained as the pumps are brought up to th[illegible] e, without encountering excessive drill p[illegible] continue the kill[illegible]

If the bit becom[illegible] completely plugged, drillpipe pressure cannot be used to [illegible] mhole pressure and the casing pressure will [illegible] the annulus. The casing pressure should be allowed to rise 100 psi above the initial SICP and small amounts of fluid should b[illegible] for fluid volume. The [illegible] followed. Consideration may be given to [illegible] orating to regain circulation.

Un[illegible]

[illegible] fluids from a high pressure zone into a lower p[illegible] pressure with changes in [illegible] [illegible]ling fluid, or the total loss of drilling flu[illegible] [illegible]nd blowouts. A common cause is the [illegible] annular press[illegible] [illegible] it may be possible to pump LCM in a lig[illegible] down the annulus while killing the high pres[illegible]

The direction [illegible] control proce[illegible] direction of [illegible]ht to be the fracturing of a formation due to shutti[illegible] upward (ass[illegible] deeper zones [illegible] is the primary source of formation flu[illegible]

If, however, [illegible] may be from [illegible]eper zone. The loss of hydrostatic head may in[illegible] the zone of l[illegible]

One method [illegible]

1. As[illegible]
   a. [illegible]
   b. [illegible] density in the pits
   c. [illegible] the heavy mud
   d. Continue to pump a few barrels of mud every 30 minutes to [illegible]
   e. [illegible] buc[illegible]
2. Rig up t[illegible] going do[illegible] the d[illegible]ing out.
   a. Determine the poin[illegible]
   b. Calculate th[illegible] the point of [illegible] The calculated mud density may[illegible] mud density [illegible]

3. Mix a minim[illegible] required mud density or the m[illegible]

Simultaneously;

a. E[illegible]dition

b. C[illegible]

c. B[illegible]t and/or perforate above the bit to maximize the fl[illegible]

4. Pump the mud at a h[illegible] DO NOT STOP UN[illegible]OLE VOLUME OF HEA[illegible] MU[illegible]

5. Run the temperature [illegible] to determine if the well is dead. If it is dead, b[illegible]erun the logs.

This procedure is kno[illegible]as a "[illegible] pumped mud will be cut, the annular density [illegible]ud is pumped. As the annular density increases, [illegible] the back pressure on the formation, resulting in a decrease[illegible] limited volume of mud [illegible] pumping is fast and continuous. A running kill [illegible] accomplished if the mud weight is only 1 to 2 ppg heavier than the estimated botto[illegible]

Lost Circulation

Loss of fluid ret[illegible] head of the drilling fluid in the wellbore, th[illegible] surface or into t[illegible]ulation can occur in naturally occurr[illegible]ous, sub-normally pressured or pressure deplete[illegible] fracturing due t[illegible] lost circulation, [illegible]ep the hole full. The hole can be filled with ei[illegible] fluid pumped sh[illegible]

[illegible] kill a kick can develop in underground blowouts. If a kick is impending or an underground blowout has started, a barite plug may [illegible]he thief zone from the kick. In addition, fine [illegible]d to control slow losses (coarse material that ma[illegible] or choke line should not be used). Occasion[illegible] may be used when bullheading down the annul[illegible]ulation zone should be sealed once the loss zo[illegible] the influx zone.

Weigh[illegible]

In the case of [illegible] blowout, lost circulation, or situations requiring the [illegible] become necessary to [illegible] settling plug. These are deflocculated [illegible] in water or oil, weighing between 18 and 26 pp[illegible] rapid settling [illegible] tion is stopped. Hematite is recommen[illegible] er 22 ppg are required and/or if the influx contai[illegible] (removing th[illegible]

If circulation [illegible] pressure and the influx must be held by [illegible] pressure to a[illegible]

Bullheading

This is defin[illegible] without circulation back to the surface. [illegible] or both. In m[illegible] formation fracturing. This will occur at the weakest point, which is usually the formation near the last casing shoe. [illegible] n prove useful since the fracture or loss zone already exists.

Wells with sh[illegible] nd zones of high permeability [illegible] with long open hole sections and low permeab[illegible]

The quicker [illegible] to be pumpe[illegible] kick will mig[illegible] ndent upon the drilling fluid's density and v[illegible]

There are no [illegible] ading should be performed. At slow rates (th[illegible] the pump rat[illegible] higher pressure will become detrimental [illegible] mp rates are desirable to pump the influx aw[illegible] ome any gas migration.

Once the infl[illegible] normal circulation should be resumed to e[illegible] fluid column. The circulation of kill fluid should be at [illegible] during bullhe[illegible] tured, it may heal with time. If not, further steps [illegible] present as a p[illegible] bullheading provides a useful means of limiting th[illegible] dealt with at the surface.

Bullheading has [illegible]sadvantages that must be considered:

Advantages

1. Preve[illegible] reaching the surface
2. Keeps [illegible]
3. Lower [illegible] are commonly used
4. Useful when underground blowouts occur
5. Can be used with or without pipe in the hole
6. Can be used to kill liner-top leaks

Disadvantages

1. Fractures formations
2. Can burst the casing
3. May break liner top
4. Can plug drillpipe
5. Will lose mud to formations (may therefore be expensive)
6. May pressure up formations, causing a back-flow when circulation is stopped

Kick and Kill Analysis

Input Data

Depth	12000.0 ft.	Pump Rate	30 str/min
V. Depth	11980.0 ft.	Flow Rate	126 gal/min
Inclination	2.00 deg	Pressure	250 psi
Mud Density	10.00 lb/gal		
Leak Off EQMD	15.10 lb/gal		

Influx Data	
Kick Volume	10 bbls
Shut In Casing Pressure	450 psi
Shut In Drillpipe Pressure	400 psi

Calculated Results

Volumes	bbls	Strokes	Minutes
Pipe Capacity	208	2085	69
Hole Annular Volume	1398	14027	466
Riser Annular Volume	180	1801	60
Choke Volume	6	61	2

Total Volumes	bbls	Strokes	Minutes
Circulating through Riser	1785	17913	595
Circulating through Choke	1612	16173	537

Kill Data	Units
Pore Pressure at TD	6624. psi
Kill Mud Density	10.81 lb/gal
Maximum Allowable Annular Pressure	2649. psi
Initial Circulating Pressure	650. psi
Final Circulating Pressure	270. psi
Length of Influx	119.6 ft.
Vertical Length of Influx	119.5 ft.
Estimated Influx Density	1.95 lb/gal
Influx Fluid Type	Gas

Self-C[illegible]

1. List five major causes of kicks.

   a. ______________________________

   b. ______________________________

   c. ______________________________

   d. ______________________________

   e. ______________________________

2. What is the typical s[illegible] observed if a kick is taken during a connection?

   ____

   ____

   ____

   ____

3. Which of the kill methods [illegible]ng the killing procedure?

   (Circle one) Drillers Method Engineers Method

4. What information is requi[illegible]?

   ____

   ____

   ____

5. While killing a well with the "Driller's Method", the first circulation is used to ________________ and the second circulation is used to ________________.

6. Why is the "concurrent method" usually not chosen to kill a well?

   ____

   ____

   ____

7. When th[illegible]e annular preventers are clo[illegible]striping and snubbing [illegible] pipe[illegible]

8. How do pipe rams diff[illegible]

9. What are the disadvant[illegible]

10. Calculate the kill mud density (no safety factor).

SIDP	=	[illegible] psi	MD	=	10.0 ppg
SICP	=	[illegible]	[illegible]	=	10,000 ft.

answer:

11. If the following data is [illegible] has entered the well bore (assume no c[illegible]):

SIDP	=	800 psi	MD	=	15.0 ppg
[illegible]	[illegible]	[illegible]	[illegible]	=	3.5 inch
Pit Gain	=	20 bbl	[illegible]	[illegible]	[illegible]

answer:

Cost Analysis

Upon completion of this chapter, you should be able to:

- Understand the limitations and i[illegible]accuracies of using older methods of analyzing drilling costs.
- [illegible] "[illegible]-per-foot" analysis equation and be [illegible]
- Draw [illegible] be used in economics ev[illegible]
- Perform a gra[illegible] when a bit is no longer cost-[illegible]
- Suggest the p[illegible]per t[illegible]pe of bit and drilling variables to obtain the most cost-eff[illegible]
- Describe the best me[illegible]

Additional Review [illegible]

Baker Hughes INTEQ, *[illegible] Manual*, P/N 80319H

Bourgoyne Jr., Adam, [illegible]PE Textbook Series, Vol. 2, 1986

Moore, Preston, *Drilling Practices Manual*, PennWell Publishing Co., Tulsa, 1986

Whittaker, Alun, *Mud Logging [illegible]*

80270H Rev. B / December 1995 Confidential

Intr[illegible]

The value of accurate [illegible]rilling data cannot be over-emphasized. Reliable, factual data is [illegible] evaluation and review. All informati[illegible]eful, from the moment it is analyzed unt[illegible] planning tool. Wellsite information i[illegible], from the morning tour driller throug[illegible]tions of the operator and service companies.

Computers a[illegible] role in drilling operations and the old adag[illegible] the final "pri[illegible]

At the field l[illegible]vel, the Bit Data Record (Figure 9-1) can be one of the well planners mos[illegible] required to complete this standard for[illegible] and readily available on the rig.

Dull bit eval[illegible]formation, when the grading is objectively p[illegible], reveal erroneous entries in other parts of the f[illegible] rotating time[illegible]

The recent tr[illegible]costlier wells has led to the development[illegible] footage, and [illegible]liminate expensive rig-time and excessive trips. As a result, ever-increasi[illegible]ypes have become available, including ma[illegible]

With these c[illegible]line and the variances in bit cost and/or perfor[illegible] hours, penetr[illegible] significance. One factor that has retained its validity is cost comparison.

To make the [illegible]e newer bits will require that much more empha[illegible] performance.

