Baker Hughes INTEQ

Advanced Logging Procedures

Workbook

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Preface

At Baker Hughes INTEQ, we have always prided ourselves on our people and their level of professionalism, experience, responsiveness and adaptability at the wellsite, where time, money and effective operations depends on rapid, reliable information management. IN-FACTS, a system for training, developing and providing professional advancement for field operations personnel, is the method behind these applications.

The IN-FACTS program provides a standardized career development path which utilizes a progression of both formal and hands-on learning, to turn potential into fully developed expertise. IN-FACTS is the tool that enables INTEQ personnel to embark on and develop successful careers within INTEQ, Baker Hughes, and the oil industry.

IN-FACTS is structured to provide an easily understood, orderly flow of learning experiences. These may or may not be in the same specialty, and allow our personnel to concentrate in one area, or to branch out into other disciplines. Movement through the IN-FACTS career progression is determined by industry experience, skills, and knowledge acquired through rigsite work and a variety of formal and informal training programs.

The training programs are modular and are composed of formal course work, self-paced learning packages, and on-the-job training.

Advanced logging requirements include increased knowledge of INTEQ's logging procedures and expanded knowledge of those drilling operations which affect logging procedures. This module will focus around logging quality control applications.

After successful completion of this course, further course work is composed of:

- DrillByte Applications
- Formation Evaluation Procedures
- Surface Logging Unit Management

These modules will provide a continuing source of education and training in a variety of wellsite operations to promote confidence and self-motivation in individuals, and ultimately produce management professionals with true "hands-on" field experience.

This course is the entry point for developing your wellsite logging and evaluation skills.

Instructions On Project Completion

The aim of this distance learning project is to provide you with the information on various logging topics that can best be studied outside a classroom. It is not the intention of the Training Department that you complete all the assignments as soon as possible. This workbook project should allow you to spend enough time on each particular subject in order to understand thoroughly those aspects of logging quality control procedures as they apply to every day wellsite operations. This workbook includes:

- Volume Calculations
- Depth & Drill Rate Monitoring
- Advanced Sample Evaluation
- Coring Procedures
- Introduction to Hydraulics
- Hydrocarbon Evaluation
- Bit Grading Techniques
- Formation Pressures
- Borehole Problems
- Final Well Report Writing - Geology Section
- Log Quality Control

At the end of each chapter are "Self-Check" exercises, designed to assist you in understanding the information covered in the chapter. Do not proceed until you are confident that you fully understand the concepts, calculations, and applications of the chapter's subject matter. Direct any questions you may have to the Training Department.

After you have complete the workbook assignments, there are several "Return" assignments to be completed and returned to the regional/area Training Department. Using these assignments, the Training Department will be able to assist you in the next step in completing the module requirements. It is in your best interest to stay in contact with your Training Department.

This workbook is designed to increase your knowledge and understanding of wellsite logging procedures. There is a lot to learn, and the learning process never ends. There are no real shortcuts. You are required to learn for yourself, with guidance and assistance from experienced field personnel and the Training Department.

The aim of the training you receive at Baker Hughes INTEQ is to develop your individual skills and knowledge to make you a fully competent, reliable professional within the oil industry. IN-FACTS is designed to assist you in this.

IMPORTANT

Do not read the text or practice the exercises in the workbook during your normal work schedule During this time you are expected to work, not study!

•Notes•

Chapter **1**

Volume Calculations

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

- Explain the importance of an accurate lag-time
- Determine “Effective Hole Diameter” from a tracer lag
- Determine the location of a pipe washout from a tracer lag
- Properly monitor both “wet” and “dry” trips
- Correctly fill out a “Trip Fill Sheet”
- Properly monitor casing and tubing runs
- Calculate the strokes required to accurately spot specialized pills
- Properly monitor slurry volumes and displacement volumes during cementing operations

Additional Review/Reading Material

INTEQ Video Tape #7 - *Logging Procedures*

INTEQ, *Drill Returns Logging Manual*, 1994

Whittaker, Alun, *Mud Logging Handbook*, Prentice-Hall, 1991

Campbell, Graham, *Wellsitting Rocky Mountain Wildcats*, Hart Publications, 1982

Kansas Well Logging Society, *Mud Logging in the Mid-Continent*, 1991

Introduction

Theoretical lag (time and strokes) is the most basic calculation performed by a logging crew. Additional calculations based on the lag formula are performed by logging crews at various times.

The purpose of this section is to re-emphasize some of the procedures and calculations and introduce other instances when simple volumetric calculations are required of the crew. The methods described for the calculations are the most straightforward to follow and easiest to check for mistakes.

The constant used in volume calculations is **0.000971**. Using oilfield units, the formula is:

$$\text{Volume (bbls)} = d^2 \times L \times 0.000971$$

where: d = Diameter of pipe, casing, collars or open hole (inches)
L = Length of section of pipe, collars, casing or hole (feet)

Adjusting Lag with Depth

During drilling, hole sections have a tendency to "washout" or become enlarged, also, due to hydrating/swelling formations and/or extreme filter cake build-up, the theoretical hole size may become reduced. This affects lag when collecting samples. To ensure that samples are collected as close to the correct depth as possible, periodic "tracers" should be dropped to check the actual open-hole volume so lag for samples can be corrected if necessary.

Running a Carbide Tracer

Dropping a carbide serves two purposes: It allows for a check on the lag time, and it serves as a check on the efficiency of the gas equipment (see Gas Normalization - section). In order to compare different carbide checks, it is important that they be run consistently, using the same amount of calcium carbide each time. A measuring cup is provided in the logging unit for this purpose. The measured amount is 100 ml.

The carbide is wrapped in an “envelope” of paper towels or toilet paper, held together with scotch tape. The wrapping material must break up easily so as not to block the jet nozzles. When a downhole motor or MWD tool is in use, confirm with the drilling supervisor and/or directional driller whether they will allow tracers to be run. Some clients are concerned that the paper and carbide going through the tools might possibly cause damage.

The best place to insert this “Carbide Bomb” is at the pin end of the next joint (or stand) of pipe going in the hole. Insertion is normally performed at connections. The carbide should be pushed inside the pin just before the kelly is put back on. Discuss this with the driller to get his cooperation.

If oil-base mud is being used, you can pour some water into the end of the pipe in the slips, and the bomb in the pin of the next joint prior to the connection. The water allows the carbide to react to release acetylene gas in the oil environment.

Once the “Carbide Bomb” is in place, the number of strokes on the counters should be noted. The carbide and its by-product, acetylene, will travel down the drillpipe, through the bit and up the annulus before reaching surface. The number of strokes required for the tracer to travel to the bit from the surface must be taken into account. This “downtime” or surface-to-bit strokes is easily calculated:

Length of 19.5 lb/ft, 5" drillpipe	= 6350 ft.
Length of 9" x 3.5" drill collars	= 1400 ft.
Pump output (bbl/stroke)	= 0.1337
Pumping rate	= 120 spm
Drillpipe volume	= $4.276^2 \times 6350 \times 0.000971 = 112.73$ bbl
Drill collar volume	= $3.500^2 \times 1400 \times 0.000971 = 16.65$ bbl

$$\text{Surface-to-Bit Strokes} = \frac{(112.73 + 16.65)}{0.1337} = 968 \text{ strokes}$$

$$\text{Downtime} = \frac{968}{120} = 8.06 \text{ minutes}$$

This value must be subtracted from the total strokes when the acetylene peak from the tracer is detected.

The frequency at which carbides are run is difficult to determine, but under normal circumstances a check should be made every twenty-four hours or 400 ft, whichever comes first. However, if carbide information is required due to suspicions of incorrect lag or washout, then carbides should be run as required.

Carbide results are recorded in the appropriate part of the worksheet and under the “Remarks” column on the Formation Evaluation Log. For example:

C = 0.025% at 45 V

Lag at 7750ft = 4956 strokes

“V” is the funnel viscosity of the returning mud at the time the acetylene peak was detected.

WARNING!

The reaction of calcium carbide with water is immediate and exothermic. Carbide reacts with water vapor, even moisture on the skin. Carbide should not be handled with bare hands; rubber gloves are provided in the logging unit for handling carbide. Also, as acetylene gas is flammable, the “Carbide Bomb” should be prepared just before use to reduce the risk of a build-up of flammable gas in the unit. No smoking is allowed during the preparation of a “Carbide Bomb.”

Correcting Lag for Carbide Results

As mentioned previously, openhole sections may be either smaller or larger than the bit size. If the carbide confirms that the actual lag is significantly different compared to the theoretical lag, then a correction to the lag figures must be made to ensure that future samples are collected at the right time, and from the correct depth. For example:

Theoretical Lag	=	8256 strokes
Actual Lag	=	8976 strokes
“Extra” strokes	=	720 strokes

At 100 spm this is 7.2 minutes. Thus samples are being collected earlier than necessary. If average drilling rate is 65 ft/hour, this difference in time represents 7.8 ft.

$$\frac{\text{feet}}{\text{min}} = \frac{65}{60} = 1.083 \text{ ft/min}$$

Footage error = 1.083 ft/min x 7.2 minutes = 7.8 ft.

If samples are being collected at 10 ft intervals, this is a significant and **unacceptable** error.

Once a carbide check has been performed and if a significant difference is noted, then the lag from the carbide must be used as a new starting point for future lag calculations. Theoretical calculations for each depth increment must be added to the most recent actual lag figure from the carbide results.

The increment is easily calculated using the volume formula given earlier. For example:

Bit size	=	12.25 inches
Pipe size being added	=	5 inch O.D.

Assuming 10 ft sample intervals

Volume increase	=	$(12.25^2 - 5^2) \times 10 \times 0.000971 = 0.5104$ bbl
Pump output	=	0.1337 bbl/stk
Lag stroke increment	=	3.8 strokes / 10 ft.

After each carbide, the lag must be updated if significant differences between theoretical and actual figures exist.

Alternative Tracers

In the event carbide cannot be used, through client instructions or lack of carbide, alternatives must be used to obtain lag data which are as accurate as possible.

A common alternative is to make up a packet of **RICE** in the same way as a “Carbide Bomb” is made. Rice is an acceptable substitute as it is small grained, does not block the jets, and is soft enough not to damage downhole motors. Procedures are the same except that an acetylene peak does not occur. The logger must wait at the shakers before the rice is theoretically due at surface, and note the time the rice appears. Any difference between theoretical and actual time can be easily calculated back into strokes.

However, plain white rice is often difficult to see on the shakers as it becomes coated in mud. One way of increasing its visibility is to coat the rice in bright, preferably fluorescent, paint and allow the paint to dry before being used. Wet, freshly painted rice is no use, as the paint washes off in the mud in the turbulent sections (drill collars and bit). It is better to prepare a large quantity of rice beforehand as this saves time, and the unit will have a ready stock of tracer in case frequent carbide checks have to be run.

Effective Hole Diameter

Comparison of the theoretical and actual lag data can provide useful information about downhole conditions. For example:

1. If, for example, the actual lag is greater than theoretical, an enlarged open hole section can be assumed. The effective hole diameter can be calculated as follows:

Theoretical Lag	:	5000 strokes
Carbide Lag	:	5980 strokes
Pump Output	:	0.069 bbl/stroke
Open Hole Section	:	1350 ft
Theoretical Hole Size	:	12.25 inch
Open Hole Volume	:	1350 x 0.1458 = 196.83 bbl
Actual open hole volume	=	196.83 + (980 x 0.069)
	=	264.45 bbl

Using d^2 x L x 0.000971	=	Volume
d^2 x 1350 x 0.000971	=	264.45 bbl
d^2	=	201.74
d	=	14.20 inches

This figure can be used by drilling engineers in the event of a balance plug having to be set. If the theoretical hole capacity was used, the top of the plug would be lower than expected.

2. If the actual lag is less than theoretical, then hydrating or swelling formations and/or extreme filter cake build-up can be assumed. The effective hole diameter can be calculated by:

Theoretical Lag	:	5000 strokes
Carbide Lag	:	4500 strokes
Pump Output	:	0.069 bbl/stroke
Open Hole Section	:	1350 ft
Theoretical Hole Size	:	12.25 inches
Open Hole Volume	:	1350 x 0.1458 = 196.83 bbl
Actual Open Hole Volume	=	196.83 - (500 x 0.069)
	=	162.33 bbl

Using d^2 x L x 0.000971	=	Volume
d^2 x 1350 x 0.000971	=	162.33 bbl
d^2	=	123.84
d	=	11.13 inches

This information can be critical, especially as the bit size is now larger than the effective hole diameter, indicating potential “tite” spots somewhere in the open hole section.

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Pipe Washout

Indications and Importance

If, when a Carbide is run, two acetylene peaks occur, a hole or "washout" in the drillstring can be assumed. This situation can also be noted on the pump pressure over a period of time. If the latter case is noted, the drill crew must be notified. A check of the surface system will verify if the pressure drop is due to a surface leak, or washout in the pump. In the event that nothing is found at surface and no other reason for the drop can be determined, a washout downhole can be assumed.

Reporting this situation is extremely important, because with pipe rotation, drilling torque and other pipe movements, a small hole in the pipe can lead to a twist-off and expensive fishing operations.

Calculation of Washout Depth

An approximate location of the hole can be calculated by using the carbide data.

Arrival of first peak	:	8 minutes after dropping carbide
Drillpipe I.D.	:	4.276 inches
Drillpipe O.D.	:	5 inches
Casing I.D.	:	9 inches
Pump output	:	16.6 bbl/minute

$$8\ \text{min} = \frac{[(4.276)^2 \times 0.000971 \times L] + [(9^2 - 5^2) \times 0.000971 \times L]}{16.6\ \text{bbl/min}}$$

$$8 = \frac{0.0177L + 0.0543L}{16.6\text{bbl/min}}$$

$$8 = 0.004337L$$

$$1844.6 = L\ (\text{ft})$$

This location will be important as it allows the drill crew to pull a fixed number of stands before looking for the washout.

Trip Volume Calculations

Importance and Procedures

The majority of blowouts occur during tripping out of the hole, due to a failure to keep the hole full of mud. By not filling the hole the hydraulic pressure exerted by the mud column drops. In addition, the upward movement of the drillstring will have the effect of further reducing the effective pressure on the formation. The combination of these two factors can, and often does cause the hydrostatic pressure to fall below the formation pressure. This will cause formation fluids from any exposed permeable formations to enter the well-bore. If this event is not detected, well problems will occur.

Prior to “pulling-out-of-the-hole” (POOH), drillers pump a heavy “slug” of mud. Its purpose is to cause an unbalanced column of mud in the pipe. As the pipe is pulled, the heavier column in the drillpipe falls due to its exerting a greater hydrostatic column than that in the annulus, thus, keeping the inside of the drillpipe “dry” at the surface when the pipe is unscrewed.

A trip tank is usually filled at this point. It is not advisable to completely fill the tank. If there is swabbing on the first few stands, it is indicated by an increase in the trip tank volume. Often the trip tank is not filling the hole during the first five stands for this reason. Some oil companies perform a flow check at this point. If swabbing, or flow, is indicated, it is caught quickly and appropriate action taken (i.e. run back to bottom and circulate the swabbed fluid out of the hole). If no swabbing or flow is detected, the trip continues.

During tripping, when the trip tank is almost empty, the rig crew will fill it up again. Ideally, they should stop tripping while filling the tank, but this rarely happens. Therefore, while filling the trip tank and filling of the hole, it is difficult for the rig crew to monitor the amount of mud used. A note of this should be made on a “Trip Fill Sheet.”

During POOH it is important to carefully monitor the volume of mud used to fill the hole. Trip tanks are often run continually during tripping, although occasionally tripping is stopped each five or ten stands to fill the hole. This is the safest method and is used when the oil company suspects a close balance between formation and hydrostatic pressures.

In this situation, any “tite” spots can cause swabbing and a subsequent influx of formation fluids.

Certain oil companies or drilling contractors have their own Trip Fill Sheets (see Table 1-1), and it is recommended that the Field Supervisor check on the type of form they would prefer the logging crew to use. A permanent hard record should be kept of every trip performed. While monitoring the mud volume, also monitor the depths of any overpull and enter this in a remarks column. Be aware that this is an indicator of possible swabbing. During swabbing there is a reduction of the hydrostatic pressure exerted on the formation. Even when in the casing, if the pipe is pulled too quickly, this negative differential pressure is exerted over the entire open hole. **Do not relax once the pipe is inside the casing**.

The normal intervals at which to check the mud volume is each of the first five stands of drillpipe pulled, then at five stand intervals afterwards. For heavy-weight drillpipe, the interval is the same, but with drill collars, the interval should be each stand. It is common during the pulling of collars that hole volume fill procedure attention slips. This is the time when most kicks occur. Once the bit is on surface, the BOPs are often closed. If at any time the logging crew have to leave the Unit, the rig floor must be notified so they can monitor more closely.

When tripping into the hole (RIH), the amount of mud returning to the pits should be noted, allowing for pipe fill-up that is required when using a float in the string, or other tools that do not allow the pipe to self-fill. Running in the hole too quickly causes surge pressures to be transmitted throughout the bore-hole, and if excessive, could cause the fracturing of exposed weak formations.

Look out for lower than expected return of mud into the pits as this could indicate fracturing of the formation and loss of returns, resulting in a drop in hydrostatic pressure and possible kick.

Wet and Dry Trips

In the case of a “dry” trip, the amount of mud that is to be pumped into the hole is equivalent to the volume of steel in the drillstring. If a slug cannot be used, for example with certain downhole tools not allowing mud to fall through, or if insufficient slug volume or density was used, then the pipe at surface will be “wet,” with mud falling out of the pipe onto the rig floor. To prevent or reduce this, a “mud-bucket” is used.

There is a hose attached to allow the mud to run back through the rotary table, into the bore-hole. This is not an efficient system, differences arise between the actual volume of mud used - vs. - the theoretical volume.

Dry Trip calculations

Metal displacement of 5" (19.5 lb/ft) drillpipe = 0.00652 bbl/ft
Average length of 1 stand = 93 ft.
Displacement of 1 stand = 93 x 0.00652 = 0.6067 bbl
Displacement of 5 stands = 5 x 0.60670 = 3.03 bbl

Metal displacement of Heavy-weight drillpipe and drill collars is not easily found in the standard books of tables produced by other service companies, so a formula is used:

$(OD^2 - ID^2) \times Length \times 0.000971 \quad = \quad Volume\ (bbl)$

Metal displacement of 5" Heavy-weight drillpipe with 3" I.D.

$(5^2 - 3^2) \times 93 \times 0.000971 \quad = \quad 1.4448$ bbl
5 stands of Heavy-weight = $5 \times 1.4448 = 7.224$ bl

Metal displacement of 8" (OD) x 2.875" (ID) drill collars

$(8^2 - 2.875^2) \times 93 \times 0.000971 \quad = \quad 5.032$ bbl

These calculated volumes should agree closely with the volume of mud used to fill the hole as this amount of pipe is removed.

Wet Trip

During a “wet” trip, the maximum amount of mud to be pumped into the hole is equivalent to the steel displacement plus the internal capacity of the pipe. Using the above formula:

5" drillpipe

$5^2 \times 93 \times 0.000971 \quad = \quad 2.2575$ bbl/stand
5 stands drillpipe = $5 \times 2.2575 = 11.2875$ bbl

5" Heavy-weight

This will not be the same as 5" drillpipe as the total volume removed is the same.

8" drillcollars

$8^2 \times 93 \times 0.000971 \quad = \quad 5.779$ bbl/stand

Due to the use of a mud-bucket, some of the mud inside the pipe is redirected back into the hole; however, as they are not very efficient, some of the mud spills on the rig floor. Thus, in actual practice, the amount of mud required to replace the volume removed will be greater than the theoretical “dry” trip volume, **but should be less than the maximum calculated volume**. This type of trip monitoring requires very close attention by the logging crew in order to obtain realistic figures of the amount of mud used versus the theoretical requirements.

Table 1-1: TRIP FILL SHEET (example)

Stand Number	Theoretical Fill (bbls)	Actual Fill (bbls)	Volume Gains (bbls)	Volume Losses (bbls)	Remarks

Running Casing/Tubing

This involves the same level of monitoring as for tripping drillpipe. The steel displacement of the casing must be calculated, as well as the internal capacity. When casing is run, the full volume equivalent to capacity plus displacement, returns to the pits. When casing is filled, the pit volume should decrease by the volume equivalent to the internal capacity of the casing run-in since the last fill-up.

Care must be taken when running in casing too quickly as the surge pressure may cause weak formations to fracture. Pit level gains whilst running casing must be closely checked against theoretical figures.

Example:

9 5/8” (47 lb/ft) casing run in hole.
Average joint length = 41 ft.

After running 10 joints of casing, the pit level should increase as follows:

$(9\ 5/8)^2 \times (10 \times 41) \times 0.000971 = 36.88$ bbls

If a complete fill-up is now performed, the pits should drop by:

$(8.681)^2 \times 410 \times 0.000971 = 30.00$ bbls.

Often the casing is not completely filled each time, so care is required when interpreting these figures, but essentially, after running then filling 10 joints of this casing, there should be a net pit volume increase of 6.88 bbls.

The same applies to tubing, although tubing is not usually filled with mud. Tubing runs being normally for DST's or completions. It is usually only necessary to check the pit increases to monitor for losses.

Tubing will probably be filled with some other fluid such as brine or fresh water. If this is being pumped from the pit system then it can be monitored.

Spotting Pills

Types of Pills and Procedures

There are many cases when special "pills" are pumped into the hole, the most common are LCM pills and pills of pipe-freeing agents, in case of stuck pipe. It is a common practice for company-men to ask the logging crew to calculate when the spacer will be in position, because the logging unit can monitor strokes easily in the unit. It is necessary that the crew be familiar with the attendant calculations. There is nothing complicated about these, they are just another way of calculating the movement of liquid volumes around a well-bore.

A pill is usually mixed in a separate pit prior to pumping. It is useful to know, as closely as possible, the capacity of the pipes between the pits and the rotary table. That is, the volume of the surface lines. This can vary between rigs from 5 to 15 bbl, or more, depending on the type of rig where the pits or the pit room is situated with respect to the rig floor. The pill is pumped from the pits, through the surface system, down the drill string, out the bit and up the annulus until it reaches the correct depth.

There are several separate volumes that must be known:

1. the volume of the spacer itself
2. the volume of surface lines
3. the capacity of the drillstring
4. the volume of the annulus from the bit up to the top depth of where the pill is to be placed

All these volumes must be then converted into pump stroke equivalents so that they can be monitored.

1. The volume of the spacer to be used must be calculated from the length of the open hole it is to cover, and must take into account the hole geometry. The easiest way to calculate the volume is to draw a diagram of the hole with the final position of the pill marked, labeling the depths of the pill with hole/pipe sizes. Then calculate the relative volumes across the drill string (see Figure 1-2). The volume of the pill will have to be greater than this as the suction level of the pit will have to be taken into account. This may be over one foot from the bottom of the pit.
2. The volume of the surface lines must be obtained from the drilling contractor and agreed upon with the Drilling Supervisor. He will need this information in the event of pumping cement plugs, etc. This volume must be converted into strokes and is important, as the number of strokes to pump the pill out of the

pits must be taken into account. If the volume of the pill exceeds the capacity of the surface lines, then by the time the pill is all out of the pits, some of it will be in the drillpipe. Displacing this pill into position then is a matter of calculating how much more volume must be pumped to fit it into place, then converting this volume into equivalent strokes. Again a drawing showing the position of the pill after it is pumped from the pits is recommended (see Figure 1-3).

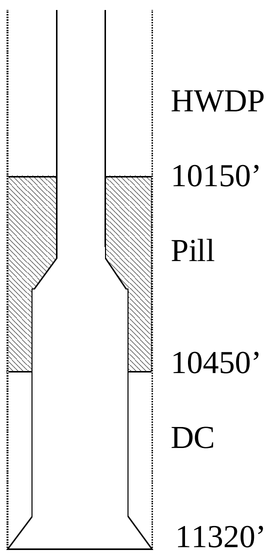

Figure 1-1

3. The capacity of the drillstring is straightforward. It is the sum of the capacities of drillpipe, heavy-weight and drill collars in the hole. Each is a result of multiplying the length of each section by its capacity determined from tables (e.g. **BJ Services** Book), or derived from the formula:

   Volume (bbls) = d^2 x Length x 0.000971
   where d = internal diameter of pipe in inches

4. The volume of the annulus is a straight forward calculation. It is a matter of calculating the annular volume from the bit to the top of where the pill is to be spotted. If this is around the drill collars, this is very simple:

Example:

Stuck pipe at 10300 ft
12 1/4" open hole to 10500 ft
Length of 8" drill collars = 850 ft
LCM pill to be spotted from 10150 ft to 10450 ft.

Top of spacer to be at 10150
Volume of annulus 10150 ft to 10500 ft =
$(12.25^2 - 8^2) \times 350 \times 0.000971 = 29.248$ bbl

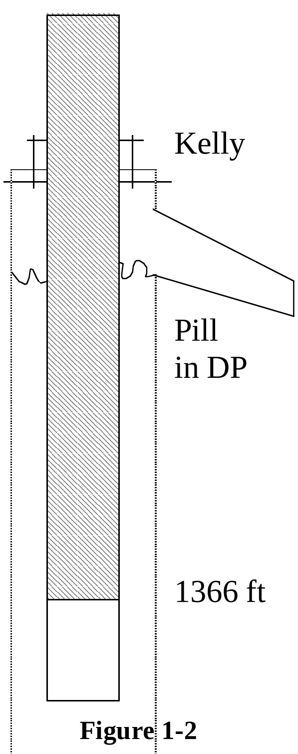

Figure 1-2

If the pill is to be spotted above the drill collars or across the drill collars and drillpipe, then the calculation becomes a little more complex. However it is still straightforward. The volume of the total annulus must be calculated for each open hole - pipe OD section and added together.

Example Calculations

Situation: Drill string stuck at 10300 ft.

Data: 13 3/8” casing (72lb/ft) at 9200 ft
12 1/4” hole to 11320 ft
5" x 19.5 lb/ft drillpipe to surface
5" x 3" Heavy-weight Drillpipe length = 1100 ft
8" x 2.875" Collars, length = 980 ft
Capacity of surface lines (incl. Kelly) = 8 bbls
Pump output = 0.1204 bbl/stk

Problem: Spot a MIL-SPOT pill from 10150 ft. to 10450 ft.

Equivalent strokes to pump pill:
Volume across Drill Collars

$= (12.25^2 - 8^2) \times (10450-10340) \times 0.000971$
$= 86.0625 \times 110 \times 0.000971$
$= 9.19$ bbl

Volume across HWDP

$= (12.25^2 - 5^2) \times (10340-10150) \times 0.000971$
$= 125.0625 \times 190 \times 0.000971$
$= 23.07$ bbl

Total volume of pill $= 23.07 + 9.19$ bbls
$= 32.26$ bbls

Strokes equivalent $= \dfrac{32.26 \text{ bbls}}{0.1204 \text{ bbl/stk}}$
$= 268$ strokes

Position of pill after pumping 268 strokes

Volume in surface lines = 8 bbl
Volume inside DP = 32.26 - 8 = 24.26 bbl
Capacity of 5" DP = 0.01776 bbl/ft

Length of pill in DP $= \dfrac{24.26}{0.01776} = 1366$ ft

0.01776

Volume to displace pill to bit

DC: $2.875^2 \times 980 \times 0.000971 = 7.865$ bbl
HW: $3^2 \times 1100 \times 0.000971 = 9.613$ bbl
DP: $4.276^2 \times (9240-1366) \times 0.000971$
$= 139.795$ bbl

Total = 157.27 bbl:	Equiv.Strokes	=	1306
Volume to displace pill from bit to 10150			
Vol opposite HW (see calc 2)		=	23.07 bbl
Vol opposite DC =	$(12.25^2 - 8^2) \times 980 \times 0.000971 =$		81.90 bbl
Total = 104.97 bbl;	Equiv.strokes	=	872
Total strokes required to displace pill		=	1306 + 872 = 2178 strokes

Cement Volumes and Displacements

Introduction

There are only two volumetric calculations that concern the logging crew during cementation. They are the volume of slurry to be pumped, and the displacement volume. Knowledge of these volumes is important so that the pit volumes and strokes to bump the plug can be monitored in the unit.

1. During the pumping of cement slurry, the volume introduced to the hole usually comes from “outside” of the normal circulating system. The final slurry volume certainly does, although the mix-water used is often prepared in the mud pits, so that this volume can be monitored. The effect of pumping slurry into the hole causes a pit gain as the mud is displaced into the pits.

2. By careful monitoring, the amount of slurry pumped, the rate of pumping and any losses down-hole can be checked on the pit level chart. This should be regularly checked against the actual pumping rate and pumped volume. Any indications of losses should be brought to the Drilling Supervisor's attention immediately. It may be possible to reduce the pumping rate to reduce these losses, or take other preventive action.

3. Once all the slurry has been pumped, the top plug is dropped and the cement displaced, usually with the drilling mud. The volume of mud to be used is the capacity of the casing from the surface to the float collar, where the plug “bumps.”

During displacement, all volumes can be monitored as the rig uses the mud circulating system. In addition other parameters can be recorded (i.e. total strokes, spm, pressure and temperature). This data gives information on displacing rates, volumes pumped, losses or gains of mud in the system, and when the plug “bumps” on the float collar.

If this data is recorded on a table with time and a Remarks column, it can give valuable information to the client in the event of anything going wrong during displacement.

Slurry Volume Calculations

Normally, before casing is run, wireline logging is performed, with one of the tools being a caliper. In the logging units, it is possible to read off the actual hole volume. This gives the client the information on the amount of slurry required. In the event wireline is not performed, or a caliper not run, then on the last circulation before running casing, it is advisable for the logging crew to run a Carbide to estimate the actual hole volume.

It is better if two carbides are run as a check on one another.

Once an estimate of open hole volume is known, then the total displacement (capacity + metal displacement) of the casing is subtracted to give the annular volume, and the amount of cement slurry to be used between the previous casing and newly run casing is easy to calculate, either from tables or the formula given earlier. The only other slurry volume to be calculated is the amount of slurry filling the shoetrack inside the casing between the shoe and float collar.

These figures give the minimum slurry volume to be used. Often, particularly in shallow surface casing runs, excess volume for the open hole is pumped as a precautionary measure. This is not really necessary if a caliper has been run, but more so if open hole volumes are estimated from tracer data. It also gives extra volume "to play with" in the event of losses during either the cementation or the displacement.

Example: Using the same data as in the **example calculation**, it is necessary to calculate the amount of slurry required to cement 9 5/8", 47 lb/ft casing with the shoe at 11300 ft. the length of shoetrack being 83.5 ft. From the caliper open hole volume is 418.28 bbls (equivalent hole diameter = 14.25"). The top of the cement slurry is to be 500 ft above the previous shoe (9200 ft). The client wants to use 5% excess volume on the open hole section.

1. Volume of open hole - 9 5/8 inch annulus
   Volume of 9 5/8" Casing = $2100 \times 9.625^2 \times 0.000971$
   = 188.90 bbl

   Capacity of open hole annulus = 418.28 - 188.90
   = 229.38 bbl
   Excess volume = 0.05 x 229.38 = 11.47 bbl
   Slurry required = 229.38 + 11.47 = 240.85 bbl

2. Volume of 13 3/8" - 9 5/8" annulus
   $(12.347^2 - 9.625^2) \times 500 \times 0.000971 = 29.04$ bbl

3. Volume of shoetrack
   Capacity of 9 5/8" casing from tables = 0.0732 bbl/ft
   Volume = 83.5 x 0.0732 = 6.11 bbl
   Total slurry requirements = 240.85 + 29.04 + 6.11
   = 276.00 bbl

This calculation method is valid for all types of simple, conventional cementation jobs and can be easily adapted for multi-stage ones.

Displacement Volume Calculations

There are two types of displacement:

- Through casing
- Through drillpipe

The former is the common one, while the latter is used for surface casing and liners. Both require the calculation of the internal volume of a particular string through which the displacing fluid is to be pumped. In the case of through-casing, it is the capacity of casing from the surface to the top of the float collar. In through-drillpipe displacement, it is the internal volume of the drillstring. In this latter case the drillstring is often under-displaced to ensure that cement is left around the bottom of the casing. As the drillstring is pulled, the cement falls to cover the stinger and shoe. The pipe is reverse circulated to prevent cementing the string.

Example:
Using the same data as in the cementation calculation for a through casing cementation:

Capacity of 9 5/8” casing from tables	= 0.0732 bbl/ft
Length of casing to shoe track	= 11300-83.5 ft = 11216.5 ft
Capacity of casing	= 11216.5 x 0.0732 = 821.05 bbl

$$\text{Equivalent strokes} = \frac{821.05}{0.1204} = 6819 \text{ strokes}$$

Example:
20" (133 lb/ft) Surface casing at 2005 ft. Drillstring is 5" x 3" heavy-weight DP. The stinger at 2004 ft. Under displace to leave 10 ft of cement inside the casing.

Capacity of 20" casing from the tables	= 0.3407 bbl/ft
Slurry volume required in casing	= 10 x 0.3407 = 3.407 bbl

Capacity of drillstring

$(5^2 - 3^2) \times 2004 \times 0.000971 = 31.134$ bbl

Under-displaced by 3.407 bbl = 31.134 - 3.407 = 27.727 bbl

$$\text{Strokes equivalent} = \frac{27.727}{0.1204} = 230 \text{ strokes}$$

Usually, the pumping of these displacement small volumes is done by the cementing unit, as accurate measurements are possible using the tanks on the cementing unit.

In this event, the logging crew can only monitor returns to the pit to check for losses.

Self-Check Exercises

1. List three reasons why the drilling fluid volume will change in the borehole, causing you to have to adjust your lag?
   a. ____________________
   b. ____________________
   c. ____________________

2. What two parameters can be checked when a carbide is dropped?
   a. ____________________
   b. ____________________

3. What precautions are necessary when preparing a "carbide bomb"?
   a. ____________________
   b. ____________________

4. Why is Calcium Carbide used to determine "actual" lag?
   a. ____________________
   b. ____________________

5. What is the normal frequency for dropping a carbide?
   a. ____________________
   b. ____________________

6. What type of information should be placed on the Formation Evaluation Log after a carbide lag has been determined?
   a.
   b. ____________________

7. What two parameters will indicate a washout in the drillstring?
   a. ____________________
   b. ____________________

8. List three reasons why most kicks occur during tripping operations?
   a. ______________________________
   b. ______________________________
   c. ______________________________
9. What is normally done if a flow is detected when the first few stands are pulled at the beginning of a trip?
   a.
   b. ______________________________
10. What additional information should be entered into the Trip Fill Sheet during tripping operations?
    a. ______________________________
    b. ______________________________
11. Why is it difficult to monitor a “wet” trip?
    a. ______________________________
    b. ______________________________
12. Why is it important to monitor pit level while running casing?
    a. ______________________________
    b. ______________________________
13. What are the two most common types of “pills” that have to be placed in the borehole?
    a. ______________________________
    b. ______________________________
14. What two volumes must the logging geologist be concerned with during cementing operations?
    a. ______________________________
    b. ______________________________
15. What two methods can be used to determine the actual hole volume, in order to calculate cement slurry volume?
    a. ______________________________
    b. ______________________________

•Notes•

Chapter **2**

Depth & Drill Rate Monitoring

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

- Understand and explain the importance of accurate depth and drill rate values
- Calculate depth and drill rate using Baker Hughes INTEQ methods or other available methods
- Convert the drill rate value to a rate of penetration value
- Determine “True Vertical Depth” from “Measured Depth”
- Understand the various ways which can produce incorrect depth values

Additional Review/Reading Material

INTEQ Video Tape #7 - *Logging Procedures*

INTEQ, *Drill Returns Logging Manual*, 1994

Whittaker, Alun, *Mud Logging Handbook*, Prentice-Hall, 1991

Campbell, Graham, *Wellsitting Rocky Mountain Wildcats*, Hart Publications, 1982

Kansas Well Logging Society, *Mud Logging in the Mid-Continent*, 1991

Introduction

Depth and drill rate can be the most important parameters monitored by the Logging Geologist. This information is used by everyone concerned with the well. After reviewing this section, it must be realized that there is no reason why the Logging Geologist cannot determine these parameters and have this information available.

To begin depth and drill rate monitoring, the Logging Geologist must first secure an accurate depth from the driller at a “kelly down.” Then by adding the measured length of successive joints of drillpipe, the Logging Geologist can determine the exact “measured” depth at any given time.

Drill rate for a given interval is simply the time (usually minutes) it takes to drill the interval. To convert this to feet per hour, the following equation is used:

$$\frac{\text{60 minutes/hour}}{\text{minutes to drill interval}} \times \text{interval (feet)} = \text{ft/hr}$$

Depth and drill rate should be annotated on the logging charts continuously, some recorders do it automatically. On others, the Logging Geologist must do it manually.

Baker Hughes INTEQ's Depth Measuring Devices

Baker Hughes INTEQ has in its inventory three depth measuring sensors/ systems. They are:

- **Bristol Recording System** - The oldest system. Still used on standard units.
- **Kelly Height System** - Built to upgrade the Bristol System. Used on most ALFA, GEMDAS and DrillByte units.
- **Block Height System** - Built to replace the Kelly Height System. It allows more accurate “bit depth” location.

To determine depth and rate of penetration, Baker Hughes INTEQ uses a system which senses the position of the kelly, the Top-Drive swivel or the travelling block. Two systems respond to changes in the hydrostatic pressure of a column of water between a sensing device and a kelly chamber (Bristol bottle) located near the gooseneck, the other monitors the outlay of drilling line to determine the location of the travelling block.

Bristol Recording System

The Bristol Recording System was one of the earliest independent depth recording systems available to mud logging companies. In many cases it has been replaced by more sophisticated versions or block height systems.

Bristol systems consist of a length of water line (generally on a reel), placed as close as possible to the rat hole, yet out of the way of the rig floor personnel. A “bristol bottle” is attached to the top connection on the line and then connected (using a link chain and heavy-duty tape) to the gooseneck. The water line is taped to the kelly hose to ensure positioning. The kelly hose should be able to unwind and rewind the bristol line (there are no obstructions to the line movement).

Another water line is used to connect the lower bristol line connection to the logging unit. After the line to the logging unit, it is connected to the line input panel “Bristol” fitting in the rear room of the logging unit (see Figure 2-1).

The entire system is filled with water and changes in the systems hydrostatic pressure are recorded on a “bristol chart” to keep track of depth and drill rate.

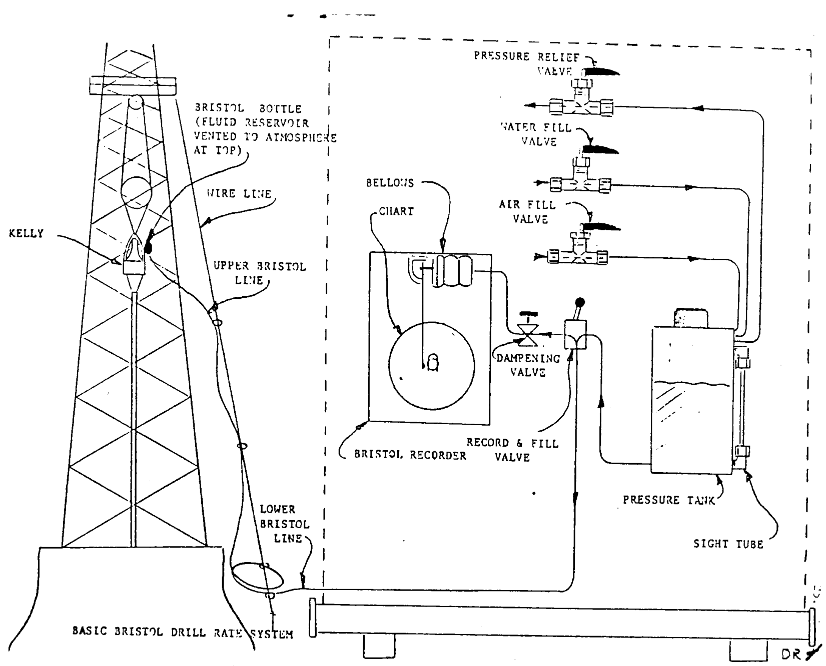

Figure 2-1: Bristol Recording System

Kelly Height Recording System

The Kelly Height system consists of three main parts: kelly height chamber, sensing hoses, and service box (Figure 2-2).

