# **IWCF United Kingdom Branch**



# Drilling Calculations Distance Learning Programme

Part 3 - Well Control

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# Introduction

Welcome to the International Well Control Forum (IWCF) UK Branch Drilling Calculations Distance Learning Programme.

Nowadays, mathematics is used almost everywhere, at home at leisure and at work. More than ever a knowledge of mathematics is essential in the oil industry.



The aim of this programme is to introduce basic mathematical skills to people working in or around the oilfield. The programme will lead on to some of the more complex calculations required when working in the industry. By the end of the programme, the user should have acquired the knowledge and skills required prior to attending an IWCF Well Control course.

The programme is split into three parts;

Part one	-	Introduction to calculations
Part two	-	Volume calculations
Part three	-	Well control calculations

This book contains part three.

### **Training Objectives**

#### Part 1 Introduction to calculations

Having completed part one you should;

- Have a good understanding of basic mathematics including;
  - The use of whole numbers
  - Rounding and estimating
  - The meaning and use of mathematical symbols
  - The use of the calculator
  - Fractions and decimals
  - Ratios and percentages
  - How to solve equations.
- Have knowledge of the main systems of measurement and their units.
- Understand the most common oilfield units and how they are used
- Know how to use conversion tables.

#### Part 2 Volume calculations

When you have completed part two you should;

- Know the names of the more common two-dimensional shapes and calculate their areas.
- Know the names of the more common solid (three-dimensional) shapes and calculate their surface area.
- Be able to calculate the volume of;
  - Square sided tanks
  - Cylindrical tanks
- Be able to calculate pipe and annulus capacities.
- Understand the geometry of a well bore.
- Be able to draw the well bore and calculate the lengths of each section.
- Be able to calculate the volume of mud in each part of a well bore.
- Be able to calculate pump strokes and times to pump.
- Understand the use of and partially complete a kill sheet.
- Be able to perform the calculations required to monitor trips.
- Understand the need to monitor trips and using a trip sheet.

#### Part 3 Well control calculations

This will cover the following;

- Introduction to pressure.
- Oilfield pressure terminology.
- The circulating system.
- Introduction to well control.
- Introduction to well control methods.
- Well control calculations.
- Fracture pressure calculations.

A more detailed list of objectives can be found at the start of each section.

# How to use this training programme

### Using the materials

This programme is designed as a stand-alone training programme enabling you to work through without external support. No one however expects you to work entirely by yourself, there may be times when you wish to seek assistance. This might be in the form of a discussion with colleagues or by seeking the help of your supervisor. Should you require guidance, the best person to speak to would normally be your supervisor, failing this contact the Training department within your own company.

### Planning

Whether you plan to use this programme at work or at home, you should organise the time so that it is not wasted. Set yourself targets to reach during a certain time period. Do not try to use the material for 5 minutes here and there, but try to set aside an hour specifically for study. It may even be useful to produce a timetable to study effectively.

	Week 1	Week 2	Week 3	Week 4
Monday	Work through	Work through		Work through
	section 1	sections 3		section 5
Tuesday			Work through	
			section 4	
Wednesday	Revise section 1			Revise section 5
Thursday			Revise section 4	
Friday		Revise section 3		Discuss with
	Work through			colleagues and/or
	section 2			supervisor
Saturday			Discuss with	
			colleagues	
			and/or supervisor	
Sunday	Revise section 2	Discuss sections 1		
		to 3 with		
		colleagues and/or		
		supervisor on rig		

### Organising your study

Once you have prepared a study timetable, think about what you have decided to do in each session. There are a few basic guidelines to help you plan each session

#### Do

• Find somewhere suitable to work, for example a desk or table with chair, comfortable lighting and temperature etc.



• Collect all the equipment you may need before you start to study, e.g. scrap paper, pen, calculator, pencil etc.



- Know what you plan to do in each session, whether it is an entire section or a subsection
- Work through all the examples, these give you an explanation using figures. Each section contains "try some yourself ... Exercises", you should do all these.
- Make notes, either as you work through a section or at the end



• Make notes of anything you wish to ask your colleagues and/or supervisor.

#### Don't

- Just read through the material. The only way to check whether you have understood is to do the tests.
- Try to rush to get through as much as possible. There is no time limit, you're only aim should be to meet the training objectives.
- Keep going if you don't understand anything. Make a note to ask someone as soon as possible.
- Spend the entire session thinking about where to start.