Cost-[illegible]

The introduction of advanced drill bit designs has not always had the effect of obsoleting ex[illegible]ailability of new designs has increased the nu[illegible] from the various bit manufacturers.

Selection of the [illegible] the variable per[illegible] Thus, the question which needs to be answered is: How can the correct bit be selected for a gi[illegible]

The decision co[illegible] based on some performance criteria, such as [illegible] footage, or maximum penetration rate. Other times [illegible] satisfactory in a[illegible] be satisfactory where drilling costs are changing, and drilling practices and bit selection var[illegible]

A realistic appro[illegible] minimum cost-p[illegible] possible to achieve an optimum relationship betw[illegible] cost.

Cost-per-foot as[illegible] equation:

cost/foot = Hou[illegible]ly Rig Cost (Trip Time + Drilling Time) + Bit Cost / [illegible]ed

Note: *Thi[illegible]. Since these cal[illegible] bit runs, time spent circ[illegible] con[illegible]ections, and so forth, is ignored in the calculations.*

The example be[illegible] evaluates the performance of two different [illegible] 16 are evaluated. Bit number 15 is a j[illegible] milled tooth bit. Bit number 16 is a journal-bearing insert bit.

Bit No.	Bit Cost	Depth Out (ft)	Footage	Rotating [illegible]	Penetration [illegible]	Cost/foot
15	$950	7,547	264	[illegible]	[illegible]	[illegible]
16	$3145	8,510	963	[illegible]	[illegible]	[illegible]

Rig Cost = \$400/hour Trip Time = 1 hr/1000 feet

$$Bit\#15\ \text{cost/ft} = \frac{\$400/\text{hr} \quad (7.5\ hr + 18.5\ hr) + \$950}{264\ \text{feet}} = \$42.99/\text{ft}$$

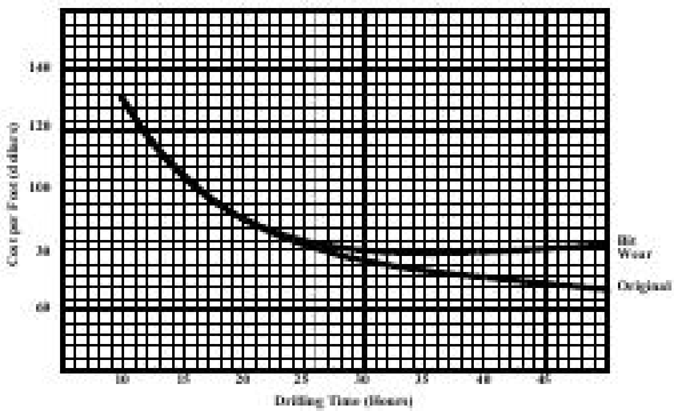
$$Bit\#16\ \text{cost/ft} = \frac{\$400/\text{hr} \quad (8.5\ \text{hr} + 76\ hr) + 3145}{963\ \text{feet}} = \$38.36/\text{ft}$$

If performance is based on using penetration rate as the criteria, bit #15 would appear to be superior. Referring to the cost-per-foot comparison, bit #16 gave the best performance, at \$4.63/ft cheaper than bit #15.

It has been demonstrated that by using this cost-per-foot formula, a bit can be pulled when it no longer becomes economical to drill. When the drilling time-per-foot begins to increase, and the footage drilled-per-time decreases, the cost-per-foot will begin to increase. When that increase is first noticed, it would be economical to pull the bit.

This analysis can also be represented graphically (see below). As drilling begins, the cost-per-foot will decrease rapidly. The longer the bit is in the hole, the more straight the curve becomes. When the curve begins to increase, it becomes necessary to pull the bit.

Cost Curve



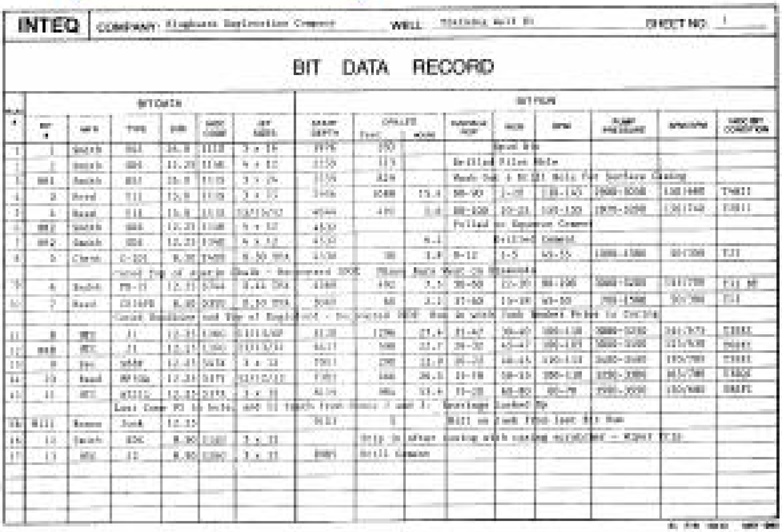


Figure 9-1Bit Data Record

Cost Per Foot Calculations Including Downhole Motors

When downhole motors are used and charged at an hourly rate, they can be included in the cost equation:

$$C = \frac{C_{Rig}(t_D + t_T) + C_{Bit} + C_{Motor}t_D}{d}$$

Where: C is the cost/ft for dril[illegible]
C_{Rig} is the rig cost per hour
C_{Bit} [illegible] cost (each)
C_{Motor} [illegible] per hour of drilling
d is the distance drilled
t_D [illegible]
t_T [illegible]

The following example is a case history. The above equation was used to qualify the savings to an operator in the North Sea when drilling a very hard conglomerate formation with an impregnated diamond bit and a turbine. Calculations were made based on all the bit runs through the conglomerate formation on five different wells.

The followin[illegible]ons:

C_{Rig} = £ 2,000 per hour
t_t = 1,000 ft/hr
C_{Bit} = £ 4,000 per insert bit
= £ 19,000 per fixed cutter bit
C_{Motor} = £ 200 per [illegible]

In the following table, the client's cost per foot for drilling the conglomerate section has been calculated for all the insert bit runs, for two PDC bit runs and for one run with a diamond bit.

In this exercise calculate the client's cost per foot for drilling with the impregnated diamond bit.

Well No.	Bit Style	C (rig) (£/hr)	$t_{(t)}$ (hrs)	$t_{(d)}$ (hrs)	C (bit) (£)	C (mtr) (£/hr)	d (ft)	Cost (ttl) (£/ft)
1	Insert Bit	2,000	13.2	16.0	4,000	-	68	917.60
	Insert Bit	2,000	13.8	13.0	4,000	-	26	2,215.40
	Insert Bit	2,000	13.8	26.5	4,000	-	65	1,301.50
	Insert Bit	2,000	13.9	30.0	4,000	-	93	987.10
	PDC Bit	2,000	14.0	24.5	19,000	-	52	1,846.20
	PDC Bit	2,000	14.1	13.0	19,000	-	63	1,161.90
	PDC Bit	2,000	14.2	30.0	4,000	-	101	914.90
	Insert Bit	2,000	14.3	29.0	4,000	-	117	774.40
	Insert Bit	2,000	14.4	18.0	4,000	-	60	1,346.70
	Insert Bit	2,000	14.5	23.0	19,000	200	134	735.80
	Insert Bit							
	Insert Bit							
	PDC Bit							
2	Insert Bit	2,000	13.4	41.3	4,000	-	125	907.20
	Insert Bit	2,000	13.8	19.4	4,000	-	67	1,050.70
	Insert Bit	2,000	13.9	13.4	4,000	-	53	1,105.70
	Insert Bit	2,000	14.0	9.2	4,000	-	32	157.50
	Insert Bit	2,000	14.0	28.9	4,000	-	152	590.80
3	Insert Bit	2,000	12.6	2.4	4,000	-	23	1,478.00
	Insert Bit	2,000	12.8	23.0	4,000	-	212	356.80
	Insert Bit	2,000	12.9	3.0	4,000	-	18	1,988.90
	Insert Bit	2,000	12.9	19.2	4,000	-	120	588.30
4	Impregnated Bit	2,000	15.1	58.5	19,000	200	495	
	Impregnated Bit	2,000	14.2	39.5	19,000	200	403	
	Impregnated Bit	2,000	15.4	39.5	19,000	200	317	
	Impregnated Bit	2,000	15.7	42.0	19,000	200	358	
5	Impregnated Bit	2,000	14.2	57.5	19,000	200	540	
	Impregnated Bit	2,000	14.2	68.5	19,000	200	283	

[illegible] determine the average cost per foot for [illegible] shows the results.

Bit Type	[illegible] Bit Runs	[illegible] (£/ft)	[illegible] Section of Conglomerate (£)
Insert Bits	[illegible]	[illegible]	[illegible]
PDC Bits	[illegible]	1,504.[illegible]	2,25[illegible]
PDC Bits [illegible]	[illegible]	735.[illegible]	[illegible]
Impregnated [illegible]	[illegible]	424.10	[illegible]

[illegible] ction of congl[illegible] ,039,950 com[illegible] [illegible] ared to PDC b[illegible]

Target Cost Per Foot and Target ROP

[illegible] generating perfor[illegible] proposals for cli[illegible] ot can be calculated based on information fro[illegible] that used competitor products. This target cost [illegible] applying a slidi[illegible] scale hourly rate for motor operations. If the target is met or e[illegible] arged at normal list price; if it is not, then the hour[illegible] target fi[illegible] to persu[illegible]de clie[illegible].