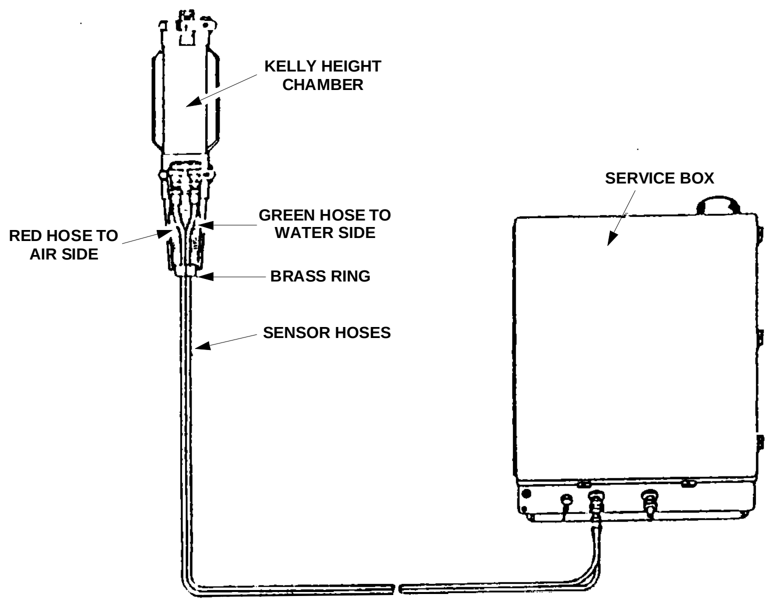

Figure 2-2: Kelly Height Sensor System

Rig Up

1. Locate a convenient, safe location for the service box, on the rig floor, near the stand pipe outlets. Secure the box using C-clamp, tie wraps, rope, etc., so that it is available for service or observation.
2. Carry the sensor hose down inside the derrick and one-half on the other side of the derrick (Figure 2-3).
3. Attach the kelly height chamber to the hose which was lowered to the inside of the derrick (Figure 2-3).
4. Attach the kelly height chamber (with hose attached) to the rotary hose just below the gooseneck (Figure 2-3). Secure the chamber with two wraps of chain and all-weather tape. (EL P/N 14859).
5. Route the kelly line along the side of the rotary hose, secure the line to the hose with all-weather tape every five feet. Leave some slack in the sensor hose to allow for changes in curvature of the rotary hose.

6. Route the sensor hose down the standpipe to the service box, securing it every five feet with all-weather tape.

7. Attach the sensor hose to the bottom of the service box. The red hose to the air connection and the green hose to the water connection.

8. Connect a separate air hose to the air supply inlet on the bottom of the service box. Route the hose to the rig air compressor, or any convenient air connection.

9. Connect a four-wire electrical cable to the service box. Feed the cable through the water-tight, strain-relief fitting on the bottom service box. Crimp a spade terminal lug to each wire and connect them to the transducer's terminal block, in the following order (red-red, black-black, white-white, green-green). Route the electrical cable to a rig floor junction box and repeat the connections at the junction box, or route the cable to the logging unit and repeat the connections at the safety barrier box.

DrillByte units carry the newer 20mA sensors. These are two wire sensors and should be connected as per instructions.

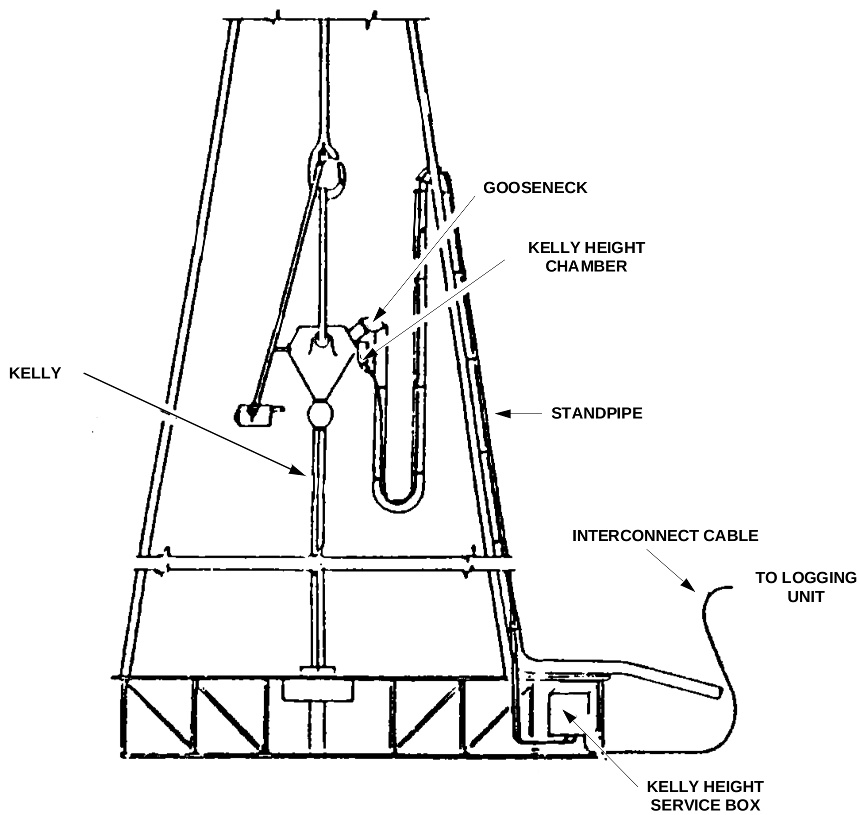

Figure 2-3: Rig-Up Kelly Height System

Filling the Reservoir

See Figure 2-4: Kelly Height Control on service box.

1. Set the CHARGE/VENT valve to VENT. The position of the OPERATE/CHARGE valve is not important.
2. Remove the reservoir cap and fill with water (or an anti-freeze mixture) to within one inch of the top. Keep dirt from entering the system.
3. Replace the reservoir cap securely.
4. Set the CHARGE/VENT valve to CHARGE.

Charging the System

1. Set the CHARGE PRESSURE to 120 psi using the PRESSURE Adjust Regulator.
2. Open the BLEED VALVE (toggle valve up), when all the air is out of the lines and there is a steady stream of water from the drain line closed the BLEED VALVE.
3. Set the CHARGE/VENT valve to the CHARGE position.
4. Set the OPERATE/CHARGE valve to the CHARGE position.
5. When a steady stream of fluid is seen flowing from the kelly chamber, set the OPERATE/CHARGE valve top to OPERATE.
6. Adjust the OPERATE PRESSURE to 30 psi using the PRESSURE Adjust Regulator.
7. Set the CHARGE/VENT valve to VENT.
8. Adjust the damping control so that the kelly height chart pens draw a smooth line on the chart recorders.

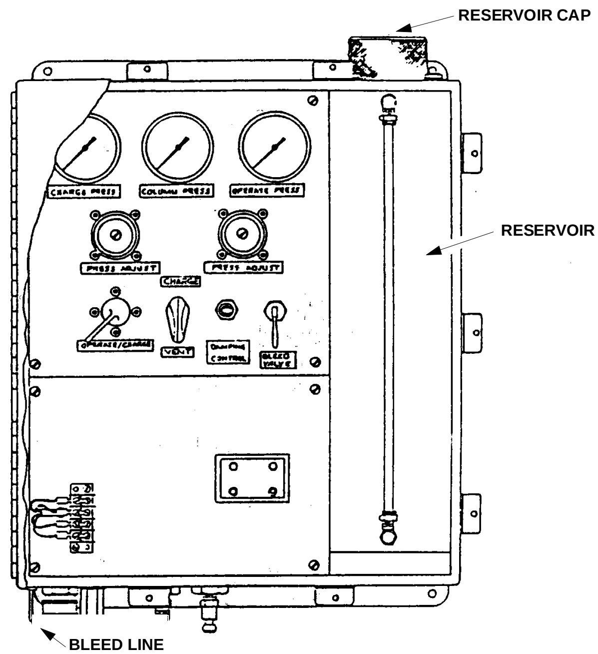

Figure 2-4: Kelly Height Controls on Service Box

Block Height System

The Block Height depth measurement system has one main advantage over the Bristol and Kelly Height systems; the ability to monitor the position of the bit during trips. With the two earlier systems, whenever the swivel and kelly are removed from the drillstring, bit position and therefore depth cannot be accurately monitored. Bit depth is of great importance during MWD runs because sections of the borehole can be analyzed during trips (termed MAD, Measurement After Drilling, runs).

The Block Height System consists of four components:

- **Two PCB Cards** - two PCB cards, housed in the logging unit's P&F rack in slots 18 (Peripheral Card) and 19 (Processor Card)
- **A Junction Box** - located on the rig floor and serves as the connection between the Optical Shaft Encorder (attached to the drawworks) and P&F rack located within the logging unit
- **The Calibration Box** - used to calibrate the Block Height System using a connection into the junction Box
- .**The Optical Encoder** - (Figure 2-5) fitted to the drawworks and connected in series between the drum shaft and the air swivel coupling (Rotoseal)

.

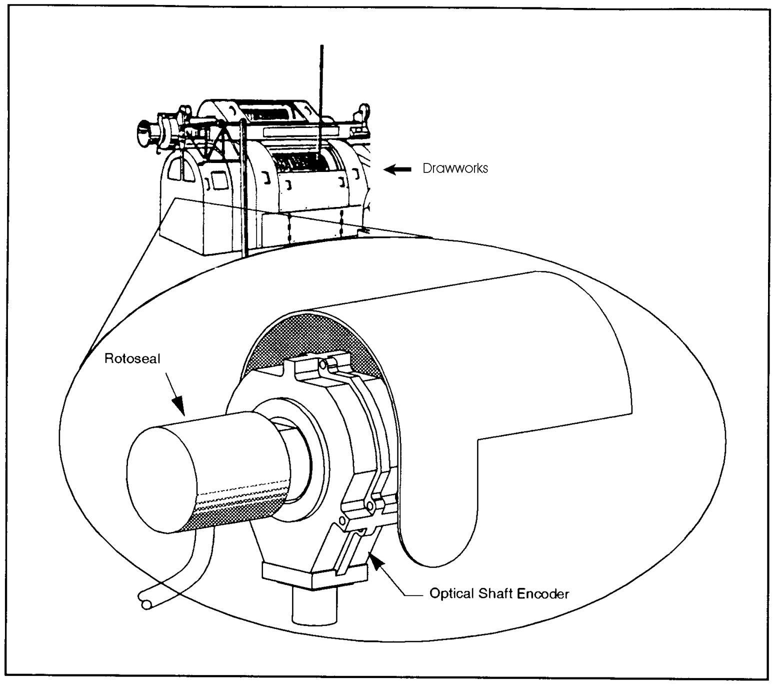

Figure 2-5: The Optical Shaft Encoder

The system uses low DC voltages and intrinsically safe (I.S.) circuits, so no special safety precautions are required. However, since installation and calibration is conducted near the drawworks, the logger should be aware of the possible dangers associated with rig floor movement.

Rig Up and Installation

Before any attempt is made to install the Optical Shaft Encoder to the drawworks, the client, toolpusher and driller must be notified. Their approval is required.

Optical Shaft Encoder installation should be done by a regional service engineer, however the Logging Geologist should be present to review the installation for calibration purposes and in case of fault conditions occur and troubleshooting is required. As mentioned earlier, the Encoder to attached to the drawworks.

The Junction Box should be mounted as close as possible to the drawworks. Two cables connect the system. One cable connects the Optical Shaft Encoder to the Junction Box, the other sends the signal, via a Cable Reel Assembly, to the P&F rack.

Operation

Once installed, Block Height software is used to calibrate the sensors and receive data from the sensors to determine block height (bit depth). These sensors include:

- **Optical Shaft Encoded** - This provides a measurement of drawworks rotation. It is an optical to digital device. Rotation of the drawworks will cause digital pulses to be transmitted, where they are decoded into linear movement, which equates to the height of the travelling block.
- **Hookload Sensor** - This measures the tension on the “dead line” portion of the drilling line. It is used in weight-on-bit and cable stretch calculations.
- **Block Separation Sensor** -This measures movement of the drillstring motion compensator, which is the distance between the top of the drillstring and the travelling block. Its distance will vary with the motion of the rig.
- **Rig Heave Sensor** - This measures the movement of the riser tensioner, which is the distance between the rig floor and sea level. Its distance will vary due fall and rise of the rig caused by wave action.

When used on floater operations, Block Height data is combined with block-separation data and rig-heave data to obtain “motion compensated block height”.

The relationship between Block Height and sensor input is illustrated in Figure 2-6.

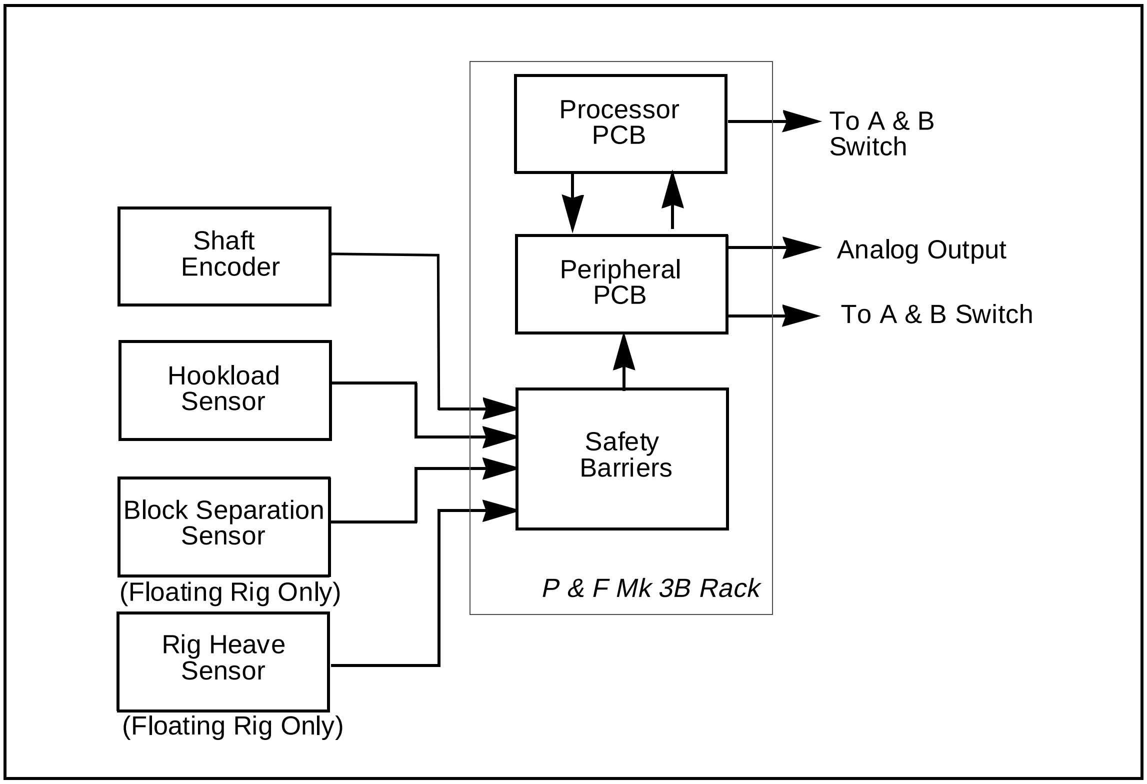

Figure 2-6: Block Height Sensor Input Diagram.

Software Interface

A software program is the interface between the data collected by the P&F rack, calibration routines and sensor output. Operator communication with Figure 2-7.

Regional variations and service levels will dictate which type of depth measurement system is in use. The information presented here is a brief outline. Always consult the pertinent service manual before installation, calibration and operation of the system used at the rig site.

```
                    EXLOG BLOCK HEIGHT SYSTEM
                    -------------------------

                    1. SYSTEM CONFIGURATION MENU

                    2. RIG DATA MENU

                    3. SHAFT ENCODER CALIBRATION MENU

                    4. OTHER SENSORS CALIBRATION MENU

                    5. OPERATION/STATUS MENU

                    6. REAL TIME SENSOR DISPLAY

                    7. VERSION

                    NEW SELECTION(1,2,3,4,5,6 or 7):


Esc-chr: ^]  help: ^]?  port:2 speed: 9600 parity:none echo:rem  VT320 ....
```

Figure 2-7: Block Height Main Menu Screen

Other Methods

By counting the time it takes to drill a certain interval of hole, a drilling time or drill rate can be calculated. Most rigs have some type of five foot measuring stick (used to mark the kelly at five foot intervals) on the rig floor. By using this measuring stick and a watch, the drilling time for a five foot interval can be determine.

For example:

$$\frac{\text{18 minutes to drill the interval}}{\text{5 foot interval}} = 3.6 \text{ minutes/foot}$$

or

$$\frac{5 \text{ foot interval} \times 60 \text{ minutes per hour}}{\text{18 minutes to drill the 5 ft interval}} = 16.7 \text{ feet/hour}$$

If a method of measuring time is not available, the pump rate (spm) can be used, if the rate is held constant. For example:

$$\frac{750 \text{ strokes necessary to drill the interval}}{60 \text{ strokes per minute} \times 5 \text{ foot interval}} = 2.5 \text{ min/ft}$$

or

$$\frac{60 \text{ spm} \times 5 \text{ foot interval} \times 60 \text{ min/hr}}{750 \text{ strokes necessary to drill the interval}} = 24 \text{ ft/hr}$$

Conversion from min/ft to ft/hr or min/meter to meter/hr

$$\frac{60 \text{ min/hr}}{\text{min/ft or min/meter}}$$

Conversion from ft/hr to min/ft or meter/hr to min/meter

$$\frac{60 \text{ min/hr}}{\text{ft/hr or meter/hr}}$$

True Vertical Depth Logging on a Deviated Hole

While working on a deviated hole it may be required to log against vertical depth. This requires some calculations and adjustments in the logging procedures.

Deviated or directional wells are started at a kick-off point. The angle of deviation will be low just after the kick-off depth, but may increase rapidly thereafter causing vertical depth to be much less than measured depth.

The Logging Geologist has to depend on survey data to calculate vertical depth. True vertical depth should be calculated at every survey, starting from the kick-off point. The vertical depth is calculated from the angle of deviation and the course length, which is the measured depth distance between the two surveys.

A general formula for calculating the increase in vertical depth from the last survey point is:

$$TVD = TVD_1 + (C_L \times \text{Cos } I)$$

Where:	TVD	=	True vertical depth at current measured depth
	TVD_1	=	Vertical depth at last survey point.
	C_L	=	Course length (ft) since last survey
	I	=	Inclination at last survey

For example:

At 10,003 feet (measured depth), where a survey was run, the true vertical depth was 9,839 feet. At 10,099 feet (measured depth) the inclination was 24.5 degrees.

Course length (CL) = 10,099 - 10,003 = 96 feet

Vertical depth of the section (TVD) = Cos 24.5^{o} x 96 ft = 87 feet

True Vertical Depth (TVD) = 9,839 ft + 87 ft = 9,926 feet.

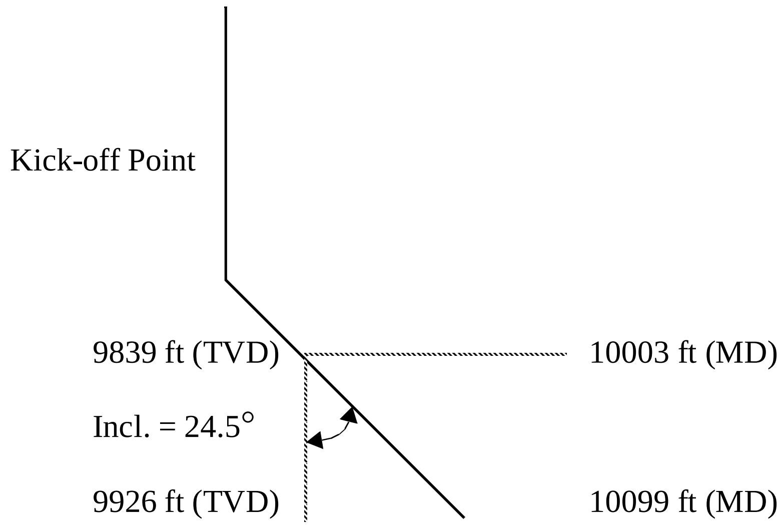

Figure 2-8: Vertical Depth Increase

In practical logging, however, the deviation of the hole since the last survey point is not known and the Logging Geologist has to project the inclination angle according to this last survey. Assuming this was 24.5° degrees, and the drill rate and other data is to be recorded at five foot intervals, the projected increase in measured depth corresponding to a change of five feet in vertical depth = 5 / (Cos 24.5°) = 5.49 feet.

This means that for every 5.49 feet measured depth increment, vertical depth increases by 5 feet. This depth could be slightly wrong due to possible changes in the angle of inclination. When the next survey is taken, a correction of the True Vertical Depth may be necessary.

Lithology, gas and other lag data are to be evaluated at measured depth and entered on the mud log at the appropriate vertical depth. Drill rate should be calculated from the measured depth taking the equivalent of every five feet of vertical depth.

Table 2-1 provides the cosine and sine values necessary for calculation of vertical depth.

Table 2-1: Trigonometric Functions

Angle degrees	Sine	Cosine		Angle degrees	Sine	Cosine
0	0.0000	1.0000		90	1.0000	0.0000
1	0.0175	0.9998		89	0.9998	0.0175
2	0.0349	0.9994		88	0.9994	0.0349
3	0.0523	0.9986		87	0.9986	0.0523
4	0.0698	0.9976		86	0.9976	0.0698
5	0.0872	0.9962		85	0.9962	0.0872
6	0.1045	0.9945		84	0.9945	0.1045
7	0.1219	0.9925		83	0.9925	0.1219
8	0.1392	0.9903		82	0.9903	0.1392
9	0.1564	0.9877		81	0.9877	0.1564
10	0.1736	0.9848		80	0.9848	0.1736
11	0.1908	0.9816		79	0.9816	0.1908
12	0.2079	0.9781		78	0.9781	0.2079
13	0.2250	0.9744		77	0.9744	0.2250
14	0.2419	0.9703		76	0.9703	0.2419
15	0.2588	0.9659		75	0.9659	0.2588
16	0.2756	0.9613		74	0.9613	0.2756
17	0.2924	0.9563		73	0.9563	0.2924
18	0.3090	0.9511		72	0.9511	0.3090
19	0.3256	0.9455		71	0.9455	0.3256
20	0.3420	0.9397		70	0.9397	0.3420
21	0.3584	0.9336		69	0.9336	0.3584
22	0.3746	0.9272		68	0.9272	0.3746
23	0.3907	0.9205		67	0.9205	0.3907
24	0.4067	0.9135		66	0.9135	0.4067
25	0.4226	0.9063		65	0.9063	0.4226
26	0.4384	0.8988		64	0.8988	0.4384
27	0.4540	0.8910		63	0.8910	0.4540
28	0.4695	0.8829		62	0.8829	0.4695
29	0.4848	0.8746		61	0.8746	0.4848
30	0.5000	0.8660		60	0.8660	0.5000
31	0.5150	0.8572		59	0.8572	0.5150
32	0.5299	0.8480		58	0.8480	0.5299
33	0.5446	0.8387		57	0.8387	0.5446
34	0.5592	0.8290		56	0.8290	0.5592
35	0.5736	0.8192		55	0.8192	0.5736
36	0.5878	0.8090		54	0.8090	0.5878
37	0.6018	0.7986		53	0.7986	0.6018
38	0.6157	0.7880		52	0.7880	0.6157
39	0.6293	0.7771		51	0.7771	0.6293
40	0.6428	0.7660		50	0.7660	0.6428
41	0.6561	0.7547		49	0.7547	0.6561
42	0.6691	0.7431		48	0.7431	0.6691
43	0.6820	0.7314		47	0.7314	0.6820
44	0.6947	0.7193		46	0.7193	0.6947
45	0.7071	0.7071		45	0.7071	0.7071

Depth Corrections

The most difficult problem to explain to a Company Man is why your depth, the driller's pipe tally depth, and the drill rate recorder are all different. Unfortunately, it seems that the Logging Geologist is always at fault. Equally exasperating is the method used to correct the problem “strapping out” of the hole.

To keep this time consuming and costly process from occurring, the Logging Geologist has to monitor the depth measuring devices constantly. Listed below are several precautions that may help you from getting in this awkward situation.

1. The primary reason for depth corrections are errors in the pipe tally. The logger must watch the drillers addition. Problems in addition can be avoided by rechecking the values each time you go to the rig floor. Also, you should ensure the depth is correct when you come on tour. The driller may make a mistake in the pipe tally that may go undetected for some length of time, making the apparent drill depth wrong. These depths will not be corrected until they “strap out” (SLM - steel line measure) of the hole.

2. Two non-drilling practices that will result in incorrect depths are reaming and cement drilling. The drill rate recorder and the kelly height monitoring systems may not recognize reaming. The logger must realize what is happening and compensate for it. To find the volume of cement that needs to be drilled you need to know the distance between the guide shoe and float collar (usually 40 ft), and if the casing was set on the bottom of the hole.

3. The changing out of pipe is a very common reason for incorrect depth measurements. Laying down and changing out different drill pipe requires the measuring of both the old and new pipe. After each trip, check the length of the bottom hole assembly. The configuration of the BHA may remain the same, but the lengths of the stabilizers, reamers, jars and collars will vary, resulting in an increase or decrease in the BHA length.

4. At the surface, keep a constant watch on the length of the kelly. The kelly itself may not change, but the saver sub or kelly cock valve may have been replaced, which will increase or decrease the kelly-down value.

5. There are many occasions when a low weight-on-bit is used, several more common ones are: correcting borehole deviations (pendulum effect), breaking in a new bit, drilling with fixed

cutter bits, coring, turbo-drilling, and deep wells. This low weight-on-bit results in greater surface hookloads and there-fore stretch in the drillstring (which is held in tension). If measured depth is determined from the pipe tally, without consideration of pipe stretch, a depth error can result.

6. Wireline tools do not always make it to the bottom of the hole, due to hole fill, so the wireline TD should be shallower than yours and the drillers. A comparison of the drill rate curve with the electric logs may indicate incorrect depths.
7. Samples are not generally corrected for depth, unless the correction is relatively large (exceeding 30 ft). If necessary, sample lithologies may be shifted when compared with the electric logs.
8. The final interpretation of depth is done by a comparison (correlation) of the electric logs, lithologies and ROP curve.

Should you have a depth correction, place the correction note in the "Remarks" section of the log, stating the previous depth, and the reason for the correction.

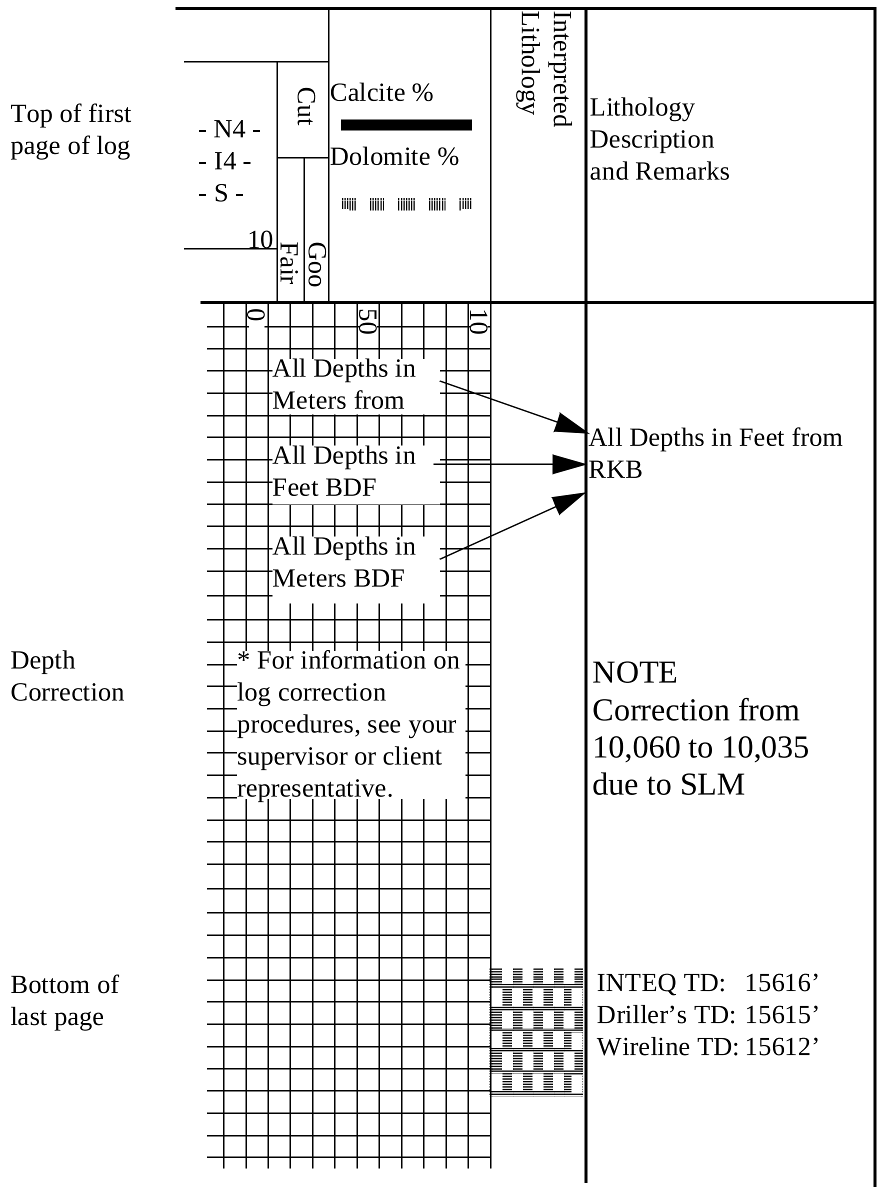

Figure 2-9:
Remarks Necessary for Proper Depth Monitoring

Self-Check Exercises

1. How is depth determined when the Logging Geologist initially arrives at the wellsite?

   ____

   ____

2. What are the three depth measuring systems in Baker Hughes INTEQ's inventory?

   a. ____

   b. ____

   c. ____

3. What is the drill rate (min/ft) and rate of penetration (ft/hr) if it took 37 minutes to drill a 5 foot interval?

   ____

   ____

4. At 7845 ft (MD), 7822 ft (TVD), drilling resumed after a connection and survey. At 8025 ft (MD) another survey was taken, with an inclination of 33.7^{o}. What is the True Vertical Depth at 8025 feet?

   ____

   ____

5. Using the inclination of 33.7^{o}, if the Logging Geologist was plotting information at five foot intervals, how much measured footage must be drilled to drill five vertical feet?

   ____

   ____

6. List two way the Logging Geologist can ensure that the logging unit's and pipe tally's depth values are correct.

   a. ____

   b. ____

7. How can drilling with low weight-on-bit result in depth discrepancies?

 ____

 ____

8. Why is there normally a difference in the wireline depths when compared with the drillers depth?

 ____

 ____

9. If a depth correction is necessary, what type of information should be placed on the Formation Evaluation Log?

 ____

 ____

10. What three depths should appear on at the bottom of the last page of the Formation Evaluation Log?

 a. ____ a.

 b. ____ b.

 c. ____ c.

•Notes•

Chapter **3**

Advanced Sample Evaluation

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

- Understand and explain the various factors affecting drill cuttings generation and sample evaluation
- Use drilling and drilling fluid parameters to refine Interpreted Lithology evaluation
- Realize the importance of lithologic descriptions in the interpretation of reservoir characteristics
- Discriminate between bit-generated rock textures and unaltered textures during sample evaluation

Additional Review/Reading Material

INTEQ Video Tape #6 - *Mudlogging: Principles & Interpretation*

INTEQ Video Tape #7 - *Logging Procedures*

AAPG Video Tape - *Sample Examination*, 1986

IHRDC Video Tape GL 303 - *Sample and Core Handling and Analysis*

INTEQ, *Drill Returns Logging Manual*, 1994

AAPG, *Sample Examination Manual*, 1981

Helander, Donald, *Fundamentals of Formation Evaluation*, OGCI, 1983

SPWLA, *Hydrocarbon Well Logging Recommended Practice*, 1983

Introduction

This chapter will emphasize and elaborate upon those cuttings evaluation procedures discussed in the Drill Returns Logging School. Most of us have seen the rock cuttings at the surface, but have you ever wondered what factors are affecting those cuttings on their journey to the surface. The pore fluids and rock chips have probably been severely affected by various factors between the time the bit crushed the rock, and the time you are ready to describe them under the microscope.

We will deal with several topics in this chapter. The first will be a detailed discussion on the cuttings' travel from the bit to the logging unit. The second will cover what is called Interpreted Lithology. Followed by how sample descriptions can be used for geologic evaluation of a reservoir. Finally, an AAPG article describing and illustrating how the drilling process and bit can alter the appearance and textures of cuttings, is included.

From Bit to Microscope

Most formations, prior to being drilled, will consist of the rock matrix (the constituent grains and any cementing material), some pore spaces, probably fluids (liquids or gases) within those pore spaces, and possibly some solid organic material. This is the picture we will try to reconstruct as we describe the cuttings under the microscope, and generate plots of this information.

In the few seconds before the bit hits the formation, alteration of those parameters may begin. This, of course, will depend on how much flushing takes place prior to bit contact. The amount of flushing will be based upon:

- The formation's porosity
- The formation's permeability
- Differential pressure between mud column and the formation
- Type of bit hydraulics
- The amount of “water loss” or mud filtrate
- The overall drilling practices

These factors will initiate and dictate the type and amount of alteration which will occur.

As the bit teeth strike the formation, the exposed rock will be crushed and the formation disaggregated. Normally, the formation porosity will be the weakest link and the rock will tear along those lines. Formations with siliceous cements may tear across the grains. The amount of formation cut per unit time (or the amount of cuttings released into the mud stream per unit time) is the penetration rate. Besides porosity, the rate of penetration is a function of:

- Differential Pressure
- Bit Hydraulics
- Bit Effort (WOB, RPM)
- Bit Design

The oil industry has been fascinated by this concept for many years. Mainly because it is felt that if the bit and drilling effects can be normalized, then formation porosity should be determined. Interesting idea, isn't it.

Once the formation has been cut, the mud system receives, 1) unflushed fluids from the disrupted porosity, 2) drilled cuttings (both rock fragments and matrix particles), and 3) unflushed fluids from the rock fragments.

During travel to the surface, these formation fluids and cuttings will interact with the drilling fluid. The amount and severity of this reaction will be dependent upon:

- Any solubility effects
- The temperature and pressure changes
- Mud chemistry versus the cuttings mineralogy
- Borehole/riser effects
- Drilled fluids being diluted by uphole produced fluids
- Drilled cuttings being diluted by uphole cavings

Examples of these are commonplace, and many occur on every well. For example, evaporites will dissolve in many drilling fluids, pressure reductions may cause cuttings to fall apart, formation clays react with many drilling fluids, washouts and large diameter risers will cause sands to settle out, and directional wells, unstable boreholes and drillstring rotation will cause cavings.

The logging geologist must recognize the factors which may occur on their well, and compensate for them.

The drilling mud will carry the rock cuttings and fluids to the surface, where they will, again, be affected by external factors. Atmospheric pressure will have a great effect on any gaseous components in the mud system. Any adverse weather conditions (high winds, freezing conditions, extreme heat, etc.) will cause problems with both cuttings and fluids. The rig environment (i.e. solids control equipment, flowline, etc.) and the individual collecting the samples, and the mechanical efficiency of the equipment can have adverse effects on the samples.

The extraction process, or sampling process, is a major responsibility of the logging geologist. It essentially involves separating the raw materials (solids, liquids and gases) from the drilling fluid for formation evaluation.

Solids	Are collected using the rigs solids control equipment
Liquids	Are measured using specialized sensors or manual samples can be collected
Gases	Are collected using a gas trap and manual samples can be collected

At this point in the discussion, we will concentrate on solids sampling.

The solids we want to extract from the mud system are the rock fragments and matrix material cut from a known interval of the borehole. As we know, these are not the only solids in the system. There are cavings from the borehole wall, recycled cuttings from inefficient surface extraction equipment and a score of contaminants; mud solids (sand and weight material), LCM, pipe dope, paint, pipe scale, junk. In fact, anything around the rig-site can end up in the sample.

This process of solids extraction is a three step process:

- 1. Removing the cuttings from the drilling fluid
- 2. Removing the drilling fluid from the cuttings
- 3. Preserving the cuttings sample

Removing the Cuttings from the Drilling Fluid

There are several areas of concern, human and equipment related, when removing the cuttings from the drilling fluid. At present, we are forced to rely on the rig's solid control equipment (shale shaker, desander, desilter and centrifuge). This reliance can lead to several problems;

- faulty equipment (torn shale shaker screens and incorrect mesh sizes for the cuttings size),
- the cuttings are exposed to interference from the rig crew and weather (washing of the screens/collecting device and freezing, wind, rain, etc.), and
- equipment vibrations tend to separate the cuttings by size.

The main reason we still use this type of equipment is because it is simple, cheap, requires low technological maintenance and does not interfere with the drilling process or rig ironware.

The bit type will affect the size and quality of cuttings collected, and various hole conditions will dictate the types of sample we see at the surface. Examples are:

- Gumbo clays can plug up the solids control equipment
- Poor hydraulic cleaning will result in bit floundering and “redrilling” of cuttings
- Lost circulation and kicks will result in few samples being collected
- Viscosity and flow rate changes will affect the carrying capacity of the drilling fluid
- Collection of the sample is a manual operation. The available options are:
- The rig crew - who don't really care, because “it’s not part of their job”
- Oil company sample catchers - they are unskilled and have no vested interest in doing it right
- Trainee Loggers - doing this is essential in their career development
- Logging Geologist - this does allow quality control of the process, but the time taken to do this is at the expense of other duties.
- Oil company geologist - will normally do this only if no one else is available or if they are keen.

Besides the “who”, there is “how” and “why” to keep in mind. Are the samples collected in sample bags, buckets, cans, or in a spoon. Are spot samples collected, interval samples, composite samples, or all of the above.

Also, are the samples unwashed, rinsed or washed. These are but a few of the items that must be answered in order for the sample collection process to operate in a smooth, cost-effective manner throughout the well.

Removing the Drilling Fluid from the Cuttings

Removing the drilling fluid from the cuttings is an involved, important process. Much has been mentioned in the Drill Returns Logging manual, so only a cursory review will be presented here.

To save much of the cuttings' character, whenever samples are washed, the base fluid of the drilling mud should be used to clean the cuttings. For example:

- If a water-based mud, use water
- If an oil-based, use the base oil

Extreme care must be taken when cleaning samples in base oils. These oils can cause skin irritation and if not used properly, can be potentially hazardous.

Over-zealous washing can remove all traces of hydrocarbons, and if drilling “top hole”, this technique will yield all sand (dissolving all the clays). Under-washing will not clean the samples, which will yield only an amorphous mud.

In any event, washing must remove the contaminants from the cuttings sample.

Preserving the Sample

The final objective in the extraction process is the preservation of the samples, for storage and future analysis, and for your sample analysis. Since there are several methods of sample preservation, they can best be illustrated using Table 3-1.

Summary

This section of the chapter should compliment what was discussed in the Drill Returns Logging manual. It should also emphasize the many variables that must be taken into account when performing sample analysis. By following what is written in this section, the logging geologist should be able to discriminate against what is seen in the sample tray and what was actually drilled at the bottom of the hole. This discrimination will assist in the construction of the **Interpreted Lithology** column. The next section of this chapter will deal with interpreted lithology.

No Heat - Ambient Temperature

Method	Advantages	Disadvantages
On Filter Paper	minimizes clay damage	slow
	reduces hydrocarbon loss	takes up space
	minimum human input	“poisons” the atmosphere in logging unit
Centrifuge	as with filter paper automatic	moderately slow sample moist, still requires drying

Heat

Method	Advantages	Disadvantages
Heat Lamp	quick	heats up logging unit, affects clays and boils off hydrocarbons
Sample Oven	very quick and compact	as with heat lamp, can burn cuttings
	can handle top hole quantities	makes “brick” out of clay
	extractor fan removes fumes from logging unit	

Table 3-1: Various Methods Available for Sample Preservation

Interpreted Lithology

Interpreted lithology is the Logging Geologist's evaluation of the formations that have been drilled. Generally based on the cuttings lithology observed in the sample tray and under the microscope, several refinements will take place after consideration of the drilling effects and other parameters affecting the cuttings lithology. Special considerations should be given to the gas curves and drilling fluid.