# How the programme is laid out

The programme is split into three parts. Each part is further divided into sections covering specific topics.

At the start of each section there is information and objectives detailing what is to be covered. Also at the start is an exercise called "Try these first . . . ".



These are questions covering the material in the section and are for you to see just how much you already know. Do just as it says and try these first! You can check your answers by looking at the end of the section.

Answers look like this;

Answers –

Throughout each section you will find worked examples .

Examples

Following these examples you will find exercises to try yourself.



They are shown with a calculator although not all require one.

Check your answers before carrying on with the sections. If necessary, go back and check the material again.

Throughout the section are boxes with other interesting facts.

Of interest / Other facts

The "Of interest" boxes are not core material but provide background knowledge.

This page is deliberately blank

# Section 1: Hydrostatic Pressure

This section looks at what hydrostatic pressure is and its importance in well control. We will also cover how to calculate hydrostatic pressure using different units.

#### Objectives

- To review pressure.
- To define hydrostatic pressure.
- To explain the importance of vertical depth.
- To show what we mean by pressure gradient.
- To show the relationship between mud density and hydrostatic pressure
- To calculate hydrostatic pressure using gradient and/or density.

Try t	hese first Exercise 3.1
1.	Select the correct definition of hydrostatic pressure.
	<ul><li>a. The pressure required to circulate fluid around a well.</li><li>b. The buoyancy force exerted by a column of fluid.</li><li>c. The pressure exerted by a column of fluid at rest.</li></ul>
2.	Which two of the flowing affect hydrostatic pressure?
	<ul> <li>a. Hole diameter.</li> <li>b. Measured depth.</li> <li>c. True vertical depth.</li> <li>d. Fluid viscosity.</li> <li>e. Fluid density.</li> </ul>
3.	What hydrostatic pressure is exerted by a fluid with a pressure gradient of 0.7 psi/ft in a well 11500 feet deep (TVD)?
	psi
4.	What mud density (ppg) is required to give a hydrostatic pressure of 6240 psi at 10000 feet?
	ppg

# A review of pressure

Pressure is the force or weight acting on a unit area.



The above examples use solid objects. Fluids (such as water) also have weight and will exert a pressure in the same way.



The pressure exerted due to the weight of a fluid is called hydrostatic pressure. As you can see from the above, the bucket with one gallon of fluid weighs more than the bucket with a half gallon of fluid. It will therefore exert more pressure.

#### Remember

Pressure is the force or weight acting on a unit of area.

Lets look again at the pressure exerted by drilling mud in a well.

Hydrostatic pressure increases as the mud density increases.



Hydrostatic pressure increases as the depth increases.



#### Hydrostatic pressure

The pressure exerted by a column of fluid at rest at a specific depth in that fluid.

It depends on the DENSITY and the vertical DEPTH of the fluid.

## **1.1 Definition of hydrostatic pressure**

If a submarine dives below the surface, the pressure on the hull will increase.



This is because the height and therefore the weight of water above the hull increases, so exerting a greater pressure. The deeper the submarine dives, the higher the pressure on the hull will become.

Hydrostatic pressure is the pressure exerted by a fluid which is not moving.

In fact			
The word hy	drostati	e is derived from	
HYDRO STATIC	=	fluid not moving	

### The effect of depth

Imagine a tall container full of water. If we make a hole in the side of the container, water will come out.

If the hole had been made further down the container, water from this hole will be forced out a greater distance.

A hole even further down shows the water forced out an even greater distance.

You can try this with any plastic water bottle.

What forces the water out of the hole is the hydrostatic pressure of the water inside the bottle. As the height of the water above the hole becomes greater, the hydrostatic pressure becomes greater and the water comes out of the bottle with greater force.

The hydrostatic pressure exerted by a fluid depends on depth.

If we look at the pressure exerted by drilling mud in a well.



Although the mud density is always 10 pounds per gallon, the pressure increases as the depth increases.

### The effect of fluid density



As the density of the fluid increases the pressure exerted increases.