Before we can p[illegible] reasonably sure [illegible] a minimum ROP. This ROP is the required d[illegible] the proposed cost per foot figure, and our p[illegible] be determined w[illegible]

Note: *All [illegible] exa[illegible] the [illegible] ROP necessary, and so forth.*

[illegible]

Since:

$C = $ [illegible]

then:

$$t_D = \frac{C\,d - C_{Bit} - C_{Rig}\,t_t}{C_{Rig} + C_{Motor}}$$

Example 1, Baker Hughes INTEQ [illegible]

Offset-well cost [illegible]

Rig Cost	=	£ 2,083 per hour
Bit Cost	[illegible]	[illegible]
Section Length	[illegible]	[illegible]
Drilling Time	[illegible]	[illegible] hours
Trip Time	[illegible]	[illegible] hours ([illegible]

Cost per foot [illegible] [illegible] 261.8 + 101) + 25,000 [illegible]

C [illegible] £ 3 [illegible]

Baker Hughes IN [illegible] perfor [illegible] reduction in the [illegible]:

Target cost/ft = £ 294.72

The performance [illegible] Mach 1C Navi-Drill. The section length is [illegible] 3,753 [illegible].

Calculation of Target ROP

Rig Cost	=	£ 2,083 per hour
Bit Cost	[illegible]	[illegible] (2 bits)
Motor Cost	=	£ 225 per hour
Section length	=	3 [illegible]
Trip Time	[illegible]	[illegible] hours (2 round trips)
Target cost	[illegible]	[illegible] 4.72

Target cost of drilling interval = **£ 1,106,092** (294.72 x 3,753 feet)

C [illegible]	[illegible]	£ 2,083 x 21.8 = £ 45,409
Bit Costs	=	£ 48,500

Target cost of drilling time [illegible] [1,106,092 - (45,409 + 48,500)] [illegible] ing time = **£ 2,308/hr** (2,083 + 225)

$$\text{Target drilling hours} = \frac{\text{target cost of drilling time}}{\text{hourly cost of drilling}}$$

$$\text{Target drilling hours} = \frac{[illegible]}{2308} = 438.6 \text{ hrs}$$

Target ROP [illegible] 438.6 hrs

Provided the section is drilled with two bit runs and [illegible] least 8.6 ft/hr, then the target co[illegible] prices will be charged to the clie[illegible]

Example 2, Calculation of [illegible] ROP with a M[illegible]

In this case, the [illegible] offset well data and no realistic value o[illegible] operator's engineers agree that the interval [illegible] provided no more than two bits are required to drill the section and provided an ave[illegible] be achieved. The proposed well is vertical and they [illegible] will be cost effective.

Calculations of [illegible]

Rig cost [illegible]
Bit cost [illegible] (2 [illegible] bits)
Section length [illegible]
Trip time [illegible] (2 round trips)
Target ROP [illegible]

If we are to drill [illegible] ROP of 16 ft/hr, then

Target [illegible]

Target cost per foot = [illegible] + 50,900 / 4,550

Target cost per fo[illegible]

Target ROP [illegible]

The Baker H[illegible] engineer decides the only way to persuade the client to use [illegible] al based on the cost [illegible]er foot calculat[illegible]

Standard hou[illegible]ling engineer)

Target co[illegible] for interval = 4,550 ft x 147.62 £/ft

or, £ 671,[illegible]

Target dri[illegible]ing [illegible]6 + 50,900)
or, £ 568,[illegible]

Target drilli[illegible] [illegible] cost / [illegible] hourly rate for (rig + motor)

Target dri[illegible]ing hours = [illegible] / [illegible] + 220 = 256.2

Target ROP = [illegible] / 256.[illegible] = 17.8 ft/hr

After consulting [illegible] INTEQ [illegible] average ROP of 18 ft/[illegible] following terms:

1. If a target c[illegible] specified m[illegible]tor will be charged at the star[illegible]
2. If the cost per foot e[illegible] for the motor will be [illegible] The minimum hourl[illegible]st price.
3. If [illegible] per[illegible]not be included in the cost per fo[illegible]
4. Dr[illegible] ho[illegible]
5. Th[illegible] agreed between the oil c[illegible]mpany [illegible] the job starts.
6. Normal [illegible] apply.

Summary

There are various [illegible] of [illegible]tions to evaluate bit runs. We have considered [illegible]ly some of the possibilities. However, all the methods are simpl[illegible]

Break[illegible]

Before deciding to run the more expensive bits (insert, PD[illegible], or diamond) through a zone [illegible] priced bit ([illegible]ll tooth). It is frequently desir[illegible]le, the required performance of [illegible] from a simple cost-per-foot compar[illegible] involving drillin[illegible]nditions and other variables. Since the ultima[illegible] comparison sho[illegible] hole.

The standard co[illegible]s no allowance for the variations in operating cos[illegible]ifferent lengths. These variations stem [illegible] trips), time for [illegible] mud treatment prior to trips, severity of operating conditions (more WOB requires more collars), and hole conditi[illegible] is the best appro[illegible] comparison, and lends itself well to the need[illegible] priced bit. Thos[illegible]he formula invariably favor using the bit which ma[illegible]

A breakeven ch[illegible]foot formula in determining just how long a [illegible] provide a drillin[illegible] expensive bits.

The first step in [illegible] is to determine the various costs of previou[illegible]d formula and considering the bit (or series of bits[illegible] a "target" cost-per-foot is deter[illegible] drilled 850 feet [illegible]s $250/hr, with trip time of 7 hours. The calc[illegible] is the target which must be equaled or bettered to prov[illegible]

On the graph, p[illegible]ro, which is a dista[illegible] cost (expressed in rig hours and trip time). I[illegible] costing $3,317 will be used and that a trip will still require 7 hours. The bit is now worth ap[illegible]ing the combined bit and trip value 21 hours. [illegible]

The cost of the [illegible]o feet of hole at the "target" cost and plotted [illegible] example, combined bit cost of $3,317 and tr[illegible] $53.45 is 95 fee[illegible]

Finally, a line [illegible] B" and projected through the grid to re[illegible] the breakeven drilling cost. Any co[illegible] equals the "target" cost, a comb[illegible] and above the line is cheaper. In t[illegible]esents $53.45/ft. Some combination[illegible], would exceed this cost; if a bit [illegible]

Based on loc[illegible] is possible to [illegible] accuracy either the hours which can be expected or the probable penetration rate. If probable hours are estimated, th[illegible] horizontal re[illegible] indicates the required footage to breakeven.

If it is known [illegible] from the inte[illegible] the breakeven line will indicate the required hou[illegible] be made is penetration rate, a line may be [illegible] intersection [illegible] provides readings of both footage and hours. In this example, it is assumed that a 600 foot section will be drilled, and the chart [illegible] less.

This chart ca[illegible] expected bit runs of any price, and is just as use[illegible] against less [illegible]

Example 3: [illegible]

Rig Cost/Hr [illegible]

Trip Time, H[illegible] 8 Bits @ 7 hr. each = 56 hrs.

Total Footag[illegible]

Total Rotatin[illegible]

Total # Bits 8 @ $710 = $5680

Avg. Cost/Ft [illegible]

$$C = \frac{B + R(T + t)}{F}$$

$$C = \frac{5680 + 250(103 + 56)}{[illegible]} = \$53.45 \text{ per foot "target" cost}$$

[illegible] Perfor[illegible]

1. trip hrs + $\frac{\text{Insert Bit Cost}}{[illegible]}$ = Hours [illegible]

$$7 + \frac{\$3317}{250} = 21\text{hrs}$$

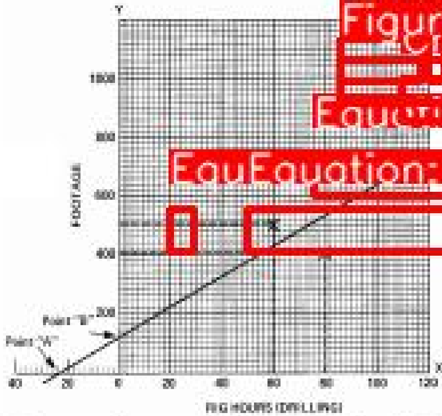
* Plot to left of zero on 'X' (ho[illegible]

2. $\frac{\text{Insert Bit Cost + Trip Cost}}{\text{Offset Cost/Ft}}$ = F[illegible] **

$$\frac{\$3317 + \$1750}{[illegible]} = [illegible]$$

** Plot footage on '[illegible] vertic[illegible]

3. Draw a stra[illegible] line exte[illegible] points 'A' and 'B'



Any footage and hour combination on this line is a breakeven point; above the line is the lower cost/ft, below is the higher cost/ft.

[illegible] Bit [illegible]
& Breakeven P[illegible]

Compar[illegible]son Drillin[illegible]

Item	Description	[illegible]	[illegible]
A	Bit Size	[illegible]	[illegible]
B	N[illegible]	[illegible]	[illegible]
C	T[illegible] time all bits being compared (cB)	48 Hrs.	8 Hrs.
D	[illegible]	$100.00	$100.00
E	[illegible]D	$4,800.00	$800.00
F	Total footage drilled all bits being compared (cB)	554 Ft.	1350 Ft.
G	[illegible]	[illegible]	165 Hrs.
H	[illegible]	[illegible]00.00	$3,350.00
I	[illegible]	[illegible].65	$15.30

Brea[illegible]

$$J = Rig\ \text{Hours} = C(\text{ Diamond Bit}) + \frac{H(\text{Diamond Bit})}{D(\text{ Diamond Bit})} = 8 + \frac{3350}{100} = 41.5$$

$$K = Footage = \frac{H(\text{ Diamond Bit}) + E(\text{ Diamond Bit})}{I(\text{ Roller Bits})} = \frac{3350 + 800}{23.65} = 175.48$$

Directions for use of graph[illegible]

1. Plot "J" value to [illegible] of zero on "X" (Horizontal) axis.
2. Plot "K" value on "Y" (vertical) axis.
3. Draw a straight line extending through points "J" and "K".
4. Any footage and hour combination on this line is the breakeven point for the diamond bit. Any point above the line extending through "J" and "K" indicates a cheaper cost per foot. Any point below the line indicates higher cost per foot for the diamond bit.

Drilling [illegible]

One of the primary parameters which directly a[illegible]fects cost analysis is the efficiency of the [illegible]e optim[illegible]zation of the drilling variables. Those [illegible]varied to achieve the best drill rate for each dri[illegible] formation. The two primary variable[illegible] the weight-on-bit (WOB) and the rotary sp[illegible]e to be manipulated, but this should [illegible] tripped into the borehole.