Normally, when a new formation is initially penetrated, the cuttings sample will contain only a few percent of that lithology. By using parameters such as drill rate, torque, etc. and any correlation materials, the interpreted lithology will show this trace lithology as the lithology being drilled. This principle is illustrated in Figure 3-1.

In this example, two drilling breaks are observed, with only a small percentage of sandstone seen in the cuttings. Each break also produced a gas show. When the drilling parameters were analyzed, an increase in torque and a decrease in weight-on-bit occurred when drilling the first break, and an increase in torque but constant weight-on-bit occurred in the second break.

When the samples were circulated out, an increase in mud density was reported from both breaks. The Logging Geologist performed a “sand content” mud test and determined the weight increases were due to a fine, dispersed, unconsolidated sand, which had passed through the shaker screens.

Using this information, the Logging Geologist decided that the first break was a transition from shale to a clean sand, and the second break was logged showing a sharp contact, but a less clean, shaley sand.

In difficult sections, it may be advisable for the Logging Geologist to leave the interpreted lithology column blank. After review of the available information and discussions with the Field Supervisor, the column can be finalized. The Field Supervisor, as always, will be the final authority in decisions affecting the information placed on the log.

When the absence of returns and difficult logging conditions prevent reliable interpretation, a section of the interpreted lithology can be left blank, until additional information (i.e. wireline logs) can corroborate your initial interpretation.

Few lithologic and stratigraphic determinations are clear-cut. To confidently arrive at an interpreted lithology, the Logging Geologist must use ALL available information. Any correlation material in the logging unit and local knowledge will be useful. Probably the most important requirement for interpreted lithology will be your geologic education and training.

The interpreted lithology column on the Formation Evaluation Log allows the Logging Geologist to function as a geologist. Using the Percentage Lithology and Interpreted Lithology columns, the Logging Geologist will be able to prepare a detailed geologic description for the lithology.

This description is a valuable piece of information to the oil company when they are evaluating potential reservoirs. The next section will highlight some examples of how your descriptions are used to assist in reservoir evaluation.

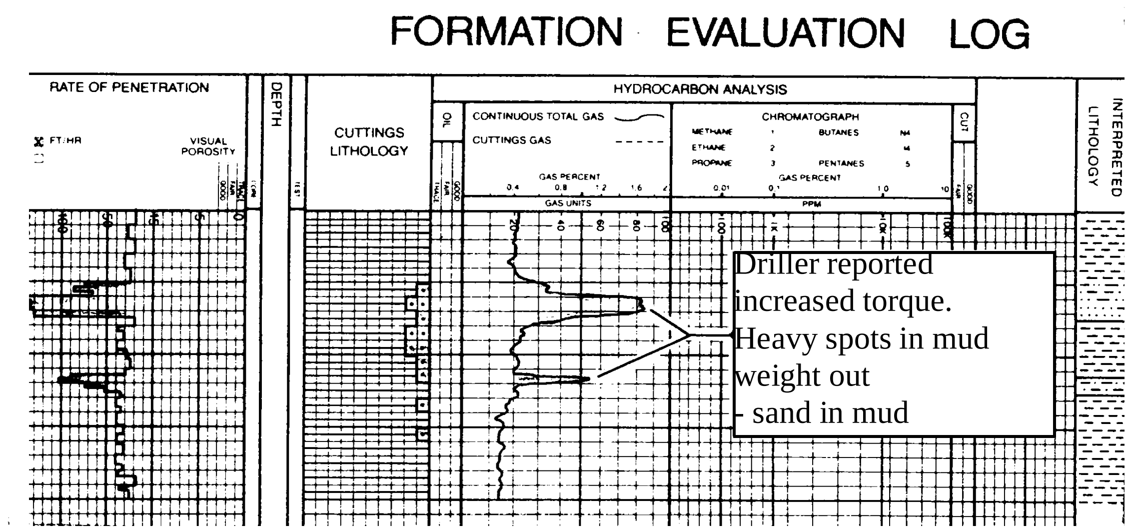

Figure 3-1: Formation Evaluation Log

Geologic Significance of Formation Evaluation Log Descriptions

The logging geologist's sample descriptions provides the oil company with a wealth of geologic information. The logs generated in the logging unit are used by many departments within the exploration and production divisions to determine reservoir characteristics. Your logs form a valuable component in the evaluation of potential reservoirs, and usually provides important clues which allow production decisions to be made with added confidence.

The remainder of this section will deal with those sample descriptions, and some geologic interpretations those descriptions provide.

SS: clr-amb,vf-f gr,rnd-sbrnd,lse cons,tr foram,tr lig

Very fine-fine grained, non-silty, well sorted

This is a fair reservoir rock with average porosity, but low permeability. It can be a commercial hydrocarbon producing reservoir if the sand is thick enough and the hydrocarbon column is large enough to prevent the influx of water from the water leg of the reservoir.

Micro-fossils, fossils, and unidentified shell fragments

This is an environmental indicator that helps when isopacing a reservoir and predicting its geometry, a real extent and facies changes. In this case, this interval would be a marine sand. It is now up to the geologist to deduce whether the reservoir is strike or dip oriented and its geometry by unraveling the sedimentological conditions, such as; was the sand deposited in a deltaic environment and, if so, whether the delta was a high constructive, a high destructive or an intermediate type between the two.

Lignite An environmental indicator. Lignite in substantial amounts in the cuttings probably means a coal bed was drilled. It is angular and sometimes splintery. In this case, the stratigraphic interval was deposited in a continental setting. Lignite is also a mud additive. It can also be detrital and deposited in a marine environment, but this type generally appears abraded and rounded.

SS: wh-clr-gy,vf-f gr,sbrnd-rnd,p srtd, abnt clay and slt size part, w cmtd w/calc and clay cmt, p vis por, tr glau, tr dk mnrl, no flor

Glauconite This is an environmental indicator for an oxygen-starved marine environment.

Very calcareous

This will cause low porosity and permeability, and inhibit production. Acidizing a reservoir like this would only unconsolidate the sand creating sand production and channels behind the cement.

Dark grains These could be iron-bearing minerals like magnetite, hematite, pyrite and biotite. These minerals can cause serious problems if the reservoir was acidized. If present in significant amounts, these minerals can chemically react with hydrochloric acid to form a ferrous hydroxide gel which will plug-up a formation.

Very fine grained sandstone, poorly sorted, very argillaceous, very silty, calcareous, pyritic in part

This is an extremely poor reservoir rock. It might look like a shale on the SP and Gamma Ray logs. It should give a good show on the mud log if hydrocarbons are present, because the oil or gas cannot be flushed away by the mud filtrate. Hydrochloric acid would ruin the production because the pyrite and chlorite (if present) would cause the precipitation of a ferrous hydroxide gel. Natural fractures or a frac job would promote hydrocarbon production.

Argillaceous

The type of clay minerals, besides reducing the permeability and effectiveness of the reservoir, can cause serious reservoir problems if certain fluids come in contact with the clays. Smectite clays will hydrate and clog a reservoir if they come in contact with fresh water filtrate. Chlorite and illite clays will precipitate the ferrous hydroxide gel if contacted by HCl used in well stimulations. Kaolinite will clog pore throats and ruin permeability if the formation experiences a lot of rough treatment during testing, shutting the well on and off, or flows at excessive rates.

Clear to light gray mineral that is soft, non-crystalline, massive, non-calcareous, waxy

This is very likely a bleached or hydrothermal alteration product from a fault breccia zone, or a weathering product from an inconformity. The logging geologist should be on the lookout for these features at stratigraphic or structural correlation points.

SS: clr-wh, vf gr, mod hd, sli fri, rnd, w srtd, calc cmt, sd gr are sli sep, mnrl flor, no cut

Very fine to fine grained sandstone, well sorted, non-silty, grain supported

This sandstone is probably a fair reservoir. Because of its porosity and permeability, it would yield only a small hydrocarbon show, since most of the hydrocarbons would have been flushed away by invading mud filtrate ahead of the bit.

SS: clr-lt gy, fri, p ind, vf gr, pred sbang, w srtd, vit lstr, n calc, cln mtx, mnr ltc %,tr glau, g vis por, no flor, no cut

Non-calcareous and poorly consolidated

This will cause the reservoir to disintegrate once production begins. Production will die because the tubing will load up with sand and production equipment will be severely abraded (holes in the tubing could result). The formation could also cave in and channels behind the cement will act as conduits for water influx.

SS: clr-lt gy, fri, mod ind, vf-f gr, mod w srtd, vit lstr, sli calc cmt, arg, sbang-sbrnd, tr calc frac fl, tr anhed calc xls, no flor, no cut

Massive calcite

This might be crystalline calcite vein filling from a fault breccia zone. The logging geologist should be alert for a fault at this point.

Summary

This should illustrate how important the sample descriptions can be to the oil company geologists and engineers. They can provide a tremendous amount of information. Using your geologic background and logging experience, you can ensure that the **Formation Evaluation Log** provides that information.

Bit-Generated Rock Textures and Their Effect on Evaluation of Lithology, Porosity, and Shows in Drill-Cutting Samples[1]

by: WILLIAM GRAVES[2]

ABSTRACT

During the drilling phase, drill cuttings provide critical data on which costly operational decisions are made. The success or failure of a well may depend on the accuracy of the interpretation of drill-cutting samples comprised of rock fragments 2 mm or less in diameter. These fragments commonly have bit-generated textures that differ substantially from those of the in-situ rocks. Under certain conditions, the bit may pulverize all or part of the rock fabric to produce bit flour, clay, or sand. The processes by which these and other less common bit-generated textures are formed and reach the drill-cutting sample are described. The generation of bit textures affects the quantitative am qualitative evaluation of the samples. These textures must be recognized to interpret samples correctly for lithology, porosity, and hydrocarbon shows.

INTRODUCTION

Drill bits are designed to remove rock from the bottom of the hole. Mill-tooth and insert bits, diamond bits, and polycrystalline diamond compact (PDC) bits all drill differently, which is reflected in the drill cuttings they produce. The nature of the cuttings also depends on the confining pressure exerted by the drilling-fluid column and on the hardness and texture of the rock. Cuttings may consist of chips retaining the in-situ rock texture, particular textural elements of the rock such as sand grains, or crushed or pulverized rock retaining little or none of the in-situ texture. During their removal to the surface, certain types of drill cuttings may dissolve, go into suspension, or hydrate to become part of the drilling fluid. Cuttings that reach the surface intact are separated from the fluid by the shale shakers. Drill-cutting samples contain both unaltered and bit-generated rock textures. Correctly interpreted and described, they provide fundamental data for the geologic, reservoir, and show evaluation of the well.

MILL-TOOTH AND INSERT BIT DRILL CUTTINGS

Bit-tooth penetration studies by Maurer (1965) and Myers and Gray (1968) on competent rocks showed what happens at the tooth/rock interface when force is applied to the tooth. Figure 1 summarizes their findings. Steel mill teeth and tungsten carbide inserts operate in the same manner.

Single-Tooth Loading to Failure Threshold

When force is first applied, the rock compresses elastically under confined stress until the confined failure strength is reached. The rock then compacts under the tooth flat, first by grain slippage, then by grain failure, forming a crushed wedge (Figure 1B). Compaction continues under the tooth flat until the failure threshold is reached. At this point the lateral stress exerted by the crushed wedge exceeds the shear strength of the virgin rock at either side, and a fracture forms (Figure 1C). The mode by which the rock continues to fail after the fracture forms varies both with the confining pressure exerted by the fluid column and with the hardness and texture of the rock.

1. Manuscript received, October 21, 1985; accepted, April 28, 1986.

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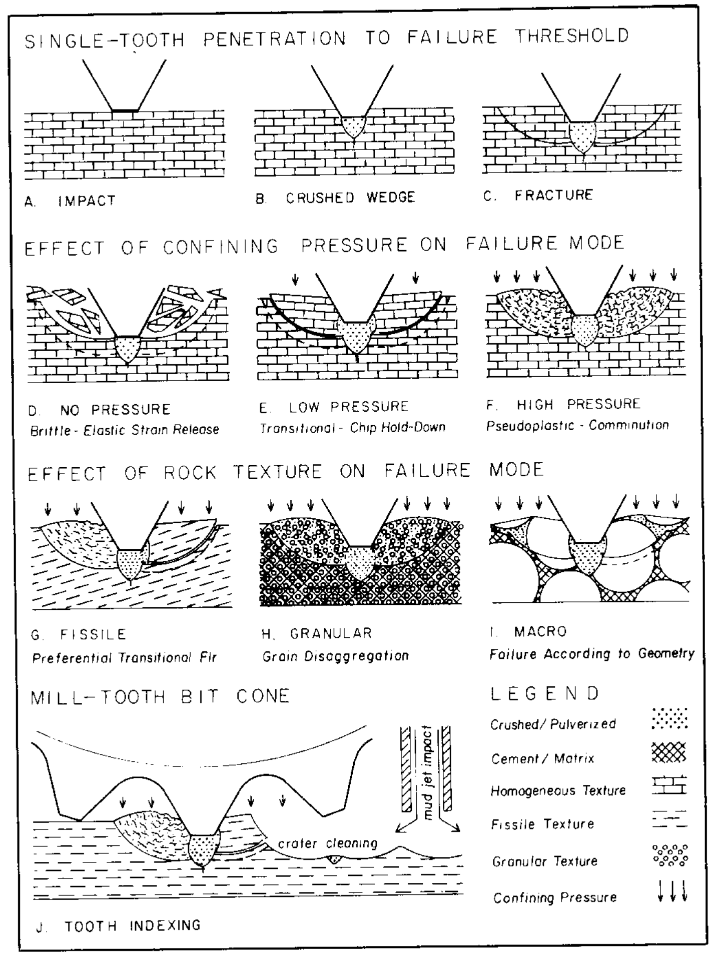

Figure 1. General features of drilling mechanisms for mill-tooth and insert bits. After Maurer (1965); Cheatham and Gnirk (1967).

Effect of Confining Pressure on Failure Modes

The confining pressure acts on the rock, giving it greater confined and shear failure strengths. It increases with the differential pressure (fluid hydrostatic pressure less pore pressure), providing the rock is impermeable or there is a seal (mud cake) between the fluid and the rock. Mud-cake sealing properties of water-base muds increase with the decrease in fluid loss. Oil-base muds have little effective fluid loss to the rock and thus develop a maximum confining pressure (Cheatham, 1984).

Once the initial fracture has formed, the confining pressure affects the failure mode as follows:

Brittle failure.—in unconfined conditions, brittle failure occurs (Figure 1D). Chips spring out of the crater generated by the fracture with the release of elastic stress, and the tooth falls to the bottom of the empty crater. If the force on the tooth is sustained, another crushed wedge is produced and more chips are generated.

Transitional failure.—Under low confining pressures, and if the friction on the surface of the fracture is less than the failure strength of the rock, transitional failure occurs (Figure 1E). The chips generated are displaced laterally but are held in the crater by the fluid pressure. Displacing the chips releases the lateral stress exerted by the crushed wedge and allows further compaction under the tooth flat. If the force on the tooth is increased, the crushed wedge deepens and new chips are generated.

Pseudoplastic failure.—Under high confining pressures, and if the friction on the fracture surface preventing displacement is greater than the shear strength of the rock, pseudoplastic failure occurs (Figure 1F). With no displacement on the initial fracture plane, the lateral stress exerted by the crushed wedge is not released. As the force on the tooth is increased, further fractures are produced parallel to the first. When this happens the rock appears to yield plastically; microscopically, it is seen to fail through the progressive comminution of mineral grains by brittle fracture. The rock is pulverized, and its original texture is destroyed.

Effect of Rock Texture on Failure Mode

The texture of the rock and the geometry of its component shear failure strengths determine the failure mode.

Hard, homogeneous rocks.—Hard, homogeneous rocks such as limestones, dolomites, and quartzites fail through brittle fracture when drilling with air or water (Figure 1D). When drilling with mud, they generally fail through transitional fracture and chip hold-down (Figure 1E). However, if the mud is heavily overbalanced, pseudoplastic failure may occur (Figure 1F).

Soft, homogeneous rocks.—Soft, homogeneous rocks such as claystones, anhydrite, and chalk fail through brittle fracture when drilling with air. When drilling with water or with thin muds at near balanced conditions, they may fail through transitional fracture and chip hold-down. However, drilling with mud generally leads to pseudoplastic failure.

Fissile rocks.—Older, hardened claystones and shales may have planes of weakness due to fissility or slickensides, and where possible, the fractures induced by the crushed wedge tend to propagate along these planes. Part of the rock may then fail transitionally with chip hold-down, and the remainder fails pseudoplastically (Figure lG).

Granular rocks.—In sandstones whose grains are harder than the cement or matrix, fracture occurs in the softer intergrain material. If the friction on the fracture surface of the chip is less than the shear strength of the intergrain material, transitional failure with chip hold-down will occur. However, if the friction on the fracture surface is greater than the shear strength of the intergrain material, the cement/matrix pulverizes, freeing the harder unbroken grains (Figure 1H). The same process commonly frees forams and other microfossils embedded in claystones and shales.

Macrotextured rocks.—In conglomerates and breccias whose grains are harder than the cement or matrix material, but in which the grains exceed the size of the tooth flat, the type of fracture will depend on the geometry of the texture (Figure lI). Generally, chips are produced from the grains and pebbles, whereas the intergrain matrix or cement is pulverized through pseudoplastic failure. The interface between the grains and the matrix or cement is a plane of weakness, and fracturing tends to follow it.

Unconsolidated sands.—In sands under low confining pressure, grains are jetted directly into the mud stream. Under higher confining pressures, however, friction occurs at the grain contacts, and the confined and shear strengths of the sand body approach those in cemented sandstones.

Unconsolidated clays.—In clays, owing to their high water content, true plastic yielding occurs in which no internal cohesion is lost. There is a complete gradation between this plastic yielding and the pseudoplastic yielding of indurated claystones in which most of the internal cohesion is lost.

Tooth Indexing

The above mechanisms describe the effect of single-tooth penetration in various types of rock under various conditions, and the generation of craters. Mill-tooth and insert bits are designed so the fracture generated on the backside of the tooth tends to propagate toward the crater produced by the previous tooth. The chip formed in the process is then displaced into the crater (Figure 1J). These bits generally produce an adequate proportion of representative chips.

Crater Cleaning

The removal of the tooth induces a tensile force that helps remove cuttings from the crater (Myers and Gray, 1968). However, the chips and the crushed and pulverized rock are cleaned out of the crater primarily by the jetting and scouring action of the drilling fluid forced through the nozzles in the bit (Sutko, 1973) (Figure 1J).

DIAMOND BIT DRILL CUTTINGS

Diamond bits drill by a loading and shearing action and are used over a wide range of rock types. Studies of the cutting action of a single diamond (Garner, 1967) showed how changes in borehole pressures and rock hardness affect the geometry of the grooves. Although the exact behavior is unknown, the drilling process is analogous to that of a bit tooth.

Brittle/transitional failure.—In homogeneous rocks under low confining pressures, the loading of the diamond crushes the rock beneath it, which in turn shears the virgin rock in a series of fractures to the front and to the sides (Figure 2A). The chips thus generated spring out (brittle) or are pushed out (transitional) in front and to the sides by the rotation of the diamond; the grooves produced have irregular sides.

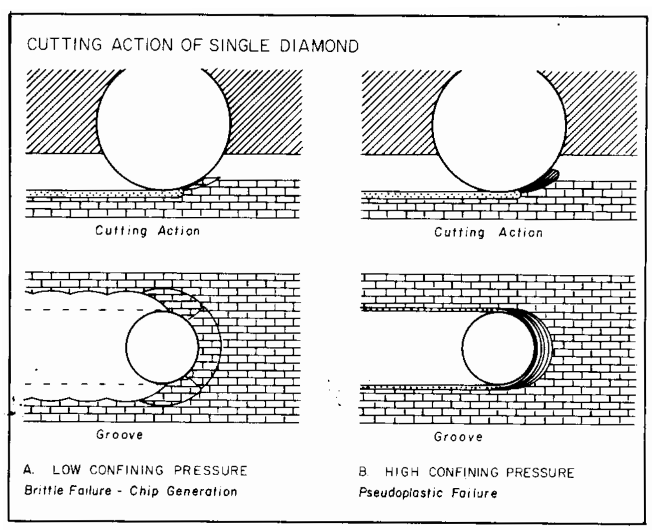

Figure 2. General features of drilling mechanisms for diamond bits.

Pseudoplastic failure.—If the confining pressure is such that the friction on the fracture surface is greater than the shear strength of the rock, pseudoplastic fracture occurs (Figure

2B). The rotation of the diamond then squeezes the material out in front of it; no lateral chips are produced under these conditions, and the grooves are smooth, conforming to the shape of the diamond. The material squeezed out in front of the diamond is removed by bottom-hole fluid scavenging. The heat produced during this process in sandstones may be enough to vitrify the quartz and cause true plastic yielding (Taylor, 1983).

Rock textures also affect the drilling process as described in the bit-tooth section. Also, sand grains are commonly liberated by pulverizing the cement or matrix in sandstones. Diamond bits in harder formations produce an adequate proportion of representative chips.

PDC BIT DRILL CUTTINGS

PDC bits drill by a shearing action (Preslar and McDermaid, 1984) and are most effective in softer formations such as claystones, evaporites, or chalk. The exact behavior is unknown. Under low confining pressures the cutter shears the rock in a finite series of fractures, which are commonly welded together in long steplike cuttings (Figure 3A). Under high confining pressures the failure is pseudoplastic, and the cuttings are generally smooth (Figure 3B) and similar in appearance to those generated in cutting ductile metals such as lead (Cheatham and Daniels, 1979). The volume of rock removed is substantially greater than with conventional diamond bits. Few representative chips are produced.

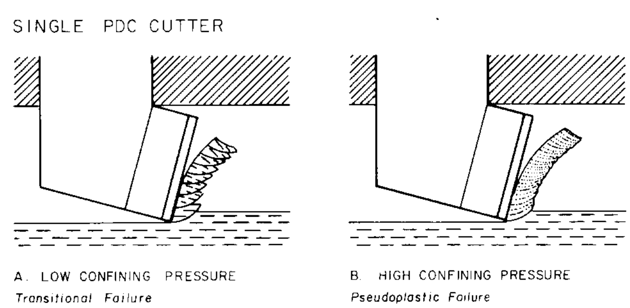

Figure 3. General features of drilling mechanisms for PDC bits.

BIT-GENERATED ROCK TEXTURES

Thus, when removing rock from the bottom of the hole, the bit may generate textures that differ substantially from those of the in-situ rocks. The following terms are proposed to describe these textures.

Bit flour.—Bit flour (Figures 4, 5) is produced by direct crushing or pseudoplastic failure of nonargillaceous rocks, or by a combination of both processes. Both processes pulverize the rock. Bit flour is generally chalky or amorphous, and white or a paler shade of the unaltered rock color. Firmness and cohesiveness depend on rock composition

Bit clay.—Bit clay (Figure 6) is produced by the hydration of bit flour of argillaceous rocks. Bit flour has a large surface area, and in the presence of water, the exposed clay minerals hydrate to produce a soft clay. Bit clay tends to have a paler shade of the unaltered rock colon

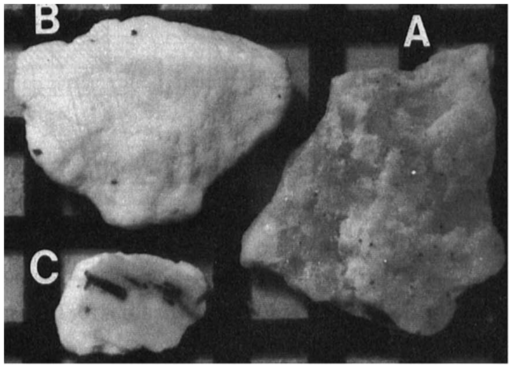

Figure 4. ***Bit flour from limestone; white,neomorphosed to microspar, dense, abundant disseminated pyrite, no visible porosity. (A) In-situ texture. (B) Typical chalky texture produced by pseudoplastic failure. (C) Surface burnished by contact with bit tooth; note also drawn-out pyrites. Photomicrographs (Figures 4-11) were taken using a WILD M-5A stereomicro-scope with photographic attachments. Chips are placed against a millimeter grid. Color descriptions follow Goddard et al (1948). Magnification is approximately x12.***

Figure 5. Bit clay from sandstone: pale brown, very fine grained, hard, siliceous cement, minor calcareous cement, dis-seminated carbonaceous material, low porosity. (A) In-situ texture. (B) Minor intergrain and occasional grain comminution; rock loses its vitreous luster and is paler. (C,D) Crushed texture and bit shearing patterns; color is grayish-orange pink. (E) Bit burnished chip; black residue is metal from mill tooth. Color descriptions follow Goddard et al (1948). Maginification approximately x12. See Figure 4 for add-itional information on photomicrographs.

Bit sand.—Bit sand (Figure 7A, B) is produced by the pseudoplastic failure of weaker intergrain cement or matrix in granular rocks. Bit sand consists of loose grains.

Bit metamorphics.—Bit metamorphics (Figure 8) are produced when the heat generated in drilling sandstones with diamond or PDC bits vitrifies the pulverized silica. True plastic flow may occur. In the presence of oil-base muds, the heat and pressure involved in the shearing process appear to crack the diesel, generating gas and giving the product a black, vesicular texture (Taylor, 1983).

PDC platelets.—PDC platelets (Figure 9) are produced by the shearing action of PDC bits.

Macrochips.—Macrochips (Figure 10) are formed from single pebbles or elements of a texture greater than the size of the cuttings in the sample.

TRANSPORT OF CUTTINGS IN DRILLING FLUID

Drill cuttings formed by the drilling process are jetted or flushed into the fluid stream and up the borehole. Depending on their texture and chemical composition, and on the type and composition of the fluid they are joining, the drill cuttings may: (1) dissolve in the water phase of the mud; (2) go into suspension in the mud and become effectively part of it; (3) hydrate, by absorbing water into the crystal lattice; or (4) remain chemically inert and mechanically resistant in their removal to the surface.

Water or Water-Base Muds

All four of the above processes occur in water or water-base muds. Salt cuttings dissolve in these muds unless the muds are salt-saturated.

Bit flour breaks into smaller particles and eventually goes into suspension, when its internal cohesion does not resist the impact of the jetting action, flushing, or turbulence of

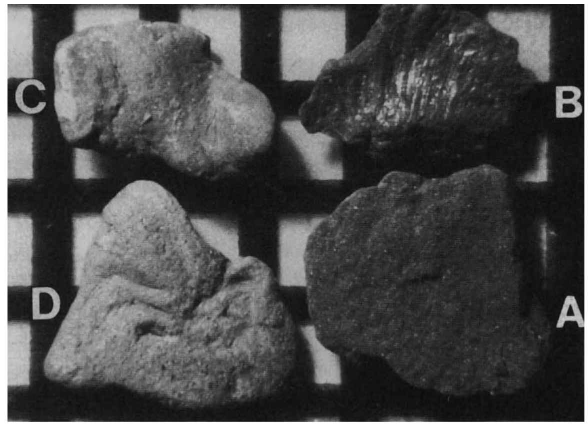

Figure 6. Bit clay from claystone: grayish red, subfissile, hard, silty. (A,B) In-situ texture; note incipient fissility (A) and slickensided surface (B) along which fracturing has occurred. C and D are soft and lighter colored (pale reddish brown). Color descriptions follow Goddard et al (1948). Maginification is approximately x 12. See Figure 4 for additional information on photomicrographs.

the water or mud. This is common in chalky limestones, gypsum, and anhydrite. However, the bit flour from most rock types is generally sufficiently cohesive to resist the hydraulic processes and to remain as larger fragments in the drilling fluid.

Bit clay is common in water-base muds. It is soft and has little internal cohesion. Unless further hydration is inhibited through chemical additives, encapsulation by polymers, or a combination of both, bit clay may disperse and go into suspension in the mud.

If they are chemically inert and sufficiently cohesive, drill cuttings with original or altered rock textures are carried to the surface in the fluid stream and are separated out there. Of

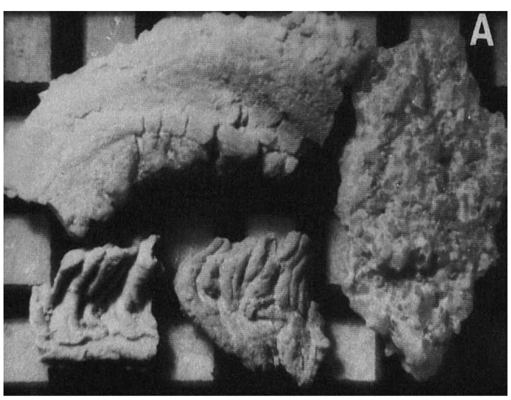

Figure 8. Bit metamorphics from sandstone: white, very fine grained, hard, illitic matrix, low porosity. (A) In-situ texture. Formation was drilled with diamond bit on a turbine. Chips were generally good, but turbine-stalling generated plastic textures on left. Material is vitrified, and plastic flow seems to have occurred. Color descriptions follow Goddard et al (1948). Magnification is approximately x12.

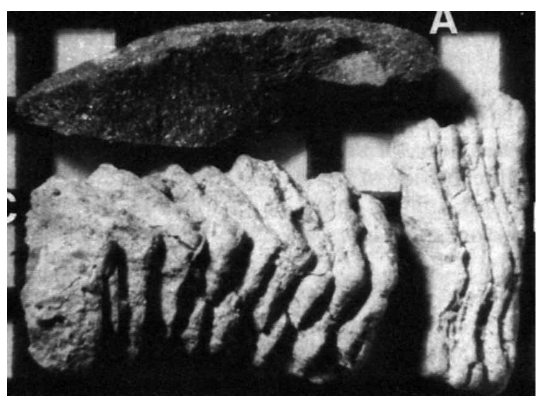

Figure 9. PDC platelets from claystone: dark gray, firm, subfissile, carbonaceous, trace pyrite. (A) In-situ texture. Formation was drilled with PDC bit and oil-based mud. Chips are rare, and sample is almost entirely comprised of pseudoplastic structures up to 10 mm long (B,C). Shape of cuttings indicates that drilling occurs by a fracture and squeeze process. Color descriptions follow Goddard et al (1948). Maginification approximately x12. See Figure 4 for add-itional information on photomicrographs.

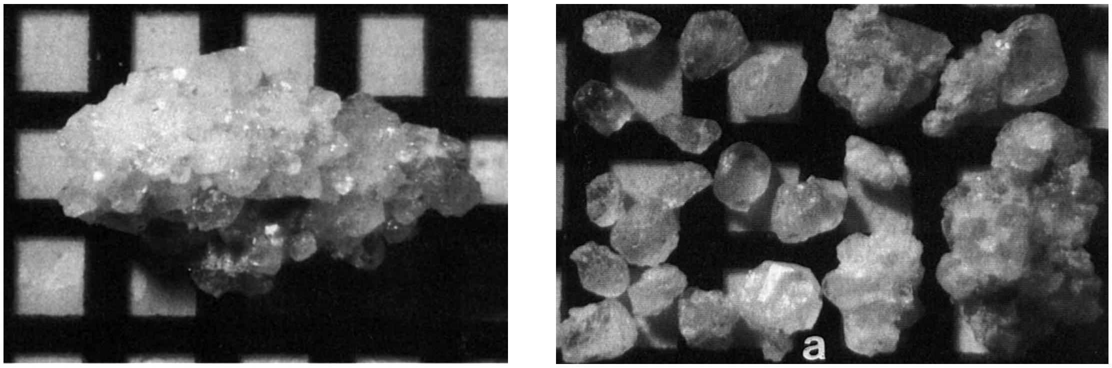

Figure 7. (A)Sandstone: white, fine to medium grained, rounded, quartz overgrowths, quartz cement, medium hard to friable, fair porosity. Core chips shows in-situ formation texture. (B) Bit sand from same formation in sidetrack hole 5 m away. Some grains preserve matrix/cement stuck to them. Occasionally two or three grains are still together. Chips on left are rare in the sample and show unaltered textures of least friable parts. Note occasional quartz overgrowths and reflection off crystal facets (a). Color description follows Goddard et al (1948). Magnification is approximately x 12. See Figure 4 for additional information on photomicrographs.

course, the upward velocity of the fluid must be greater than the settling velocity of the cuttings.

Oil staining tends to remain in the pore space of unaltered textures. However, any oil remaining on the surface of bit sand is generally washed off, unless the gravity is low.

Oil-Base Muds

In general, drill cuttings are inert to oil-base muds. Salts do not dissolve, and argillaceous rocks do not hydrate. Bit flour tends to remain in fairly cohesive fragments, although

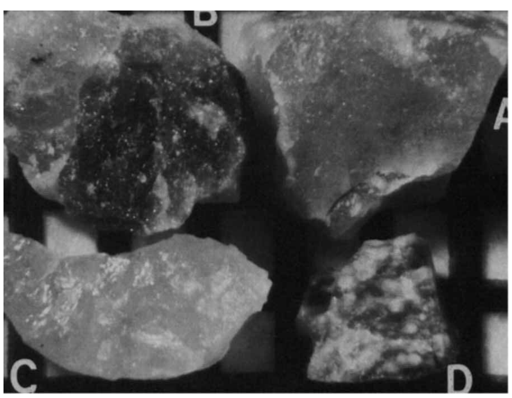

Figure 10. Macrochips from congomerate: rounded pebbles, predominantly white with moderate orange-pink and medium-gray quartzite, occasional medium dark-gray volcanic, in white quartzitic matrix, very hard. Deductions as to overall texture and nature of rock must be based on such details as rounding of parts of chips A and C; martix/peble contact in B; variation in rock types comprising the sample, including volcanic pebble chip D. Color descriptions follow Goddard et al (1948). Magnification is approximately x12.

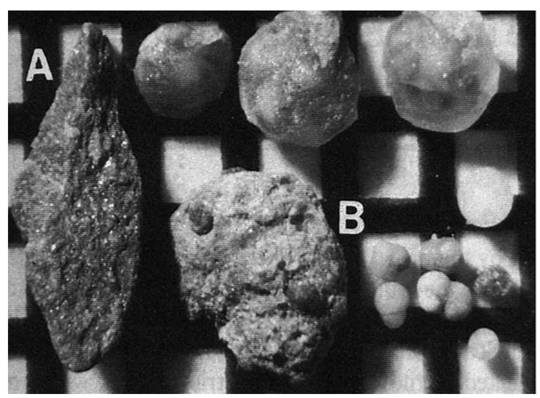

Figure 11. Claystone: medium gray, firm, massive, carbonaceous, fossiliferous. (A) In-situ texture. (B) Bit clay. Forams in sample have been liberated by pseudoplastic failure that generated bit clay. Color descriptions follow Goddard et al (1948). Maginification approximately x12. See Figure 4 for add-itional information on photomicrographs.

jetting and turbulence have a disaggregating effect. Oil staining from all but the most impermeable unaltered textures tends to be dissolved out.

Air

With air drilling, the rocks fail through brittle fracture However, chips are crushed by the bit until they are reduces to a size at which they can be carried in the air stream. The rock dust produced in the process is, in effect, bit flour. As the cuttings of softer rocks (anhydrites, dolomites, limestones) are carried to the surface, they are further reduced through multiple impacts; and more rock dust is produced. Unless the carrying capacity of the drilling fluid is good, few representative chips reach the surface.

Oil staining tends to be masked by the rock dust.

Other Factors

Claystones and shales open to the well bore may become unstable (Cheatham, 1984) and produce cavings that join the fluid stream and mix with the drill cuttings. Cavings are commonly hard to distinguish from drill cuttings. In addition to cavings, other contaminants such as cement, mud products, pipe scale, and lost-circulation material may also mix in. However, these contaminants are generally readily identifiable.

DRILL-CUTTINGS SEPARATION ON SURFACE

As the fluid reaches the surface, it passes through shaker screens. All material coarser than the screen mesh is removed. The bit flour and bit clay in suspension and any salt in solution pass through the screen. Although the smallest mesh capable of handling the fluid flow is generally used, the finer bit sand may also pass through. Table 1 shows the relation of screen sizes to grain sizes.

With air drilling, chips are separated by decantation or with cyclones.

Table 1: Relationship Between Shale-Shaker and Sieve Screen Mesh Sizes and Wentworth Grain-Size Scale

Mesh Size	Opening (mm)	Wentworth Scale*
230	0.0625	Silt
120	0.125	Very fine sand
60	0.25	Fine sand
35	0.5	Medium sand
18	1.0	Coarse sand
10	2.0	Very coarse sand

DRILL-CUTTING SAMPLE PREPARATION

The sample caught at the shale shakers contains proportions of bit-generated textures, larger fragments that are generally caved, and smaller fragments that are fairly representative of the textures being drilled. The sample is generally washed through a 2-mm (10-mesh) sieve over a 0.074-mm (200-mesh) sieve. Larger cavings and contaminants are retained on the upper screen. Bit flour and especially bit clay, which have low cohesive strengths, may be partly or entirely broken up when washing the sample through the lower screen. The more representative textures are retained on the lower sieve, and this fraction is evaluated. The proportions of sample, cavings, and solubles provide a useful guide to drilling efficiency, mud condition, and hole stability, and to the quality of the drill-cutting samples.

DRILL-CUTTING SAMPLE EVALUATION

Drill-cutting samples are evaluated under the binocular microscope (Swanson, 1981). Where possible, only those chips retaining the in-situ rock textures should be used to describe the rocks in the sample interval and to evaluate porosity and shows. However, bit-generated textures should be recognized, related to the unaltered textures, and reported. They may indicate whether the unaltered chips are representative. If no unaltered chips are present, an educated guess must be made as to the in-situ rock texture. When describing samples the following factors should be considered.

Bit flour.—Bit flour produced by direct crushing is difficult to distinguish from that produced through pseudoplastic failure. Crushed rock that has been in direct contact with a tooth surface commonly shows concave, burnished, or striated surfaces. In some situations a gradation can be seen within cuttings between the bit flour and the original rock texture (Figures 4, 5). it is commonly confused with kaolinite (silica bit flour) or chalk (lime bit flour).

Bit clay.—Clays are unlikely to be present below a depth where significant compaction and dewatering have occurred. Most clays described in drill cuttings are bit clays, as are most soft claystones.

Bit sand.—Beneath the depth at which most granular rocks are cemented, loose sand is likely to be bit sand. Diamond bits commonly produce bit sand even where the sandstone is well cemented. Chips with the original texture (several cemented grains) may comprise only a small percentage of the sample, especially in coarser grained sandstones (Figure 7B). The tendency for the coarser grained and higher porosity sandstones in a section to become bit sand produces a bias toward describing the finer grained and less porous textures.

Bit sand can also be produced from sandy claystones, so grains should be examined for residual cementing material. The presence of associated bit flour may indicate the origin.

Loose microfossils in samples have generally been freed from a claystone matrix by the same process that generates bit sand (Figure 11).

Bit metamorphics.—Bit metamorphics occur only under the special circumstances previously mentioned and are not generally encountered. The bit metamorphics described by Taylor (1983) can be confused with volcanics but give a crushed cut.

PDC platelets.—Even the rock type may be difficult to determine in PDC platelets. In general, PDC bits are not used to drill reservoir rocks, but both porosity and oil staining can be missed if they are.

Macrochips.—When the sample contains chips with a partly rounded surface but an angular break, chips with traces of cement or matrix, or chips indicating an abnormal geologic assemblage, macrochips should be suspected (Figure 7). Then, the coarser sieved fraction should be examined for more representative chips. Porosity generally must be inferred unless it is intragranular. Oil staining is rarely preserved.

The percentages of rock types in the sample correspond to the proportion of the different rock strata in the interval sampled only if all these rocks produce similar types of cuttings. Quantitative evaluation of the drill-cutting sample may be further complicated by the dissolution of formation salts, by incorrect logging and sample collection, or by the presence of cavings and mud products. It is, therefore, unwise to interpret the cuttings in terms of bed thicknesses and absolute depths without using a drill-rate plot or measurement-while-drilling (MWD) logs during the drilling phase. Porosity should be interpreted with drill-rate plots, and hydrocarbon shows should be evaluated using gas detection systems. Drill-cutting sample interpretations should be reevaluated in the light of wireline logs and sidewall cores.

CONCLUSIONS

1. Mill-tooth and insert bits generally produce an adequate proportion of representative chips. Diamond bits in harder formations also generally produce satisfactory samples. However, PDC bits tend to destroy all in-situ textures and produce few or no usable chips.