Try	some yourself Exercise 3.2
1.	Select the correct definition of hydrostatic pressure.
	a. The pressure which must be overcome to move a fluid.
	b. The pressure exerted by a column of fluid at rest.
	c. The pressure of drilling mud passing through the bit.
	d. The weight of the drift string in mud.
2.	Select the correct statement regarding hydrostatic pressure.
	a. Hydrostatic pressure increases with depth.
	b. Hydrostatic pressure decreases with depth.
	c. Hydrostatic pressure is not affected by depth.
3.	Select the correct statement regarding hydrostatic pressure.
	a. Hydrostatic pressure increases with fluid density.
	b. Hydrostatic pressure decreases with fluid density.
	c. Hydrostatic pressure is not affected by fluid density.
4.	Two wells have been drilled and cased.
	Well 1 has $9^{5}/_{8}$ inch casing set at 10000 feet
	Well 2 has $13^{3/8}$ inch casing set at 10000 feet
	Both wells are full of 10 ppg mud.
	Which of the following statements is correct?
	a. The hydrostatic pressure is greater in well 2 because of the smaller size of casing.
	b. The diameter of the casing does not affect the hydrostatic pressure; it is the same in both wells.

# 1.2 Calculating hydrostatic pressure

As we have just said, hydrostatic pressure depends on depth and density.

Lets go back to the example of a submarine.

As the submarine dives the pressure on the hull will increase.



As the density of the seawater does not change significantly, the increase in pressure will be the same for each foot the submarine dives.

In sea water this is approximately 0.5 psi for each foot of water.

50 psi

So if the submarine is 100 feet under water, the hydrostatic pressure on the hull would be approximately

100 ft

What happens when the submarine, remaining at 100 feet under water, travels along for 5000 feet? The pressure on the hull will not change. So long as the submarine is 100 feet vertically below the surface, the hydrostatic pressure on the hull is approximately

 $100 \ge 0.5 = 50 \text{ psi}$ 

 $100 \ge 0.5 =$ 

It does not matter how far the submarine travels horizontally.

Hydrostatic pressure depends on the density of the fluid and the vertical depth.



Lets look at pressure in a well again.

The pressure exerted by the column of 10 ppg mud is the same in each case because the vertical depth is the same.

Remember	
Measured depth:	the total length of the well measured from surface along the path of the wellbore (abbreviated to MD).
True vertical depth:	the depth of a well measured from the surface vertically down to the bottom of the well (abbreviated to TVD).
Total depth:	refers to the final depth of the well (abbreviated to TD). This is normally the measured depth.
<b>Note</b> : In drilling, dept (abbreviated to Occasionally d	ths are usually measured from the rotary table on the rig floor BRT – below rotary table or RKB – rotary Kelly bushings). epths can be quoted below surface or sea level.



# **1.3 Pressure gradient**

Previously we have shown that the hydrostatic pressure in a fluid increases by the same amount in a given vertical depth. The example below shows a pressure increasing by 1 psi for each additional foot of depth.



This can be expressed as unit of pressure per unit of depth, in our case using API units this would be

'Pounds per square inch per foot usually abbreviated to psi/ft.'

Previously we used an approximate value of 0.5 psi/ft, the actual value for sea water is closer to 0.45 psi/ft. The value for fresh water would be 0.433 psi/ft.

This is known as a pressure gradient.

Sea water is more dense and therefore has a higher pressure gradient than fresh water because of the salt dissolved in sea water.





Try som	e yourself Exercise 3.4	
1. Se pro	a water in the North Sea exerts a presessure be at	ssure gradient of 0.45 psi/ft. What would the
	a. 10 feet?	psi
	b. 100 feet?	psi
	c. 1000 feet?	psi
	d. 11570 feet?	psi
2.	If a well is full of fresh water with hydrostatic pressure be at	a gradient of 0.433 psi/ft, what would the
	a. 150 feet?	psi
	b. 1500 feet?	psi
	c. 15000 feet?	psi
	d. 14930 feet?	psi

Of interest		
Different densities of fluids will l For example: -	nave different pressure gradients.	
Diesel oil	0.3 – 0.4 psi/ft	
Fresh water	0.433 psi/ft	
North Sea water	approximately 0.45 psi/ft	
Dead Sea water	approximately 0.59 psi/ft	
Drilling mud	up to 1 psi/ft	
Gas	0.1 psi/ft	
If we know the gradient and the ve	rtical depth, we can calculate the hydrostatic pressure	

exerted by any fluid.

Example	
Calculate the hydrostatic pressure exerted by a mud with a gradient of 0.6 psi/ft in a well 15000 feet true vertical depth (TVD).	M U D
Hydrostatic pressure = mud gradient x TVD	0.6
= 0.6 x 15,000	psi/ft
= 9000 psi	?