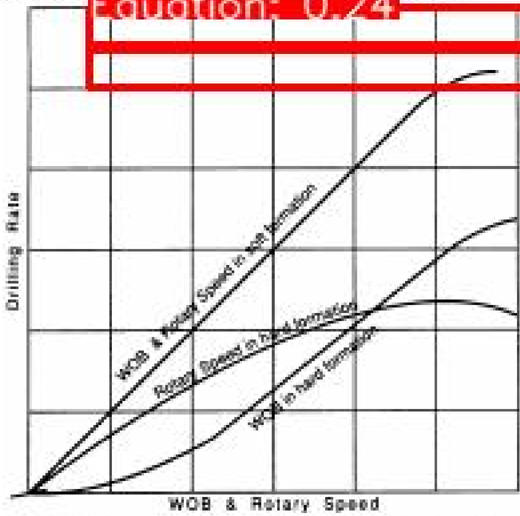
Many tests have [illegible] WOB and RPM [illegible]eral results:

1. <u>Soft F[illegible]</u> [illegible]ary speed can improve the penetr[illegible] rate with little effect on bit cutter wear. Relatively low W[illegible]

2. <u>Mediu[illegible]</u> [illegible] RPM will not have the same result [illegible] in soft formations. Moderate RPM with moderate WOB should [illegible] begin [illegible]o wea[illegible] to maintain the drill rate.

3. <u>Hard Forma[illegible]ions</u>: In[illegible] increased RPM. Mo[illegible]erately high WOB with minimum RPM yields the m[illegible]

The relations [illegible] OB, and between penetration r[illegible] below.



Additional WOB and RPM considerations must be kept in mind. A very high rotary speed can drastically reduce the life of many roller cone bits, thereby increasing their cost per foot (because of the cost of extra bits and extra trips). Similarly, running excessively high weight-on-bit may buckle the drill pipe as well as damage the bit, and will almost certainly cause problems because of excessive drilling torque. It would be best, therefore, to use values of WOB and rotary speed corresponding to the top end of the linear portions of the previous graph. The actual values of WOB and RPM at the point at which the graph departs from linearity depends on the type of bit and the hardness of the formation (as well as on the efficiency of the hydraulics in [illegible] the hole).

Drill-Off Tests

A drill-off te[illegible] the most appropriate WOB and RPM, using [illegible] process to ac[illegible] rate.

Preliminary [illegible]

1. Be[illegible] the [illegible]

2. Driller and [illegible] ate before the start of the test - logg[illegible] one second intervals.

3. Lift bit off bottom ap[illegible] stop pumps and rotary speed [illegible]

4. Start pumps - wait te[illegible]

5. Start rotary speed - wait ten seconds

6. Start drill-off test

Example Drill-Off Test Parameters

1. Maintain each WOB for 60 seconds

2. Flow rate: 520 gpm

3. Bit Type: 126S

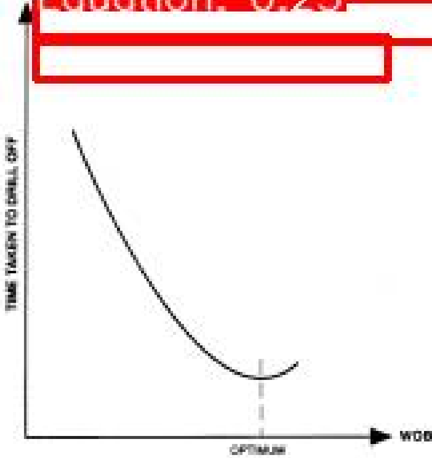
Test #1: RPM 120
WOB 48, 36, 24, 18 klbs

Test #2: RPM 60
WOB 48, 36, 24, 18 klbs

Test #3: RPM 90
WOB 48, 36, 24, 18 klbs

Test #4: RPM 90
WOB 24, 36, 48 klbs

After the completion of the drill-off test, select the RPM and WOB which provided the best penetration rate. A graph like that shown below should be obtained if th[illegible] ment is plotted against the average WO[illegible]



The lowest point on the graph indicates the optimum WOB. A variation of the drill off test is to mark off the kelly in one inch segments and (with the brake locked) measure the time and weight for each inch drilled off.

As shown above, the test is repeated for several different values of rotary speed in order to find the optimum rotary speed also.

Surface Indicators

Once the drill rate has been optimized and drilling has commenced, there are several su[illegible] nitored to ensure this drill rate remains [illegible] d. Usually, problems with the drill rate [illegible] several surface indicators, and cross-referen[illegible]

As mentione[illegible] parameters, a[illegible] Their interaction with the following in[illegible]

Torque

Torque is usually measured in foot pounds. When diesel or SCR rigs are being used, t[illegible] in amperes (amps), which is the amount of el[illegible] e motors to rotate the drillstring.

Torque is a f[illegible] and will be induced into the drill[illegible] ted. Some of the torque comes from the bit, the r[illegible] e interaction with the borehole.

There is no "bas[illegible]ns from an established baseline which i[illegible]ular bit run.

Constant Torque

In soft formatio[illegible]ively low. The harder the formation, the h[illegible]

Irregular Torq[illegible]

Changes from the constant value(s) may indicate:

- Interb[illegible]
- Stabil[illegible]
- Keyse[illegible] or doglegs
- Exces[illegible]ive W[illegible]
- The bit is bec[illegible]
- Junk in the hole

Increases in Torque m[illegible]

- A formation [illegible]
- Increasing hole inclination
- Increasing filter cake
- The bit becom[illegible]

Decreases in Torque may be due to:

- A formation change
- Decreasing hole inclination
- Decreasing filter cake
- Bit balling

Pump Pr[illegible]

Pum[illegible] inch (psi), with readings bein[illegible] taken a[illegible]

Constant Pu[illegible]

This should [illegible]

Irregular Pu[illegible]

Changes fro[illegible]ld mean

- A [illegible]
- Th[illegible]

Increases in [illegible]

- Th[illegible] annul[illegible]
- The bit is [illegible]
- Inadequat[illegible]
- A plugge[illegible] [illegible]uid p[illegible]ssageway or nozzle

Decreases in Pump [illegible]

- A washout in the nozzles or drillstring
- Losing cir[illegible]
- Aerated d[illegible]

Pump Strokes

The pistons on the m[illegible]d pu[illegible]ush the drilling fluid throug[illegible]he sy[illegible]tem. The stroke rate is meas[illegible] minute (spm). A set [illegible]umbe[illegible] at the predetermined[illegible]essure constant variations in [illegible]

Increased Pump St[illegible]

- A washou[illegible]
- Losing cir[illegible]latio[illegible]
- [illegible]

Decreased Pump Strokes indicates:

- An[illegible]
- A [illegible]
- Th[illegible]

Pulling [illegible]

[illegible] not make a bit last for the entire well. Pulling a worn b[illegible] the drilling operations more efficient. [illegible] d when determining when to pull the bit are:

Cost-per-Foot

This value, men[illegible] oned earlier, is a reliable guide in predicting when to pull a bit. The cost p[illegible] cost per foot val[illegible] ease, it may be necessary to put a new bit into the hole.

Breakeven Ana[illegible]

This value can b[illegible] run. If the calculated value is not being met, then [illegible] y have to be run.

Drill Rate

A gradual decre[illegible] tent formation generally indicates a worn [illegible]

Drilling Param[illegible]

A sudden chang[illegible] tors, or a value beyond acceptable limit[illegible] problem which may require the [illegible]

Summary

Wellsite person[illegible] for monitoring the efficiency of the drilling oper[illegible] ways to optimize the drill rate. Monitoring the [illegible] atching the surface drilling parameters will [illegible] more effective members of the drilling team[illegible]

DRILLING COST ANALYSIS

Bit Number24.0 Bit Cost24000.00 $

Bit Start Depth6578.0 ftRig Cost/hr1000.00 $

Average Trip Speed9.80 ft/min

Record No	Depth ft	Interval ft	Bit Time min	Interval min	Average ROP ft/hr	Instantaneous Cost $/ft	Cumulative Cost $/ft
0	6580.0	2.0	10.0	10.0	12.0	83.37	23273.84
1	6585.0	5.0	16.0	6.0	50.0	20.01	666.39
2	6590.0	5.0	21.0	5.0	60.0	16.67	3897.09
3	6595.0	5.0	27.0	6.0	50.0	20.01	2757.77
4	6600.0	5.0	37.0	10.0	30.0	33.35	2139.36
5	6605.0	5.0	46.5	9.5	31.6	31.68	1749.68
6	6610.0	5.0	58.0	11.5	26.1	38.35	1482.81
7	6615.0	5.0	71.0	13.0	23.1	43.35	1288.75
8	6620.0	5.0	81.0	10.0	30.0	33.35	1139.70
9	6625.0	5.0	870	6.0	50.0	20.01	1020.95
10	6630.0	5.0	96.0	9.0	33.3	30.01	925.98
11	6635.0	5.0	109.0	13.0	23.1	43.35	848.87
12	6640.0	5.0	125.0	16.0	18.7	53.35	784.09
13	6645.0	5.0	139.0	14.0	21.4	46.69	730.14
14	6650.0	5.0	151.0	12.0	25.0	40.02	682.45
15	6655.0	5.0	167.0	16.0	18.7	53.35	641.82
16	6660.0	5.0	197.0	30.0	10.0	100.04	609.00
17	6665.0	5.0	230.0	33.0	9.1	110.04	580.52
18	6670.0	5.0	272.0	42.0	7.1	140.06	556.76
19	6675.0	5.0	323.0	51.0	5.9	170.07	537.01
20	6680.0	5.0	370.0	47.0	6.4	156.73	518.53
21	6685.0	5.0	422.0	52.0	5.8	173.40	502.56
22	6690.0	5.0	488.0	66.0	4.5	220.09	490.10
23	6695.0	5.0	560.0	72.0	4.2	240.10	479.57
24	6700.0	5.0	645.0	85.0	3.5	283.45	471.67
25	6705.0	5.0	779.0	134.0	2.2	446.85	470.82
26	6710.0	5.0	933.0	154.0	1.9	513.54	472.57
27	6715.0	5.0	1087.0	154.0	1.9	513.54	474.19
28	6720.0	5.0	1255.0	168.0	1.8	560.22	477.34
29	6730.0	10.0	1480.0	255.0	2.7	375.15	470.84
30	6735.0	5.0	1680.0	200.0	1.5	666.93	477.19
31	6740.0	5.0	1710.0	30.0	10.0	100.04	465.66
32	6745.0	5.0	1760.0	50.0	6.0	166.73	456.83
33	6750.0	5.0	1825.0	75.0	4.0	250.10	450.90
34	6755.0	5.0	1965.0	130.0	2.3	433.51	450.50
35	6760.0	5.0	2105.0	140.0	2.1	466.85	451.08
36	67565.0	5.0	2225.0	120.0	2.5	400.16	449.78
37	6770.0	5.0	2355.0	130.0	2.3	433.51	449.44
38	6775.0	5.0	2470.0	115.0	2.6	383.49	447.85
39	6780.0	5.0	2635.0	165.0	1.8	550.22	450.47
40	6785.0	5.0	2867.0	232.0	1.3	773.64	455.36