2. Bit-generated textures are common. To describe the textures, the terms bit flour, bit clay, bit sand, bit metamorphics, PDC platelets, and macrochips are proposed.

3. Higher mud weights produce more bit-generated textures.

4. Water and water-base muds may dissolve salts, hydrate bit clay, and take into suspension bit flour with low cohesion. Only oil shows in the unaltered textures are likely to be preserved.

5. Oil-base muds have greater effective confining pressures, so pseudoplastic failure is more common. They are a better transporting medium. Oil shows are generally dissolved out.

6. Air drilling generally produces small cuttings and abundant rock dust; dust masks oil shows.

7. Sandstones may be disaggregated into bit sand. This occurs preferentially in the coarser grained and more porous textures. Oil shows may be washed or dissolved off the grain surfaces. The grains that are finer than the shaker screens may not be represented in the sample.

8. Where possible, unaltered textures should be used to describe the rocks drilled in the sample interval. However, bit-generated textures should be recognized, related to the unaltered textures, and reported.

9. The percentages of different rock types in a drill-cutting sample are unlikely to correspond directly to the proportion of the different rock strata in the interval sampled.

With experience, the significant textures in the drill-cutting samples can be recognized. The resultant lithology, porosity, and show descriptions provide basic data for decision making during the drilling phase. These data are not superseded by wireline logs, although the latter serve to quantify many of the parameters and form the basis for the geologic interpretation of the well.

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Self-Check Exercises

1. What are the six factors which dictate how much formation flushing will occur prior to the bit striking the formation?
   a. ____________________
   b. ____________________
   c. ____________________
2. Name the three parts of the formation that are introduced into the mud system when the bit strikes the formation?
   a.
   b.
   c.
3. List four surface effects which will affect drill cuttings and fluids once they are circulated to the surface?
   a.
   b. ____________________
   c. ____________________
   d. ____________________
4. Why do logging companies still rely on the drilling rig's equipment to collect cuttings samples?
   ____
   ____
5. What options are available to the oil company in regards to cuttings sample collection?
   ____
   ____
   ____
6. Describe the interpretation problems which can occur whenever correct sample washing procedures are not followed.
   ____
   ____
   ____

7. List five parameters that can be used to assist the logging geologist in determining “interpreted lithology.”
   a. ______________________________
   b. ______________________________
   c. ______________________________
   d. ______________________________
   e. ______________________________

8. What procedures should the logging geologist follow when difficult sections prevent analysis for interpreted lithology.
   ____
   ____
   ____

9. Since the cuttings seen at the surface are generated by the cutting action of the bit, state how the various types of bits drill formations to produce cuttings:
   a. PDC Bit
   b. Insert Bit
   c. Diamond Bit
   d. Mill-Tooth Bit

10. What is the difference between “bit flour” and “bit sand”?
   ____
   ____
   ____

11. Which type(s) of bits will produce “bit metamorphics”?
   ____
   ____
   ____

12. Which type(s) of bits produce the best representative cuttings?
   ____
   ____
   ____

•Notes•

Chapter **4**

Coring Procedures

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

- Understand and explain the procedures for both conventional and sidewall coring operations
- Assist in the recovery, handling, sampling, packing and shipping of cores
- Provide comprehensive macroscopic and microscopic descriptions on conventional and sidewall cores
- Provide complete core reports for the client and for attachment to the Formation Evaluation Log

Additional Review/Reading Material

INTEQ Video Tape #7 - *Logging Procedures*

IHRDC Video Tape GL 303 - *Sample and Core Handling and Analysis*

EXLOG, *MS-3023 The Coring Operations Reference Manual*, 1982

Core Labs, *The Fundamentals of Core Analysis*

Anderson, Gene, *Coring and Core Analysis Handbook*, The Petroleum Publishing Company, 1975

Helander, Donald, *Fundamentals of Formation Evaluation*, OCGI, 1983

Introduction

At various points in a well, and particularly at potential producing horizons, it may be necessary to obtain more detailed information concerning the lithology than can be deduced from drill cuttings. Cores from 2 to 5 inches in diameter may be recovered in normal cases, and they can be a reliable source of data for porosity and permeability (both horizontal and vertical). Although the relative saturations of formation fluids can be altered during coring, information of this type can also be obtained.

Conventional Coring

Cutting the Core

Fixed-Cutter core bits are the best for coring, and are almost exclusively used because of the expense of coring, their long down-hole durability, their reliable cutting and recovery capability.

Figure 4-1 shows a diamond bit core barrel where the core is retrieved by pulling the barrel to the surface with the drillstring. This figure also shows a wireline core barrel, where the core is retrieved while leaving the drillstring in the hole.

Every method of coring stresses the necessity for a clean borehole, especially when using a diamond bit, because of the expense of the bit. Most operators will run a “junk basket” prior to coring or run it with the core barrel and circulate off-bottom for a period of time to clean the hole prior to coring.

Once the core barrel is on bottom, a metal ball will be dropped down the drillstring which engages a valve in the tool and diverts the drilling fluid to the outside of the inner barrel. The fluid is then discharged through the water courses in the face of the bit. A normal core barrel is made up in 30-ft lengths, so 30, 60 or 90 feet can be cored at one time, with diameters up to 5 inches.

While the core is being cut, the logging geologist is primarily concerned with the drill rate (recorded over one foot intervals) and gas recordings. Cuttings samples should be caught at the shakers, in case of incomplete or negligible core recovery. The drill rate during coring varies with the type of bit, the pump pressure, weight-on-bit, rotary speed and formation type. Gas curves will be severely dampened, since there are fewer cuttings and drilling is slow.

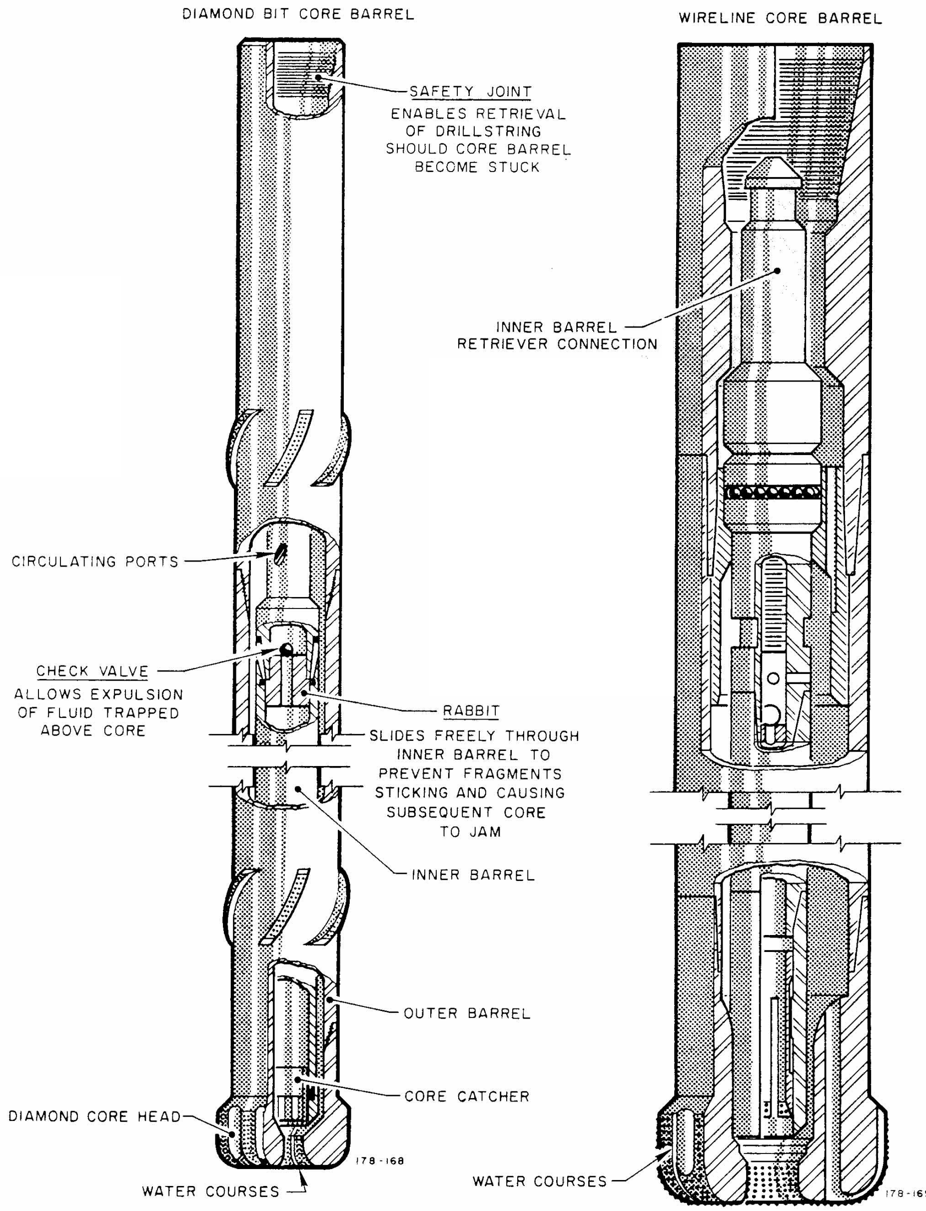


Figure 4-1: Diamond Bit Core Barrels

Receiving the Core

When coring is completed and the core barrel arrives at the surface, the logging geologist will often be requested to assist in the collection of the core from the barrel. The barrel will be hung in the derrick. Using special tongs designed to grip the core, the core can be recovered in sections. Core boxes are arranged on the drill floor in the order in which they are to be filled.

To speed up the manipulation of the core and ensure its correct orientation, the boxes should be premarked. The system for marking core boxes varies from company to company, but they are generally marked on the end with the core number and box number written underneath, starting with box #1. On the side of the box an arrow is used to show the orientation (top and bottom) of the core, with a "T" for top and a "B" for bottom. As the pieces of the core are removed from the barrel they should be placed immediately into the boxes. When collecting a core, never place your hands directly under the core barrel. A sudden drop of the core may cause injury. Box #1 will contain the lower three feet of the core, as illustrated in Figure 4-2.

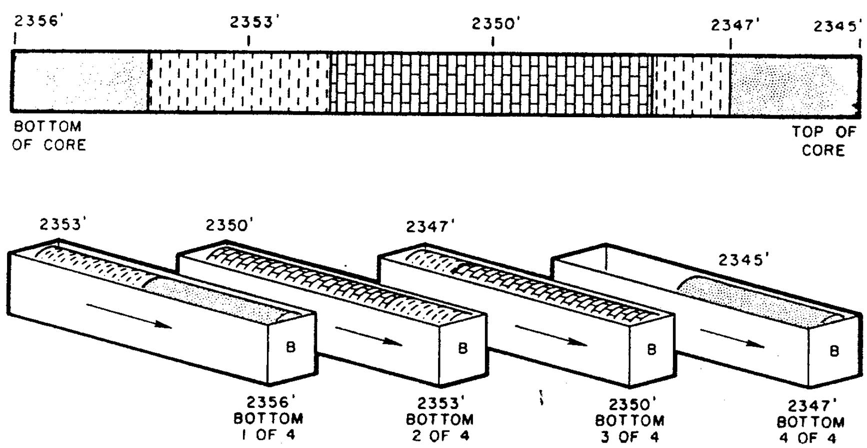


Figure 4-2: Suggested Method of Boxing Cores

When all the core has been removed from the barrel, the length recovered is measured as accurately as possible. If recovery does not equal the cored interval, it is assumed that the missing portion was lost at the bottom, unless there is additional evidence to suggest otherwise.

Sampling the Core for Special Purposes

Immediately upon removal from the core barrel, the core is wiped (never washed) free of drilling fluid. The wellsite geologist will then conduct an initial examination to decide whether to run another core. Then a macroscopic examination will be performed.

Normally, one sample per foot is taken for microscopic examination. Additional samples can be taken if warranted. The samples chipped from the core are placed in a labelled enveloped and taken to the logging unit for examination. They can be compared with the cuttings samples.

After examination, the envelopes can be inserted into the core box at the correct interval, or the boxes can be shipped separately.

The logging geologist should then combine the macroscopic description with the microscopic description, along with an ultraviolet examination, and prepare a core description to accompany the Formation Evaluation Log. This supplement is attached to the base of the log.

Packing and Shipping

Cores can be very heavy and must be carefully packed for shipment, so they do not break or fall out of their boxes. Some form of packing material, paper or rags, will prevent the core from moving during shipment. Once the core is sealed inside the box, the following information should be placed on each box:

Well Name
Core Number (in the sequence of cores taken in the well)
Box Number
Total Number of Boxes Containing the Whole Core

A copy of the field description of the core should accompany the shipment. The outside of the boxes should never display the depth, unless specified by the client, as this information is proprietary.

Summary - Conventional Coring

The purpose of coring is to:

- obtain formation data to aid in the evaluation of potentially productive sections,
- obtain lithologic and paleontologic information not available from cuttings, and
- aid in the subsurface interpretation of cuttings.

The disadvantages of coring are:

- it must be planned before the objective formation is penetrated,
- it is expensive, and
- it may result in hole problems.

The coring process consists of:

- Picking the coring point (Formation Evaluation Log, cuttings samples)
- Coring, with frequent loss of material during coring (shales, highly fractured or friable lithologies)
- Removing core from barrel, layout on pipe rack, cleaning, measuring, labelling, examination and sampling.

Specialized Coring Techniques

Specialized Coring Technique - Tricore

Purpose - To retrieve continuous cores in selected zones for quantitative determination of rock properties and for qualitative examination of strata characteristics such as dip and fractures. This type of coring is used after drilling the section. It also provides a means for studying the effects of mud cake and invasion.

The Coring Process - This is a wireline coring device which saws a 60-inch long triangular sample (1.5-inch equilateral triangle) of the formation with a pair of cutters moving up the bore-hole wall parallel to the axis of the tool.

Quality of Sample - With the wireline, depth is known; better than cuttings for lithologic evaluation and superior to sidewall coring. Porosity, permeability, lithology and saturations can be determined with the same laboratory equipment used to analyze conventional cores.

Specialized Coring Technique - Rubber Sleeve Coring

Purpose - To obtain complete cores in soft, unconsolidated formations or badly fractured formations, and to reduce contamination of the core by drilling fluids.

The Coring Process - During coring, the rubber sleeve tightly wraps the core and protects it from the drilling fluid, and keeps the core intact. The diameter of the rubber sleeve is smaller than the diameter of the core, thus when encased, the core is supported.

Quality of Sample - Scrambled cores are eliminated and fracture planes undisturbed. Recovered cores can be cut to any length and are ideal for shipping and handling. They can be stored without altering their physical or fluid content.

Specialized Coring Technique - Wireline Core Barrel

Purpose - For continuous coring operations without coming out of the hole. With the use of two inner barrels, coring can be carried out over longer intervals, thereby lowering coring cost per foot.

The Coring Process - The inner core tube is removed when it is full or when the desired length of core is cut. It is removed using an overshot run on a sand line. The tube is laid down with a lifting bail and cat line. Coring can be continued while the first core is being removed and examined.

Specialized Coring Technique - Oriented Cores

Purpose - To obtain: 1) direction of fractures, joints, etc., 2) dip and strike of beds, 3) direction of maximum permeability, and 4) oriented thin sections for petrographic studies.

The Coring Process - When a core is oriented, the hole inclination and azimuth are recorded, in addition to the directional orientation of a reference mark on the core itself. Three knives continuously scribe the core to provide maximum reliability in identifying the reference marks. A telescopic alignment is used to accurately align the reference knife and the multishot survey reference.

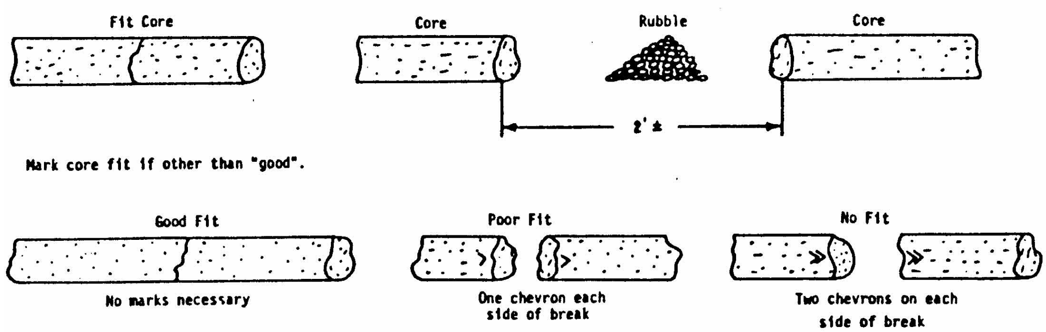
Specialized Coring Technique - Pressure Cores

Purpose - To obtain cores without the loss of reservoir pressures and components. Conventional coring may not give correct values for two reasons: 1) hydrocarbons may be flushed from the core by filtrate during coring, and 2) hydrocarbons may be forced from the core by expansion as the core undergoes pressure reduction from bore-hole to surface conditions.

The Coring Process - Similar to conventional coring, the main difference being the closing of the pressure barrel after the core is cut. The barrel is capable of taking a maximum of ten feet of 2 5/8-inch diameter core.

CORE HANDLING PROCEDURE

- PREPARE ADEQUATE NUMBER OF BOXES, HAVE RAGS AVAILABLE
- SET UP JOINTS OF DRILLPIPE AS REQUIRE TO LAY OUT CORE
- ENSURE CORRECT ORIENTATION AND LAYOUT ORDER OF CORE
- WIPE CORE CLEAN WITH CLEAN DRY RAGS
- FIT CORE. SPACE RUBBLE BETWEEN ENDS OF CORE. SACK RUBBLE

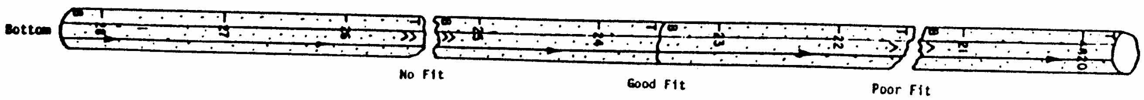


- STRAP CORE; UNRECOVERED INTERVAL UNDERSTOOD TO BE AT BOTTOM

Figure 4-3: Core Handling Procedures

CORE HANDLING PROCEDURES (CONT)

7. SCRIBE CORE WITH REFERENCE LINES AND DEPTHS, USING FELT PENS AND STRAIGHT EDGE. BLACK LINE TO THE RIGHT, RED TO THE LEFT MARK TOP OF CORE WITH "T" AND BOTTOM WITH "B"



8. DESCRIBE CORE

9. BOX CORE AND MARK BOXES

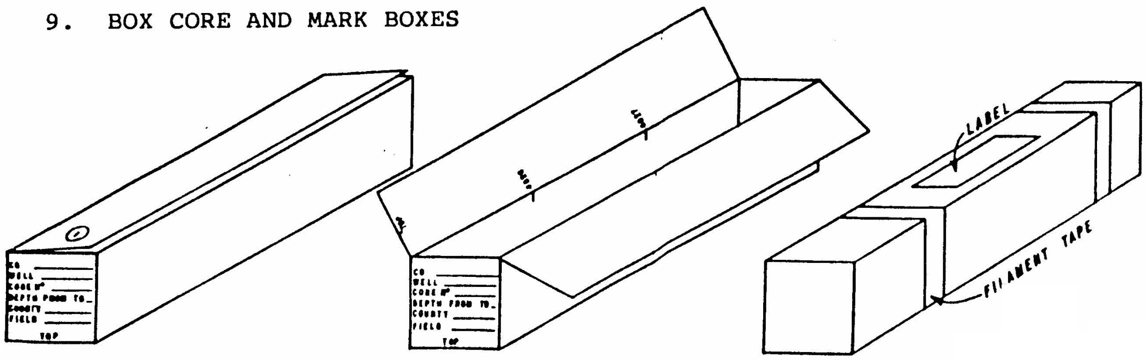


Figure 4-3: Core Handling Procedures (Cont)

Examining Cores

Macroscopic Examination of Cores

It should be a complete geological description of the entire core, including:

1. The lithology and thickness of major lithologic units
2. The dip and nature of lithologic boundaries
3. The size and dip of bedding, sedimentary and diagenetic structures
4. Types of bedding and gradations within bedding
5. Type, amount and distribution of secondary porosity
6. Surface condition of natural fracture surfaces
7. Any hydrocarbon staining or odor
8. An estimation of permeability
   a. Excellent - The core will be poorly consolidated and may fall apart during recovery
   b. Very Good - Fluid will be bubbling from the core, giving an impression it is effervescing
   c. Good - It will be impossible to wipe the core dry. Any fluid wiped off will be replaced from within
   d. Fair - The core can be wiped dry, but after a period of time it will become wet again
   e. Tight - The drilling fluid on the surface will dry in air without wiping

It is advisable to make a rough sketch of the core showing lithologic boundaries and major structures.

Microscopic Examination of Cores

Keeping core breakage to a minimum, take small chips of the core at one foot intervals, and at points of special interest. Place chips in labeled envelopes.

Each chip should be given a complete microscopic examination, and described according to:

1. Rock Type	9. Sorting
2. Classification	10. Cementation
3. Color	11. Matrix
4. Induration	12. Microstructures
5. Mineralogy	13. Porosity Type
6. Grain Size	14. Porosity Size
7. Grain Shape	15. Accessory Minerals
8. Grain Texture	16. Fossils

Combine these descriptions with the macroscopic examinations to form a complete core report.

The core chips are returned to their labeled envelopes.

Hydrocarbon Evaluation of Cores

View the entire core under an ultraviolet light, making note of the location, distribution, color and intensity of fluorescence.

Individual core chips should be subjected to a complete oil evaluation, noting the following:

- Petroleum Odor
- Color and Distribution of Oil Stain
- Color, Intensity and Distribution of Fluorescence
- Type and Rate of Cut
- Color and Intensity of Cut Fluorescence
- Color of Cut Residue

Add this information to the core description

If bleeding gas samples are available, they can be analyzed in a chromatograph. Keep in mind that this analysis cannot be directly related to the quantity of gas in place. However, it does give a useful estimate of the proportion of gases present. The results can be reported on the core report as ratios.

Sidewall Coring

Introduction

Sidewall cores are commonly collected from poorly consolidated zones, after the interval has been drilled. A hollow shaped charge is detonated and enters the formation at a chosen depth. A small cylinder of rock is captured and retrieved by a wireline. Figure 4-4 illustrates the recovery sequence and bullet shape.

The advantages of sidewall cores are:

- lithology and mineralogy of sections are readily obtained, and
- shows from cuttings analysis can be confirmed.

Several disadvantages include:

- detonation often induces fractures in the sample and strata,
- the small volume of rock is not highly representative of the strata, unless multiple shots are taken, and
- sidewall cores are easily broken when handled after collection.

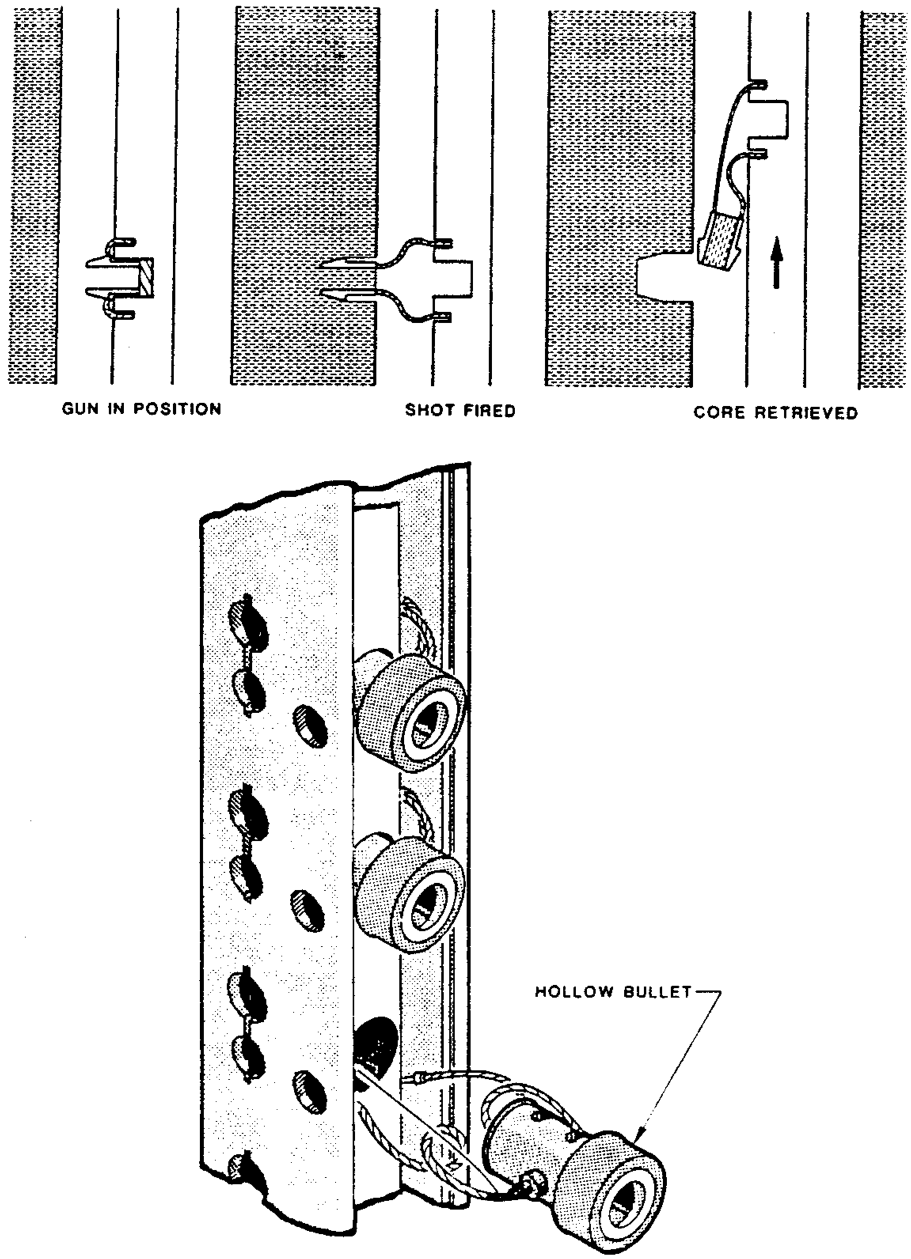


Figure 4-4: Sidewall Core Gun

Considerations During Gun Set-Up

Hole Size - The wire fasteners used to retrieve the core from the bore-hole come in a variety of lengths. Since the gun is "centered" in the hole, large diameter holes require longer fasteners. If long fasteners are used in a small diameter hole, the bullet will penetrate too deeply and become trapped. Therefore, careful scrutiny of the caliper log and lag time "hole diameter" for zones to be shot, should be made to decide fastener lengths. Avoid large washouts.

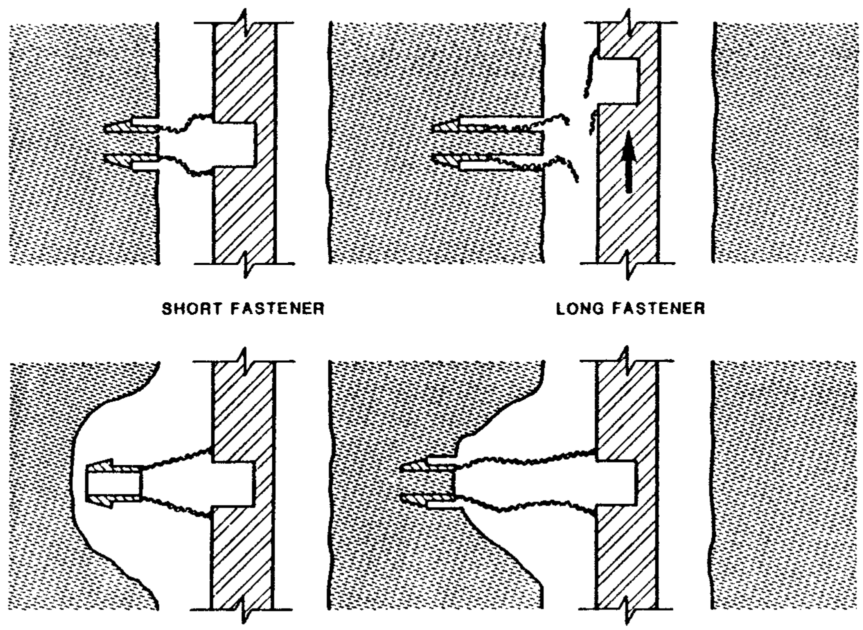


Figure 4-5: Selection of Correct Bullet Fasteners for In-Gauge and Out-of-Gauge Holes.

Formation Hardness - Where formations are hard, it may require a hardened bullet or larger explosive charge to ensure sufficient penetration. Soft formation bullets will not penetrate or may be broken on impact. Hard formation bullets will penetrate too deeply in soft formations and become trapped.

Considerations During Analysis

1. Long exposure to the bore-hole greatly modifies the saturations
   a. Water saturations (S_w) are lower
   b. Oil saturations are slightly higher
2. Percussion sample porosities in softer, looser sands are higher (shatter porosity) than in conventional cores
3. If cores contain clays, they will swell and reduce both porosity and permeability

4. Usually not enough material to perform appropriate porosity, permeability and water saturation measurements
5. Hydrocarbon odors are usually masked by the explosive odors

Considerations During Sidewall Core Extraction

1. Make sure that all misfired bullets and charges are removed from the gun. Baker Hughes INTEQ personnel will not be involved in removing misfired bullets, charges or sidewall cores from the sidewall core gun.

No sidewall core recovery should be attempted until this is done!

2. Throughout the extraction operation, great care is needed to ensure the bullets, cores, and bottles are kept in the correct order.

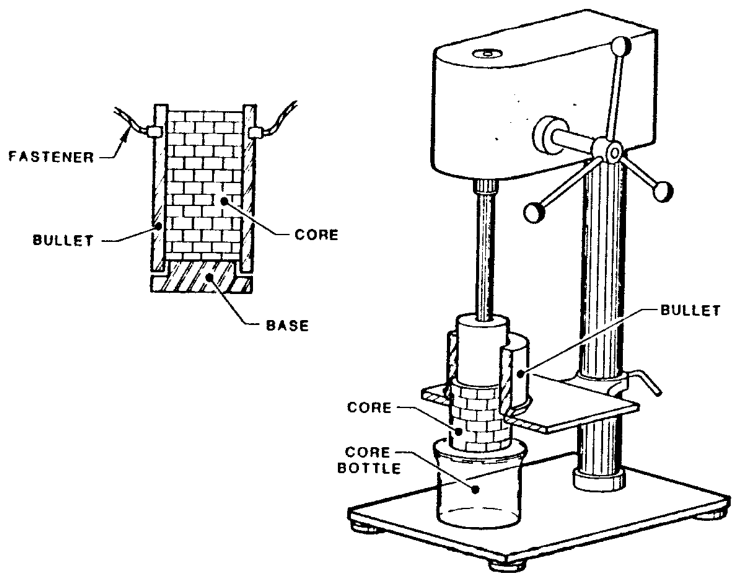


Figure 4-6: Sidewall Core Extraction Press

3. Estimating sidewall core recovery is important for financial reasons.

Cost is between $60 to $100 per core!

   a. Successful recovery is 0.5 inches
   b. If a smaller sidewall core is wanted, usually a compromise price is reached between logging engineer and geologist

Considerations During Examination and Description

1. Try to minimize breakage
2. One end will be obscured by filter cake

3. The sides will consist of material pulverized and compacted by bullet impact.
    a. Make an incision around the circumference of the core about two thirds of the length from the bore-hole end and carefully break apart.
    b. Using the shorter piece, make further cuts, if necessary, to display any sections that are normal and parallel to any structure.

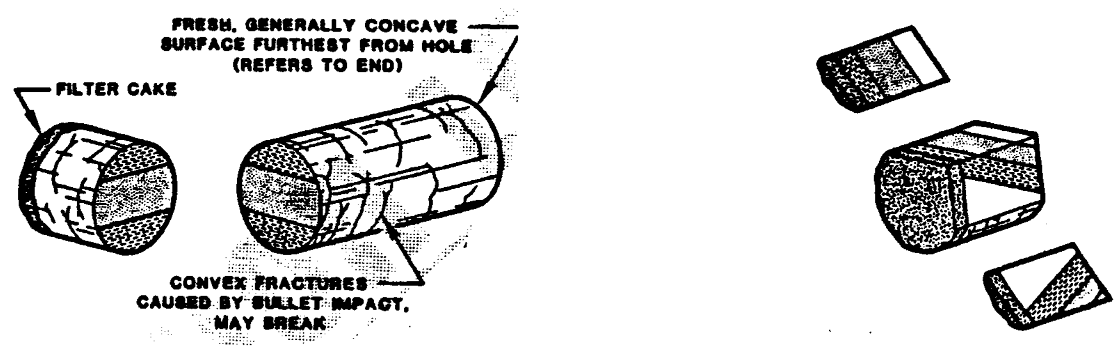


Figure 4-7: Break Core Laterally and Split Shorter Piece Longitudinally

    c. Check the fresh surfaces for fluorescence, look for any contamination from lubricants used in preparing the gun

4. Hydrocarbon Evaluation
    a. Usually the core has been invaded and flushed by filtrate
    b. If fluorescence is seen, perform a cut test on a small piece of core
    c. Gas analysis can be performed in the same way as conventional cores - by punching a small hole in the metal cap

Sidewall Core Report - Example

Sidewall cores should be described carefully and a core report prepared.

The core report should include recovery, a tabulation of misfires, and lost and broken bullets.

Sidewall Gun #3: 4163-5296’, Recovered 22, Misfire 1, Lost 2, Broken 1

Number	Depth	Recovery	Description
30	4163’	2”	Shale: gy-gy/gn, fm, waxy, strong fis, sl slty w/occ f sd gr, sl calc, tr foram
29	4206’	1 1/4”	Shale: gy-gy/gn, fm, waxy, fair fis, incr slt & f sd, sl calc
28	4251’	Misfire	
15	5193’	Lost Bullet	
2	5243’	Broken Bullet	

Figure 4-9: Sample Sidewall Core Report

Table 4-1: Physical Limitations of Cores and Cuttings Observable Lithologic Features

	Whole Cores	Sidewall Cores	Normal Cuttings	Air Drilled Cuttings
Color	Y	Y	Y	?
Basic Lithology	Y	Y	Y	?
Grain Size & Sorting	Y	Y	Y	N
Mineralogy	Y	Y	Y	Y
Crystal or Grain Type	Y	Y	Y	Y
Basic Texture	Y	Y	Y	N
Matrix	Y	Y	Y	N
Diagenetic Features	Y	Y	Y	N
Pore Size	Y	Y	Y	N
Microfossils	Y	Y	Y	N
Megafossils	Y	Y	Y	N
Megafossil Type	Y	?	?	N
Accessory Minerals	Y	Y	Y	N
Oil Shows	Y	Y	Y	?
Gas Shows	?	?	?	N
Laminations	Y	Y	?	N
Large Components	Y	?	?	N
Lithologic Contacts	Y	N	N	N
Structures	Y	?	?	N

Table 4-2: Common Geological Analyses or Techniques

	Whole Core	Sidewall Core	Normal Cuttings	Air-Drilled Cuttings
Micropaleo Analysis	Y	Y	Y	N
Palynological Analysis	Y	Y	Y	N
X-Ray Mineralogy	Y	Y	Y	Y
Petrographic Sections	Y	Y	Y	Y
SEM Studies	Y	Y	Y	?
Acetate Peels	Y	Y	Y	N

Table 4-3: Common Physical and Chemical Analysis

	Whole Core	Sidewall Core	Normal Cuttings	Air-Drilled Cuttings
Porosity Analysis	Y	?	?	N
Permeability Analysis	Y	?	?	N
Fluid Content	Y	?	N	N
Mercury Injection	Y	Y	Y	N
Surface Area Analysis	Y	Y	Y	N
Grain Density	Y	Y	Y	N
Bulk Density	Y	Y	Y	N
Trace Element Analysis	Y	Y	Y	Y

Self-Check Exercises

1. What are the logging geologists main responsibilities during the coring process?

 ____

 ____

2. List five specialized coring techniques which can be used when conventional coring techniques are not applicable?

 a. ____

 b. ____

 c. ____

 d. ____

 e. ____

3. If a 60 foot core was being cut, how many boxes would the logging geologist have to prepare in order to box and ship the core?

 ____

4. What is meant by a "good" estimation of a cores permeability?

 ____

 ____

 ____

5. What are the two general rules when taking core chips for microscopic examination?

 a. ____

 b. ____

6. How is hydrocarbon evaluation carried out on a whole core?

 ____

 ____

7. What are the three formation parameters that are evaluated from whole core analysis?

8. What are three disadvantages of using sidewall cores for sample evaluation?

   ____

   ____

9. Why is it difficult to use “odor” for hydrocarbon evaluation in sidewall core samples?

   ____

   ____

10. What is the most important safety precaution when dealing with sidewall core recovery and examination?

    ____

    ____

11. List two “samples” the logging geologist should have available when describing sidewall core fluorescence?

    a. ____

    b. ____

Chapter 5

Introduction To Hydraulics

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

- Explain the basics of drilling fluid hydraulics
- Perform fluid system pressure loss calculations using the Bingham Model

Additional Review/Reading Material

INTEQ, *Theory and Application of Drilling Fluid Hydraulics*

SPE, *Applied Drilling Engineering*, 1986

Rabia, Hussain, *Oilwell Drilling Engineering: Principles & Practice*, Graham and Trotman, 1985

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

Introduction

Proper maintenance of annular hydraulics during the course of a well is important for several reasons:

- It allows for the calculation of bottom-hole pressure losses for proper bit utilization
- It provides a means of returning rock cuttings to the surface
- It maintains a stable borehole during drilling and tripping activities

These are dependent on the annular flow type and drilling fluid rheology.

Annular Flow Types

There are three main types of flow regimes which are found in the annulus, they are:

- **Plug Flow** - the flow pattern is one where the fluid flows in a solid/semi-solid mass. This flow type is common during cementing operations.
- **Laminar Flow** - the flow pattern is one where the fluid moves in parallel layers and the layers are always parallel to the direction of flow. This is a “bullet” shaped flow pattern in the annulus due to frictional forces between the drilling fluid being in contact with the drillpipe and borehole wall.
- **Turbulent Flow** - The flow pattern is one where there are secondary eddies within the main or average flow pattern. There is a swirling motion in the fluid.

Of the two flow patterns involved in drilling operations, turbulent flow has a more uniform flow across the borehole, and thus better cleaning and carrying capacity. It does, however, damage the face of the borehole causing “washouts” and create higher pressure losses.

Laminar flow, therefore, is the most desired flow pattern because it has the least tendency to damage the borehole, and still has adequate cleaning and carrying ability.

Rheology

There are essentially two types of fluids/liquids we must be concerned with:

- **Newtonian Fluids** - fluids that have a constant viscosity, regardless of the shear rate applied to them. Examples are water, mineral oil and kerosene.
- **Non-Newtonian Fluids** - fluids that change viscosity as the shear rate applied to them changes. Examples are most drilling fluids and blood

Since most drilling fluids are non-Newtonian, there are several methods used to describe their behavior in the annulus. The two most common are:

- **The Bingham Model** - which assumes that the fluids are like a “Bingham Plastic” and all rheological calculations are made from an extrapolated linear relationship between shear stress and shear rate.
- **The Power Law Model** - which assumes that the fluids are “pseudo-plastic” and all rheological calculations are taken from the actual curve produced from the shear rate and shear stress.

Because of its simplicity and ease of calculation, we will concern ourselves with the Bingham Model. The Power Law Model will be dealt with in Baker Hughes INTEQ's Drilling Engineering Courseworkbook.

The Bingham Model

A “Bingham Plastic” fluid differs from a Newtonian fluid by the presence of a “yield stress.” In oilfield terms, this is known as Yield Point (YP), caused by the electrical attraction of the mud solids. No bulk fluid movement will occur until the applied stress (pump pressure) overcomes the yield stress. Once this occurs, equal amounts of shear stress produces equal amounts of shear rate.

The “apparent viscosity” is the shear stress divided by the shear rate, and therefore varies with shear rate. As shear rate increases the apparent viscosity decreases. This is known as “shear-thinning”.