Try s	Try some yourself Exercise 3.5		
Calcu	late the hydrostatic pressure ex	erted by the drilling m	ud in the following wells.
1.	Measured Depth (MD) True Vertical Depth (TVD) Mud gradient 0.5 psi/ft Hydrostatic pressure	15000 ft 15000 ft	nsi
2.	MD 15000 ft TVD 12000 ft Mud gradient 0.5 psi/ft		- For
3.	Hydrostatic pressure MD 17500 ft		_psi
	TVD 17500 ft Mud gradient 0.728 psi/ft		
	Hydrostatic pressure		_psi
4.	MD 16430 ft TVD 9850 ft Mud gradient 0.55 psi/ft		
	Hydrostatic pressure		_psi
5.	MD 5520 ft TVD 2590 ft Mud gradient 0.52 psi/ft		
	Hydrostatic pressure		psi

### Of interest – Other gradient related units

When measured in psi/ft most fluids encountered in the oilfield are very small numbers (e.g. between 0.4 and 1).

For convenience, some operators quote gradients not in psi per foot but in psi per 1,000 feet. (Abbreviated to pptf - psi per thousand feet).

pptf = psi/ft x 1000

Thus fresh water would have a gradient of;

0.433 psi/ft or 433 pptf

In this book we will use the more commonly used psi/ft.

# **1.4 Hydrostatic pressure calculations using density**

Although some companies do operate using pressure gradients for fluids, other companies in the oilfield use density, so it is important to know how to convert.

In API units fluid densities are measured in pounds per gallon (ppg).

Converting between psi/ft and ppg

To convert we must use the constant 0.052



To convert	<u>from</u>		<u>to</u>
	psi/ft	divide by 0.052	ppg
	ppg	multiply by 0.052	psi/ft
	or	$ppg = psi/ft \div 0.052$	
		$psi/ft = ppg \times 0.052$	

Exa	Example – Converting between psi/ft and ppg		
1.	Convert 0.63 psi/ft to ppg.		
	$ppg = 0.63 \div 0.052$ = 12.12 ppg (to 2 decimal places)		
2.	Convert 17.2 ppg to psi/ft.		
	$psi/ft = 17.2 \times 0.052$ $= 0.894 psi/ft $ (to 3 decimal places)		

If you need to refresh your skills on converting between units, look at Section 8 of Part 1.

A word about accuracy			
Mud density =	normally quoted to 1 decimal place, occasionally to 2		
Gradients =	normally quoted to 2 or 3 decimal places		

Try s	some yours	elf Exercise 3.6		
1.	Convert the	e following:		
	psi/ft	to	ppg	
	0.572	$ppg = 0.572 \div 0.052$	11.0	
	0.884			
	0.5876			
	0.5564			
	0.9464			
2.	Convert the	e following:		
	ppg	to	psi/ft	
	9.7	$psi/ft = 9.7 \ge 0.052$	0.504	
	11.8			
	12.2			
	17.9			
	16.2			
			1	

#### Calculating hydrostatic pressure

#### Remember

Remember how we calculated hydrostatic pressures using gradients?

```
Hydrostyatic pressure (psi) = gradient (psi/ft) x TVD (ft)
```

If we substitute fluid density x 0.052 for gradient we get;

Hydrostatic pressure (psi) = fluid density (ppg)  $\times 0.052 \times TVD$  (ft)

This formula allows us to calculate hydrostatic pressures in psi using fluid density in ppg and depths in feet.



ry so	me yourself Ez	xercise 3.7		
alcula	te the following hydr	ostatic pressures (answ	vers to a round number)	
	Mud density	Depth (TVD)	Hydrostatic pressure	
	ppg	feet	psi	
	12.1	8600	5411	
	10	10000		
	16.2	17010		
	13.8	11530		
	14.4	9850		

### **Review of hydrostatic pressure formulae**

Hydrostatic pressure = pressure gradient  $\times$  TVD (psi) (psi/ft) (ft) Hydrostatic pressure = mud density  $\times$  0.052  $\times$  TVD (psi) (ppg) (ft)

These formulae can be rearranged to allow us to calculate;

The mud density or gradient required to give a pressure

Mud density (ppg) =  $\frac{\text{hydrostatic pressure (psi)}}{\text{TVD (ft)} \times 0.052}$ 

Mud gradient (psi/ft) =  $\frac{\text{hydrostatic pressure (psi)}}{\text{TVD (ft)}}$ 