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Self-Check Exercises

1. The least expensive type of bit may be the proper choice when practices an [illegible]

2. Since the ultimate goal is to make a profit, any cost comparison should be tied to ________ or ________.

3. Those factors not included in the cost-per-foot formula invariably favor ________.

4. What is the first step in making a breakdown analysis?

____

____

____

5. Which of the following bits would be the most economical?

Bit No.	Bit Cost	Depth Out	Footage	Rotating Hours	ROP
3	10000	12100	500	20.5	24.3
4	12600	12700	600	18.3	32.7

Rig Cost = $1000/hr

Trip Time = 1.2 hr/1000 ft

6. Determine which series of bits was most economical for the operator, then graph the breakeven analysis.

		Case #1	Case #2
A	Bit size	8.5"	8.5
B	# of bits to be compared	5	3
C	Total trip time all bits being compared (of B)	90 Hrs.	45 Hrs.
D	Rig cost per hour	$1250	$1250
E	Total trip cost all bits being compared (of B) C X D	$112500	$56250
F	Total footage drilled all bits being compared (of B)	1000 ft	900 ft
G	Total rotating hours all bits being compared (of B)	100 hrs	70 hrs
H	Total bit cost all bits being compared (of B)	$25000	$35000

Graph:

Technical Writing

Upon completion of this chapter, you should know how to:

- Follow correct procedures for organizing and writing engineering sections of technical reports.
- Proof [illegible] the contents are accurate, complete, and relevant to the client's requirements.
- Correctly use [illegible] of Baker Hughes INTEQ tech[illegible]
- Include all the [illegible] the Drilling and [illegible] "Final Well Report.

Additional Review [illegible]

Hicks, G., and C. Valo[illegible] *Communications*, McGraw-[illegible]

Houp, K., and T. Pears[illegible] *Rep*[illegible], McMillan Publishing Co., New York, 19[illegible]

Murray, Melba, *Engineered R*[illegible], PennWell Publishing Co., Tulsa, 1969

Shipley Associates, *Writing In* [illegible], Utah, 1985

The American Geological Insti[illegible] *Dictionary Of Geological Terms*, Anchor Press/Doubleday, New York, 1960

Watkins, F, et al., *Practical English Handbook*, Houghton [illegible] Co., Boston, 1978

Tec[illegible]hiques

The most efficient, and easiest, way to produce good written materi[illegible]l is to follow a prov[illegible] enough experience to de[illegible]elop the procedur[illegible] INTEQ's, particular requirement[illegible] writers. The checklist presented be[illegible]chnical writers from around the w[illegible] you are just beginning to write technic[illegible] many years. By following this checklist [illegible] technical writing task.

Checklist For Tec[illegible]

1. *Be[illegible] writing task:* The Final W[illegible] Engineering section, is an "engineering report".

2. [illegible] *the desired length of the written work:* The length of the FWR is determined by company recommendations, modified by the a[illegible]n to be presented.

3. [illegible] The FWR is used to report fi[illegible]ings, c[illegible]ndations concerning the well [illegible] was [illegible] for the FWR are to persuade the client to continue to use our services and to publiciz[illegible]ervices.

4. *Classify [illegible] typic[illegible]* The typical readers of The FW[illegible] will be[illegible] of age and probably have at least a Masters degree. They will probably be an engineer or geolo[illegible] business [illegible]

5. *Collect [illegible] you [illegible]:* Most of the data will come fr[illegible]the lo[illegible] computers, chart[illegible]al data will come from the logging geolo[illegible]ators working at the wellsite.

6. *Get add[illegible]* well much [illegible] discussions with others a[illegible] well[illegible] and/or operations as they [illegible]n pro[illegible]ell prognosis, and visiting the Bake[illegible] office for discussions.

7. *Determine* [illegible] *ng:* There is an FWR format and it u[illegible] questions/s[illegible]ments [illegible]

8. *Determine deadlines* [illegible] Normally, r[illegible] point and at [illegible] adlines also include when the final versio[illegible] or plots/prints are du[illegible] delivered to the client.

9. *Estimate the writing* [illegible] take to prepare the r[illegible] running the plots/pri[illegible] red. Costs are incurred for copying [illegible] errors in the report.

10. *Establish co*[illegible] Baker Hughes INTEQ, there are technical sp[illegible] R review, preparing the final d[illegible] y to the client. They should be able [illegible] during the preparatio[illegible]

11. *Assemble your data:* Use the FWR capabilities of the computer/ workstation [illegible] y of the regional/area office. The unit diary will p[illegible] are produced during [illegible]. During the course of the well, so[illegible]

12. *Prepare a rough out*[illegible] temporary headings [illegible] hat will be discussed (i.e. hole sections, casing operations, surveys, borehole problems, e[illegible]

13. *List the available da*[illegible] of bits, casing types [illegible] onfigurations, drilling problems and [illegible] parameters and mod[illegible] ta, should be entered under the he[illegible]

14. *Regroup the data under "Introduction", "Body", and "Conclusio*[illegible] specific hole sec[illegible] Engineering section.

15. *Prepare the final out*[illegible] *data:* Using the proper form[illegible] cid[illegible] order of importance, [illegible] er Hughes INTEQ usually uses an order-of-events arrangement to present the data in chronolog[illegible] phrases in this outline [illegible] lots/illustrations will be referenced.

16. *Have the [illegible] pertinent technical specialists:* Again, the region[illegible] who routinely check th[illegible]put and recommendations[illegible] changes.

17. *Collect and evalu[illegible]* study these plots/prints and b[illegible] they illus[illegible] properly[illegible]ach plot (i.e. 8.5 x 11, 8.5 x [illegible] etc.[illegible]s/prints in the report; are there [illegible] in the wrong part of the section, etc[illegible]

18. *Begin your writi[illegible]*

a. Be certain you[illegible]

b. Be sure you kn[illegible] about.

c. Write for your readers.

d. Use w[illegible]readers interest.

e. Try to [illegible] shor[illegible] sentence length should not exceed 20 [illegible]

f. Alternate short[illegible]

g. Define any wo[illegible]

h. Be specific, av[illegible]

1. Use exact n[illegible]uipment, tools, etc.
2. Provide par[illegible] previously [illegible]
3. Refer to plots [illegible]
4. Use clear la[illegible]
5. Be brief

i. Write out the c[illegible] plots, prints, and tables

j. Write the conc[illegible]tents, etc.

19. *Finish the writing[illegible]* elapse between th[illegible] the start of the review. Read the tex[illegible] comprehensiveness.

a. Check the technic[illegible]

b. Check all main an[illegible]

c. Evaluate the summ [illegible]

d. Check the proportions of the entire written piece - is any portion too long o [illegible]

e. See that all plots and [illegible]

f. Check the plot cap [illegible] someone else read [illegible] for errors in grammar and usage.

20. *Ensure that your rep* [illegible] the report is typed and a [illegible] regional/Baker Hughes [illegible] bound and copied [illegible]

If you use this checklist regula [illegible] Report, you will find that you will proc [illegible] Most technical writers spend approx [illegible] preparing to write (i.e. collecting data, organizing [illegible] and only [illegible] of their time doing the actual writing. If you [illegible] have more time to devote to the writing.

Gra[illegible]

You need not memorize the meaning of sentence, subject, verb, and the like. But read [illegible] glossary, whenever you have a chance. After [illegible] the meaning of most of these thirty-five ke[illegible] one of the parts of speech, a ph[illegible] more alert and you'll correct the e[illegible] ted for this glossary are those you'll n[illegible] and easy to u[illegible] grammar can[illegible]

Active Voice [illegible] subject of the sentence acts. [illegible] for direct, personalized expression.)

[illegible] charges 300 gal/min.

The borehole *collapsed* during a trip.

[illegible] oun.

Adjective Word that modifies a noun or pronoun; used to describe, tell or number.

The *large noisy* helicopter took off quickly. (Two adjectives, both modifying *helicopter*.)

Business was *good* during the *last* month of the year.

Three rigs sank off the reef.

Adjective Cl[illegible]

Subordinate clause [illegible] noun or pronoun.

He is the engineer *whom we met in Texas*.

They use chromatographs *that have automatic* [illegible]

Adverb Modifies verb, adjective, or other adverbs; sho[illegible] degree, time, or place.

The burner ignited *quickly*. (M[illegible]

There is *only* one petroleum engineer. (Degree)

Begin your writing [illegible]

The logging uni[illegible]

Adverbial Clause

Subordinate clause use [illegible] of how, why, when, wher [illegible]

The rig will be buil [illegible] (How)

A fire started *after* [illegible]*e motor failed.* (When)

Antecedent Word or group of words to which a pronoun refers.