As the shear rates approach infinity, the apparent viscosity will reach a limit called “plastic viscosity”. This plastic viscosity (PV) is the slope of the Bingham Plastic line, plotted from the various shear stress/shear rate points.

The Yield Point and Plastic Viscosity are obtained using a Fann V-G meter. The Yield Point is the intercept at zero rpm and the Plastic Viscosity is the slope of the line drawn through the 600 rpm and 300 rpm data points. Or mathematically:

$$P.V. = 600_{rpm} - 300_{rpm}$$

$$Y.P. = 300_{rpm} - P.V.$$

Because the Bingham Model does not accurately represent drilling fluids at low shear rates, the yield point is usually extrapolated back to the zero rpm line.

Formulas Necessary for Bingham Model Calculations

Annular hydraulic calculations begin with a determination of the amount of pressure lost on the various annular sections. The Bingham “pressure loss” equation is:

$$P_{la} = \frac{L \times P.V. \times Vel}{60,000(d_1 - d_2)^2} + \frac{L \times Y.P.}{200(d_1 - d_2)}$$

where:

where:	P_{la}	=	Pressure Loss in the Annular Section (psi)
	L	=	Length of the Annular Section (ft)
	Vel	=	Velocity of the Drilling Fluid (ft/min)
	d_1	=	Borehole or Casing ID (inches)
	d_2	=	Collar or Drillpipe OD (inches)
	P.V.	=	Plastic Viscosity (cps)
	Y.P.	=	Yield Point (lbs/100ft^2)

The drilling fluid velocity in each annular section can be determined using:

$$Vel = \frac{24.51 \times Q}{(d_1^2 - d_2^2)}$$

where:	Vel	=	Velocity of Drilling Fluid (ft/min)
	Q	=	Drilling Fluid Flow Rate (gal/min)

Since the drilling fluids viscosity is changing with the annular shear rate (velocity), an “equivalent viscosity” for each annular section must be determined, using:

$$\mu = \frac{60,000 \times P_{la} \times (d_1 - d_2)^2}{L \times Vel}$$

where: μ = Equivalent Viscosity (cps)

The flow pattern is determined using the equivalent viscosity of the annular section, and comparing it to a dimensionless quantity known as the “Reynolds Number”:

$$Re = \frac{15.47 \times MW \times Vel \times (d_1 - d_2)}{\mu}$$

where: MW = Mud Density (lbs/gal)

Common oilfield practice dictates that if:

Re > 2000 Flow is Turbulent
Re < 2000 Flow is Laminar

To determine the velocity needed to enter the turbulent flow regime, the "critical velocity" is:

$$Vc = \frac{64.68(PV) + 64.68\sqrt{PV^2 + 9.271(YP) \times MW(d_1 - d_2)^2}}{MW \times (d_1 - d_2)}$$

The circulating fluid causes pressure losses to occur throughout the annulus. Pressure losses are dependent on velocity changes (going from one annular section to another) and the annular dimension changes (the length of the annular section). The net pressure loss throughout the annulus is the sum of the pressure losses in the annular sections.

This annular pressure represents a net "back pressure," in addition to the "normal" hydrostatic pressure of the column of drilling fluid. This is known as the "Equivalent Circulating Density" (E.C.D.) or "Bottom Hole Circulating Pressure" (B.H.C.P.).

$$H_p = MW \times 0.0519 \times TVD$$

$$B.H.C.P._{psi} = \Sigma P_{la} + H_p$$

$$E.C.D._{ppg} = \frac{B.H.C.P.}{0.0519 \times TVD}$$

High annular pressure losses result in a decrease in the bit's hydraulic horsepower, or a decrease in the cleaning capacity of the bit. High E.C.D.'s result in lower drill rates, possible fracturing of formations and poor bottom hole cleaning.

Pressure Losses in the Drillstring

There can be a large percentage of circulating pressure lost within the drillstring. To optimize pump output, these pressure losses must be taken into account. Fluid flow within the drillstring can be laminar, turbulent, or both. Depending again on the critical velocity and Reynolds Number. Since turbulent flow is much more common in the drillstring, both formulas will be given.

The velocity in each drillstring section is calculated using:

$$V = \frac{24.51 \times Q}{d^2}$$

where:

where:	V	=	Velocity (ft/min)
	Q	=	Flow Rate (gal/min)
	d	=	Inside Diameter of Drillstring (inches)

The fluid velocity that will produce the turbulent flow, inside the drillstring is:

$$Vc = \frac{64.68(PV) + 64.68\sqrt{PV^2 + 12.34(YP) \times MW \times d^2}}{MW \times d}$$

where:	Vc	=	Critical Velocity (ft/min)
	PV	=	Plastic Viscosity (cps)
	YP	=	Yield Point (lb/100ft^2)
	MW	=	Mud Density (lb/gal)
	d	=	Inside diameter of drillpipe (inches)

A Reynolds Number greater than 2000 indicates turbulent flow. It is calculated using:

$$Re = \frac{15.47 \times MW \times V \times d}{\mu}$$

where: μ = Equivalent Viscosity (cps)

As shown earlier, the equivalent viscosity is the viscosity of the drilling fluid at a point in the borehole with a defined shear rate imposed by the fluid velocity, and is calculated using:

$$\mu = \frac{90,000 \times P_{la} \times d^2}{L \times V}$$

where:	P_{la}	=	Pressure loss in the section (psi)
	L	=	Length of section (ft)

The pressure loss formulas for the drillstring are:

For laminar flow (Re < 2000) -

$$P_{la} = \frac{PV \times V \times L}{90,000 \times d^2} + \frac{YP + L}{225 \times d}$$

For turbulent flow (Re > 2000), a friction factor (a ratio of the actual shear stress imposed on the pipe wall to the dynamic pressure imposed on the system) is required:

$$f = \frac{0.079}{Re^{0.25}}$$

The pressure loss formula then becomes:

$$P_{la} = \frac{f \times L \times MW \times V^2}{92903 \times d}$$

Surface Equipment Pressure Losses

There will be some pressure losses as the drilling fluid is pumped through the surface equipment. The amount of pressure lost during this surface travel will be dependent on the lengths of the equipment and their diameters. The effects of the standpipe, rotary hose, swivel, and kelly are shown on the attached table.

A very close approximation of surface pressure losses can be obtained from the following formula:

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

where:
- P_{ls} = Surface Pressure Loss (psi)
- k_s = Surface Pressure Coefficient (from table)
- MW = Mud Density (lb/gal)
- Q = Flow Rate (gal/min)

Most modern drilling rigs will have a surface pressure coefficient of between 2 and 10. There may be times when extrapolation will be necessary. When extrapolating, bear in mind that increased lengths of equipment will increase the coefficient, while increased I.D.'s will decrease the coefficient.

Table 5-1: Surface Pressure Loss Coefficients

Class	Description	ks
	Standpipe: 40 ft and 3.00 inch I.D.	
1	Rotary Hose: 45 ft and 2.00 inch I.D.	19
	Swivel: 4 ft and 2.00 inch I.D.	
	Kelly: 40 ft. and 2.35 inch I.D.	
	Standpipe: 40 ft and 3.50 inch I.D.	
2	Rotary Hose: 55 ft. and 2.50 inch	7
	Swivel: 5 ft. and 2.50 inch I.D.	
	Kelly: 40 ft and 3.25 inch I.D.	
	Standpipe: 45 ft and 4.00 inch I.D.	
3	Rotary Hose: 55 ft and 3.00 inch I.D.	4
	Swivel: 5 ft and 2.50 inch I.D.	
	Kelly: 40 ft. and 3.25 inch I.D.	
	Standpipe: 45 ft and 4.00 inch I.D.	
4	Rotary Hose: 55 ft. and 3.00 inch	3
	Swivel: 6 ft. and 3.00 inch I.D.	
	Kelly: 40 ft and 4.00 inch I.D.	

If the surface configuration on the drilling rig does not match a class from the table, then the coefficient must be extrapolated using the class which most nearly represents the rig configuration.

When extrapolating, note:
Increased lengths will increase the coefficient
Increased I.D.'s will decrease the coefficient

Self-Check Exercises

1. What are the three types of fluid flow regimes which can be found in the annulus?
   a. ______________________________
   b. ______________________________
   c. ______________________________

2. What causes the Yield Point (YP) in Bingham Plastic fluids?
   ____
   ____

3. What is a “shear-thinning” fluid?
   ____
   ____

4. Graphically, how are the Yield Point and Plastic Viscosity obtained, using the Fann V-G Meter?
   ____
   ____

5. If the P.V. is 39 and the Y.P. is 17, what are the 300 and 600 rpm values from the Fann V-G Meter?
   a. 300rpm = ______________________________
   b. 600rpm = ______________________________

6. Why is it necessary to calculate an “equivalent viscosity,” when there ia a Plastic Viscosity value?
   ____
   ____

7. What is meant by the term ΣP_{la}?
   ____
   ____

8. Given the following information, calculate the total annular pressure loss.
   a. Hole: 13 3/8” casing to 4000' (12.75" ID)
   b. 10 3/4” open hole to 5000'
   c. Pipe: 500' of 8" collars (2 3/4” ID)
   d. 5" drill pipe to surface (4.25” ID)
   e. Mud: PV = 20, YP = 12
   f. Flow = 500 gpm
   g. MW = 11.5 ppg

9. Determine the flow regime and critical velocity for the collar/ open hole combination in the previous problem.

10. For the given information, calculate the surface pressure loss (class 2 rig).

    PV = 20, YP = 12

    Flow = 500 gpm

    MW = 11.5 ppg

•Notes•

Chapter **6**

Hydrocarbon Evaluation

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

- Understand and explain the parameters used in hydrocarbon evaluation
- Discriminate between the types of gases which occur during drilling and non-drilling operations
- Perform gas ratio analysis using Baker Hughes INTEQ's Gas Ratio formulas
- Interpret hydrocarbon type from gas ratio analysis
- Normalize the total gas values to a set of standard parameters
- Describe and evaluate an oil show
- Interpret the quality of an oil show using the Baker Hughes INTEQ Score Chart
- Completely describe and report a hydrocarbon show on the Formation Evaluation Log and show report forms

Additional Review/Reading Material

INTEQ Video Tape #6 - *Mudlogging: Principles & Interpretation*

INTEQ Video Tape #7 - *Logging Procedures*

IHRDC Video Tape GL 304 - *Mud Logging*

INTEQ, *Drill Returns Logging Manual*, 1994

EXLOG, *Advances in Mud Logging*, Oil and Gas Journal, 1987

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Introduction to Gas Evaluation

The ability of the Logging Geologist to interpret the gas curves that are recorded while drilling, requires an understanding of the types of gases that occur and their interrelationships with formation pressures, formation porosity, the drilling fluid, and the mechanical drilling parameters.

Attempts to simplify nomenclature for gas types and curves have resulted in a great deal of confusion to logging personnel, who must try to explain the difference between, for example, drilled gas and liberated gas, or a gas show and a gas kick.

Unfortunately, many people in the oilfield, from drilling crews to company men, feel that there are only five types of gases:

- Gas in shale that forms a baseline for continuous gas levels
- Gas from sands that cause sudden changes in gas levels
- Connection gas that is associated with swabbing
- Trip gas that is associated with swabbing during trips
- Gas that enters the mud because of low mud weights

Even though this simplified classification is generally correct, it is insufficient to describe such a complex parameter as gas. The Logging Geologist must analyze both the source and cause of the gases, for proper gas curve interpretation.

Gas Types

Gas curves are highly oriented towards sources and causes. There are basically two types of gas which are entered on the Formation Evaluation Log. These are continuous and discontinuous gases. Continuous gases are entered as a smooth curve, examples being background gas and gas shows. Discontinuous gases are entered in histogram fashion, or with an alpha-numeric designation, examples being chromatograph gas and cuttings gas, and connection gas and trip gas.

Continuous Gas

The types of continuous gas needs a little more clarification before the factors affecting them can be considered. **Background gas**, is that value “read above zero gas”, when drilling through a constant lithology. This value is plotted on the log. A **gas show**, is any deviation in gas, amount or composition, from the established background and requires interpretation as to its cause. These terms defined, “continuous gas” can be stated as “the gas released into the mud stream while drilling is in progress, with no break in the circulating system.”

One source of gas in the mud stream is **liberated gas**. During drilling the bit will introduce into the mud stream rock cuttings from the cylinder of formation being cut. As the bit crushes the formation, it creates a type of permeability which allows the gas contained in the pore spaces to enter the mud stream and be carried to the surface. If there is gas in the rock cuttings, it will be transported to the surface, either by being liberated directly into the mud stream, or contained within the cuttings.

Factors Influencing Continuous Gas Readings

Several factors will affect the amount of gas liberated into the mud stream. Normally, the most important is the drill rate, since the amount of gas released into the bore-hole is proportional to the speed at which it is cut. Other factors are: pore volume (indirectly related to drill rate), formation pressure, hole size and flow rate. Total Gas “normalization” can help take these factors into consideration.

The fluid phase is another important consideration. Only methane and ethane are gases at depth. All other hydrocarbons will be liquid or gas, depending on the pressure and temperature. During its circulation to the surface, a liquid may change to a gas due to a decrease in pressure and temperature and will expand as it nears the surface. This will result in an observed increase in the amount of gas associated with the formation.

Flushing

When drilling overbalanced, especially excessively overbalanced, flushing of the formation may occur (depending on the permeability). Mud filtrate invades the formation until a filter cake is built up. This flushing will cause the gas to be forced away from the bore-hole perimeter and reduce gas readings, or may release only mud filtrate to be released when the cylinder is cut.

Produced Gas

Another source of gas is commonly called post-drilling gas or **produced** gas. This occurs when a condition of underbalance exists and, if there is sufficient permeability, there is a natural tendency for the formation fluids to flow into the bore-hole. This “feed-in” of gas, if not controlled, may result in a “kick”. Recognition of such feed-in begins with an initial gas show which continues beyond the time of a normal gas show, or with a steady increase in back-ground gas with no change in lithology.

Recycled Gas

One source of gas which should always be recognized is **recycled gas**. If the rig's degasser is not on, or if a gas show is not completely released from the mud at the surface, the gas will be pumped back down the hole and reappear at the surface. An accurate lag is necessary, for recycled gas will return at one complete cycle (down time + lag time + time to travel through the surface equipment) after the initial show. The recycled gas should be no larger than the original, though similar in appearance. Don't be misled by the recycled gas's composition, since the more volatile components are often liberated to the atmosphere, resulting in the recycled show having a larger proportion of heavy gases.

Contamination Gas

A source of gas which is introduced to the mud system at the surface is contamination gas. The biggest culprit is diesel, whether in the form of an oil-based mud or simply added to the mud to reduce torque on the drillstring.

The degradation of organic mud additives will result in increased amounts of methane. Common examples are lignosulfonate, soltex, resinex and lignite. Contaminants will usually be noticed by an increase in background gas, which will linger after the pumps are off.

If the pipe becomes differentially stuck, a heavy oil-based compound (black magic) will be spotted to dissolve filter cake. These hydrocarbons will persist long after the pipe is freed. If a hydrocarbon bearing section has been previously drilled or tested, the zone may release further hydrocarbons when a condition of under-balance exists. Hydrogen is often detected in the mud, either from the effects of an acid mud (pH<7) on the drillpipe, or the effects of a caustic mud (pH>7) on the cement and float collar when drilling out cement.

One interesting example of contamination, which may occur at any time, is when the rig personnel want to “test” you. Most crews know what types of gas affect the gas detectors. They will, at times, introduce butane into the gas trap.

Large volumes of air introduced into the mud system can result in small gas shows, the most common example being **kelly-cut** gas. This results from air, contained in the kelly or the last few stands of a trip, being pumped down the hole, cutting the initial volume of mud. It arrives one lag time plus a downtime after circulation commences. Kelly-cut gas does not reflect increased gas concentration, though some gas may enter the bore-hole when the cut mud is pumped out of the bit, but rather a greater gas trap efficiency when the air-rich mud reaches the surface.

Discontinuous Gas

The term discontinuous gas is used to describe those gases produced when drilling is halted and the pumps are stopped. It is also used to describe gases read at specific intervals.

Gases read at specific depths or time intervals are cuttings gas and chromatograph gas. A blender test (cuttings gas) is performed only when a sample is caught, while the chromatograph runs on a four minute cycle. These two gases are drafted on the log in histogram fashion, the cuttings gas as a broken line and the chromatograph analysis as a solid line.

Several discontinuous gases are “produced” during an underbalanced condition, when the pumps are off or when the hole is swabbed. Trip gas (TG), short trip gas (STG), connection gas (CG), survey gas (SVG), pump-off gas (POG), etc., are produced during those situations. Those gases are placed on the log in alpha/numeric fashion at the correct depth.

Conclusion

Experience has shown the necessity of thorough explanations of the gas curves associated with drilling. It is the responsibility of the Logging Geologist to account for all gas curves recorded at the surface. The interpretation of gas curves necessitates a thorough understanding of the relationships between drilling parameters, formation factors and surface conditions.

Additional information and interpretation procedures ca be found in the *Drill Returns Logging Training Guide* (P/N 80910).

INTEQ'S Gas Ratio Analysis

For many years mud logging companies have been trying to determine the usefulness of chromatograph ratios as a tool for reservoir evaluation. After much research and evaluation of field data, from various geologic and geographic areas, three plots and ratios bave been selected which meet four basic requirements. They have: 1) simplicity of calculation, 2) the ability to be plotted against depth on a continuous basis, 3) simplicity of interpretation with visual evaluation, and 4) repeatability.

These three ratios have replaced two of the earlier industry versions: the rectangular plot (Pixler Plot), and the triangular plot (Geoservices) for Baker Hughes INTEQ's gas analysis at all service levels (standard gas analysis to EAP-PC).

The gas ratios used by Baker Hughes INTEQ have been published by several industry societies (SPE and AAPG) and journals (*Oil and Gas Journal*). In addition, regional research into the relevance of the ratios have led to published reports.

Hydrocarbon Wetness - expressed as a percent (W_h)

$$\frac{C_2 + C_3 + C_4 + C_5}{C_1 + C_2 + C_3 + C_4 + C_5} \times 100$$

When this parameter is plotted, values in both gas and oil densities. Certain repeatable setpoints have been determined regarding Hydrocarbon Wetness, and the reservoir potential. They are:

Table 6-1:

Hydrocarbon Wetness	Fluid Potential
< 0.5	Dry gas
0.5 - 17.5	Potential gas - increasing density with increasing value
17.5 - 40	Potential oil - increasing density with increasing value

Hydrocarbon Balance (B_h)

$$\frac{C_1 + C_2}{C_3 + C_4 + C_5}$$

This parameter has been found to be related to the density of the reservoir fluid, as the value decreases, the fluid density increases. the following relationships between the Bh and Wh have been noted:

1. If Bh is > 100, the zone is excessively dry gas
2. If Wh is in the gas phase, and Bh > Wh, the closer the curves, the denser the gas
3. If Wh is in the gas phase, and Bh < Wh, gas/oil or gas/condensate is indicated
4. If Wh is in the oil phase, and Bh < Wh, the greater the separation, the denser the oil
5. If Wh is in the residual oil phase, and Bh < Wh, residual oil is indicated

Hydrocarbon Character (C_h)

$$\frac{C_4 + C_5}{C_3}$$

This parameter is used when excessive dry gas is present, which retards the Wh and Bh, affecting their values. The Ch can also be used as a check, and will aid in determining whether gas/oil or condensate is present, using the following setpoints:

- If Ch < 0.5, gas potential is indicated, and the Wh vs Bh interpretation is correct
- If Ch > 0.5, gas/light oil or condensate is indicated

Interpretation

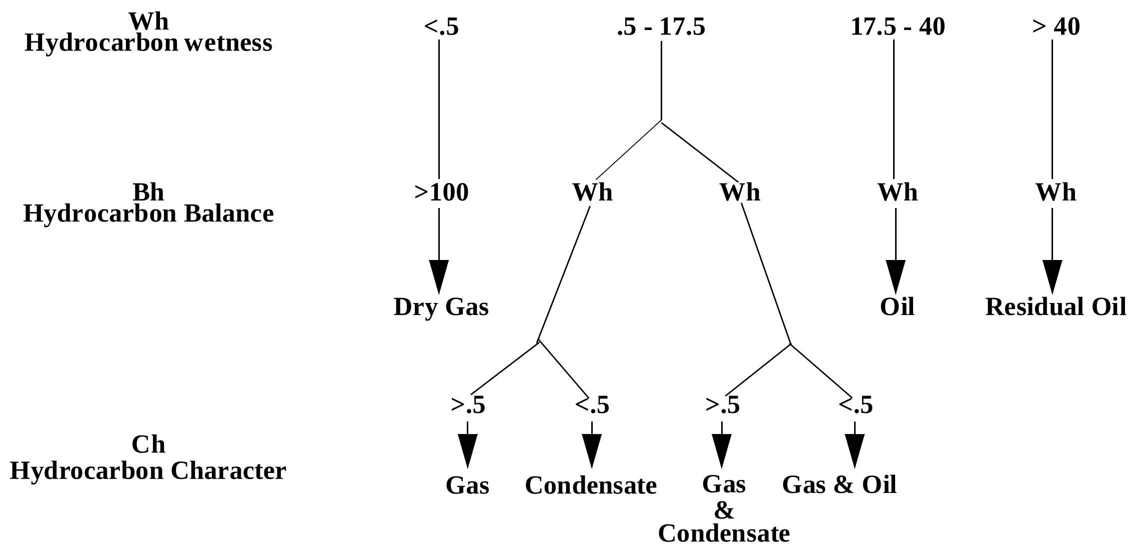
Interpretation of these ratios is a visual study of the relationship of the three curves.

The first step is to study the Wh curve position, using the setpoints, to determine the potential fluid character.

The second step it to compare the relative position of the Bh curve to the Wh curve to confirm the fluid character

After comparing the Wh and Bh curves, the Ch curve is reviewed to see if additional checks are required.

Gas Ratios Flow Chart



When evaluating gas ratio characterizations, the Logging Geologist must integrate this data with other factors, because no gas ratio method is a stand-alone system. An inspection of lithology is imperative, along with changes in the drill rate. A comparison of cuttings gas with total gas, to evaluate the retention (effective porosity) and permeability, and the fluorescence and solvent cut should be checked.

Visual Interpretation

The relationships of the resulting curves, when plotted on compatible scales, are used in the interpretation of the fluid potential. Figure 6-1 illustrates various curve relationships, along with their suggested reservoir fluid potentials.

Very Light Dry Gas

The samples are predominately methane with some ethane. There is a slight increase in the Wh, although the Bh shows no change. In the example, the Bh scale is set at a maximum of 100. Although the value will often be greater than 100, values greater than 100 indicate dry gas and are insignificant in terms of potential. Due to the absence of heavier hydrocarbons, the Ch is very low.

Medium Density Gas

The Wh has a value less than 17.5, suggesting gas potential; the Bh is less than 100, implying a heavier gas than in “A.” The Ch value is less than 0.5, suggesting than only gas is present.

Gas Cap or Light Oil/Gas

An excess of methane may result in the plotted ratio values indicating a heavier gas rather than oil. In this example, the Ch curve is greater than 0.5, suggesting that the gas is associated with oil/condensate.

Coal Horizon The presence of coal will cause the gas sample to be enriched with methane and ethane. In some situations, this may cause the Wh to exceed the 17.5 setpoint, suggesting oil. If the Ch is less than 0.5, the lithology should be checked to see if the high Wh is due to lithology or contamination. The high Bh will help confirm a coal-produced gas peak.

Medium Gravity Oil

The idealized plot shows crossing Wh and Bh curves, with the Wh values located between 17.5 and 40. The degree of curve separation will be indicative of the oil's density; the narrower the separation, the lighter the oil. In a known area, an experienced logger should be able to derive an approximate oil density.

Residual Oil It has been found that if a Wh is greater than 40 and the Bh is less than the Wh, the formation fluid is often associated with tars and asphaltenes.

Other considerations that must be taken into account during the interpretation are:

- total or normalized gas
- lithology
- fluorescence
- cuttings gas

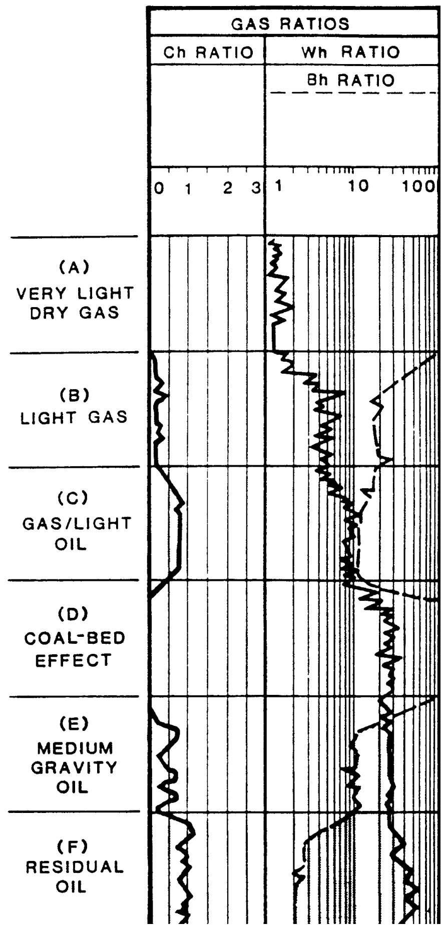


Figure 6-1: Gas Ratio Interpretation - Visual Analysis

INTEQ'S Gas Normalization Analysis

Introduction

The Formation Evaluation Log is a depth-related plot of varying physical parameters as the well is drilled, the most important parameters being changes in the concentration and composition of the formation's hydrocarbons. The gas curves begin with the establishment of a baseline (background gas), and deviations from that baseline are considered “gas shows.”

At no time should the absolute magnitude of a gas show be taken as a basis for any quantitative statement. The gas phase seen at the surface may not have the same composition as the hydrocarbon phase in-situ. It will, nevertheless, reflect the overall hydrocarbon composition (i.e. liquid and gas of the reservoir), and chromatograph analysis can be used as another important key in evaluation.

Again, however, it is not simply the magnitude of gas shows, but the relative composition, linked with all other log parameters, which is the key.

Certain mathematical treatments are available as an aid in interpreting gas shows. Although some of these are attempted normalizations (adjustments to the Total Gas value, for the drilling effects), most treatments are for the chromatograph analysis in order to determine characteristic relationships typical of types of production.

Total Gas Normalization

A generalized form for a normalized gas equation is:

$$G_n = G_d \times \frac{R_n}{R_a} \times \frac{\pi\left(\frac{D_n}{2}\right)^2}{\pi\left(\frac{D_a}{2}\right)^2} \times \frac{Q_a}{Q_n} \times \frac{1.0}{E}$$

In this case, the normalized gas (G_n), calculated from the ditch gas reading (G_d) is increased by an increasing mud flow rate (Q) and decreased by an increasing volume of formation cut, hole diameter (D) and drill rate (R), in the formula. A more specific, though equally simplistic formulation would include numerical constants, allowing the normalization of gas to some standard conditions of flow rate, hole diameter and rate of penetration. Ideally, there should be a universal set of standard parameters for Q_n, D_n, and R_n. In reality, however, an ideal situation in one area may not be ideal for another.

The extraction efficiency (E) of the gas trap, if reliably determined can be included in the formula. If unsure of its efficiency, it can be left out.

If we choose normalization parameters to be:

ROP = 100 ft/hr pump output = 1,000 gpm
bit diameter = 9 7/8” trap efficiency = 60%

Once “ideal” parameters have been determined, the constants can be multiplied out to give a “constant of normalization” (C_n), and the expression reduces to:

$$G_n = G_d \times 16.253 \times \frac{Q_a}{R_a \times D_a^2}$$

In the following example, the normalization of the two gas curves is as follows (see next page for chart):

Zone 1 (7570 ft to 7640 ft)Zone 2 (7650 ft to 7720 ft)

ROP = 21 ft/hr (70 x 60/200)ROP = 40.77 ft/hr(70 x 60/103)
Gas = 18 units Gas = 35 units
Flow Rate = 600 gpm Flow Rate = 600 gpm
Bit Size = 12.25 inches Bit Size = 12.25 inches

$$\text{Zone 1:} G_n = 18 \times 16.253 \times \frac{600}{21 \times 12.25^2}$$

G_n = 18 x 16.253 x 0.1904

G_n = 55.70 units

$$\text{Zone 2:} \quad G_n = 35 \times 16.253 \times \frac{600}{40.77 \times 12.25^2}$$

G_n = 35 x 16.253 x 0.0981

G_n = 55.80 units

Although numerous gas normalization models have been used in the field, no one model has yet received industry acceptance. This may be due to the fact that Total Gas readings, even when normalized, cannot yield reliable correlations with gas or oil volumes in place; nor do present normalizations correct for any of the complex in-situ and downhole processes which affect the magnitude of gas seen at the surface.

Although yielding no major breakthrough in reservoir evaluation, the results may provide some assistance in the use of gas curves for stratigraphic correlation, and for general interpretive evaluation.

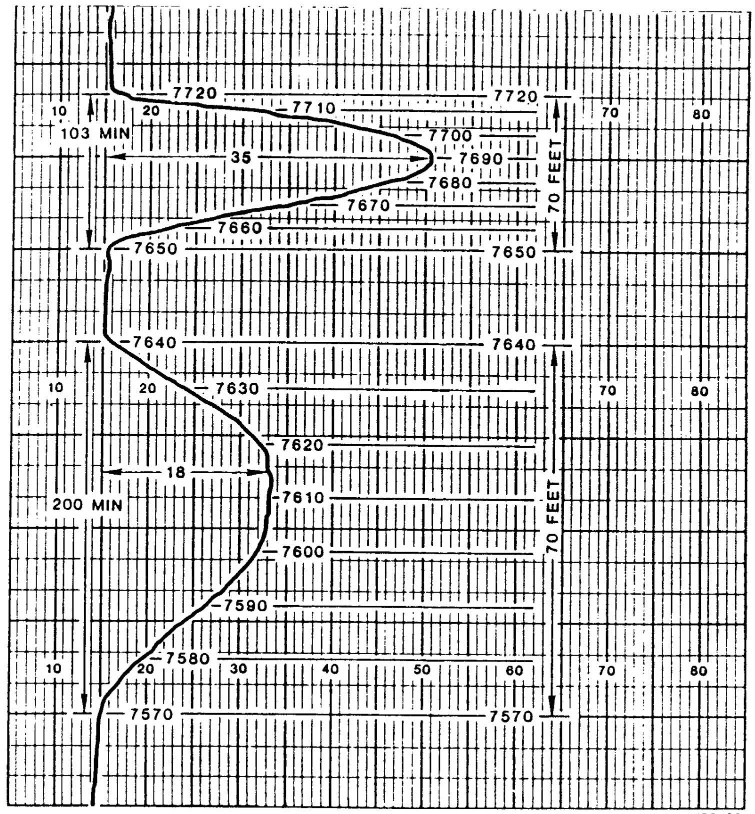


Figure 6-2: Total Gas Normalization

Oil Evaluation

Mediums Used To Assist in Oil Show Determination

Feature	Instrument
Oil Staining	Microscope and Dried Cuttings
Hydrocarbon Odor	Blender and Nose
Fluorescence	Ultra-Violet Light and QFT
Cut Test	Solvent
Cut Fluorescence	Solvent and Ultra-Violet Light
Hydrocarbon Bleeding	Microscope
Effervescence	Hydrochloric Acid
Porosity	Microscope, Drill Rate, Gas Curves
Permeability	Cut Test, Cuttings Gas, Gas Curves
Gas Amount	Total Gas Detector, Gas Normalization
Gas Composition	Chromatograph, Gas Ratios
Oil/Gas/Water Contacts	Gas Curves, Gas Ratios
Water Content	Chloride Content, Ultra-Violet Light

Recording Information

Information obtained from “checklists” and tests is recorded on the Regional “Show Report Form”. In addition, all information, observations, test results, etc., should be recorded on the logging unit's worksheet, entered into the computer (if present), and a summary placed on the Formation Evaluation Log.

Clients may have their own report forms. If so, theirs should be completely filled-out and sent to the client.

This information is also necessary for the Final Well Report (FWR).

If WITS records are being recorded and transmitted, show evaluation information is entered into WITS Record #16.

Natural Fluorescence

This is the fluorescence of the washed cuttings as seen under the U.V. light. Note the percent fluorescence in the total sample. Do not include any cavings in the representative sample. If only certain cuttings fluoresce, note the lithology which gives the fluorescence. Check for mineral or contaminant fluorescence.

The color of oil fluorescence can be used to make a **qualitative** identification of the API Gravity. Colors range from brown to orange, green to gold, and yellow to blue-white, with a variety of colors and shades in-between. The darker colors, browns to orange, are associated with the heavier oils. Refined oils, such as diesel and pipe-dope will have bluish-white fluorescence. Often very-light oils (condensates) and heavy tars will not fluoresce at all.

The intensity and color of the oil fluorescence is a useful indicator of oil gravity and mobility. Decreased intensity and darker colors will usually mean decreases in gravity. Water-wet and residual oils (which contain smaller amounts of the volatile hydrocarbons) will have the fluorescence color representative of their gravity, but will normally be much paler in color and less intense.

A note should be made on how the fluorescence is distributed in the cutting. The fluorescence may be found around the grains, in the matrix. There may be “pin-point” fluorescence around the pore throats, or the fluorescence may be occurring along certain “lines” on the cutting, indicating fractures.

Natural Fluorescence	**Oil in Mud**
Amount (percentage)	Amount
Color	Color
Intensity	Odor
Distribution	Fluorescence

Oil in Mud

When oil is seen in the mud, or even suspected to be present, a sample should be placed under the U.V. light. As with above, the amount, color and fluorescence should be noted. Some of the mud should be placed in a closed container (i.e. blender) and agitated. When opened, note any petroliferous odor. Other odors, such as sulphurous, may be noted.

If there is any doubt concerning the presence of oil, distilled water can be added to a mud sample. This will lower the mud's viscosity and separate the oil from the mud.

Visible Stains

Any observed staining, on washed or “air-dried” samples should be noted. As with fluorescence, the stain color will give an indication of the gravity.

The darker the stain, the heavier the oil. The distribution of the stain around the cutting can also give an indication about the porosity of the sample.

Solvent Cut

An organic solvent allows the oil to be removed from the colored background of the cutting. The rate at which the solvent “cut” occurs can yield useful information on the permeability of the sample. If no cut can be seen from a “normal” washed cutting, the test can be repeated when the cutting has been dried, acidized, crushed, etc., to yield further evidence on permeability.

The cut fluorescence will help confirm the gravity of the oil. The color should increase when the cut occurs.

After the cut solvent has evaporated, a residue of oil will remain in the spot dish, displaying the oil's natural color.

Visible Staining	**Solvent Cut**
Amount	Type
Type	Normal
Oil	Dried
Solid Residue	Acidized
Color	Hot Water
Distribution	Crushed
Spotty	Rate
Streaky	Instant
Patchy	Fast
Uniform	Moderate
	Slow
	Streaming
	Fluorescence
	Color
	Intensity
	Residue
	Amount
	Color

Oil Show Evaluation Checklist

Show Description for the Formation Evaluation Log

1. Free Oil in the Mud - Amount, Color
2. Petroleum Odor
3. Visual Staining - Amount, Color, Distribution

4. Cut - Rate, Color, Intensity, Residue

General Qualitative Estimates of Oil Show

API Gravity	Fluorescence Color	Visual Stain
2 - 10	None - Dark Brown	Black
10 - 18	Brown - Orange	Brown
18 - 35	Gold - Yellow	Light Brown
35 - 45	Blue-White - White	Tan
> 45	White - None	Transparent

Common Mineral Which Fluorescence

Rock/Mineral	Fluorescence Color
Dolomite	Yellow to Yellowish Brown
Limestone	Yellow to Brown
Fossils	Yellow-White to Yellow
Anhydrite	Grey-Blue to Grey
Pyrite	Purple to Yellow-Brown
Calcite	Orange to Gold

* Always take a sample of Pipe Dope and Mud Additives to check their fluorescence

Lithology Description

Rock Type
Classification (Dunhams)
Color
Hardness (Induration)
Grain Size
Grain Shape
Sorting
Luster
Cementation/Matrix
Structure
Visual Porosity
Accessories/Inclusions

Hydrocarbon Show Evaluation - Procedures

1. Collect enough sample from shale shakers. Check the desanders for sample. Collect a drilling fluid sample in an air-tight container.
2. Run blender test on unwashed cuttings. Check for oil on top of fluid and petroliferous odor. Record data.
3. Run blender test on drilling fluid. Check for oil on top of fluid and petroliferous odor. Place drilling fluid in filter press and perform a chloride content test. Record data.
4. Check if Total Hydrocarbon Detector or Chromatograph (and Integrator) require attenuation. Check for Pit Level change.
5. Place unwashed cutting sample into U.V. box. Check for amount, intensity and color of fluorescence. If in doubt, cover sample with water and agitate. Record data.
6. Wash cuttings sample. Observe under microscope. Place selected samples in spot plate to air dry. Check for staining - amount, color, distribution. Record data.
7. Place selected cuttings sample into U.V. box. Check for amount, intensity and color of fluorescence. Apply solvent on selected sample - observe speed of cut, color and intensity of fluorescence. Check for residue. Record data.
8. Record a complete lithology description for each sample caught.
9. Perform a gas ratio analysis from Chromatograph/Integrator recordings.
10. Perform show rating analysis from Hydrocarbon Score Sheet.

Hydrocarbon Show Evaluation - Interpretation

1. Porosity: Estimate amount and type from visual and microscopic examination of cuttings, drill rate, and from the distribution of any staining. Record.
2. Permeability: Estimate from cuttings gas/total gas ratio, and from type and speed of solvent cut. Record.
3. Hydrocarbon Type: Estimate from odor, visual examination of cuttings and gas ratio analysis.
4. Oil Gravity: Estimate from color of stain, color of fluorescence, color of cut fluorescence, and color of cut residue. Record.
5. Oil/Water Contact: Estimate from intensity of fluorescence, color of fluorescence, gas ratio analysis and chloride content.

Hydrocarbon Show Evaluation - Precautions

1. Fluorescence:
   a. Check for mineral fluorescence from cut test
   b. Check for mud additive fluorescence/cut fluorescence by observing mud additive samples
   c. Check for oil-in-mud from mud report, retort test, and sample mud fluorescence
   d. Low gravity oils may not fluoresce until cut solvent is added
   e. High gravity oil fluorescence may disappear when cut solvent is added
   f. Refined oils fluoresce bright white to blue-white
   g. Pipe dope fluoresces bright white to blue white
2. Cuttings:
   a. Collect representative sample across collecting-board
   b. Collect sample from desander during show interval
   c. Wash through three screens. Observe samples from all three screens
   d. Float off lost-circulation-material. Observe samples of various LCM under microscope
   e. Use all drilling parameters to determine “Interpretative Lithology” vs “Cuttings Lithology”

Hydrocarbon Analysis Score Chart

The “Hydrocarbon Analysis Score Chart” (Figure 6-3) was constructed to evaluate fourteen features commonly associated with oil shows.

The first four are quantitative measurements available from the logging unit. The remainder are visual observations seen during the analysis of the show.

Each feature is awarded a score of “0” through “12,” based on identifiable progression in that characteristic.

Points for each feature are added together to produce a total score.