The depth of mud to give a certain pressure;

$$TVD (ft) = \frac{hydrostatic pressure (psi)}{mud density(ppg) \times 0.052}$$

TVD (ft) =  $\frac{\text{hydrostatic pressure (psi)}}{\text{mud gradient (psi/ft)}}$ 



Try	some yourself Ex	ercise 3.8		
1.	Fill in the gaps.			
	Mud density	Depth (TVD)	Hydrostatic pressure	
	ppg	feet	psi	
	12	10000		
	11.5	12500		
		9780	5390	
		13430	10475	
	9.7		4237	
2.			1	
	Mud gradient	Depth (TVD)	Hydrostatic pressure	
	ps1/ft	teet	ps1	
	0.75	12550		
	0.91	15800		
		9050	5647	
		7450	4098	
	0.8		13440	

### Section 2: Primary Well Control

In the previous section, we looked at hydrostatic pressure and how to calculate it and other parameters associated with it. In this section we will look at why mud hydrostatic (and mud weight) is so important. We will explain what is meant by "Primary Well Control".

Objectives

- Explain what is meant by formation pressure
- Define porosity and permeability
- Explain the terms normal and abnormal formation pressure
- Explain the concept of balance
- Define primary well control
- Explain what is meant by fracture pressure

Try these first . . . Exercise 3.9

- 1. What is the correct term to describe the percentage volume of pore space in a formation?
  - a. Permeability
  - b. Porosity
  - c. Siltiness
  - d. Shaliness
- 2. Select the correct definition of *formation pressure*.
  - a. Pressure exerted by fluids in the pore spaces of a formation.
  - b. The total weight of the overlying sediments and fluid.
  - c. The ability of a formation to allow fluid to flow.
- 3. Select the correct definition of normal formation pressure.
  - a. A formation pressure equal to the overburden.
  - b. A formation pressure in excess of normal formation fluid hydrostatic pressure.
  - c. A formation pressure less than the mud weight.
  - d. A formation pressure equal to the hydrostatic pressure of the water in the formation.

Try	these first continued
	$\mathbf{P}$
1	What would the formation pressure he in a normally pressured well at 5000 feet?
4.	psi
5.	What does the term <i>overbalanced</i> mean?
	a. Maintaining mud hydrostatic <i>equal</i> to formation pressure.
	b. Maintaining mud hydrostatic <i>greater than</i> formation pressure.
	c. Maintaining mud hydrostatic <i>tess than</i> formation pressure.
6.	Which is the correct definition of <i>primary well control</i> ?
	a. A mud weight at least 1000 psi above formation pressure.
	b. The blow out preventers.
	c. Controlling formation pressures with the hydrostatic pressure of the drilling fluid.

# Mud hydrostatic

Firstly, lets look back at mud hydrostatic and why it is important.

#### Remember

Hydrostatic pressure is the pressure exerted by a column of fluid at rest.

Mud hydrostatic is the pressure exerted by a static column of mud such as that in the well bore.

Inside the well bore, mud exerts a hydrostatic pressure, proportional to its density and the vertical depth.



Whilst mud has many functions, including;

- transporting cuttings;
- suspending cuttings;
- transmitting power;
- cooling and lubricating;
- reducing formation damage;
- protecting cuttings;

one of its most important functions is to provide the hydrostatic pressure to balance formation pressure.

This is why the mud density is so important.

Try	some yourself Exercise 3.10		
1.	Select the statement that best describes hydrostatic pressure.		
	<ul> <li>a. The pressure exerted by a moving column of water.</li> <li>b. The pump pressure to circulate mud around the well.</li> <li>c. The pressure of water used to generate electricity.</li> <li>d. The pressure exerted by a column of fluid at rest.</li> </ul>		
2.	Hydrostatic pressure depends on which of the following (two answers)?		
	<ul> <li>a. Fluid density</li> <li>b. Measured depth</li> <li>c. True vertical depth</li> <li>d. Hole diameter</li> </ul>		
3.	Which property of a drilling mud determines its ability to balance formation pressure?		
	<ul> <li>a. pH</li> <li>b. Viscosity</li> <li>c. Gels</li> <li>d. Density</li> </ul>		

### **Formation pressure**

#### What is formation pressure?

#### Formation

Formation is a term used to describe the various rock types that we may drill through. These might be;

Mudstone or shale Siltstone Sandstone Limestone or Dolomite Salt and of course many others.