The *motor* that failed was new.
([illegible])

Article Either definite (*the*) or indefinite (*a, an*); used as adjectives.

Auxiliary [illegible]erb used to form othe[illegible] verbs: *will, shall, ca*[illegible] *do, must,* and *ought* are typical auxiliaries.

The report *had been* reviewed by the su[illegible]

She [illegible] design the plot format.

Clause [illegible]g subject and verb, used as part of a sentence. May be independent (a sentence) or depe[illegible] ([illegible]s subject and predicate but does not express a complete [illegible])

The collar fell but *it didn't injure anyone.*
(Two independent clauses; each is a s[illegible]

When the company-man was fired, the crew cheered.
[illegible] express a complete [illegible]

Complex Sentence

Contains one indepen[illegible] clauses.

The helicopter cra[illegible]

Compound Sentence

Contains two or more indepe[illegible] clauses.

The well was tested and [illegible]

Conjunction Word used to connect claus[illegible] *or, for, nor, so, yet* (coordin[illegible] connect clauses, phrases, or words o[illegible]

She w[illegible]nt to the logging unit *but* she returned immediately.

After, although, as (not like), because, if, since, that, unless, when, while [illegible]s) connect subordinate (dependent) clauses [illegible]

The report will be [illegible]

Either...or, neither...nor, both...a[illegible] [illegible] used in pairs.

Either the Field Supervisor *or* his assistant will write the report.

Dependent Clause

Contains subject a[illegible] express a complete thought.

Ellipsis Omission of words from [illegible] affecting the clarity of th[illegible]

Use gas detecto[illegible]

Mercury is hea[illegible]

Gerund Noun formed by a[illegible] to a verb. Used like a noun but [illegible]

[illegible] a FWR [illegible]

[illegible] logging [illegible]

Independent Clause

Contains subject and ver[illegible]ght; can be a simple sentence[illegible] coordinating conjunction[illegible]

A[illegible] geologists [illegible] writers.

Infinitive [illegible] or by another [illegible] form of the verb. C[illegible] verb.

His greatest desire is to *design* l[illegible]

To *plan* the job, he wor[illegible]

This helicopter [illegible]

Modifier [illegible] quality, limit, or descri[illegible]

The *engin*[illegible]*r* wrot[illegible]the *report* at his office.

A *logger* collided [illegible]th a roughneck in the galley.

Object Word or words (noun, pronoun, phrase, o[illegible] noun) which receives the action of a verb [illegible] is governed by a preposition.

They placed the [illegible]
[illegible] is the obj[illegible]
[illegible] the object of [illegible]

Participle Word derived from a v[illegible] both verb and adjective. Present participle ends in *ing;* past participle can end in *ed, en, t, n, d.*

The *rising* pressure caused a head los[illegible]

The [illegible]

Parts of Speech [illegible]ames of the w[illegible]rds us[illegible]d in a sentence. There are eight parts o[illegible] pronou[illegible] verb, adjective, adverb, preposition, conjunction, and interjection. The interjection is probably the least used in technical writing[illegible]

Passive Voice Verb form which indicates the subject is b[illegible]

The report *was written* by the logger.
(The same thought expressed in active voic[illegible]
[illegible].)

Person [illegible]her a [illegible] or spoken of (third per[illegible]

I *am* a technical wr[illegible]

You are a technical [illegible]

He (or *she*) *is* a tech[illegible]

Phrase [illegible] cate; used as a part of speech.

Hurried writing *of Final Well Reports* causes confusion. *(Of Final Well Reports* is a participle phras[illegible] used as a noun.)

Predicate Word or words in a sente[illegible] about the subject.

[illegible]

Most well-writt[illegible] of *thought* from th[illegible] *known to the unknown.*

Preposition Relation word that connects a noun or pronou[illegible] element in the sentence.

The work-boat crashed *into* the rig.

Make an outline *of every* proposed report.

Pronoun [illegible] are: (1) personal *(I, we,* [illegible] interrogative *(who, which, what)* (3) relative *(who, which, that);* (4) demonstrative *(this,* [illegible] *nobody, someone, anything, etc.)* (6) reflexive *(myself, yourselves, himself, etc.).*

Sentence Group of words expressing a complete thought; contains a subject and a predicate.

[illegible] (subject is *he,* predicate is *logged.*)

Mad-Dog, the driller, smiled broadly as he began to chew the tobacco. (Subject in italic, predicate in roman.)

Subject Word or group of words naming the person or thing about which something is said in a sentence.

Some *engineers* [illegible] (Simple subject)

Some engineers [illegible] (Complete subject)

Some engineers and geologists write their own reports. (Compound subject)

Tense	C[illegible]
	English language has si[illegible]t perfect, past perfect, fu[illegible]
Verb	Word or group of words expressing action or a state of being.
	He wrote the paper for a geological society.

Note: *A verb should always agree with its subject in number and person. Examples: I am; You are.*

Verbal	Having the nature of or derived from a verb, but used as a noun or adjective[illegible] infinitives, gerunds, and partic[illegible]
Voice	Form of a verb that shows whether the subject acts or is acted upon.
	The logging geolog[illegible] active voice)
	The sample bag was opened by the logging geologist. (Passive voice)

Fina[illegible]

In[illegible]ormation Collection

[illegible] tremendous amount of engineering [illegible] accurate and comprehensive Final Well R[illegible] when writing the Drilling [illegible]of information is best suited for T[illegible] references at the end of the section o[illegible]

Drillstring/[illegible]

Drill Bit - ty[illegible]

Drill Collars [illegible]

Specialized [illegible]etc.

Heavyweigh[illegible]

Drillpipe - si[illegible]

Reasons for [illegible]ral Point, Build/H[illegible]d/Drop [illegible]nbly, etc.

Casing Prog[illegible]

Hole Size - [illegible] size

Casing Size [illegible]foot

Casing Shoe [illegible]

Accessories [illegible]

Possible Plot[illegible]: casing running speeds (surge pressures) make-up torque [illegible]

Cementing Program

Cement Clas[illegible]

Washes and [illegible]

Additives - t[illegible]

Cement Vol[illegible], weight, yield

Mixing Wat[illegible] per sack

Displacemen[illegible]

Possible Plot[illegible]

Drilling Fluid P[illegible]

Type of Mud Sy[illegible] - depth changed or modified

Additives - dept[illegible] which additions are made, why added

Mud Rheology - [illegible]

Possible Plots: P[illegible]velocity)
R[illegible]anges

Bit Program

Type of Bits - S[illegible]e, IADC code and Manufacturer name

Bit Operating Parameters - Weight-on Bit, Rotary Speed, Pump Pressure

Bit Hydraulics - [illegible] Velocity, Nozzle/TFA Size

Bit Grading - IA[illegible]

Possible Plots: C[illegible]antaneous Cost
B[illegible]
N[illegible]
N[illegible]

Directional Dri[illegible]

Location - Coor[illegible]

Drillstring Asse[illegible]

Type of Well - Vertical, Directional, H[illegible]

Survey Data and Calculations

Type of Survey - Single-shot, MWD, Gyro

Borehole Trajectory - Build-and-Hold, Build-Hold-and-Drop, Modified

Target Location[illegible]

Well Problems

Stuck Pipe - Ty[illegible]medial Measures, Results

Fishing Operatio[illegible]

Lost Circulation [illegible] Remedial Measures, Results

Well Kicks - Pr[illegible]cedures, Results

Twist-Off - Cau[illegible]

Shale Problems [illegible]ts

Brochure

General Catalog EC - 1990-1991

Self-Check Exercises

1. Who is the typical reader of the drilling and engineering section of the Final Well Report?

2. What determines the length of the FWR?

3. What data can be integrated into the FWR, in addition to that available from the logging unit, and where can it be obtained?

4. List several rules that should be followed to ensure that the client will have a readable, useful FWR.

5. Once the FWR text is read for clarity and conciseness, what is the next step to follow?

6. What type of cementing information should be included in the FWR?

7. What are some deadlines that should be used when preparing the FWR?

____

____

____

8. Once the available data for the FWR has been listed in a random order, it should be regrouped under three general headings. What are these headings?

a. ____

b. ____

c. ____

End Of Manual Return Exercises

1. Name the classifications of drilling fluid systems.

2. Excess filt[illegible]e them.

3. Give the generalizations that have been made concerning cuttings tran[illegible]

4. Compute the volume and density of a mud composed of 25 lb of bentonite, 6[illegible]

   Where: [illegible]

   [illegible]

   Density of Water = 350 lb/bbl

5. There are 5[illegible]e following composition: Oil = 5[illegible]%, Water = 9%, Solids = 40%

   Determine:

   1) The oil/water ratio.

   2) The fluid type and amount to increase the oil ratio to 90/10.

   3) The fluid type and amount to decrease the oil ratio to 80/20.

6. What is the velocity (ft/min and ft/sec) of the mud inside drill collars with an I.D. of 2 inches and a pump rate of 300 gpm?

7. Assume a flow rate of 920 gpm in a 17.5-inch hole with 4.5-inch drill pipe. What is the annular velocity (ft/min and ft/sec) of the mud?

8. If the bo[illegible] a depth of 8000 ft and 10.0 p[illegible] effective mud den[illegible] at th[illegible]

9. What is the casing standard called "burst strength"?

10. What three important properties of cement that must be known when water is added for hydration?

11. What is [illegible] sack of cement (94 lb)?

12. Determine the water requirement and yield for the following cement s[illegible]

13. Calculate the absolute volume, mixing water, yield, density, and mixing water per sack for the following class H cement:

Cement: 70: [illegible]

Given:

	Bulk Vol.	Abs. Vol	Abs. Vol/lb	Water Needed
Fly Ash	74	[illegible]	[illegible]	[illegible]% of ash
Cement	94	[illegible]	[illegible]	[illegible]
Gel	94	[illegible].650	0.00691	530% of gel

14. Describe the circumstances when a casing whipstock would be used.

15. What nozzles sizes would you fit into a 12.25-inch tri-cone bit for jetting purposes?

16. List a possible BHA you would use to jet drill a 12.25 pilot hole starting from vertical.

17. You are going to perform a kick-off in a 17.5-inch hole with a Navi-drill and a bent sub. The required build-up is 2.5°/100 ft. List the BHA you would use.