Point Range	Show Rating	Show Description
0 - 15	1	No Show/Very Poor Trace
15 - 30	2	Poor Trace
30 - 45	3	Trace
45 - 60	4	Good Trace
60 - 75	5	Moderately Fair
75 - 90	6	Fair
90 - 105	7	Moderately Good
105 - 120	8	Good
120 - 130	9	Very Good
130 - 143	10	Excellent

Figure 6-3: Hydrocarbon Analysis Score Chart

Points Awarded	ROP Change	C1 Increase	Increase C2-C5	Cuttings Gas	Oil in Mud	% Staining	Staining	Color of Staining	% Fluorescence	Fluorescence Color	Fluorescence Intensity	Cut	Residue	Odor
0	1	trace	x0.25	none	none	none	none	none				no	none	none
1	x1	50	20	x0.5		trace	residual		trace	brown	very dull	30 sec	trace	
2	x1.5	200	50	x1	rare	5%		black	5%	orange brown	dull	cloudy		trace
3	x2	500	100	x1.5		10%	globular		10%	orange		slow crush	thin ring	
4	x3	1000	200	x2	trace	20%		brown	20%	gold	moderate	slow	mod ring	faint
5	x4	1500	300	x2.5		30%	spotty		30%	yellow	moderate bright	slow stream -ing	good ring	

Points Awarded	ROP Change	C1 Increase	Increase C2-C5	Cuttings Gas	Oil in Mud	% Staining	Staining	Color of Staining	% Fluorescence	Fluorescence Color	Fluorescence Intensity	Cut	Residue	Odor
6	x5	2000	500	x3	moderate	40%		tan	40%	yellow white			thick ring	fair
7	x7.5	5000	750	x4		50%	streaky		50%		bright	mod strng	thin film	
8	x10	7500	1000	x5	good	60%		gold	60%	white	very bright	fair strmg		strong
9	x12	10000	1250	x6		70%	patchy		70%	blue		immed strmg	thick film	
10	x15	15000	1500	x8	abundant	80%		yellow	80%					
11		20000	2000			90%			90%					
12		30000	3000			100%	uniform		100%					

Self-Check Exercises

1. What are the two types of gases entered on the Formation Evaluation Log?
   a. ______________________________
   b. ______________________________

2. How are these two types of gases entered on the Formation Evaluation Log?
   a. ______________________________
   b. ______________________________

3. What is the definition of a "Gas Show"?

4. Excluding methane and ethane, what two factors determine whether the other alkanes will be a gas or a liquid?
   a. ______________________________
   b. ______________________________

5. What two factors dictate how much formation flushing takes place?
   a. ______________________________
   b. ______________________________

6. List the three ratios that INTEQ's uses in gas ratio evaluation?
   a. ______________________________
   b. ______________________________
   c. ______________________________

7. What two gas ratio setpoints indicate zones of excessive dry gas?
   a. ______________________________
   b. ______________________________

8. What five parameters are used to "normalize" gas?
   a. ____
   b. ____
   c. ____
   d. ____
   e. ____

9. What three parameters which should always be stated when describing hydrocarbon fluorescence?
   a. ____
   b. ____
   c. ____

10. How can a hydrocarbon stain color be related to its API gravity?

    ____

    ____

11. How can permeability be estimated from a show evaluation?

    ____

    ____

    ____

12. What four parameters are used when describing a solvent cut test?
    a. ____
    b. ____
    c. ____
    d. ____

Chapter **7**

Bit Grading Techniques

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

- Understand the importance of dull bit grading
- Understand and explain the standardized IADC code and grading formats
- Accurately grade Roller Cone Bits
- Accurately grade Fixed Cutter Bits
- Use the correct IADC codes for roller cone and fixed cutter bits
- Correctly enter information on Baker Hughes INTEQ's “Bit Data Record”

Additional Review/Reading Material

INTEQ Video Tape # 7 - *Logging Procedures*

HCC Video Tape - *Dull Bit Grading*

HCC Video Tape - *Introduction to PDC Bits*

HCC Video Tape - *Tri-Cone Bit Design*

IADC/SPE 23940, *Development of a new IADC Fixed Cutter Bit Classification*

IADC/SPE 23937, *The 1992 IADC Roller Bit Classification System*

IADC/SPE 16145, *Application of the New IADC Dull Grading System for Fixed Cutter Bits*

IADC/SPE 16146, *Application of the 1987 Roller Bit Dull Grading System*

Introduction to Dull Bit Grading

Dull bit grading is the procedure for describing the condition of a drill bit after it has drilled a section of rock and has been pulled from the borehole. It is important that the individual describing the condition use guidelines so they can convey correct and consistent reports to others. The International Association of Drilling Contractors (IADC) has spent much time coming up with a standardized system of numbers and abbreviations so that the conditions described at the wellsite can be used by those who will never see the bit, but require the information for future well planning.

There are many reasons for accurate dull bit grading, the most important being that it can save money. This is accomplished in several ways:

- Accurate bit grading will provide reliable information for future well planning. It should improve future bit selection.
- Accurate bit grading will improve drilling practices. It should provide clues as to what is happening downhole during drilling operations and suggest possible drilling practice changes or change bit selection procedures.
- Accurate bit grading provides the basis for determining optimum bit life. It should assist the operators in establishing optimum bit pull procedures.
- Accurate bit grading will improve bit design. Reliable bit records will assist the bit manufacturer in designing future bits for increased performance.

Dull bit grading is directed at two main areas. The first is determining the amount of physical wear on the bit. Normally related to the cutting structure, bearings (if present) and the gauge of the bit. The second is an analysis of the cause of the wear. This relates to the factors, or combination of factors, which were responsible for the degree of wear on the bit.

The industry, in 1987 and 1992, standardized an eight factor system which records the physical wear characteristics, as well as other remarks pertinent to the pulling of the bit from the hole.

To correctly grade a bit, the bit must first be identified. The IADC has a coding system in place to assist in this process.

IADC Classification for Roller Cone Bits

In March 1987, the IADC revised an older code to help eliminate some of the confusion among contractors and operators arising from the new bits being introduced into the oilfield. The code was established for identification purposes only.

In setting up the new identification system for roller cone bits, the IADC selected a four character code which identifies tri-cone bits as; 1) steel-tooth or insert, 2) formation hardness they are suited for, 3) seven categories of bearing design and gauge protection, and 4) additional features which may affect bit cost, application or performance.

Classification Description

The first **digit** represents a “series” classification and relates to the cutting structure. Series 1,2,3 represent steel-tooth bits. Series 4,5,6,7,8 represent insert bits. The formations the bits are suited for get “harder” as the number increases.

The second **digit** represents a “type” classification and indicates a formation hardness sub-classification within each series. The numbers 1 to 4 designate increasing hardness as the number increases. (see Table 7-1). The major difference between bits designed for a given formation type is the length and configuration of the cutting structures.

The third **digit** refers to a “feature” classification. It indicates bearing and gauge features that are common to tri-cone bits. For example:

1. Roller bearings that are non-sealed having no gauge protection
2. Air cooled roller bearings, non-sealed, no gauge protection
3. Roller bearings that are non-sealed with gauge protection
4. Roller bearings that are sealed with no gauge protection
5. Roller bearings that are sealed with gauge protection
6. Journal bearings that are sealed with no gauge protection
7. Journal bearings that are sealed with gauge protection

The fourth **character** is used to identify any additional features on the tri-cone bit. Eleven such alphabetic characters are presently defined (see Table 7-2). Additional characters may be utilized as required by future bit design. Although the fourth character does not normally appear on IADC charts, it should appear everywhere else the IADC code is recorded (i.e. Bit Data Record).

Referring to the **Hughes Tool Company “Bit Selector,”** an IADC designation of **517Y** would indicate:

5 - An insert bit suited for drilling soft formations

1 - Best suited for drilling very soft formations

7 - The bit has a journal bearing and gauge protection

Y - The bit has conical shaped inserts

Table 7-1: Correlation of Formation Hardness to the IADC Code

	Series	Type
M	1. Soft formations having low	1. Very Soft Shales
I	compressive strength	2. Soft Shales
L	and high drillability	3. Medium Soft Shales
L		4. Medium Limey Shales
E		
D	2. Medium to medium hard	1. Medium Shales
	formations with high	2. Medium Limestones
T	compressive strengths	3. Medium Hard Shales
O		4. Anhydrites
O		
T	3. Hard semi-abrasive or	1. Hard Limestones
H	abrasive formations	2. Hard Evaporates
		3. Hard Dolomites
		4. Hard Sandstones
	4. Soft formations with	1. Clays/Gumbo Shales
	low compressive strength	2. Very Soft Sandy Shales
	and high drillability	3. Unconsolidated Sands
		4. Salt/Bentonites
	5. Soft to medium	1. Very Soft Shales/Sands
	formations of high	2. Soft Sands/Shales
	compressive strength	3. Medium Soft Limestone
		4. Anhydrites/Salts
I	6. Medium hard formations	1. Medium Shales/Limes
N	of high compressive	2. Medium Hard Shales
S	strength	3. Medium Hard Sandstones
E		4. Medium Hard Dolomites
R		
T	7. Hard semi-abrasive and	1. Hard Limestones
	abrasive formations	2. Hard Sandstones
		3. Hard Dolomites
		4. Chert & Pyrite

	8. Extremely hard and	1. Hard Chert
	abrasive formations	2. Very Hard Chert
		3. Quartzites
		4. Hard Granite

Table 7-2: IADC Code Additional Design Features

Code	Feature
A	Air Drilling Application
B	Special Bearing Seal
C	Center Jet Bit
D	Deviation Control Bit
E	Extended Jets Bit
F	
G	Extra Gauge/Body Protection
H	Horizontal/Steering Application
I	
J	Jet Deflection Bit
K	
L	Lug Pads
M	Motor Application
N	
O	
P	
Q	
R	
S	Standard Steel Tooth Bit
T	Two Cone Bits
U	
V	
W	Enhanced Cutting Structure
X	Chisel Shaped Inserts Bit
Y	Conical Shaped Inserts Bit
Z	Other Shaped Inserts Bit

The remainder of the characters are reserved for future use.

IADC Classification for Fixed Cutter Bits

The IADC has recently revised the 1990 classification system. This revision was mainly due to the difficulty for field personnel to determine the bits IADC code without extensive training and visual aids. In 1992, the IADC has adopted this modified version for Natural Diamond, PDC and TSP bits. This format was developed with two specific applications in mind: 1) only a basic classification of the overall length of the bit's cutting face are considered, and 2) the code has placed the bits into two main divisions, PDC and TSP/Natural Diamonds.

A four character code is used when describing fixed cutter bits. These features are:

1. Bits Body Material
2. Cutter Density
3. Cutter Size or Type
4. Bits Profile or Body Style

This code can be applied to both drill and core bits.

Classification Description

The first **character** describes the bit body material. Two letters are used:

M - Fixed Cutter bit with a Matrix Body

S - Fixed Cutter bit with a Steel Body

Matrix Body Normally a tungsten carbide powder bonded with a copperplates compound to form the bit body.

Steel Body A steel body with a thin layer of tungsten carbide applied to the face of the steel to enhance abrasion and erosion resistance. This is called "cladding."

The second **digit** refers to the bit's cutter density. Numbers 1 to 4 are used with PDC bits, 6 to 8 are used with TSP and diamond bits. Numbers 0, 5, and 9 are reserved for future use.

This cutter density is "total" cutter density, which now includes the gauge cutters, regardless of cutter size.

For PDC bits the number 1 represents a "light set" used for softer formation, increasing to number 4, a "heavy set" used in harder formations. The same scale is used with the TSP/Natural Diamond bits, the larger stone bits are intended for softer formations and the smaller stone bits intended for harder formations (see Table 7-3).

Table 7-3: IADC Classification of Cutter Density in Fixed Cutter Bits

	PDC Bits		TSP/Natural Diamond
1	30 or fewer cutters	5	diamond sizes larger than 3 stones/carat
2	30 to 40 cutters	6	diamond sizes from 3 to 7 stones/carat
3	40 to 50 cutters	7	diamond sizes smaller than 7 stones/carat
4	50 or more cutters		

The **third** digit refers to the size of the cutters in PDC bits and the type of cutters in TSP/Natural Diamond bits (see Table 7-4).

For PDC bits, an example of a "1" would be Hughes Christensen's King Cutter (1-inch or greater). The most common PDC cutter size is 19 mm (3/4 inch) and would be classified as a "2." Another common size is the 13.3 mm (1/2 inch) cutter, which would be a "3."

Table 7-4: IADC Classification of Cutter Size and Cutter Type

	PDC Bits		TSP/Natural Diamond
1	cutter larger than 24 mm	1	natural diamond cutters
2	cutters from 14 - 24 mm	2	TSP material cutters
3	cutters from 14 - 8 mm	3	combination of natural diamond and TSP cutters
4	cutter smaller than 8 mm	4	impregnated bit

The fourth **digit** refers to the basic appearance of the bit, based on overall length of the cutting face of the bit (see Table 7-5).

The exception to this "Profile" is the fishtail PDC bit; this is based on "Body Style" as opposed to profile. All others will follow the same format, as the increasing numbers indicate longer bit profiles.

Table 7-5: IADC Classification of Profile or Body Style

	PDC Bits		TSP/Natural Diamond
1	Fishtail	1	Flat
2	Short	2	Short
3	Medium	3	Medium
4	Long	4	Long

Conclusion

While this 1992 system is not as detailed as the 1990 version, it provides field personnel with a more usable and learnable system.

Roller Cone Bit Grading Procedures

The procedures for grading roller cone bits have not changed much since dull grading guidelines were established in the early 1950's. These bits still require that the teeth (T), the bearing (B) and the gauge (G) wear be determined. Bit design has changed much over the past eighty years, and as a result dull bit grading practices have expanded to meet the need for more precise information.

Tooth Wear

For steel-tooth bits, the grading procedures still use the scale from “0 to 8,” where “0” indicates no wear and “8” indicates total wear. Though it may be impractical to measure all the teeth on the bit to determine wear, measuring one tooth per row can be most helpful. Remember, this grading is an overall assessment of overall tooth condition, not the worst row or tooth. Broken teeth, chipped teeth and unusual wear conditions should be noted separately.

Insert bit wear is noted by the amount of broken or lost inserts. When noting this wear, besides a number code, letter codes should be used for further grading the cutting structure. It will be even more useful if you state the number of lost or broken inserts.

Bearing Wear

Roller cone bits come with two types of bearings, either roller bearings or journal bearings. Roller bearings can be sealed or non-sealed, while journal bearings are always sealed. The best way to tell if a roller bearing bit is sealed is to look for the compensation plug. If it has one, it's a sealed bearing bit. It can also be seen by the “feature” number on the IADC code.

If the bit is sealed, then bearing wear will be based on how much wear there is on the seals. Since it is normally impossible to see the seals, they are either intact and functioning (SE) or they are mutilated and gone completely (SF). Regardless of the type of sealed bearings, the grading of the sealed bearings is, at best, only an estimate.

When the bit contains non-sealed bearings, the bearing life is indicated by using an amount, in eights, of the total life expected, where “0” indicates no bearing life has been used up, and an “8” indicated all bearing life has been used up. Since this is, again, only an estimate, if the cones are loose and “shake” freely, they should be graded a B6 or B7. Locked cones are always graded a B8, regardless of how much bearing life has been “used up.”

Gauge Wear

A ring gauge is used on all roller cone bits to determine whether the bit is in gauge or out of gauge. o correctly determine gauge wear, first stand the bit up on the pin and rotate the cone until the gauge teeth are at their maximum diameter. Place the ring gauge over the cones and push the ring gauge against two of the cones so that it contacts the two cones at their outermost points. Then the distance between the outermost point on the third cone and the gauge ring is measured with a ruler.

The distance measured using this method is then multiplied by 2/3's, and that value rounded to the nearest 1/16th of an inch. This will give the correct diameter reduction.

1987 IADC System Structure

The IADC revised the grading scheme in 1987 to reflect changes in bit design, and to standardize, both roller cone and fixed cutter grading procedures. The T, B, G, of roller cone bits has been expanded to note eight separate components.

The **cutting structure** grading is now broken into four parts: Inner Row grading, Outer Row grading, Dull Characteristics, and Location of where the dulling characteristics occurred. The **bearings/seals** grading is the same as before. **Gauge** grading is the same. There is now a **Remarks** section with two components; an “Other Dulling Characteristics,” for any other items which are necessary for correct grading, and a “Reasons Pulled” section to note why the bit was pulled.

These eight components should give whoever is reviewing the Bit Data Record a very good idea of what the bit looked like when it was pulled. The grading of a roller cone bit is not more difficult, just more concise and accurate.

Fixed Cutter Bit Grading Procedures

Grading fixed cutter bits in the past was very similar to modern dancing - everybody goes in all directions and does his own thing. Most bit manufacturers had their own system, and since the average person at the wellsite had limited knowledge in grading fixed cutter bits, very little information was recorded.

The introduction of PDC and TSP bits into the drilling operations added to the confusion in bit grading.

The standards developed in 1987, have greatly increased the ability of the wellsite individual to grade fixed cutter bits and will assist bit manufacturers to increase the efficiency of these bits through reading accurate dull bit reports.

Cutting Structure Wear

The grading of diamonds, PDC cutters and TSP's can be very difficult, but very important.

The cutters in fixed cutter bits will show some wear under all working conditions. The type and amount will vary with the type of bit, operating conditions, and the formations encountered. Cutting structure wear is usually indicated by a decrease in the drill rate or by an increase in the pump pressure.

Broken, lost or faceted cutters will show up readily. Matrix erosion is a common problem, which will lead to cutter wear. As with roller cone bits, record the amount of breakage, lost cutters or chipped cutters, then try to determine the cause of this type of wear.

Gauge Wear

Gauging practices are different than tricone bits, because “GO” and “NO-GO” ring gauges are used. The procedures for grading gauge wear is relatively easy:

1. If the bit can enter the “GO” ring gauge, it is not too large.
2. If the bit cannot enter the “NO-GO” ring gauge, it is not too small
3. Should the bit fit inside the “NO-GO” ring gauge, measure the distance with a ruler and record the amount in 1/16th's of an inch

Loss of gauge is usually the result of prolonged reaming.

1987 IADC System Structure

The system uses the same eight component grading scheme as used for roller cone bits, the exception being the lack of bearings in fixed cutter bits. Grading, therefore, is mainly concerned with cutter wear and the causes of that wear.

The Inner Row section refers to the inner 2/3 radius, and the Outer Row section is the outer 1/3 radius. The same is true for core bits. The Dulling Characteristics change slightly with fixed cutter bits, because, as mentioned previously, the dulling is mainly due to breakage or lack of cooling. The Location of dulling also is different with fixed cutter bits. You must look at the cone, nose, taper, shoulder and gauge to describe wear locations.

An “X” is placed in the Bearing Wear section.

Whether the bit is “In” gauge or the amount of “Out” of gauge (in 16ths of an inch) is placed in the Gauge section.

As with roller cone bits, the Remarks section should list the Other Dulling Characteristics and the Reasons Pulled. If there are no other dulling characteristics, then a “NO” is placed in this section.

Bit Data Record

The Bit Data Record is one of the most important “additional” information collected by the Logging Geologist. Complete and accurate records are necessary for the safe and cost-effective operations at the wellsite. It is also the most used source of information in post-well evaluation and pre-well planning. As stated earlier, it is also used by the bit manufacturer to assist in future bit designs.

The Bit Data Record is divided into three sections:

Run Information

This refers to the number of times a drill bit, under-reamer or hole opener was run into the hole. This should be consecutive numbering. The only time a run would not be numbered, is when none of the above are run into the hole (i.e. a mill). When this occurs, enter “NB” in the column.

Bit Data Information

Bit Number

- The numbers are consecutive whenever a new bit, under-reamer, or hole opener is run into the hole
- Reruns use the original bit number, plus “RR,” for rerun (i.e. RR3)
- If no bit is in the hole, enter how the drill string is being used (i.e., “Open” for opened ended or “Mill” for milling activities)

Manufacturer

Use the bit manufacturer's name, or an abbreviation, some examples are:

HTC -	Hughes Tool Company	SEC - Security
CHRST -	Christensen	SNDVK - Sandvik
SMITH -	Smith Tool Company	VAREL - Varel Bits
REED -	Reed Tool Company	

Type

- The bit type is the bit name, using the manufacturer's nomenclature

Size

- The bit size is reported in inches using decimal formats (i.e., “9.875”, not “9 7/8”) or in millimeters

IADC Code

- Use the standard codes for tricone and fixed cutter bits
- Use “HO” for hole opener and “UR” for under-reamer

Jet Sizes

- This is the nozzle size in 32nds of an inch. It can be entered; “3 x 12" or “12/12/12”
- Use “OP” if a jet is left open, “12/12/OP”
- Use “BL” if a jet is blanked (closed), “12/12/BL”
- Fixed cutter bits use Total Flow Area or Total Nozzle Area, in square inches, “0.50 TFA”

Bit Run Information

General Information

- In the “Drilled” column, enter the units of measurements. Normally “Feet” or “Meters”
- All depths and time measurements are reported in decimal formats: e.g.: Depth 5120.6 ft - Drilled 589.4 ft in 22.7 hrs
- State the range of operating conditions during the bit run. List separately any significantly different conditions

IADC Bit Condition

- Use the IADC standards when grading either tricone or fixed cutter bits

Comments

- State any pertinent comments concerning the bit run. Use as many lines on the sheet as necessary to convey the information. For example:

Run Comments

- Drilling Cement: State top of cement, length of column, problems with drilling
- Drilling Junk: State type of junk, if milling, problems with drilling
- Conditioning Hole: State time spent, drillstring configuration
- Directional Drilling: State angle, inclination, drillstring configuration

Other Comments

- BHA Make-Up: State if shock subs, downhole motors, etc., are being run
- Stuck Pipe: State where stuck, type of sticking
- Formations: State formation tops, changes, problems with drilling, etc.
- Mud parameters: State large variations during bit runs, mud changes, etc.

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COMPANY: Kinghurst Exploration Company WELL: Training Well #1 SHEET NO. 1

BIT DATA RECORD

RUN #	BIT DATA						BIT RUN								
	BIT #	MFR	TYPE	SIZE	IADC CODE	JET SIZES	START DEPTH	DRILLED Feet	DRILLED HOURS	AVERAGE ROP	WOB	RPM	PUMP PRESSURE	SPM/GPM	IADC BIT CONDITION
1	1	Smith	DSJ	26.0	111S	3 x 16	1976	280			Spud Bit				
2	2	Smith	SDS	12.25	114E	4 x 12	2259	513		Drilled Pilot Hole					
3	RR1	Smith	DSJ	26.0	111S	3 x 24	2259	829		Wash Out & Drill Hole for Surface Casing					
4	3	Reed	Y11	15.0	111S	3 x 15	2956	1088	15.4	80-90	2-20	130-145	2900-3050	150/680	T4B5I
5	4	Reed	Y11	15.0	111S	15/15/12	4044	492	5.6	80-100	10-25	150-155	2970-3200	150/740	T2B1I
6	RR2	Smith	SDS	12.25	114E	4 x 12	4532			Pulled to Squeeze Cement					
7	RR2	Smith	SDS	12.25	114E	4 x 12	4532		6.2		Drilled Cement				
8	5	Chrst	C-201	8.50	T4X8	0.50 TFA	4538	30	3.8	8-12	1-5	45-55	1000-1500	50/350	T2I
			Cored Top of Austin Chalk - Recovered 100% Minor Burn Wear on Diamonds												
9	6	Sndvk	PD-21	12.25	S744	0.44 TFA	4568	492	7.5	50-60	22-30	80-100	3000-3200	155/700	T1I BT
10	7	Reed	CS16FD	8.50	0350	0.50 TFA	5060	60	2.2	37-40	15-18	45-50	700-1500	50/300	T1I
			Cored Woodbine and Top of Eagleford - Recovered 100% Run in with Junk Basket Prior to Coring												
11	8	HTC	J1	12.25	116G	13/13/OP	5120	1296	27.4	35-47	30-40	100-110	3000-3250	144/675	T3SEI
12	RR8	HTC	J1	12.25	116G	13/13/12	6417	598	22.7	26-32	45-47	100-105	3000-3100	125/630	T6SEI
13	9	Sec	S88F	12.25	547X	3 x 12	7051	290	12.9	20-22	40-45	110-115	3400-3480	170/780	T5SEI
14	10	Reed	HP53A	12.25	537Y	12/12/13	7305	466	26.5	15-18	50-55	100-110	3250-3300	165/780	T3SQI
15	11	HTC	ATJ11	12.25	517X	3 x 12	8119	984	53.6	15-20	60-80	60-70	3500-3550	150/680	T8SFI
			Lost Cone #1 in hole, and 12 teeth from Cones 2 and 3: Bearings Locked Up												
NB	Mill	Bowen	Junk	12.25			9103	5		Mill on Junk from last Bit Run					
16	12	Smith	SDS	8.50	114G	3 x 12		Trip in after casing with casing scratcher - Wiper Trip							
17	13	HTC	J2	8.50	126G	3 x 12	8985	Drill Cement							

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Figure 7-1: INTEQ's Bit Data Record

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Self-Check Exercises

1. What are the two parameters that dull bit grading is concerned with describing?
   a. ________________________________
   b. ________________________________

2. What does the “series” digit in a roller cone IADC code represent?
   ____
   ____

3. a. Are journal bearing bits manufactured without seals: Y N
   b. Are roller bearing bits manufactured with seals: Y N

4. What is the difference between a 517X bit and a 517Y bit?
   ____
   ____
   ____

5. If the first character in a fixed-cutter bit's IADC code was a “M,” what would it represent?
   ____
   ____

6. What parameter defines a fixed-cutter bit profile?
   ____
   ____

7. What are the three cutter types available for fixed-cutter bits?
   ____
   ____
   ____

8. What formations are ‘light-set” and “heavy-set” bits designed for?

 ____

 ____

 ____

9. How is cutter density defined in fixed-cutter bits?

 ____

 ____

10. How are the following items graded on roller cone bits?

 a. ___________ A sealed-bearing bit with the seals intact:

 b. ______________ A non-sealed bit with the cones loose:_

11. What multiplier is used when determining gauge wear on roller cone bits?

 ____

 ____

12. What multiplier is used when determining gauge wear on fixed-cutter bits?

 ____

 ____

13. What is placed in the “RUN#” column if a junk mill is run into the hole?

 ____

 ____

14. What is placed in the “JET SIZES” column is a PDC bit has seven jets
 (4 x 11 and 3 x 10)?

 ____

 ____

15. What is placed in the “IADC CODE” column when a hole opener is being used?

 ____

 ____

Chapter 8

Formation Pressures

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

- Understand the importance of monitoring formation pressures
- Identify the types of formation pressures which are encountered during the course of a well
- Recognize the mechanisms which generate abnormal pressures
- Realize that proper evaluation and maintenance of formation pressures results in safe, cost-effective drilling practices

Additional Review/Reading Material

INTEQ Video Tape #1 - *Formation Pressure Theory*

INTEQ, *Formation Pressure Evaluation*, 1993

Fertl, Walter, *Abnormal Formation Pressures*, Elsevier Scientific Publishing Company, 1976

McClure, Leo, *Drill Abnormal Pressure Safely*, 1977

Elf Aquitaine, *Abnormal Pressure While Drilling*, 1989

SEG, *Geopressure*, Reprint #7, 1990

Types of Formation Pressures

The objective of this section is to familiarize the Logging Geologist with the terms and expressions used during the evaluation and interpretation of subsurface pressures. It is not intended to make the logger proficient in calculating or determining formation pressure values. Detailed analysis of formation pressures will be discussed in Module L4.

Abnormal formation pressures occur in most sedimentary basins worldwide. They occur in all geologic age formations, though are most common in younger (Tertiary) formations. These pressures occur at all depths, from a few hundred feet to over 20,000 feet. Finally, statistically between one third to one half of all wells drilled experience abnormal pressures.

Therefore, an understanding of formation pressures is important for several reasons:

- Increased drilling costs due to lost time and equipment problems caused by abnormal pressures, through:

  1. Well kicks and Blowouts
  2. Stuck Pipe
  3. Lost Circulation

- Environmental pollution resulting from abnormal pressure problems
- Loss of reserves resulting from abnormal pressure problems
- Loss of life or injuries resulting from abnormal pressure problems

Understanding formations pressures will ensure the safety of all rig personnel and minimize drilling costs.

Formation Pressure Terminology

There are several kinds of formation pressures which will be discussed. They are:

Overburden Pressure
Formation Pore Pressure
Mud Hydrostatic Pressure
Equivalent Circulating Density
Fracture Pressure
Kick Tolerance

Overburden Pressure

Overburden Pressure is the pressure at any point in the formation exerted by the total weight of the overlying sediments. This is a “static load” and is a function of the height of the rock column and the density of the rock column.

Since subsurface rocks/formations are not homogenous, to calculate the overburden pressure (**S**), the rock column must be broken up into relatively homogenous intervals (D_z). Thus, the incremental over-burden pressure is:

$$S = 0.433 \times \rho_b \times D_Z$$

where:

	S	=	Overburden Pressure (psi)
	ρ_b	=	Rock/Formation Density (gm/cc)
	D_z	=	Depth Interval (feet)

The Overburden Gradient (**OBG**), is the sum of these increments divided by the total depth.

$$OBG = \frac{\Sigma S}{\Sigma D}$$

There are several sources of formation density values. One of the most accurate is from the Formation Density wireline logs. Another source is the shale density/bulk density measurements. Both are read directly in gm/cc.

Overburden pressures and gradients are used in Fracture Pressure calculations.

Formation Pore Pressure

Formation Pore Pressure is the pressure exerted by the pore fluids within the rock/formation. Pore pressure is considered to be:

Normal = Hydrostatic
Subnormal < Hydrostatic
Abnormal > Hydrostatic
or Overpressure
or Geopressure

The Hydrostatic Pressure is the pressure exerted by a column of fluid (water) at any given point. The pressure is a function of:

- The vertical height of the column
- The density of the fluid

Hydrostatic pressure is calculated using:

$H_p = 0.0519 \times W \times D_v$

where: H_p = Hydrostatic Pressure (psi)
W = Weight of Water (lb/gal)
D_v = Vertical Height of Fluid (feet)

The density of water, especially formation water, will vary with salinity. Below are listed several examples.

Table 1: Variation of Hydrostatic Pressure with Water Salinity

Salinity NaCl ppm	Pressure Gradient (psi/ft)	Equivalent Water Density (kg/m^3)	Equivalent Mud Weight (lb/gal)
0	0.433	1.000	8.34
10,062	0.435	1.005	8.38
54,450	0.448	1.034	8.63
62,554	0.451	1.042	8.69
107,709	0.465	1.074	8.96
130,457	0.470	1.085	9.05

Mud Hydrostatic Pressure

Mud Hydrostatic Pressure is the pressure exerted at any point by the mud column. As with hydrostatic pressure, it is a function of vertical height and mud density.

$H_p = 0.0519 \times MW \times D_v$

Equivalent Circulating Density

The E.C.D. is the apparent density of the drilling fluid while circulating, including the annular pressure losses. The annular pressure losses are affected by:

- Plastic Viscosity and Yield Point
- Hole Size and Pipe Geometry
- Flow Rate/Annular Velocity

The “Bottom Hole Circulating Pressure” is determined using:

$B.H.C.P. = 0.0519 \times E.C.D. \times D_v$

Fracture Pressure

Fracture Pressure is the stress which must be overcome for hydraulic fracturing to occur. This stress is known as the **minimum lateral stress**, which is essentially the matrix stress plus the pore pressure. Since the pore pressure is usually known, the matrix stress is estimated using:

matrix stress = k(S - PP)

The value, (S - PP), is known as the “effective overburden” and is read in psi. The “k” is a coefficient which in effect describes the ratio of vertical-to-horizontal stress transmission.

When fracturing occurs, the fracture orientation will usually be parallel to the greatest stress (which is normally the over-burden pressure), which means the fractures will be vertical. For horizontal fractures to occur, the overburden pressure will have to be exceeded. This will occur in areas of large horizontal tectonic stresses.

Although there are several methods for estimating fracture pressure, the best way to arrive at an accurate value is to perform a Pressure Integrity Test (PIT), or “Leak-Off Test.”

Kick Tolerance

Kick Tolerance is the maximum pore pressure that may be encountered, with the well shut-in, without down hole fracturing resulting (at the present depth and with the current mud weight).

Kick Tolerance is a “safety measure.”

Pore Pressure Terminology

Before leaving this introduction to terminology, several terms should be understood when describing pore pressures. They are:

Cap Rocks These are impermeable formations/rocks (shales, evaporites, carbonates), which form a layer keeping underlying fluids trapped. Precipitation of minerals from solutions as those solutions move through the cap rocks will assist in creating this permeability barrier.

Often thought to be necessary for abnormal pressures to occur, by acting as a seal, cap rocks are not always present.

Transition Zone
This is a zone over which there is a transition from normal to abnormal pressure, or from abnormal pressure to a higher pressure.

The thickness of transition zones varies from area to area. These normally develop when the seal or cap rock is not perfect, and pressurized fluids migrate upwards from the seal increasing the pressure as they move.

Generation of Abnormal Pressures

Abnormal pressures develop when some process affects the components of the subsurface stress system, such that the pore fluids accept a greater share of the overburden stress than would be expected (greater than hydrostatic pressure), and a permeability barrier prevents the migration of the fluids to equalize the pressures.

There are several geologic conditions favorable to abnormal pressure development:

- Young Sediments (Tertiary)
- Large Total Thickness (Basins)
- Presence of Clay Rocks (Shale Sequences)
- Interbedded Sandstones of Limited Extent (Deltaic and Transgression-Regression Sequences)
- Rapid Loading and Burial (Deltaic Sequences)

As can be seen, most petroleum exploration takes place in these types of environments. It should be recognized that abnormal pressure will be seen in most wells.

Mechanisms of Abnormal Pore Pressure Development

There are several mechanisms for abnormal pore pressure development, some proven, some still theoretical. Many times, several combine to form the mechanism for pressure generation. The important ones are:

- Compaction Disequilibrium
- Aquathermal Pressuring
- Montmorillonite Dehydration
- Osmosis
- Geologic Uplift
- Tectonism
- Recharge or Communication

Compaction Disequilibrium

When sediments are deposited in an area, there is normally an equilibrium established between the sedimentation rate of materials, the loss of permeability and reduction of pore space with burial and increased overburden, and the rate of pore fluid expulsion to equalize the pressures.

As mentioned above, when there are high sedimentation rates of young, fine grained sediments (sands and clays), and these interbedded sands are thin or of limited lateral extent, then mechanisms are present to disrupt the compaction equilibrium.

If the sands are isolated by impermeable clays or shales, then as they are buried, the pore fluids cannot escaped. With further burial, the fluids are compressed and begin to assume some of the overburden pressure, and hence become abnormally pressured.

Should some of the fluids begin to escape, through micro-fractures in the overlying shale, then a transition zone will be formed. This zone should indicate the presence of increasing pressure before the pressured zone is drilled.

Aquathermal Pressuring

If during deposition, the fluids are completely isolated by a permeability barrier, pore fluids cannot escape. With burial to increasing depths, the increasing geothermal gradient will cause the fluids to expand. Since there is no room for expansion the pressure within the isolated formation will increase

Temperature-related pressure increases can exceed the overburden if the seal remains intact. Pore pressure may increase until it equals the sum of the overburden pressure and the tensile strength of the seal. Any further pressure increase will result in the fracture of the seal, escape of the pore fluid, and the reduction of the pore pressure.

If the seal of the isolated clay/shale zone is thin, there will be no transition zone, and very little warning of incipient pressure. For this reason, observation of the geothermal gradient is used to predict aquathermal pressuring. Due to the insulating effect of the greater fluid content within the geopressured interval, an increase in the geothermal gradient should be noticeable.

A pore pressure reduction may also occur as a result of the aquathermal effect. If a lithologic section is displaced such that the present temperature is less than the temperature at its state of maximum geopressure, the pore pressure will be reduced. This may occur along inconformities, where erosion has removed overlying strata.

Montmorillonite Dehydration

Since 1950, it has been known that, with burial, montmorillonite clays (or more correctly, smectites) undergo an alteration to illite. The process was proposed to explain the abundance of montmorillonite at shallow depths and the relative abundance of illite at greater depths. This transition is predominantly depth related, but is also affected by temperature variations and ionic activity.

Although the conversion is not related to geologic age, it often appears that way because older rocks are generally encountered at greater depths.

To illustrate the change, the smectite and illite molecular formulae are:

smectite = $Al_4Si_8O_{20}*nH_2O$
illite = $K_yAl_4(Si_{8-y},Al_y)O_{20}(OH)_4$

Smectites have the ability to absorb water between their structural layers. The amount of water varies with the type of clay, the nature of the interlayer cations, and the prevalent physical conditions. As the clays undergo burial and encounter increasing temperatures, interlayer water is driven off. Most of this dehydration takes place between the 100 and 250 degree C isotherms.

Since smectites can have ten levels of water between their layers, huge volumes of water will be liberated to the pore spaces and must be expelled for normal pore pressure to be preserved. After the first six fluid layers have been removed, the clay is altered from a stacked to a herringbone structure. As burial progresses, the remaining four water layers are driven off and dehydration is complete.

If the waters also undergo an ionic loss during liberation, an accompanying density reduction will result in expansion and pore pressures will rise.

For montmorillonite dehydration to be important in the generation of geopressures, the expulsion rate of pore fluids must be less than the production of waters from within the clay layers. Compaction of adjacent sediments may contribute to higher pressure through a reduction of permeability. Reduction of permeable conduits can be further enhanced by precipitation of silica released during the montmorillonite/illite conversion.

Osmosis

Osmosis is defined as the spontaneous flow of fluids from a dilute solution to a more concentrated solution, when the two solutions are separated by a semi-permeable membrane. The osmotic pressure differential is almost directly proportional to the difference in ionic concentrations; when the differential is constant, the pressure varies with the absolute temperature.

Clays can act as semi-permeable membranes, with the efficiency increasing with higher clay purity. Ions dissolved within the pore waters are filtered by the clay membrane when the waters flow to the higher-concentration solution.

When an equilibrium is finally attained, the pore pressure on the influx side will be anomalously high. Laboratory experiments have determined that the pressure generated by a saturated brine solution and 1.02 gm/cc NaCl in water may reach 4500 psi under the proper conditions.

"Electro-osmosis" may also be an active process. This occurs where two solutions contain dissolved ions that tend to be chemically active. The electrical potential across the semipermeable membrane induces fluid movement. Furthermore, temperature may also influence fluid movement, in a process termed "thermo-osmosis."

The combined effects of osmosis, electro-osmosis, and thermo-osmosis can act in concert to exceed the hydraulic conductivity, and potentially reverse the predominant direction of compaction-related dewatering. The relative importance of the osmotic mechanisms increases with greater compaction and decreasing porosity.

Uplift

If a normally pressured formation is uplifted, such that the total vertical stress on the rock is decreased, abnormal pressures may be produced.

Note, though, that this will only be the case if the uplift is also accompanied by other geological processes that reduce the relief between the buried rock and the surface; typical processes are piercement salt domes, shale diapirs or erosion.

Time is an important factor in this process. Uplift must occur rather rapidly relative to geological time. As formation is lifted and the overburden reduced, the stress in the system will be reduced to equilibrium. There will be a lag in reaching this equilibrium, however.

A dynamic uplift of a given amount has different effects at different depths. The shallower the uplift, the greater the abnormality.

Tectonism

The mechanism of generation of geopressures due to tectonic compression is very similar to the process involved in compaction disequilibrium with the exception that the time factor is a function of strain rate and not of deposition.

In non-tectonic geosynclinal basins, porosity may be directly related to the effective weight of the overlying sediments if the pore water can escape in response to increasing overburden pressures. However, in a tectonic environment, if additional pore water can escape sufficiently fast to maintain equilibrium at all times, then normal pore pressures will prevail; however, the clay will be denser due to the reduction in porosity caused by tectonic stress.

As tectonic load is added, the immediate effect on the clay strata is for the increment of load to be assumed by the pore fluid. Then as excess water is expelled from the clay, compaction occurs due to the decrease in porosity and the increase of effective stress in the solid. Since it is likely that the rates of overburden stress buildup and pore water expulsion from compacting clays are close, any further increase in stress could cause disequilibrium; pore water would not be able to escape at a rate equal to the volumetric reduction in pore space, resulting in an increase in pore pressure.

Tectonically produced geopressures will behave and appear much the same as those resulting from (vertical) subcompaction. Clues to their origin may be found in signs of deformation in regional structure and rock fabric.

Recharge

Abnormally pressured formations may be caused by a phenomenon known as “recharge.” This occurs when shallow, previously normally pressured, zones are charged by the re-distribution of fluids or gas by flow through some conduit from a deeper, higher pressure zone. Possible conduits are faults, fractures and wellbores.

Geopressures caused by recharge can be very significant, especially if gas is the medium which transmits the pressure.

Recharge of shallow sands may be caused by an underground blowout. This occurs when a kick is shut in and the fracture pressure at the casing shoe (or the weakest formation in open hole) is exceeded, causing a flow of fluid into the shallower zone. If the shallow sands have sufficient permeability, other wells drilled nearby may encounter unexpected shallow abnormal pressure. Offset well logs and reports should be examined for any mention of well kicks in order to be prepared for this situation.