The rock types we have listed above are all "Sedimentary" rocks, that is they were originally formed from sediments, most often deposited at the bottom of an ocean.



By a process of compaction due to burial, or cementation or a combination of these processes and others, these sediments turn into rock.

e.g. Mud becomes mudstone or shale Sand becomes sandstone

Thus the formations which we drill through mainly consist of flat beds of various rock types. They are usually shown in a diagram as a vertical column representing the sequence of formations encountered in a well.



These formations may be a few or many thousands of feet thick. The types of formations we encounter vary greatly from area to area.
Before we discuss formation pressure we must look at how these rocks are actually made up.

Lets take sandstone as a good example (called sandstone because it is made from grains of sand stuck together). If we examine sandstone very closely (using a magnifying glass or microscope) we can see these grains of sand.



Notice that there are spaces between the sand grains. These are called pore spaces. The total amount of pore space is called the *porosity* and is usually expressed as a percentage %.

Most of the formations we drill through will have a degree of porosity although it will vary enormously.



Of course in a formation, these pore spaces cannot be empty but would contain fluid which is usually water, but could be gas or oil.



Different types of rock have different porosity and permeability. Shale, unlike sandstone may have porosity but has very low or no permeability.



The pressure of the fluid in these pore spaces is what we refer to as *formation pressure*.

# Definitions Remember – the formations that we drill through are made up of rock and fluid in the pore spaces. Overburden is the total mass of the rock and the fluid above a formation. Overburden pressure is the pressure on a formation generated by the combined weight of rock and fluid above the formation. Formation (or pore) pressure is the pressure exerted by the fluid in the pore spaces of a formation.

# Porosity and permeability

As we have just previously discussed, *porosity* is the name for the amount of pore (or *void*) space within a rock.

This can vary greatly from formation to formation and even within a formation.



Rocks also have another property in varying degrees, called *permeability*.



Permeability is a measure of the ability of a rock to allow fluid to flow from pore space to pore space within the formation.

Permeability can vary for many reasons, perhaps the connections between pore spaces are blocked as above.

Another possibility is that a formation, which is both porous and permeable is sealed by surrounding formations e.g. sandstone formations in between layers or strata of shale.



Imagine a sponge.



The sponge has porosity and also permeability – compress it and fluid will run out.



Put the same sponge in a polythene bag.



While the sponge still has the same porosity, the bag will not allow fluid to escape – there is no longer any permeability.

You can also see that the pressure inside the bag will increase.





# Normal formation pressure

## Remember

Formation pressure is the pressure exerted by the fluids in the pore spaces of a formation.

Imagine a bucket one foot deep with a pressure gauge attached.



When the bucket is empty the pressure gauge will read zero. (The gauge will not read atmospheric pressure.)

When we fill the bucket with fresh water (0.433 psi/ft), the pressure will increase due to the hydrostatic pressure of the water.



Hydrostatic pressure = Pressure gradient (psi/ft) x TVD (ft) =  $0.433 \times 1$ = 0.433 psi

The gauge would read 0.433 psi.

Back to the empty bucket.



Now we fill the bucket with golf balls.



What happens to the pressure on the gauge – nothing it will remain at zero.

The overall weight of the bucket will increase, but the pressure on the gauge will not be affected by the golf balls.

Now we again fill the bucket with water. The pressure on the gauge will increase. It will show the hydrostatic pressure of the water in the bucket.

What is happening in the bucket represents what happens in a rock formation such as sandstone. The gauge is reading formation pressure.



So far in our bucket example, we have shown a "formation" pressure which is equal only to the hydrostatic pressure of the fluid.

The situation will be exactly the same in formations where there is a continuous column of formation fluid back to surface (i.e. permeability back to surface).

That is, the formation pressure is equal to the hydrostatic pressure exerted by the column of fluid in the formation.

If this is water, the gradient would be 0.433 psi/foot for fresh water.

#### Normal formation pressure

A formation pressure which is equal to the hydrostatic pressure of water of normal salinity for that area.

The amount of salt dissolved in a liquid is called its salinity.

Formation water has many salts dissolved in it so we assume a gradient of 0.465 psi/foot.

## Example

A well is 10000 feet deep and the formation pressure is normal (0.465 psi/ft)

a. What is the formation pressure at 10000 feet?

Hydrostatic pressure (psi) = Pressure gradient (psi/ft) x TVD (ft)

= 0.465 x 10000

Formation pressure = 4650 psi

b. What mud weight would be required to balance this pressure?