18. Design two specific NDS assemblies to drill the two well sections defined by the plan below.

Well Section	Build Rate	Hole Size	Bit Type
1,500' to 7,000' M.D.	2.0°/100'	17 1/2"	Rock
7,000' to 11,000' M.D.	-1.0°/100'	12 1/4"	PDC

19. What is the sequence of events that normally leads to a kick being detected during the drilling process?

20. What are four major considerations when deciding upon the best manner to kill a kick?

21. What three factors determine the maximum casing pressure that can be allowed during the killing process?

22. What general procedures should be followed to shut-in an onshore well once a kick has been recognized?

23. Why is the choke opened prior to closing the annular preventer or pipe rams?

24. How can you obtain the SIDP when a float valve is in the drillstring (assume the slow circulation rate pressure is known)?

25. What options are available if the maximum casing pressure is reached while circulating out a kick?

26. Calcul[illegible] lling ten, 93 ft stands of drill p[illegible] e hole.

Given:

Hole Size = 8[illegible]

Drillpipe = [illegible]

Collars = [illegible] -inch

Mud Density = 1[illegible]

27. Determine:

A) The maximum shut-i[illegible]

B) The reservoir pressur[illegible]

C) The i[illegible]

D) The f[illegible] pressure

E) The length of [illegible]

F) The density a[illegible]

Given:

Depth [illegible]
MW [illegible]
Hole Size [illegible]
Collars [illegible]
Pipe [illegible]
Leak Off [illegible]
SCP [illegible]

SIDP [illegible]
SICP = 4[illegible]
Pit Gain [illegible]

28. Journal angles in tri-con[illegible] the relative hardness of the [illegible]. What are [illegible] s that are used with soft, medium, and hard lithologies?

29. Discuss the three types of jet nozzles used in tri-cone bits.

30. What are the six components of the bearing structure in a sealed roller bearing bit?

31. What are th[illegible] hard formation bits?

32. When using PDC bit[illegible], there are many pre[illegible]utions and drilling parameters that shou[illegible] bit will run as efficiently a[illegible]

33. What are th[illegible] cr[illegible] diamond bits?

34. What are the five major operating parameters that must be considered when deciding run a diamond bit?

35. What will cause the cost per foot to increase?

36. The standard cost-per-foot formula makes no allowance for miscellaneous variations in operating costs. List four items that are included in these variations:

37. A recommended bit program is being prepared for a new well using bit performance records from nearby wells. Drilling performance records for three bits are shown for a thick limestone formation at 9,000 ft. Determine which bit would be the best choice.

Rig Cost = $400/hr

Bit	Cost Bit ($)	Drilling Time	Trip Time	Feet Drilled
A	800	14.8	7.0	204.2
B	4900	57.7	7.0	727.0
C	4500	95.8	7.0	977.2

38. What are four disadvantages of long-radius horizontal wells?

39. What are six characteristics of an ideal reservoir for a horizontal drilling?.

40. Why is torque not a good indicator of lithology changes in horizontal [illegible]

41. Find the [illegible] weight [illegible] bit:

a Desired WOB [illegible] 16 ppg; hole angle 20 [illegible]
Air Weight Required =

b Desired WO[illegible] [illegible]gle
48 [illegible]
Air Weight [illegible]

c Desired WOB 20,000 lbs; mud density 13 ppg; hole angle 20°; safety f[illegible]
Air Weight Required [illegible]

42. Find the number of joint[illegible] air weights:

a 62,000 lbs air weight needed; 30 joints of 4.5-inch heavy weight are [illegible]
inch I.D. drill collars [illegible]

b 35,000 lbs air weig[illegible] 2 inch I.D. drill collars, th[illegible]
collars are available. How many joints of 3-1/2 inch heavy we[illegible]

43. Calculat[illegible]

a 4-1[illegible] joint = 6.5-inch) w[illegible] of 18.37 lb/ft in a 8-1/2 inch hole [illegible]
of 11.5 ppg.

44. A well has been kicked [illegible]
The hole has been opene[illegible] now planned to run a conventional angle [illegible] the
inclination to 62.0°, whic[illegible]
tangent section. The build up section will all be in 17½" hole.
The plan[illegible] well is "on the line
on the vertical plan. Desi[illegible] BHA using a soft
formation tri-con[illegible]. State the
actual ga[illegible] of s[illegible]ble
drilling paramete[illegible]

45. Write down a packed assembly which could be used to hold angle in the tangent section of a directional well. Assume the inclination angle is in the range 45° - 50° and that the 12¼" hole section is being drilled. Indicate the gauge of all stabilizers. Suggest possible drilling parameters, assuming you are drilling medium hardness formation. State whether a PDC or roller cone bit is to be used.

Drill Collar Weights
(pounds per foot)

OD/ID	1"	1-1/4"	1-1/2"	1-3/4"	2"	2-1/4"	2-1/2"	2-13/16	3"	3-1/4"	3-1/2"	3-3/4"
3" OD	21	20	18									
3-1/8"	22	22	20									
3-1/4"	26	24	22									
3-1/2"	30	29	27									
3-3/4"	35	33	32									
4" OD	40	39	37	35	32	29						
4-1/8"	43	41	39	37	35	32						
4-1/4"	46	44	42	40	38	35						
4-1/2"	51	50	48	46	43	41						
4-3/4"			54	52	50	47	44					
5" OD			61	59	56	53	50					
5-1/4"			68	65	63	60	57					
5-1/2"			75	73	70	67	64	60				
5-3/4"			82	80	78	75	72	67	64	60		
6" OD			90	88	85	83	79	75	72	68		
6-1/4"			98	96	94	91	88	83	80	76	72	
6-1/2"			107	105	102	99	96	91	89	85	80	
6-3/4"			116	114	111	108	105	100	98	93	89	
7" OD			125	123	120	117	114	110	107	103	98	93
7-1/4"			134	132	130	127	124	119	116	112	108	103
7-1/2"			144	142	139	137	133	129	126	122	117	113
7-3/4"			154	152	150	147	144	139	136	132	128	123
8" OD			165	163	160	157	154	150	147	143	138	133
8-1/4"			176	174	171	168	165	160	158	154	149	144
8-1/2"			187	185	182	179	176	172	169	165	160	155
9" OD			210	208	206	203	200	195	192	188	184	179
9-1/2"			234	232	230	227	224	220	216	212	209	206
9-3/4"			248	245	243	240	237	232	229	225	221	216

Answers to Self-Help Exercises

Chapter 1 - Drilling Fluids And Fluid Hydraulics

1. a) Liquid
   b) Dispersed Solids
   c) Dissolved Solids

2. a) Will not hydrate
   b) Good lubricating properties
   c) Normally, higher cost muds

3. Emulsifier

4. Electrical Stability

5. Shear Stress

6. Yield Stress

7. Weak

8. a) Dilution
   b) Shaker Screens
   c) Centrifuge
   d) DeSander or DeSilter

9. Weak

10. H_2S and CO_2

11. $V_c W_c$ + [illegible]

12. Total lb = 37[illegible]00 lb (Or, 374 sacks)

Volume [illegible]

13. V_a = 1.5[illegible] ft/sec

14. PV = 10 [illegible]
YP = 20 [illegible]

15. n = 0.41[illegible]
k = 2.40 [illegible]

16. Hole Cleaning [illegible]

17. a) Flow [illegible]

b) Operating Pressure [illegible]

18. 1587 hhp

19. Hhp = 2[illegible]80 psi
Hif = 1[illegible] psi

20. PDC Bit: Fluid [illegible]
Diamond Bit: Fluid Volume [illegible]

21. Water-B[illegible]
Oil-Base[illegible]

22. a) Fluid Course Area

b) Diamond Exposure Area

23. a) Cross Pa
b) Radial Flow Syst

24. It damages the face of the borehole, causing "washouts" and creates higher pressure loss.

Cha[illegible]d Cementing

1. The weight of a casing joint with threads on both ends and a couplin[illegible]

2. a.) P-1[illegible]0 / 125k psi

   b.) N-80 / 100k psi

   c.) H-4[illegible]

3. Clinker [illegible]

4. $AbsoluteVolume(gal/lb) = \frac{[illegible]}{8.34lb/gal * S.G.ofcomponent}$

5. 60: fly a[illegible]
   40: cement
   2: additives

6. a) Low gel strength, low PV and YP

   b) Low density

   c) Low [illegible]

   d) Chemical m[illegible]

7. 500 psi

8. Reduce [illegible]

9. The total slurry volume:

   2102 ft^3 + 559.2 [illegible]

   The total sacks:

   901 sks + 473 sks [illegible] sks

10. Short pieces of casing used to connect the individual casing joints.

Chap[illegible]gy

1. a.) Heel bearings are roller bearings which carry mo[illegible] of the load a[illegible]
   b.) Middle bearings are b[illegible] the jou[illegible] and [illegible] t[illegible]rust on longitudinal loads in either directi[illegible]
   c.) Nose bearings consist [illegible] pressed into the [illegible] hard faced with [illegible]

2. Positive

3. a.) Soft Formations = [illegible]
   b.) Medium Forma[illegible] = 43 to 46°
   c.) Hard Formations = 46 to 50°

4. 75%, 1/2 to 3/4 dull

5. "T" type teeth

6. Solid metal bushings or direct cone to journal contact.

7. The cutting configuration

8. a.) No bearings to wear out.
   b.) No matrix to come apart.
   c.) No broken cones to fish out of the hole.