Abnormal Pore Pressure Maintenance

In the case of a geopressured zone, where no fluid is expelled, several situations might occur:

- The pore pressure gradient might equal the overburden gradient if pore fluids assume the total weight of the overlying sediments and pore fluids.
- The pressure gradient could increase to twice the overburden gradient if aquathermal pressuring and montmorillonite dewatering have been active.
- The pressure gradient could assume any value due to the effects of tectonic stress, osmotic pressures, or any combination of the pressure producing mechanisms.

Compaction disequilibrium and aquathermal pressuring can continue to raise geopressures with increasing burial and temperature. There is rarely a perfect seal for compaction disequilibrium, and aquathermal pressuring will be limited when geopressures eventually result in horizontal fracturing and subsequent release of pore fluids. Montmorillonite dewatering is limited in its contribution to geopressure because of the finite amount of water available in the clay sediments. Exploration has demonstrated that the “ideal case” geopressured zone is unlikely. Abnormal pressure is usually restricted to younger sediments. This suggests that geopressures are transient and leakage from the zones must eventually occur, either because of a non-perfect seal, or through fracturing and faulting.

Self-Check Exercises

1. Abnormal pressures are most often encountered in formations of which geologic age?

   ____

2. What two parameters form what is called “Overburden Pressure”?

   a. ______________________________

   b. ______________________________

3. If the pressure gradient of a solution of salt water is 0.468 psi/ft, what is its equivalent mud weight in lb/gal?

   ____

4. What is the difference between the Formation Pore Pressure and the Mud Hydrostatic Pressure?

   ____

   ____

5. What two components make-up the Bottom Hole Circulating Pressure?

   a. ______________________________

   b. ______________________________

6. When hydraulic fracturing occurs, what is the predominant orientation of the fractures?

   ____

   ____

7. What is the most accurate method for estimating fracture pressure?

   ____

8. List five geologic conditions which can assist in the development of abnormal formation pressures?
   a. ______________________________
   b. ______________________________
   c. ______________________________
   d. ______________________________
   e. ______________________________

9. Describe a depositional occurrence which can produce abnormal pressure through compaction disequilibrium?
   ____
   ____

10. What is the smectite to illite conversion process known as when it is related to abnormal pressure generation?
   ____
   ____

11. Which rock type can act as a semi-permeable membrane in the development of osmotic pressures?
   ____
   ____

12. List three “conduits” which can recharge shallow formations with fluids from greater depths?
   a. ______________________________
   b. ______________________________
   c. ______________________________

Borehole Problems

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

- Understand the importance of preventing borehole problems
- Recognize the indications of specific borehole problems
- Assist the drilling operations through prompt communication of indications concerning possible borehole problems
- Perform normal logging activities during the occurrence of any borehole problems
- Confirm mud weight fluctuations and determine its cause

Additional Review/Reading Materials

INTEQ Video Tape #7 - *Logging Procedures*

Messenger, Joseph, *Lost Circulation*, Pennwell Publishing Company, 1981

Kemp, Gore, *Oilwell Fishing Operations: Tools and Techniques*, Gulf Publishing Company, 1986

Milpark, *Drilling Fluids Manual*, 1991

Moore, Preston, *Drilling Practices Manual*, Pennwell Publishing Company, 1986

Introduction

Few wells are drilled as they are planned. Problems always seem to occur. One of Baker Hughes INTEQ's functions at the wellsite is to recognize and help prevent as many of those costly problems, as possible.

As a Logging Geologist, there are several borehole problems that can be recognized during the course of your logging activities. They are:

- Wellbore Instability
- Stuck Pipe
- Lost Circulation

Knowing the causes and effects of these problems will assist in the recognition of a potential problem, or at least solving it at an early stage before the question of safety and money enter the picture.

It is realized that every well is different. The indication of a problem on one well may be different on another, but the problem still occurs. It is not easy. Constant vigilance on the parameters monitored in the logging unit and a knowledge of what is taking place both at the surface and in the borehole, will prevent, or at least reduce the severity, of many borehole problems.

Lost Circulation

- The partial or complete loss of whole drilling fluid to a formation
- Not to be confused with volume reductions due to loss of filtrate to permeable formations
- The loss may range from a gradual lowering of the mud level in the pits, to a complete loss of returns
- May occur at any depth -- anywhere that the total pressure against the formation exceeds the total pressure of the formation, and the openings in the formation are sufficiently larger than the largest particles in the mud

Solution to Lost Circulation Problems

- Recognition of the loss
- Identification of the cause of the loss
- Location of the “thief” zone
- Proper remedial treatment to combat the loss

Recognition

May be made by:

- Pit volume totalizer (PVT)
- Flow return sensor
- Pump pressure reduction
- Drilling break - often first indication

Causes

- Poor cement job
- Coarsely permeable, unconsolidated formations
- Cavernous or vugular formations
- Natural or intrinsic fractured formations
- Mechanically induced fractures

Mechanically induced fractures

Causes

1. Running in too fast after trip producing high surge pressures. also when running casing.
2. Excessive pump pressure to break circulation after trip.
3. Cuttings or sloughing shale close off annulus --pressure build up in system.
4. High gel strengths & viscosity -- requiring higher pump pressure to break circulation
5. Unbalanced mud column -- raising mud weight too rapidly.
6. Opening pumps too rapidly.
7. Pipe whipping.
8. Pressure developed while killing a well.
9. Effective circulating density greater than fracture gradient.

Preventative measure to avoid inducing fractures

1. Rotate drill pipe before starting pump -- a lower pressure will be required to break circulation
2. Break circulation slowly
3. When running in hole, do not run in too fast and break circulation at intervals

4. Avoid thick wall cake which reduces hole diameter and can thus increase surge pressures
5. Maintain the minimum mud weight necessary to control the formation pressure of the borehole
6. Avoid excessive annular velocities which result in high annular pressure losses, and thus high circulating pressures
7. Maintain the minimum mud viscosity, gel strength and yield point to prevent settling of the weight material
8. In areas where losses are known to occur, maintain fine lost circulation material in the system at all times

Location of Lost Circulation Zone

Temperature Survey

1. First run one wireline temperature survey to establish the temperature gradient of the well after the mud has come to equilibrium with the formation.
2. A second run is then made immediately after adding fresh mud to cool the well.
3. A sharp temperature discrepancy will occur at the point of loss.

Radioactive Tracer Survey

1. First run one gamma ray survey to establish a base log.
2. Pump a slug of mud containing radioactive tracer around the hole.
3. Run a second gamma ray log.
4. High concentrations of the tracer will be located at the point of loss.

Classification of Loss Zones

1. Seeping Losses: can occur in any formation type when the (1-10 bbl/hr) formation openings are larger than the coarsest mud particles, and any lost circulation material in mud is not fine enough to complete the seal.
2. Partial Losses: occur in gravels, small natural fractures (10-500 bbl/hr) and barely induced fractures.
3. Complete Losses: occur to long, open sections of gravel, or long intervals of natural fractures, caverns, or open induced fractures.

Lost Circulation Materials

Fibrous:
- Sugar Cane Fiber (Bagasse)
- Wood Fiber
- Paper
- Leather Fiber

Granular:
- Nut Hulls (Walnut, Almond) (Fine, Medium & Coarse)

Flakes: Cellophane
- Mica (Fine & Coarse)

Reinforcing Plugs:
- Bentonite-diesel Oil
- Time-setting Clay
- Salt Gel & Granular Material

Reasons Why Application of L.C.M. to Mud System Is Not Recommended

1. Expensive
2. Some materials lose their strength, especially fibrous materials
3. L.C.M. removed by shaker; bypassing shaker retains material. Material - increasing weight of column and possibly aggravating the problem
4. Higher circulation pressure required with L.C.M. in mud
5. Possibility of plugging the bit

Usual Causes of Failure to Control Lost Circulation

1. The location of the thief zone is not well established - slurries spotted opposite wrong zone.
2. L.C.M. size not systematically matched to the type and severity of the loss zone.
3. Failure to keep accurate records of successful procedures which can then be applied to offset wells.

Effect of Lost Circulation on Logging Evaluation

1. Partial or no returns - loss of samples, gas information.
2. Contaminants in cuttings - lost circulation material.

3. Changing hydrostatic column - allows possible easier entry of formation gas as bottom hole pressure is reduced - resulting in increased gas readings.

Stuck Pipe

Causes and Types

The most common causes/types of stuck pipe are:

Sand Sticking
Mostly found with tubing more than drill pipe/collars, unconsolidated sand falls in around pipe

Mud Sticking
Caused by the setting up or dehydration of mud in the annulus,
high temperature additives in mud at low temperatures, barite settling out, or formation fluids entering annulus upsetting mud chemistry.

Mechanical Sticking
Caused by stuck packers or other downhole assemblies, a crooked pipe - usually dropped into hole, or junk in hole - usually wedges in collar section, tool joint, etc.

Key Seat Sticking
Caused when the drill pipe, under tension wears a slot in the wall during drilling operations, or the slot is usually smaller than borehole diameter, and parts of the drill string with large diameters get stuck while tripping. Key seat sticking is commonly seen in directional wells or wells that deviate from vertical, usually at the drill collars or a tool joint.

Cement Sticking
Caused by mechanical malfunction, hole in casing or drillpipe, cement pump breaking down, human error, miscalculation of displacement volumes, or cement setting-up too soon.

Undergauge Hole Sticking
Caused with shales (plastic) with expandable clays that hydrate when penetrated by the drilling fluid, causing the shales to deform into the hole; salt, very plastic, will flow with oil-based muds; or when hard sandstone formations wear down the bit, after a trip, the new bit cannot get to bottom.

Differential Sticking (Probably 75 to 80 percent of all stuck pipe)
Caused by wall sticking - with high overbalance pressures, permeable formations cause drilling fluid to flow into the formation, and hold the drilling assembly against the wall by differential pressure. The drilling fluid can still circulate; the

bore-hole is still in good condition; and the wall cake becomes thick around drilling assembly.

Blowout Sticking

Caused by formation/fluids entering bore-hole, causing the pipe to be bridged by debris and becoming stuck. This occurs when there is insufficient mud weight or a failure to keep hole full of fluid.

Lost Circulation Sticking

Caused by lost circulation in upper zones, which causes sloughing and caving to occur, thus sticking pipe in lower sections.

Sloughing Hole Sticking

Caused by unstable shales which slough into the hole, packing-off around the drilling assembly.

Recovery

Wire line tools for pipe recovery

Free Point and Torque Indicator

Typically, two electromagnets connected by telescopic joint/ micro cell measure differential strain and elongation. For non-magnetic drill assemblies, the above uses spring tension to hold tool in place. During the lowering of the “indicator” into the hole, the pipe is rotated at selected depths. Free pipe will move/rotate, thus causing reading at surface sensor. Stuck pipe will not move/rotate, thus when at a selected depth when no readings are monitored, stuck point can be determined.

String Shot Back Off

This is a calculated quantity of explosive detonated by electronic blasting cap. The string shot is lowered on wireline to the stuck point (usually nearest tool joint). The drillstring is then rotated “to the left” (normally four times), based on steel's physical properties. With opposite torque on drill string, the force of explosion will “break” pipe loose.

Wellbore Instability

Shale Problems

Indications of Shale Problems

a. Hole Fill on Connections and Trips

b. Excessive Cavings Coming Across Shale Shaker

c. Torque and Drag on Connections and Trips

d. Reduced Rate of Penetration
Bit Balling - Clay Particles Adhering to Bit Surface
Bit Floundering - Regrinding of Cuttings

e. Lag Changes

Remedial Measures

a. To reduce high annular velocities - decrease the PV/YP ratio (i.e. raise the YP)

b. To balance formation pressures - increase the mud density

c. To keep the drillstring in tension - stay within the "neutral point" limits

d. To avoid swabbing and surges: run or pull. drillstring slowly, reduce the YP and Gel Strengths, and periodic breaking of circulation to clean the bit, stabilizers and borehole

e. Correct use of mud additives, correct mud pH, use of water loss control agents

f. Use of correct mud system - using low CEC systems

Unconsolidated Formations

Indications of Unconsolidated Formations

a. Rough Drilling

b. Fill-up and excessive torque and drag on connections and trips

c. Frequent packing-off and bridges at specific depths

d. Large amounts of cavings across the shaker after trips

e. Continual re-drilling of footage

f. Drilling fluid loss

Remedial Measures

a. Increase viscosity and gel strengths to improve hole. cleaning and suspension

b. When possible raise mud weight

c. When fluid losses occur in unconsolidated formations, use viscous pills containing fibrous LCM

d. Reduce annular velocity across unconsolidated zones

e. Squeeze cement into zones

f. Case off problem sections

Evaporites

Indicators of Evaporite Problems

a. Increase in chlorides with no increase in volume. Salt saturation at 186,000 ppm chloride. Cannot treat out chlorides - only dilute with water

b. Flocculation of freshwater muds

c. Increase in plastic viscosity

d. Increase in “total hardness” - Anhydrite. Gypsum/Anhydrite saturation at 600 ppm hardness

e. Decrease amounts of cuttings across shale shaker

Remedial Measures

a. Use an inhibitive mud system - oil base or salt saturated

b. Increase the viscosity and gel strengths to improve hole cleaning

c. Case off sections after drilling them

Mud Density Problems

Changes in mud density are caused by:

Surface Effects

1. Additions of Water
   a. to reduce mud viscosity
   b. to replace water lost to the formations while drilling
   c. to reduce mud density for a specific reason
2. Recirculated Gas - gases left in the system after one circulation
3. Kelly Cut Gas - air entering drillstring whenever the kelly is broken off
4. Aeration of Mud at the Surface
   a. turbulence in the mud system at the surface.
   b. check mud density after degasser for any changes.
   c. look for “frothy” appearance of mud in pits.
5. Weighting-Up of Mud
   a. will get “light spots” if weighted-up too quickly.
   b. this weighting-up will reduce its viscosity.

Downhole Effects

1. Increases caused by formation solids going into solution - normally a “top hole” problem
2. Decreases caused by:
   a. Invasion of formation fluids (gas or water) into mud. system.
   b. Gas from drilled cuttings/cavings - gas in cuttings will expand as cuttings are circulated to the surface; this will cause a reduction in the flowline mud weight. Increasing the mud weight will have little effect.

Invasion of Gas into the Borehole

1. Shallow Gas
   a. will get high drill gas readings - much expansion
   b. will get significant mud density reductions
2. With increasing depth, drill gas should decrease
   a. decreasing rate of penetration
   b. decreasing formation porosity

3. Other than “reservoirs,” invading gas is due to - swabbing or serious invasion (kicks) - reduction of hydrostatic pressure

Abnormal Pressure

1. Increases in Formation Pressure
2. If formations are porous and permeable - fluids will invade borehole
3. If formations are impermeable - sloughing will occur
4. Differentiated from Drilled Gas - when pumps are off, fluid invasion continues

Swabbing

1. When bit is pulled, it acts like a plunger
2. May reduce hydrostatic pressure enough to cause a flow of formation fluids into the borehole.
3. If clearance is small - swab pressure will be greater.
4. If formations are permeable - greater amount of fluids will enter.
5. If formations are impermeable - will see torque and drag increases.

Not Filling Hole During Trips

1. Causes reduction of hydrostatic pressure.
2. Will see large trip gases.

Connection gas

1. Swabbing effect of raising kelly.
2. Shows that ECD is greater than Formation Pressure.

Stopping Pumps During Drilling Operation

1. Gases present will show that formation pressures are greater than hydrostatic pressure.
2. May cause problems if pumps are off over a long period of time.

Lost Circulation

1. Height of mud column is reduced - hydrostatic pressure is decreased.
2. Fluids from other formations may enter borehole causing problems.

Increasing Mud Density to Combat Problems

1. Will begin flushing permeable formations.
   a. will see a reduction in gas readings.

   b. will build a thick mud cake when pumps are off.

2. Will reduce drill rate.
   a. greater hydrostatic pressure.

   b. greater “hold down” effect on cuttings.

3. When drilling through permeable formations, may cause differential sticking.

Self-Check Exercises

1. What are four common borehole problems that can be recognized by the Logging Geologist?
   a. ______________________________
   b. ______________________________
   c. ______________________________
   d. ______________________________

2. What is the difference between lost circulation and filtrate loss?
   ____
   ____

3. When does lost circulation occur?
   ____
   ____
   ____

4. How can the Logging Geologist recognize that lost circulation is occurring?
   ____
   ____
   ____

5. What are four types of Lost Circulation Material?
   a. ______________________________
   b. ______________________________
   c. ______________________________
   d. ______________________________

6. List three ways in which lost circulation disrupts logging and evaluation procedures?
   a. ______________________________
   b. ______________________________
   c. ______________________________

7. What is the most common cause of stuck pipe?
   ____

8. In what types of wells is "key-seating" a problem?
   ____
   ____

9. How can the Logging Geologist identify borehole instability caused by shale problems?
   ____
   ____

10. How can the Logging Geologist identify borehole instability caused by evaporite problems?
   ____
   ____
   ____

11. What are some of the surface effects which could cause changes in the mud density?
   a. ______________________________
   b. ______________________________
   c. ______________________________
   d. ______________________________
   e. ______________________________

12. How can the Logging Geologist identify swabbing effects from the following formations?

    Permeable Formations: ______________________________

    ____

    ____

    Impermeable Formations: ____________________________

    ____

    ____

FWR - Geology Section

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

- Understand the importance of technical writing when preparing the Final Well Report
- Use outlines and writing aids to convey the geologic information in an organized manner
- Prepare an accurate geologic report from the information gathered at the wellsite
- Enter the geologic information into the correct Final Well Report format

Additional Review/Reading Materials

INTEQ Video Tape # 7 - *Logging Procedures*

Hicks and Valorie, *Handbook of Effective Technical Communications*, McGraw-Hill, Inc., 1989

Murry, Melba, *Engineered Report Writing*, Pennwell Publishing Company, 1969

Technical Writing - Techniques

The writing of the geology section of the Final Well Report (FWR) should be approached in much the same way as the Formation Evaluation Log. This log is organized and drafted to visually display a well-ordered geologic investigation of a particular well. The reporting of that project is usually undertaken with little or no preparatory organization and little regard to the rules of communication. We all realize that the “rules” are somewhat elastic, and no two Logging Geologists agree completely on all of them.

The first rule is to keep the reader in mind. From your daily communication with the client geologist, you will have a pretty good understanding of how much they know concerning well drilling, mud logging, etc. Keep the reader in mind when writing the FWR. Do not try and impress them with terms or unfamiliar words, they might obscure the important ideas.

Avoid writing “between the lines.” Many of us are so familiar with our work that we tend to omit key words or introductions which the reader needs for complete understanding. You should always ask someone else to read the section. If portions have to be re-read or if questions are asked, those portions should be re-worked.

Outlines

The Formation Evaluation Log and your worksheets provide very good outlines for your geologic analysis of the well.

During the course of the well, probably during the tour change, when you have a few minutes to think about what has happened, enter onto a pad, diary, or the worksheet items of importance which you may have omitted during the busy times. These may become important later on.

When writing the FWR, write within the framework of these outlines.

Paragraphs

The paragraph can be very useful or it can be an obstacle to the reader. These breaks should coincide with intentional changes in the trend of thought. Whether the paragraph is long or short is of secondary importance. Some may consist of only a few words, other of twenty sentences or more. Paragraphs are designed to help the reader. The reader should not be thrown off balance by a change in direction. In short, start a new paragraph whenever you wish to redirect the line of thought.

Topics for new paragraphs may include the evaluation of a new lithology type, a discussion of drill rate and gas analysis, etc.

Sentences

Sentences are the building blocks of the section. If they are poorly written the composition cannot be good, no matter how well planned or organized the section.

Remember, it is the writer who gets the praise or blame for the quality of the final product.

Below are a few examples of common errors which present themselves on the geology section.

- “All of the sandstones consist of medium to fine grains of quartz which are uniformly nonfriable” - (a quartz grain is never friable, the aggregate might be).
- “An upper massive sandstone consisting of massive sandstones 40-80 feet thick” - (awkward repetition).
- “Fault F-2 is an east-dipping fault which strikes essentially parallel to the . . .“ - (awkward repetition, why not: Fault F-2 dips east and strikes nearly parallel to the . . .).
- “ . . .lenticularity of the individual members renders lateral correlation virtually impossible.” - (a pompous statement of a simple fact, why not: The lenticular members are almost impossible to correlate).
- “Limy, calcareous sandstone” or “Porous, vuggy limestone” - (redundant words).
- “The well lies 560 FNL and 1025 FEL of Block 125" - (can a well lie?).

Word Usage

The wise use of an extensive vocabulary is not only in good taste, it is very practical. The geology section should not serve as a medium for a display of word knowledge, nor should it be so barren or repetitious of specific terms, that the meanings are vague or boring. The purpose of the geology section is to impart information to the reader. The more concise and exact, the better. Conciseness and precision can be achieved to a high degree by the search for the right word. Too often, we are content to use the first word that comes into our mind, even though it only approximates our thought.

Your best aids are an up-to-date dictionary and a glossary of geologic terms.

Possessive Case

It is generally better to use an “of” phrase than the possessive case when referring to inanimate subjects. For example:

“The surface of the cuttings is polished” - not “The cutting's surface is polished”

“The east limb of the anticline is faulted” - not “The anticline's east limb is faulted”

Punctuation

The meaning of a sentence may be made clear or obscure, depending on the punctuation used. The number of punctuation marks within a sentence is not in itself important. It is important, however, that punctuation be used for the purpose of clarity and ease of reading. If complex punctuation is required in order to ensure the reader's comprehension, then the sentence should be reworded or broken into two or more sentences.

Several examples include:

- “The interval consists of dark gray siliceous, silty shales; fine-grained, arkosic sandstones; and gray to black dolomitic, hackly limestones.”
- “Red, green and gray shales”
- “Fine red sandstone” (no comma between one color and another adjective)

Final Comments on Technical Writing

The most common question raised when dealing with the FWR is “I'm too busy and why bother with the technicalities so long as the material is correct?” The answer to that is two fold.

First, the objective of the geology section of the FWR is to convey the information as concisely and clearly as possible. Baker Hughes INTEQ does not expect a literary classic, but passably good grammar, sentence structure, and word usage is required to do justice to our service, the subject and your own standing as a professional geologist.

The second consideration is that you must keep in mind the reaction of the readers. Muddled, disorganized, repetitious writing not only frustrates the reader, but is liable to generate a lack of confidence in the technical competence of the service. Although the conclusion that poor presentation reflects equally shoddy work may be erroneous, it is a natural response.

You should realize that the FWR is of general interest to many departments of the client oil company, and many readers will review it, possibly several times. It is not only read, it is studied.

Technical Writing - Geologic Reports

Geologic Reports in the petroleum industry are concerned with following three aspects while drilling:

- the formations and an evaluation of those formations
- hydrocarbon data and the analysis of those hydrocarbons
- a lithologic summary of the rock types encountered during the course of the well

The report should also cover any factors which may affect the analysis, evaluation, and interpretation of those three aspects.

Formations

The first classification which must be established concerning formations is the age of the formation. This is normally accomplished by using the Era,Period, or Epoch, using a stratigraphic column

The formation is the most fundamental unit in lithostratigraphic classification. Formations are the basic lithostratigraphic units used in describing and interpreting the geology of a region.

With the above in mind, most formations will be named. The name may be known world-wide (Austin Chalk, Kimmeridge Clay), the same formation may have different names in different locales (Woodbine in Texas, Tuscaloosa in Louisiana), and some may be named for the microfossil content (Siphonina Davisi, offshore Gulf of Mexico).

It must be realized that a formation is only one part in the ranking of lithostratigraphic units. There are:

Supergroups A formal assemblage of related groups or groups and formations.

Groups Defined to express the natural relationships of associated formations.

Formations A body of rock identified by lithic characteristics and stratigraphic position.

Members A recognized entity within a formation which possesses characteristics distinguishing it from adjacent parts of the formation.

Beds Distinctive units whose recognition is particularly useful. It is the smallest lithostratigraphic unit of sedimentary rocks

Table 1:

Era	Period	Epoch
Precambrian (PE)		
Paleozoic (Pz)	Cambrian (E)	
	Ordovician (O)	
	Silurian (S)	
	Devonian (D)	
	Carboniferous (C)	
	Mississippian (M)	
	Pennsylvanian (|P)	
	Permian (P)	
Mesozoic (Mz)	Triassic (Tr)	
	Jurassic (J)	
	Cretaceous (K)	Upper Cretaceous (Ku)
		Lower Cretaceous (Kl)
Cenozoic (Cz)	Tertiary (T)	
	Paleogene (Pg)	Paleocene (Pc)
		Eocene (Eo)
		Oligocene (Ol)
	Neogene (Ng)	Miocene (Mi)
		Pliocene (Pl)
	Quaternary (Q)	Pleistocene (Ps)
		Holocene (Ho)

Recognizing a formation or formation top is usually done prior to the drilling of the well. This can be accomplished using seismic data, regional geologic literature or through correlation with nearby wireline logs or mud logs. The geologic structure of the area and the sedimentary environment of the formation will determine how accurate the correlation will be.

The information received from the client is their best estimate as to when the formation will be encountered during the course of the well. Careful analysis of the cuttings and drilling parameters will be the most accurate method to recognize the formation when it is penetrated by the drill bit.

When noting formation tops and formation names on logs and reports, there should be an introductory remark staring that all tops are based on wellsite analysis and are provisional. Confirmation of your assessment will take place during coring, wireline log runs, or formation (drillstem) tests.

Evaluation is mainly concerned with the structural and sedimentary setting of the formation and the geologic variations since the initial model was developed. Size (vertical thickness), Shape (lateral extent), Composition (lithology types), and Fluid Saturation will be affected by the formation's structural setting and depositional environment.

Structural Setting

Folds - symmetrical, asymmetrical, plunging, domes
Faults - normal, reverse, thrust, lateral
Inconformities - angular, disconformity

Depositional Environment

Continental - eolian, alluvial, lacustrine, glacial
Transitional - deltaic, coastal
Marine - shelf, slope, pelagic

Additional information about the formation, especially concerning the petroleum aspects, is whether the formation is considered to be a Source Rock, Reservoir, or Seal.

Source Rock	Kerogen Content - agal, liptinic, humic Maturation - diagenesis, catagenesis, metagenesis
Reservoir	Porosity - primary, secondary, effective Permeability - horizontal, vertical Fluid Migration - primary, secondary
Seal	Type - lithology, structural, sedimentary Characteristics - permeability, thickness, pressures

Hydrocarbon Data

Hydrocarbon fluid information deals with the types of hydrocarbons present (gases or liquids) and the relative amounts of each. Other gases (hydrogen sulphide, carbon dioxide, etc.) and fluids (fresh or saline water) can be mentioned under this heading since they will impact exploitation capabilities.

Various gases can be found in most formations. The amounts are recorded in percentages (percent/volume) or parts-per-million.

One type of gas, gas hydrates, occurs in specific temperature-pressure conditions, normally in cold/arctic climates and deep water/oceanic deposits.

Hydrocarbon Gases

Paraffins (C_nH_{2n+2}) - methane, ethane, propane, butanes (iso and normal), pentanes (iso and normal)

Non-hydrocarbon Gases

Inert - helium, argon, radon
Acidic - nitrogen, hydrogen, carbon dioxide, hydrogen sulfide

Liquids also occur in most formations. Most oils are lighter than water. The density of oil is expressed as the difference between its specific gravity and that of water. Normally, expressed in API gravity units, where:

$$\text{API Gravity} = \frac{141.5}{\text{S.G. at } 16°\text{C } (60°\text{F})} - 131.5$$

Hydrocarbon Liquids

Oil - paraffinic, naphthalenic, aromatic
Characteristics - fluorescence (color, quantity, intensity), stain, odor, cut, cut fluorescence

Non-Hydrocarbon Liquids

Water - saline, fresh
Most gases and liquids will occur together in varying combinations and percentages.

Lithologic Summary

Throughout the course of a well, a detailed description of cuttings samples will be placed on the worksheet and Formation Evaluation Log. These lithologic descriptions will compliment the formation and hydrocarbon summaries. The report should contain summaries of:

Lithology Type

Clastic - sandstone, siltstone, shale, sand, clay
Carbonate - limestone, dolomite
Other - igneous, metamorphic

Classification Dunham's - mudstone, wackestone, packstone, grainstone, boundstone, crystalline

Color Sample - wet, majority, grain, matrix, cement, minerals
Type - primary color, multi-colored, variegated

Hardness Induration - unconsolidated, consolidated, cemented

Texture Size - rudaceous, arenaceous, argillaceous
Shape - sphericity, roundness
Sorting - size & shape comparison, size modality

Matrix - nature, percentage
Cementation - nature, percentage

Visual Porosity
Type - intergranular, vuggy, moldic, fracture
Determination - cuttings, cuttings gas, lost circulation, free grains

Accessories Types - macrofossils, microfossils, minerals
Amount - trace, common, abundant

In areas where there were no cuttings samples or poor quality cuttings, those should also be summarized as to the reason and possible consequence to future operations. Where large amounts of contaminants are seen, not those added to the drilling fluid, those should be noted, with accompanying remarks.

Sample Quality
No Samples - lost circulation, large washout, bed load
Poor Samples - recycled cuttings, large washout, bit floundering, going into solution, large amounts of LCM, lost circulation

Contaminant Metal Shavings - bit wear, casing wear, drillstring wear
Cavings - hole washout, pressure increase, hole stability

The report should make reference to the two types of lithologies plotted on the Formation Evaluation Log. The “percentage” lithology is a report of the amount of cuttings in the sample as a percentage of the total. The “interpretative” lithology is an attempt to filter out background material and indicate only the lithology being drilled at a specific depth. These two lithologies are complimentary, and useful in evaluation.

Conclusion

The Geology Section of the FWR must incorporate the information obtained on the formations, hydrocarbons, and lithologies to present a complete geologic evaluation of the rock drilled.

The Logging Geologist's interpretation, present on the worksheets and Formation Evaluation Log, should be summarized in the FWR. A professional report will justify to the client the professional service performed by Baker Hughes INTEQ.

INTEQ's Final Well Report

Introduction

The Geology Section should open with an introduction containing a brief description of the geology of the area, the well location in respect to the area's geology, target(s) location, expected depths, lithology and formation names, if known. Correlation wells, if any, should be included.

The types of samples, sample interval and the sieve sizes used when washing the cuttings should be stated in the introduction. If an oil-based drilling fluid was used during the well, cleaning procedures should be stated, as well other pertinent affects of an OBM.

Baker Hughes INTEQ's gas analysis system should be explained. The type of detectors involved and the output values, especially if "gas units" are used, require explanations.

Since the Geology Section will be a summary of events, the introduction should close with a statement saying that if detailed inspection is required, the Formation Evaluation Log should be viewed.

Main Body

The main body of the Geology Section should be subdivided into sections based on lithology, formations, casing points, or some other distinguishing characteristic. It is advisable not to make the subdivisions too long because the descriptions and analysis becomes too generalized.

The heading of the sections will state the depths which the section covers. The units, feet or meters, should be the units which the Formation Evaluation Log is based upon. If the well is a directional well, include both vertical and measured depths. If the formation name(s) are known, they can be included in the heading.

Following the section heading, there should be a detailed, brief description of the lithologies. Begin with the major lithology, followed by minor lithology types. The description should follow the "standardized" format which the cuttings were described in. A geologic dictionary will be helpful in the spelling of the terms.

Any effects the lithology had on the drilling parameters should be noted in this section (i.e. slow ROP in the hard streaks, increased torque in the shale sections, etc.). Any borehole problems concerning lithology should also be mentioned (i.e. lost circulation in fractured limestones, sloughing shales in such-and-such formation, etc.).

This section should be a descriptive narrative of the "interpreted lithology." Using the cuttings lithology and descriptions to supplement the narrative.

The narrative should not be so detailed as to obscure the important characteristics. Be selective and report what is important.

A brief hydrocarbon show analysis should be included, if shows were present in the section. Mention the fact that a more detailed description can be seen on the “show report”.

Following the narrative, the Rate of Penetration and Gas (Background, Total, and Chromatograph) values should be summarized, in table format. This should include the maximum, minimum and average values. If Gas Ratios or Gas Normalizations were done, these should also be included.

Also include items that affected the drilling practices or show analysis, which might be important at a later date. Examples are pit gains, poor or lack of returns, duration of drill breaks and fluctuations in torque.

This section format should be repeated as required, keeping the information brief, but thorough and accurate. If details are necessary for a full understanding of the lithology, show, etc., then the details should be included.

Summary

A geologic summary of the well's lithology and show intervals can be included to highlight the information in the Geology Section.

It should be emphasized that the information on the worksheets, logs and Final Well Report should be very similar, if not identical. Many times the client will cross-check the information on these reports to ensure consistency and as part of their quality control measures.

Self-Check Exercises

1. What are two important technical writing rules which should be borne in mind when writing the Final Well Report?
   a. ______________________________
   b. ______________________________

2. List two outlines which should be followed when preparing to write the Final Well Report?
   a. ______________________________
   b. ______________________________

3. What two aids should the Logging Geologist have available whenever writing the Final Well report?
   a. ______________________________
   b. ______________________________

4. List three pieces of information available to the Logging Geologist to assist them in picking formation tops?
   a. ______________________________
   b. ______________________________
   c. ______________________________

5. What four geologic parameters are affected by a formations structural setting and depositional environment?
   a. ______________________________
   b. ______________________________
   c. ______________________________
   d. ______________________________

6. What are the types of non-hydrocarbon fluids that can be present in a formation?
   ____
   ____

7. What two lithology plots provide complimentary information to lithologic descriptions in the Final Well Report?
   a. ____
   b. ____

8. What type of sample information should be included in the "Introduction" if the geology section of the Final Well Report?
   ____
   ____

9. Why is it important not to make the subdivisions within the "Main Body" of the geologic section too long?
   ____
   ____

10. What information, in addition to lithology, should be included in the "Main Body" section of the Final Well Report?
   ____
   ____

Chapter 11

Log Quality Control

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

- Understand the importance of quality control in the production of the Formation Evaluation Log
- Apply quality control measures to the collection of information before it is entered onto the Formation Evaluation Log
- Ensure that all information on the Header, Main Log, and Supplemental Sheets is accurate and entered into the correct track
- Ensure that the final product of the logging unit has a professional appearance

Additional Review/Reading Materials

INTEQ Video Tape #7 - *Logging Procedures*

INTEQ, *Drill Returns Logging Manual*, 1994

Log Headings

The first portion of the log that the client notices is the log heading. If the log is the product that Baker Hughes INTEQ sells, then the heading is the label. Like any label, it must be both informative and attractive. To continue with this analogy, the label must contain many ingredients concerning the well.

The SPWLA has attempted to standardize log sizes (8.5-inch and 11-inch), and mud logging companies use the has two different log headings. The 8.5 inch heading is the same size as electric log headings, and may be the size of future logs, especially computerized logs.

The heading is an extremely important part of the log and should be treated as such. It should be kept up-to-date, be neat and professional in appearance. It should be updated in the same manner as it was started. It should also be completed in the same manner as the log. Whenever it is updated, an updated copy should be sent to the client, and, last but not least, every log has its own heading.

Below are some points that may be useful in filling out the log headings (see Figures 11-1 and 11-2 for examples).

Company This is the oil company's name. Use capital letters and spell out the complete name. If you use abbreviations, use the ones standardized by the oil company.

Well This is the complete well name, e.g.,

Offshore	Onshore
OCS-G-1234 #2	Billy Bob #2

Field This is the complete field name, e.g.,

Offshore	Onshore
East Cameron Block 125	North Appleby Field

Location/Region

For onshore wells, this is the smallest regional unit which the well is in, and the overall regional name. Offshore, give the sea area in which the well is located, e.g.,

Offshore	Onshore
Offshore Congo	Harris County, Texas

Coordinates These are usually latitude and longitude reference points. Land wells may use section, township, and range units, e.g.,

82 deg 34 min 56.6 sec South (or North)
21 deg 14 min 27.4 sec West (or East)

API Well Index Number
When this information is supplied by the oil company, enter it on the heading.

Spud Date This should be provided by the oil company, or can be obtained from the wellsite drilling records. Dates should be formatted as follows:

Day	Month	Year
24	October	1987

Logging Start Date/Depth
This should be the date on which the first downhole information was recorded. The log start depth should be the depth that the first logged information came from.

Logging End Data/Depth
As above, the end depth and date should be those of the deepest information on the log. The date should include any additional time on the rig for any non-drilling activities which were monitored and data recorded.

Total Depth This is the final depth of the well. If it was a directional well, then both measured depth (MD) and true vertical depth (TVD) should be included.

Elevation All well information should be referenced from two points*. Always use the shallower depth first. The preferred abbreviations are:

From	To
RKB - Rotary Kelly Bushing	MSL - Mean Sea Level
DF - Drill Floor	GL - Ground Level
	SB - Sea Bed

* Do not use the term “Mud Line” (ML)

Contractor This is the drilling company or the company contracted to perform the drilling operations.

Rig/Type Onshore, the rig type is normally designated as “Rig 86."

Offshore, the rig type can make a significant contribution to the drilling procedures and progress. If the rig name is too long to allow the rig type to be written in full, use the following:

Drillship	D.S.	Jackup J.U.
Semisubmersible	S.S.	Drilling Barge D.B.
Platform	Name of the platform	

Casing/Hole Sizes

When compiling casing and hole sizes, information prior to the logging unit arrival can be obtained from the company man's records.

Fractions should not be used; use the decimal equivalent. When starting, plan the spacing to allow for alignment of later sizes and depths; the columns should be right justified.

Mud Types Mud type has a major effect on the cuttings condition, and the magnitude and mode of appearance of gas shows. A complete record of mud types and depths is necessary for correct evaluation of the information.

Lithology Symbols

Whenever hand drafted lithology is present, a corresponding lithology symbol should be drawn in the block next to the typewritten lithology. Computerized versions (i.e. RockIT/ Logit) should enter the symbol/ character used in the cuttings lithology column. The following symbols are most commonly used:

- The traditional brick patterns for limestone and dolomite
- Cross hatching for anhydrite and gypsum
- Perpendicular tic-tac-toe for halite
- Solid black for coal and lignite
- Empty block or an elongated S for clay
- Dashes for shale
- Parallel lines with a dot for siltstone
- A mixture of siltstone and sand for sandy siltstone
- A dot for sand or sandstone
- Circles for conglomerate

- Empty triangles for chert
- An “X” for igneous rocks
- An “M” for metamorphic rocks

If an Interpreted Lithology is not required, then the standard symbol should be placed in the appropriate box.

Several empty boxes are available for additional types of lithology or accessories that may need clarification. The appropriate symbols for accessories can be found using the screens in RockIT and Logit.

Log Scale The log scale should be in the form of a ratio. The most common log scales are:

1" = 100 ft - 1:1200	1" = 200 ft - 1:2400
2" = 100 ft - 1:600	1" = 250 ft - 1:3000
5" = 100 ft - 1:240	

Unit The unit number must be followed by the unit type. Remember that ALFA, GEMDAS and DrillByte are acronyms and must be in upper-case characters.

Unit type: Standard or Std
DMS
DrillByte

Log Prepared By

Credit on the log should be reserved for those who have made a major contribution to the log. Computer operators should not be listed on the Formation Evaluation Log, nor should Logging Geologists be listed on any computer related logs. Trainees and temporary personnel should not be listed. The Unit Superintendent's decision is final.

INTEQ Log Suite

Put an “X” or type in the appropriate boxes for ALL logs being produced, on ALL log headings.

Abbreviations/Symbols

In this section, it will be necessary to put in the abbreviations used in the engineering sections of the log. Use the appropriate symbols and abbreviations for casing seat, coring, testing, wireline logs, etc. Avoid over-crowding.

Data Storage Media

The 8.5 inch log heading has a section for the types of media on which we store or illustrate data from the well. For example:

Chart Recorders	Core Reports
Sidewall Core Reports	DST Reports

Or any other report, other than an Baker Hughes INTEQ preprinted form.

Other Services These include any additional services supplied by Baker Hughes INTEQ.

Delta Chlorides	P-K
Autocalcimeter	Data Transmission
Shale Factor (CEC)	QFT

Remarks This is any information that may help the reviewer of the log in evaluating the well.

Change to Oil-Based mud at 10,000 ft
Sidetrack from 9700 ft (see sidetrack log)
Stuck pipe at 9800 ft
Unit upgrade to Integrated/MWD at 10,000 ft

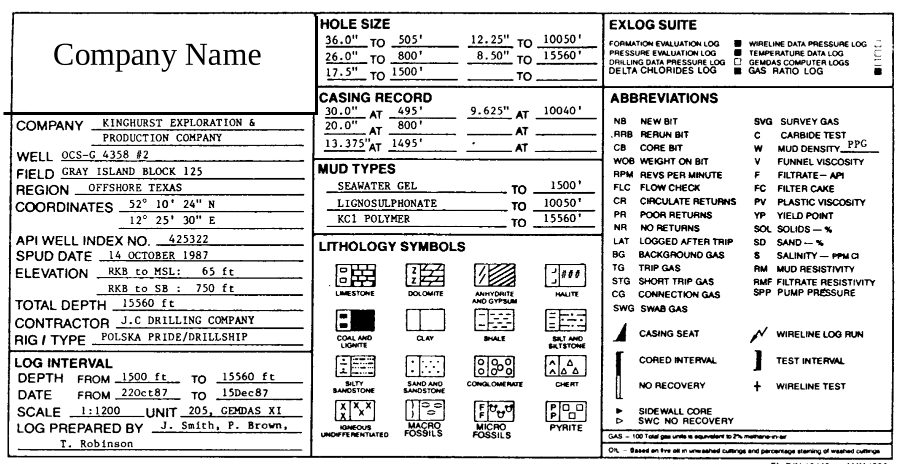

Figure 1-1: 11-inch Log Heading

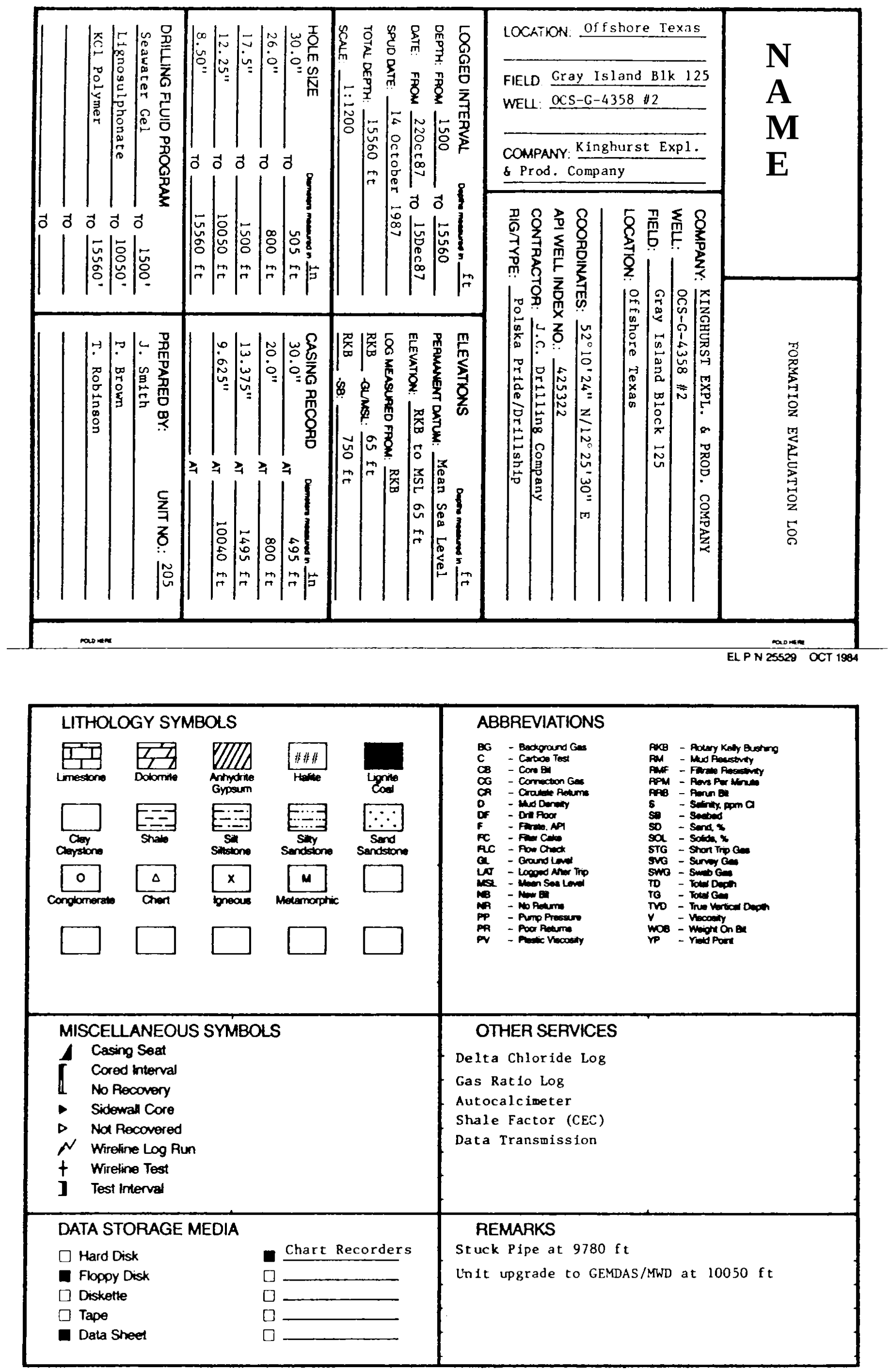

Figure 11-2: 8.5-inch Log Heading

Formation Evaluation Log

Preparation

Regardless if the drafting method, always ensure that the drafting area is clean and clear of coffee cups, ashtrays, etc. If hand-drafting, use a piece of paper or paper towel to protect the log while your drafting hand rests on it. Drafting materials should be readily available, pens bevel-edged ruler or triangle, single-edged blade for corrections, transfer sheet for log symbols, etc.

If entering the information into a computer, all the information should be at hand (from the worksheet). You should have all the correct abbreviations and format procedures near-by for reference.

Drill Rate Column

The method of calculation (ft/hr, m/hr, min/ft, min/m) should be displayed in the column, along with the scale. The scale should be constructed so that the drill rates increase from right to left. Linear, logarithmic, or “pseudo-logarithmetic” are all acceptable. The scale chosen should be one that makes the best use of the whole column without recourse to scale changes or back-up scales. Should a back-up (or wrap-around) scale be necessary, the normal back-up is “x10”. If scale changes are necessary, then a prominent note should be made illustrating the previous scale and the new one.

The drill rate curve can be drafted either in a histogram fashion or as a vector plot. Drill rate is normally calculated and plotted every five feet (two meters). Coring intervals are plotted at one foot intervals.

The casing shoe symbol should be placed inside the right margin of the penetration rate column. Visual porosity (if it doesn't have its own column) should be marked by diagonal strokes of appropriate length.

The date is recorded at the left-hand edge of the column, using the form “day/month.” The year does not have to be used.

- 26/11 for November 26th

Drilling information which affects the drill rate should be included at regular intervals. The most important are WOB, RPM and SPP. The pump strokes, SPM, can be added if desired.

Radical changes in the drilling parameters should be noted at the depths where they occur. For example:

WOB 35 Klbs Incr WOB
RPM 100 or

SPP 2500 Decr RPM
SPM 90

Bit information is recorded at the depth the bit put into the borehole. The bit number and name is entered first, and when the bit is pulled, the run information is entered. For example:

NB#9 HTC J33
565 ft 46 hrs

The following abbreviations are used for bit data:

NB	new bit	RRB rerun bit
CB	core bit	RRCB rerun core bit
ft or m	feet or meters	hrs hours

Intervals logged after trip (LAT) and intervals circulated out (CR) are also noted in the drill rate column. Flow checks should be noted using “FLC” followed by (+) denoted a positive flow check or (-) for a negative flow check.

Core Column

Block in a line approximately 2mm wide for the whole core recovered. Continue the line, but do not block-in, for any core not recovered; this is always assumed to be from the bottom of the core. Sidewall cores are also entered in this column, at appropriate depths. Filled triangles representing the cores recovered are entered at representative depths. Empty triangles are used for “no recovery”.

Depth Column

The depths, at the appropriate scale, should be aligned to exactly bisect the depth line on the log. Try to avoid depth markings which overlap at the top and bottom of the sheet, but if this is unavoidable, be sure that they will align properly when the log is spliced.

Test Column

Entry is similar to that of cored intervals. However, the whole tested interval is blocked in on the right side of the column. Wireline tests (FITs, RFTs, etc.) should be annotated with the cross symbol.

Cuttings Lithology Column

This column is usually filled using standard symbols. Where hand-drawn cuttings lithology is requested, great care should be taken to achieve consistency and neatness.

The standard lithology symbols must be represented on the log. The correct order, going from right to left is*:

Right Margin

Metamorphic Rocks
Undifferentiated Igneous Rocks
Volcanic
Chert/Flint
Conglomerate/Gravel
Sandstone/Sand
Silty Sandstone
Siltstone/Silt
Shale
Clay/Claystone
Coal/Lignite
Halite Anhydrite/Gypsum
Limestone
Dolomite

* if the first rock is not present, then move to the next, until the full 100% of the sample has been entered.

Left Margin

Convention states that sand, sandstone and conglomerate be separated from the other lithologies by a line to highlight those classes. Separating all lithologies by a line is acceptable if done neatly.

If for some reason there are no returns, then NR (no returns) should be placed over the interval. For poor returns a PR is used.

Oil Evaluation Column

Block in the appropriate evaluation. It is acceptable to use part divisions to indicate degrees of the show.

Continuous Total Gas and Cuttings Gas Column

Curves should be carefully evaluated before they are drawn onto the log. Remember that chart recorders are time constant, while the log is drawn against depth.

Try to incorporate on the log as much of the peak and trough detail as possible. The Continuous Total Gas curve is drawn as an unbroken straight line in proportion with the curve.

Where gas goes offscale at 2% (100 units), it should be brought back onto scale using x10 as the back-up scale. Start the back-up curve at exactly the depth that the xl curve goes offscale. The curve should commence at 10 units and not at 0 units. The reverse is true when the gas drops back below 2% (100 units). The area of the curve representing the x10 scale should be cross-hatched from left to right with equally spaced lines. If there is a need for a second back-up scale of x100, then cross-hatch from right to left on top of the x10 cross-hatching, which will result in a cross-pattern on the x100 curve. The x10 (and x100) curves should be annotated as such.

When a computer is drafting the log, the scale can be set to read from 0 to 100 percent. Remember though, when the gas is measured as equivalent methane-in-air (EMA), more than 100% gas can be measured. A back-up scale will still be required.

The Cuttings Gas curve is drawn in square-plot, using a broken line. Take care to ensure that the line is drawn at right-angles at each reading.

When produced gases are recorded, they should be aligned under one another, except where this would obscure the total gas curve. The following abbreviations are used:

TG	Trip Gas	STG	Short Trip Gas
CG	Connection Gas	SVG	Survey Gas

Chromatograph Column

This is also drawn as a square-plot. Again take care that lines are kept parallel and that lines are drawn at right-angles for each reading. Think before plotting, so that it will be possible to plan where lines cross, thus avoiding too much confusion. Where values almost coincide it is permissible to slightly increase or reduce the values to obtain more clarity and definition.

It is generally acceptable to plot on 10 ft intervals, but show variations when they occur. Near the top of each log sheet, the chromatograph curves should be labeled by a number representing the gas (e.g. 1 for C1, 2 for C2 etc.). The re-appearance of a gas onto the plot should also be labeled in this way, otherwise it is not necessary to re-label the curves again on the sheet unless confusion would result from not doing so. Peaks in the chromatograph curves should correspond to peaks in the Continuous Total Gas curve.

If the values for the parts-per-million go off scale (e.g. greater than 100,000 ppm), the line should be drawn to the edge of the column and the value entered below the line (i.e. 125K ppm C1). This should continue until the gas value returns on scale.

Cut Column

As with the Oil Evaluation column, this is a “quick look” evaluation. Details concerning the cut should be noted in the Lithology Description and Remarks column. Block the column in the same manner as the Oil Evaluation column.

Miscellaneous Column

This column can be used for plotting calcimetry, shale density, gas ratios, etc. The E-log flash can also be entered in this column.

Interpreted Lithology Column

This column is not on the hand-drafted log sheet. Instead, marks within the Remarks column indicate where the logging geologist should draw in the column; if interpreted lithology is to be included in the log, draw in the line on the reverse side of the log sheet. The column heading can be obtained from transfer sheets. All lithology entered in this column should be ink-drafted using the recommended Baker Hughes INTEQ lithology symbols shown on the Heading.

Computer-drafted logs may have this column in the format. If not, it can be added as with the other columns.

Remember that this column is interpreted lithology as opposed to cuttings lithology. While cuttings lithology is intended to portray the actual lithology and percentages seen in the cuttings sample, the interpreted lithology permits the logging geologist to use other data such as drill rate, gas, etc. as well as cuttings lithology, to interpret the actual rock being cut. The two columns will therefore not be identical.

Lithology Description and Remarks Column

The amount of sample used in the cuttings gas analysis should be noted on the first sheet of the log, suitably spaced and boxed:

Using 100 ml unwashed sample

Lithology descriptions must follow a logical order as outlined below:

rock type
classification (if carbonate)
color
hardness
grain size
grain shape or texture, as appropriate
sorting
cementation or matrix
visual porosity

accessories or inclusions
show parameters

All abbreviations must conform to the SPWLA/AAPG standardized abbreviation format. Any word not listed must be spelled out in full. Punctuation is also standardized as follows:

- capitalize the initial letter of each rock type
- put a comma after each item of description
- new line for each rock type
- use <u>no</u> full stops(periods) at end of description
- do not use A/A (as above) in the description

When describing a lithology, put yourself in the place of the geologist who will read it. Make the description readable and useful, not just a "filler" for the column. The standardization of abbreviations is essential if the reader is to understand your description. More than anything else on the log, you are being judged as a geologist on your lithologic descriptions.

Record mud checks and carbide information on the log at least once per day unless a notable change requires this sooner. Mud weight and viscosity should be noted more frequently, particularly where drill rates are high. Remarks of this type must be centered and boxed within the column. Ensure that the box is squared within the column, with horizontal and vertical lines paralleling the grid on the log. When using an oil-based drilling fluid, also include the oil/water ratio and the electrical stability (ES) in the mud report.

Deviation surveys should be handled similarly whenever they are run. Drift surveys require only inclination (i.e. 0.5^o), while directional surveys require azimuth, inclination, measured depth and vertical depth. Horizontal wells may require displacement.

When wireline logs are run, make a note of the logs that were recorded. Do not name the wireline company, it is sufficient to state "Run wireline logs at 4790 m", followed by the log abbreviations.

Casing information is entered as "20 inch casing run to 100 m". This information should line up with the casing symbol in the Drill Rate column.

If a positive flow check is recorded, the following information is required:

SIDP (Shut-in Drillpipe Pressure, in psi)
SICP (Shut-in Casing Pressure, in psi)
Gain in Pits (barrels)

Carbide lag information is entered in this column whenever it is performed. The information recorded is:

Carbide Gas (in percent)
Lag Strokes
Funnel Viscosity of Return Mud

Core and Drill Stem Tests should be noted here, though full descriptions should be made on supplemental sheets that will be spliced at the end of the log. For example:

Core from 10500 ft to 10530 ft
Recovered 85%, see Core Report

DST from 11500 ft to 11580 ft
see DST Report

Summary

The logging crew should ensure consistency throughout the log, with no discernible changes due to personnel changes. The information that is put on the log must be accurate and supported by the worksheet, that must be completed fully.

Make the log as comprehensive as possible without losing its readability. Remember the log is the main product of the logging unit and is used to judge the job being done, and the Logging Geologists performing the job. Each logger's name appears on the Header, and the log is a reflection of the quality of their work. If the crew feels that the log sheet does not accurately reflect the quality of their work, either through lack of adequate data, or lack of neatness, then the log sheet should be redrafted to produce the best product possible.

Self-Check Exercises

1. How are dates formatted on the log heading and Formation Evaluation Log?

   ____

   ____

2. How many reference points should appear on the log heading?

   ____

   ____

3. What is the normal back-up/wrap-around scale for the drill rate column on the Formation Evaluation Log?

   ____

   ____

4. What drilling parameters should be included in the drill rate column?

   ____

   ____

5. List three circulation procedures that should be annotated in the drill rate column?

   a. ____

   b. ____

   c. ____

6. What types of “tests” are entered into the Test Column?

   ____

   ____

7. What is placed in the “Cuttings Lithology Column” if there are no returns, due to lost circulation?

   ____

   ____

8. Explain how a computer-drafted log with a gas column scaled from 0 to 100% will require a back-up scale?

    ____

    ____

9. How often should mud checks and carbide information appear in the Remarks Column?

    ____

    ____

10. What additional information should appear in the mud report, when an oil-based mud is being used?

    ____

    ____

11. What information concerning directional surveys is required for the log?

    ____

    ____

12. Is it necessary to include the name of the wireline company when entering wireline information in the Remarks Column?
    Yes No

13. Where a full core reports and DST reports placed on the Formation Evaluation Log?

    ____

    ____

14. Which names appear on the header of the Formation Evaluation Log?

    ____

    ____

15. List two occasions when the Formation Evaluation Log will have to be redrafted?

    a. ____

    b. ____

Return Exercises

1. List some instances when it would be advisable to discuss with the Drilling Superintendent/Company Man, the procedures for using tracers for determining actual lag-time.
   a. ____
   b. ____
   c. ____

2. List and explain, using several examples, how cuttings can act with the drilling fluid during the cutting's transport to the surface.
   a. ____
   b. ____
   c. ____

3. Explain how the Logging Geologist's sample description can be used by the oil company to determine reservoir characteristics.
   a. ____
   b. ____
   c. ____

4. It is generally assumed that if the core recovery does not equal the cored interval, the missing interval is from the bottom, unless there is additional evidence to suggest otherwise. What would you consider such “additional evidence” to be?
   a. ____
   b. ____
   c. ____

5. If turbulent flow has the most efficient cuttings carrying capacity, why isn't it used as the optimum flow regime in the annulus?
   a. ______________________________
   b. ______________________________
   c. ______________________________

6. What parameters would the Logging Geologist have to take into account (when extrapolating from a table) to determine the surface pressure loss coefficient, when using a top drive instead of a kelly (use 5 inch, 19.5 lb/ft, drillpipe as an example)?
   a. ______________________________
   b. ______________________________
   c. ______________________________

7. Using the standard dull bit grading form, describe the condition of bit #15.

BIT# 15NAME: HTC ATJ-11IADC CODE: 437XSIZE: 12.25

Cutting Structure Inner	Cutting Structure Outer	Major Dull Char.	Location	Bearings Seals	Gauge	Other Dull Char.	Reason Pulled
2	6	BT	H	E	O(3)	WT	PR

   a. Column 1: ______________________________
   b. Column 2: ______________________________
   c. Column 3: ______________________________
   d. Column 4: ______________________________
   e. Column 5: ______________________________
   f. Column 6: ______________________________
   g. Column 7: ______________________________
   h. Column 8: ______________________________

8. Using the following information, fill in the dull bit grading form for bit #16.

Upon examination of bit #16, it was noticed that there was an excessive amount of fluid erosion on the nose of the bit. This erosion resulted in all of the inner PDC's and half of the outer PDC to be lost. The gauge pads on the bit were intact. The bit was pulled because the well had reached casing point.

BIT# 16NAME: CHRST R535IADC CODE: M313SIZE: 12.25

Cutting Structure Inner	Cutting Structure Outer	Major Dull Char.	Location	Bearings Seals	Gauge	Other Dull Char.	Reason Pulled

9. Based on the Overburden Gradient equation, what are the units of measurement for overburden gradient?
   a. ______________________________
   b. ______________________________
   c. ______________________________

10. How can the Logging Geologist assist in the detection and prevention of stuck pipe problems?
   a. ______________________________
   b. ______________________________

11. If a positive flow check (FLC +) is occurring due to lost circulation, what should be included in the “Remarks Column” on the Formation Evaluation Log?
   a. ______________________________
   b. ______________________________
   c. ______________________________

12. What types of tracers can be used when an oil-based mud system is being used?
   a. ______________________________
   b. ______________________________
   c. ______________________________

13. What volumes must be known before accurate pill spotting calculations can be made?
    a. ____________________
    b. ____________________
    c. ____________________

14. Why does the driller pump a “slug” prior to coming out of the hole?
    a. ____________________
    b. ____________________
    c. ____________________

15. How do the calculations for hole-fill differ between “dry” and “wet” trips?
    a. ____________________
    b. ____________________
    c. ____________________

16. Given the following set of surveys, calculate the true vertical depth at 10,000 ft (MD).

MD	Incl	TVD
9700.0	24.2	9650.0
9800.0	25.5	
9900.0	26.8	
10000.0	26.0	

17. Prior to drilling, what are the four constituents of subsurface formations?
    a. ____________________
    b. ____________________
    c. ____________________
    d. ____________________

18. The drill rate will vary due to many factors. Name five of the more common ones.
    a. ______________________________
    b. ______________________________
    c. ______________________________
    d. ______________________________
    e. ______________________________

19. List six factors which affect the amount and severity of interaction between drill cuttings and drilling fluid.
    a. ______________________________
    b. ______________________________
    c. ______________________________
    d. ______________________________
    e. ______________________________
    f. ______________________________

20. What three step process is involved in sample solids extraction?
    a. ______________________________
    b. ______________________________
    c. ______________________________

21. Why are oil-based drilling fluids preferred for drilling evaporite and argillaceous sediments?
    a. ______________________________
    b. ______________________________
    c. ______________________________

22. During coring, list five factors that will affect the drill rate?
    a. ______________________________
    b. ______________________________
    c. ______________________________
    d. ______________________________
    e. ______________________________

23. What are three major disadvantages of conventional coring?
    a. ______________________________
    b. ______________________________
    c. ______________________________

24. Oriented cores are run for several purposes. List four.
    a. ______________________________
    b. ______________________________
    c. ______________________________
    d. ______________________________

25. How does a “non-Newtonian” fluid differ from a “Newtonian” fluid?
    a. ______________________________
    b. ______________________________
    c. ______________________________

26. What types of gases in the returning drilling fluid contribute to the magnitude of gas readings?
    a. ______________________________
    b. ______________________________
    c. ______________________________

27. A logger noted that the background gas from a sand was lower than that associated with an adjacent shale. The sand was clean and uncemented. Drilling proceeded with a ECD which was two pounds per gallon higher than the pore pressure. No increase in mud chlorides were noted. What dynamic situation may have occurred as the sand was drilled?
    a. ____
    b. ____
    c. ____

28. Given the information from the previous question, what phenomena might occur once the drill collars are drilled past the sand body?
    a. ____
    b. ____
    c. ____

29. Using Baker Hughes INTEQ's gas ratio analysis technique, evaluate the following gas show.
    a. C1 = 13316 ppm ________ C4 = 284 ppm
    b. C2 = 4272 ppm _________ C5 = 88 ppm
    c. C3 = 1041 ppm

30. When evaluating a “show” using Baker Hughes INTEQ's gas ratio technique, what factors other than the gas ratios should be considered?
    a. ____
    b. ____
    c. ____

31. What evaluation “tools” should be used when you are attempting to identify oil/gas/water contacts?
    a. ____
    b. ____
    c. ____

32. What are the primary reasons for accurately grading bits?
    a. ____
    b. ____
    c. ____

33. Referring to the Hughes Tool Company “Bit Selector,” determine the IADC code for a HTC “R4” bit. State the special characteristics of this bit.
    a. ____
    b. ____
    c. ____
    d. ____

34. A TSP bit has been graded. Using the following information, describe the wear on this bit.
    6,6,RO,N,X,I,LT,TD
    a. ____
    b. ____
    c. ____
    d. ____

35. What is the usual cause of gauge wear on fixed cutter bits?
    a. ____
    b. ____

36. What are some causes for a broken cone on a roller cone bit?
    a. ____
    b. ____
    c. ____
    d. ____

37. What situations can lead to off-center bit wear?
    a. ____
    b. ____
    c. ____
    d. ____

38. What can be determined about the selection of bit #11?
    a. Bit #11: _____________ 5-1-7-X
    b. Bit Wear:__ 0,0,NO,A,E,I,LN,PP
    c. ____
    d. ____
    e. ____
    f. ____

39. How does tooth grading vary between mill tooth and insert bits?
    a. ____
    b. ____
    c. ____
    d. ____

40. Determine the overburden pressure in pounds per gallon at 5000 feet, using the following information.
    a.

Interval (feet)	Lithology Density (gm/cc)	Water_____ Rock Density (gm/cc)
0 - 250	1.10	
250 - 2000	1.80	
2000 - 3000		2.05
3000 - 4500		1.98
4500 - 5000		2.00

41. What variables are taken into account when determining hydrostatic pressure?
    a. ____________________
    b. ____________________
    c. ____________________

42. What pressures contribute to the total pressure being exerted on the bottom of the borehole while circulating?
    a. ____________________
    b. ____________________
    c. ____________________

43. What factors affect annular pressure losses?
    a. ____________________
    b. ____________________
    c. ____________________

44. What conditions will affect the magnitude of aquathermal pressuring, and will limit it as an abnormal pore pressure generating mechanism?
    a. ____________________
    b. ____________________
    c. ____________________

45. What situations might occur in a geopressured zone where no fluid is expelled during compaction?
    a. ____________________
    b. ____________________
    c. ____________________
    d. ____________________
    e. ____________________
    f. ____________________

46. What is the general procedure for solving lost circulation problems?
    a. ______________________________
    b. ______________________________
    c. ______________________________

47. What are the usual causes of failure to control lost circulation?
    a. ______________________________
    b. ______________________________

48. What can be done to free drill pipe that is differentially stuck?
    a. ______________________________
    b. ______________________________
    c. ______________________________

49. In which direction is drill pipe torqued to back-off a tool joint before an explosive charge is detonated?
    a. ______________________________
    b. ______________________________

50. What indications of well bore instability problems can be attributed to shale in a zone that is in an underbalanced state?
    a. ______________________________
    b. ______________________________
    c. ______________________________

51. You have been drilling with a funnel viscosity of 35. Suddenly, there is a total lack of cuttings coming across the shale shakers and the funnel viscosity has risen to 105. What is the most likely cause of these changes?
    a. ______________________________
    b. ______________________________
    c. ______________________________

52. What problems may occur when the mud weight is raised to combat hole problems?
    a. ____________________
    b. ____________________
    c. ____________________

53. Why is an accurate and complete unit diary important when you are writing the final well report?
    a. ____________________
    b. ____________________
    c. ____________________

54. What are formations likely to be named after, in an offshore depositional basin, when the formations do not outcrop at onshore locations?
    a. ____________________

55. Why should non-alkane gases, such as carbon dioxide and hydrogen sulfide, be mentioned in the geological section of the final well report?
    a.

56. What are distinguishing characteristics of a well that can provide logical subdivisions in the geology section of the final well report?
    a. ____________________
    b. ____________________

57. The formation evaluation log has a scale of 1:6000, how many feet are equivalent to the inch of log?
    a. ____________________
    b. ____________________

58. How should a sidewall core that is not recovered be annotated on the formation evaluation log?
    a. ____________________
    b. ____________________

59. Why should the chromatograph data on the formation evaluation log be a histogram (square) plot?
    a. ____
    b. ____

60. What factors other than cuttings lithology should be the logger use to construct the interpreted lithology column of the formation evaluation log?
    a. ____
    b. ____

61. What information should be included in the remarks column of the formation evaluation log if a positive flow check has occurred?
    a. ____
    b. ____
    c. ____

62. What information should be included in the remarks column of the formation evaluation log if a carbide test is performed?
    a. ____
    b. ____
    c. ____

•Notes•

Self-Check Answers
Chapter 1 - Volume Calculations

1. a. The borehole is getting deeper (more volume)
   b. The borehole may washout (more volume
   c. Hydrating formations or thick filter-cake (less volume)

2. a. lag time
   b. efficiency of gas extraction system

3. The wrapping material must be able to dissolve in the mud system and the area (or hands) must be dry.

4. Calcium Carbide reacts with water to form acetylene gas.

   $CaC_2 + 2H_2O \text{ --> } Ca(OH)_2 + C_2H_2$

5. Every 24 hours or 400 feet (122 meters), whichever is first, unless conditions dictate that they be run more often.

6. Carbide Gas amount (%), Funnel Viscosity of returning drilling fluid, depth of carbide and lag strokes

7. a. arrival of two carbide peaks
   b. loss of pump pressure

8. a. failure to keep the hole full
   b. loss of Bottom Hole Circulating Pressure
   c. swabbing effect of pulling the drillstring

9. The drillstring is run back to bottom and the swabbed fluids are circulated out.

10. The depths of any overpull and other circumstances which may be of interest.

11. Some of the drilling fluid inside the drillstring is lost at the surface.

12. High surge pressures are produced which can fracture formations resulting in a loss of drilling fluid.

13. a. Lost Circulation Material
    b. Pipe-Freeing Agents

14. a. Slurry Volume
    b. Displacement Volume

15. a. Wireline Caliper
    b. Carbide Calculations

Chapter 2 - Depth & Drill Rate Monitoring

1. By securing an accurate depth from the driller at a "kelly down" position. This depth should be confirmed.

2. a. Bristol recording System
   b. Kelly Height System
   c. Block Height System

3. 7.4 min/ft or 8.1 ft/hr

4. 7971 feet (TVD)

5. 6 feet

6. The logging geologist should watch and check the drillers addition whenever they go to the rig floor, and the logging geologist should ensure the correct depth when they come on tour.

7. Low weight-on-bit results in greater hookloads, which result in more of the drillstring being kept in tension, and therefore more pipe stretch.

8. Wireline logging tools may not make it to the bottom of the borehole, due to hole fill.

9. Present Depth, Previous Depth, Reason for Depth Correction

10. a. INTEQ TD:
    b. DRILLER TD:
    c. WIRELINE TD:

Chapter 3 - Advanced Sample Evaluation

1. a. Formation Porosity
   b. Formation Permeability
   c. Differential Pressure
   d. Drill Bit Hydraulics
   e. Amount of Water Loss
   f. Drilling Practices

2. a. Unflushed fluids from the disrupted porosity
   b. Rock fragments and matrix particles (cuttings)
   c. Unflushed fluids from the rock fragments

3. a. Atmospheric Pressure
   b. Adverse Weather Conditions
   c. Rig Equipment and Its Efficiency
   d. The Individual Collecting the Sample

4. The rig's equipment is simple, cheap, requires low technological maintenance and does not interfere with the drilling process.

5. The options include members of the rig crew, oil company contract sample catchers, trainee loggers, the logging geologist, and the oil company geologist.

6. Over-washing of the sample will remove all traces of hydrocarbons, and will dissolve any clays in the sample, leaving only sand present.

   Under-washing the sample result in an amorphous mud remaining, and will not remove any contaminants.

7. a. Drill Rate
   b. Drilling Torque
   c. Gas Values
   d. Drilling Fluid Changes
   e. Cuttings Lithology

8. The logging geologist should leave the interpreted lithology column blank until a comprehensive review of the section is done and the section's lithology agreed upon. If still in doubt, then the logging geologist should wait until supporting evidence

or information is available.

9. a. PDC Bit drills by a shearing action
   b. Insert Bit drills by a crushing and gouging action
   c. Diamond Bit drills by a loading and shearing action
   d. Mill-Tooth Bit drills by a crushing and gouging action

10. Bit flour is produced by the direct crushing or pseudoplastic failure (or both) of nonagrillaceous rocks, leaving a chalky, amorphous looking powder

11. Bit sand is produced by the pseudoplastic failure of weaker inter-grain cement or matrix, leaving loose grains

12. Diamond and PDC Bits

13. Mill-Tooth and Insert Bits

Chapter 4 - Coring Procedures

1. The logging geologist's responsibilities include:
monitoring the drill rate over 1 foot intervals
monitoring gas readings over the cored interval
collecting samples over the cored interval

2. a. Tri-Core Coring
b. Rubber Sleeve Coring
c. Wireline Coring
d. Oriented Coring
e. Pressure Coring

3. 20 boxes (core boxes come in 3 foot lengths)

4. It will be impossible to wipe the core dry. Any fluid that was wiped off will be replaced by fluid from within the core.

5. a. at one foot intervals
b. at points of special interest

6. The entire core is viewed under an ultra-violet lamp, noting the location, distribution, color and intensity of any fluorescence.

7. a. Porosity
b. Permeability
c. Fluid Saturations

8. a. detonation of the bullet often induces fractures in the sample, resulting in poor porosity and permeability values
b. the small volume of rock sample is not usually representative of the formation being samples
c. sidewall core samples are easily broken when handled

9. Because the hydrocarbon odors are usually masked by the explosive (gun powder) odors

10. Do not begin core recovery or examination until all misfires and charges are removed from the core gun

11. a. since the core is probably flushed - a sample of the mud filtrate
    b. a sample of any lubricants used in preparing the core gun

Chapter 5 - Introduction to Hydraulics

1. a. Plug Flow
   b. Laminar Flow
   c. Turbulent Flow

2. The electrical attraction of the mud solids, particularly the clays which are added to the mud system.

3. A fluid in which the apparent viscosity decreases as the shear rate increases.

4. Yield Point is the intercept at zero rpm

   Plastic Viscosity is the slope of the line drawn through the 600 rpm and 300 rpm data points

5. 300 rpm = 56
   600 rpm = 95

6. Because the drilling fluid is shear-thinning, each time the shear rate (velocity) changes, the viscosity will change.

7. The sum of the pressure losses in the various annular sections.

8. 55.0 psi

9. Laminar, 243.3 ft/min

10. 84 psi

Chapter 6 - Hydrocarbon Evaluation

1. a. Continuous Gas
   b. Discontinuous Gas

2. a. Continuous Gas - a smooth curve
   b. Discontinuous Gas - a histogram or alpha-numeric

3. A gas show is any deviation in gas, amount or composition, from the established background gas, and requires interpretation as to its cause.

4. a. Formation Pressure
   b. Formation Temperature

5. a. Drilling Fluid Overbalance
   b. Formation Permeability

6. a. Hydrocarbon Wetness (Wh)
   b. Hydrocarbon Balance (Bh)
   c. Hydrocarbon Character (Ch)

7. a. Hydrocarbon Wetness values < 0.5
   b. Hydrocarbon Balance values > 100

8. a. Drill Rate
   b. Flow Rate
   c. Hole Diameter
   d. Ditch Gas Value
   e. Extraction Equipment Efficiency

9. a. color of the fluorescence
   b. intensity of the color
   c. amount and distribution of the fluorescence

10. The darker the stain, the lower the API gravity

11. From the cuttings gas to total gas ratio
    From the type and speed of the solvent cut test

12. a. Type of solvent cut test
    b. Rate (speed) of the cut
    c. Fluorescence color of the cut
    d. Residue remaining after the cut test

Chapter 7 - Bit Grading Techniques

1. a. The amount of physical wear on the bit
   b. An analysis of the cause(s) of the wear

2. The cutting structure of the roller cone bit
   1,2,3 - milled tooth bits
   4,5,6,7,8 - insert bits

3. a. No
   b. Yes

4. 517X has chisel shaped inserts
   517Y has conical shaped inserts

5. A tungsten carbide matrix bit body

6. a. The overall length of the cutting face of the bit.

7. a. PDC cutters
   b. Natural Diamond cutters
   c. Thermally Stable PDC cutters

8. Light set - soft formations
   Heavy set - hard formations

9. The total amount of usable cutters on the bit.

10. a. SE
    b. B6

11. The distance measured by a ruler is multiplied by 2/3's (0.67).

12. There is no multiplier, the distance measured by a ruler using the “NO-GO” ring is the amount out-of-gauge

13. NB (No Bit) - only drill bits, under-reamers and hole openers are numbered.

14. The TFA in square inches

15. HO

Chapter 8 - Formation Pressures

1. Tertiary age formations

2. a. the height of the rock column
   b. the density of the rock column

3. 9.02 lb/gal

4. Though the formulas are similar, the formation's fluid density is based on salinity, while the drilling fluid's density is based on the amount of weight material added to the system.

5. a. Mud Hydrostatic Pressure
   b. Annular Pressure Losses

6. Parallel to the greatest stress. In a borehole, the greatest stress is usually the overburden pressure, so most of the fracture orientation will be vertical.

7. Performing a Pressure Integrity Test (Leak-Off Test)

8. a. Geologically young sediments
   b. Large total thickness of sediments
   c. Presence of clay rocks
   d. Interbedded sandstones of limited extent
   e. Rapid loading and burial of the sediments

9. The deposition of large amounts of fine-grain sediments, which result in isolated, interbedded sands of limited lateral extent.

10. Montmorillonite Dehydration

11. clays/shales

12. a. faults
    b. fractures
    c. previously drilled boreholes

Chapter 9 - Borehole Problems

1. a. Lost Circulation
   b. Stuck Pipe
   c. Borehole Instability
   d. mud weight problems

2. Lost circulation is the loss of whole drilling fluid (solids and liquids), while filtrate loss is the loss of the liquid portion of the drilling fluid.

3. Lost circulation will occur when the total pressure against the formation exceeds the formation pressure, and the openings in the formation are larger than the largest particles in the mud system.

4. A drill break is usually the first indication. There will be a reduction in the return flow and a change in differential flow (Flow In vs Flow Out). There will be a loss of pit volume, and a standpipe pressure reduction.

5. a. Fibrous
   b. Granular
   c. Flakes
   d. Reinforcing Plugs

6. a. Loss of cuttings samples and gas information
   b. Contamination of cuttings samples with LCM
   c. Spurious gas information due to hydrostatic pressure changes

7. Differential Sticking

8. Directional wells
   Wells that deviate from Vertical

9. a. Hole fill on connections and trips
   b. Excessive cavings at the shale shaker
   c. Torque and drag on connections and trips
   d. Reduced drill rate
   e. Lag changes

10. a. Increase in chlorides in the mud and mud filtrate
    b. Flocculation of the drilling fluid at the shale shaker
    c. Decrease in the amount of cuttings at the shale shaker

11. a. Additions of water to the mud system
    b. Recirculated gas
    c. Kelly-cut gas after trips
    d. Aeration of the mud at the surface
    e. Weighting-up the mud at the surface

12. <u>Permeable Formations</u>: there will be greater amounts of fluids entering the borehole, and therefore larger trip or connections gases (increases in chlorides also).

    <u>Impermeable Formations</u>: there will be increases in torque and drag on connections and trips and large amounts of cavings after "bottoms-up."

Chapter 10 - F WR - Geology Section

1. a. Keep the reader in mind when writing
   b. Avoid writing between the line to avoid confusion

2. a. the Formation Evaluation Log
   b. the Formation Log Worksheets

3. a. an up-to-date dictionary
   b. a glossary of geologic terms

4. a. Correlation material provided by he client
   b. Careful analysis of the drill cuttings
   c. Analysis of the drilling parameters

5. a. Size (vertical thickness)
   b. Shape (lateral extent)
   c. Composition (lithology type)
   d. Fluid Saturation

6. Inert Gases - helium, argon, radon
   Acidic Gases - nitrogen, hydrogen, carbon dioxide, hydrogen sulfide
   Water - saline, fresh

7. a. Percentage (Cuttings) Lithology
   b. Interpreted Lithology

8. Types of samples collected, sampling intervals, sieve sizes used for cleaning, also any additional procedures followed (i.e. air drilling samples, oil-based muds, etc).

9. Because the descriptions and analysis of the section becomes too generalized.

10. Rate of Penetration and Gas Values (Background, Total, Chromatograph) in a table format (maximum, minimum, average).

Chapter 11 - Log Quality Control

1. Day/Month/Year

2. Two

3. x 10

4. weight-on-bit (WOB)
   rotary speed (RPM)
   standpipe pressure (SPP)
   strokes per minute (SPM), if required

5. a. Intervals logged after a trip (LAT)
   b. Intervals circulated out (CR)
   c. Flow Checks (FLC)

6. Drillstem Tests (DST)
   Wireline Tests (FIT or RFT)

7. NR - over the interval of no returns

8. When gas values are measured in “equivalent methane-in-air”, more than 100% can be measured

9. At least once per day, unless conditions dictate otherwise

10. the oil/water ratio
    the electrical stability (ES)

11. azimuth, inclination, measured depth, true vertical depth

12. No

13. Those reports are written on a separate, supplemental sheet, which is then placed/spliced to the base of the last log page.

14. Only those logging geologists who performed the drafting of the log

15. a. when there is a lack of adequate data
    b. when there is a lack of neatness or consistency