9. a.) Higher
   b.) Lower

10. a.) Single crystal
    b.) Coated
    c.) Carbonado

Cha[illegible]ng Basics

1. a.) 201, 960 lbs

   b.) 165[illegible]

   c.) 36,[illegible] lbs

2. 14,412 feet

3. a. 58,386 lbs

   b.) 61,040 lbs

   c.) 33 joints

4. 32,400 lbs

5. a.) 66,739 lbs

   b.) 29 joints

Chap[illegible] Drilling

1. a. Multiple wells from offshore platforms
   b. Relief [illegible]
   c. Contro[illegible]ing ver[illegible]
   d. Sidetr[illegible]king
   e. Inaccessible lo[illegible]
   f. Fault drilling
   g. Salt dome drilli[illegible]
   h. Shoreline drilli[illegible]

2. True North - this is t[illegible] pole, which lies on the Ea[illegible]

   Magnetic North - Th[illegible] which lies in norther[illegible]

   Grid North - the nor[illegible]n di[illegible]ection as depicted on a f[illegible]t surface (i.e. a map)

3.

   S64.75E = 1[illegible]5.25

   N35E = 35

   S88.75W = 268.75

   N66.5W = 293.5

   S22.25E = 157.75

   N35.5W = 324.5

   S89E = 91

   N71.5E = 71.5

   S25.5W = 205.5

   N3.75W = 356.25

   S11.5E = 168.5

4. Advanta [illegible] intenance and no temperatu [illegible]

Disadva[illegible]ges:

a. A large num [illegible] e the kic[illegible] off

b. It produces [illegible]

5. Nudging is used [illegible] d conductor casings to mi[illegible]e the chance of collisions.

6. This is a [illegible] verse of the Moineau [illegible] consists of a rotor a[illegible] stator [illegible] rotor.

7. Torque [illegible] o the motor's differential press[illegible]

8. There is no direct [illegible] RPM is directly proportional to fl[illegible]

9. Reactive [illegible] fluid pushing against the stato[illegible] A to twist counter-clockwise [illegible] effect changes the tool face ori[illegible]ion o[illegible] bent subs and other directional drilling tools.

10. a. They drill a [illegible]mooth, continuous curve, wh[illegible]ch minimizes doglegs and [illegible]

b. They [illegible]

c. The[illegible]s no [illegible] allowing the use of wir[illegible]e ste[illegible]

11. % Foota[illegible] LR) / (DLO - DLR)] x 100

where: D[illegible]L = [illegible]
DLO = [illegible] ined (°/100')
DLR = [illegible]

12. a. Increase [illegible] first string stabilizer

b. Increase in hole inclination

c. Reduction of dr[illegible]

d. Increase in wei[illegible]

e. Reduction in ro[illegible] spe[illegible]

f. Reduction in fl[illegible]

13. Initially, low WOB [illegible] towards the low side [illegible]d is established, increase WOB [illegible] Use high RPM (based on bit type).

14. a. When [illegible]ended to have the first st[illegible] up in the casing to prevent hanging [illegible]ssembly reactions.

b. When using a steerable motor assembly in vertical or near vertical holes, the actual dogleg may be less than the calculated TGDS.

c. Initiall[illegible] dogleg severity for the [illegible] of at least [illegible] feet. [illegible] oriented dogleg severi[illegible] oriented/rotary drilling [illegible]

d. Minimizing rotary speed will slightly increase the fulcrum effect. This prac[illegible]

e. During the initial stage[illegible]bilizer hang-up can occur. Th[illegible]e wellbore is inclined and/or the first string stabilizer enters the curved, orie[illegible]

f. Consider beginning the [illegible] oriented drilling requir[illegible]n of the wellpath.

15. By movi[illegible] make it harder to get awa[illegible] off, however, once an initial in[illegible]ion [illegible] is often greater than the [illegible]S. [illegible] increasing the distance from [illegible]abilizer will reduce the dogleg [illegible]

16. If the first string [illegible] less than the UBHS, 1) in an u[illegible] the oriented dogleg will be increased. 2) in a downward orientation, the oriented dogleg i[illegible]

17. a. Aft[illegible] obser[illegible] over a min[illegible] [illegible] drilling long[illegible] should be established. This plan should minimize the number of orientation [illegible] pen[illegible] rate.

b. Oriented [illegible]imized. Oriented dril[illegible]med to correct the present wellpath [illegible]nated trends.

c. Never let the drilled [illegible] the planned trajectory, because [illegible] more expensive. A[illegible] plot the position on both horizontal and vertical plans. At all times there [illegible] the current location to [illegible]

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Chap[illegible]ells

1. Short Radius: 100° / 100 ft

   Medium R[illegible]

   Long Radiu[illegible] Le[illegible]

2. a.) Downhole tools [illegible] measurements [illegible]

   b.) Downhole mot[illegible] and have extended lives.

   c.) Drilling fluids can be t[illegible] or format[illegible] stabi[illegible] requirements.

   d.) Bending stresse[illegible] drill pipe in horizontal holes can be[illegible]

   e.) Evacuation of [illegible] from horizontal holes is now achieved throug[illegible]

   f.) Horizontal hole[illegible] perforated, and [illegible]ely treated.

3. a.) Accelerated fie[illegible]

   b.) Increased ultim[illegible]

   c.) Reduced drilling infra[illegible]

   d.) Improved reser[illegible]

4. Short Radius: 40 [illegible] ft

   Medium Radius: 700 to 1[illegible] ft

   Long Radiu[illegible]

5. a.) The ho[illegible] vert[illegible]

   b.) The location of [illegible]

   c.) The presence o[illegible]

6. a.) Bit [illegible] [illegible]ring modes)

   b.) Bit weights vary widely (as shown)

   c.) Surface weig[illegible] WOB.

7. It may indicate th[illegible] cuttings [illegible] circulated past the build section.

8. You need a solid [illegible] [illegible]ilar to cuttings. The cuttings [illegible] take longer to reach the surface because they will roll along the bo[illegible] sections.

9. Leaving [illegible]inger[illegible]

Chapt[illegible]

1. a.) Monitor the drill rate for changes
   b.) [illegible] ples
   c.) Check [illegible] bore[illegible]
   d.) Monitor annular [illegible]
   e.) Determine the [illegible]

2. High CEC values ca[illegible] and geopressured [illegible]

3. Increased torque is th[illegible]

4. The differe[illegible] betw[illegible] pressure and the formation's p[illegible]

5. A stickomet[illegible]

6. The first ste[illegible] to es[illegible]

7. a.) work t[illegible] drillst[illegible] of formation
   b.) pump [illegible] an [illegible]

8. A low visco[illegible] [illegible] d, followed by a high visco[illegible] pill to [illegible] cuttings.

9. Soft cement [illegible] d

Cha[illegible]

1. a.) Failure to keep the hole full.

   b.) [illegible]

   c.) Insufficient [illegible]

   d.) Poor well planning.

   e.) Lost circulation.

2. a.) The well may [illegible]

   b.) An increase [illegible] only after the connection.

   c.) Similar pump pressure and rate changes to those exp[illegible] successive connections. However, the flow rate will increase during each connec[illegible]

   d.) Mud density reduct[illegible] associated with the connection period is circulated to the surface.

3. The Engineer's Method

4. a.) The circulating pressure at the kill rate.

   b.) The surface to [illegible]

   c.) The bit to surface time.

   d.) The maximum allowable surface annular pressure.

   e.) The formulas used for calculating the kill mud density.

   f.) For[illegible]ing pressure due[illegible]

   g.) The client's policies on safety factors and trip margins.

5. To circulate out the kick fluids, to circulate around the proper mud weight to kill the well.

6. It is the [illegible] types of killing procedures.

7. Snubbing means that downward force must be applied to counteract the [illegible] If the kick is not exerting up[illegible] weight of the drill string can [illegible] the hole.

8. Pipe rams have a [illegible] around the drillpipe. Shear rams [illegible] the drillpipe and seal against themselves.

9. a.) It can [illegible]

b.) It can [illegible] the [illegible]

c.) It may break the [illegible]

d.) It can plug the [illegible]pipe.

e.) It can [illegible]

f.) It may pressure up the formation, resulting in back-flow when [illegible]

10. MW_{kill} = 11.1 [illegible]

11. D_{kick} = 0.08[illegible]

Cha[illegible]ysis

1. Are constants

2. Total drilling cost / drilling cost-per-foot.

3. The use [illegible]

4. Determining the [illegible]

5. Bit #4 is more economical.

6. Case #2 was more economical.

Chap[illegible] Writing

1. a.) Between 25 and 50 years old.

   b.) Probab[illegible]

   c.) Geolog[illegible]or en[illegible]

   d.) Will use the FW[illegible]

2. The company recom[illegible] information to be pr[illegible]

3. a.) Discus[illegible]e wellsite.

   b.) Observing equi[illegible]ey are in progress.

   c.) By studying the well prognosis.

   d.) Visiting the [illegible]

4. a.) Be cer[illegible] your [illegible]

   b.) Be sure you kn[illegible]

   c.) Write for your [illegible]

   d.) Use words that will [illegible] interest.

   e.) Try to avoid ex[illegible]

   f.) Alternate long a[illegible] sentences and paragraphs.

   g.) Define any word[illegible]

   h.) Be spe[illegible]

5. a.) Check the techn[illegible]

   b.) Check all the m[illegible]

   c.) Evaluate the su[illegible]

   d.) Check to see if [illegible] short.

   e.) Be sure that all [illegible]

   f.) Check the plot [illegible]

6. a.) Ce[illegible]

b.) Washes and Spacers - pre-flush type, volumes

c.) Additives

d.) Cement Vol[illegible]d

e.) Mixing wat[illegible]

f.) Displacement rate, pumping time and setting time

7. a.) Rough draft[illegible]

b.) When the final version of the text is due.

c.) When the illustrations or plots/prints are due.

d.) Wh[illegible]

8. a.) Introduction

b.) Body

c.) Conclusion