Mud weight (ppg) = Pressure gradient (psi/ft)  $\div 0.052$ 

$$= 0.465 \div 0.052$$

(In reality a 9.0 ppg would be mixed.) Rules for the accuracy of mud weights will be discussed in a later section.

Try s	some	e yourself Exercise 3.12						
1.	Selec	ct the best definition of <i>normal formation pressure</i> .						
	a. A formation pressure which requires a mud weight of less than 10 ppg.							
	b.	A formation pressure due only to the weight of the overlying rocks.						
	c.	A formation pressure equal to the hydrostatic pressure of the water in the formation.						
2.	What	t is normal formation pressure normally assumed to be (in psi/feet)?						
	a.	0.5 psi/ft						
	b.	0.433 psi/ft						
	с.	1.0 psi/ft						
	d.	0.465 psi/ft						
3.	A for	rmation at 10,000 feet has a pressure of 5200 psi. Is the formation pressure;						
	a.	Above normal						
	b.	Below normal						
	c.	Normal						

#### What happens when a formation is compressed?

Lets return to a bucket of golf balls. The bucket contains golf balls and is full to the top with water.



If we put some more balls into the bucket and give it a shake to pack them in tighter, what happens?

The porosity will get less as we pack more golf balls into the bucket. The excess water will overflow out of the top of the bucket (because a bucket of golf balls has permeability).

We still have a pressure on the gauge equal to the hydrostatic of water in the bucket. Therefore the pressure is still dependant on the height of fluid only.



# Definitions

#### Normal formation pressure

A formation pressure which is equal to the hydrostatic pressure of water of normal salinity for that area. Assumed to be 0.465 psi/ft or 8.94 ppg.

#### Abnormal formation pressure

A pore pressure in excess of (or less than) the hydrostatic of formation fluid.

# The concept of balance

We have said previously that the mud hydrostatic is used to control formation pressure, that is, mud hydrostatic must be sufficient to keep the formation fluid in the formation and not allow any into the wellbore.



We use several terms to describe the relationship between mud hydrostatic and formation pressure.



# Remember

- > greater than
- = equal to
- < less than

#### **Abnormal formation pressure**

If the formation is not permeable or fluid is trapped (remember the sponge in the polythene bag), then any increase in compaction or movement can result in formation pressures much higher than normal.



In this case the formation below the barrier is abnormally pressured – the fluid is supporting some of the weight of the overburden and not just the fluid column.

Abnormal formation pressures can result from compaction, faults, folds and many other reasons. These will be discussed further in a later section.

# **Primary Well Control**

In normal drilling operations it is important that we maintain a slight overbalance.

It is also important that we do not let this overbalance get too high. If the overbalance is allowed to increase too much the mud hydrostatic could exceed the actual strength of the rock itself (or fracture pressure) and mud losses will ensue. This will be discussed in more detail later.

## Primary well control

Primary well control is maintained by controlling formation pore pressures with the hydrostatic pressure of the drilling fluid.

Primary well control is exercised between two distinct limits; these being the maximum pore pressure and the minimum fracture pressure.

Try some yourself Exercise 3.13						
1.	What is meant by <i>abnormal formation pressure</i> .					
	a. b. c.	A formation pressure which requires a mud weight of less than 10 ppg. A formation pressure due only to the weight of the overlying rocks. A formation pressure in excess of the hydrostatic pressure of the fluid in the formation.				
2.	Matcl	h the following description to definitions.				
	i.	Mud hydrostatic = formation pressure				
	ii.	Mud hydrostatic > formation pressure				
	iii.	Mud hydrostatic < formation pressure				
3.	a. b. c. What a. b. c.	Underbalance Balance Overbalance is meant by <i>primary well control</i> ? Maintaining mud weight at least 1000 psi above formation pressure. The blow out preventers. Maintaining mud hydrostatic above formation pressure but less than fracture pressure.				

# **Fracture Pressures**

We know what is meant by formation pressure, but what is fracture pressure?

Fracturing



When too much stress is put on something it will eventually break.

For example a plastic ruler will flex as we apply a force to it.



When the force is released the ruler will return to its normal shape.

If a higher force is applied, the ruler may not return to its normal shape when the force is released – it has *deformed*.





If a sufficiently high force is applied, the ruler will eventually break. At this point the ruler could be said to have *fractured*.

Although different formations behave in different ways (for example, a sandstone behaves differently from a shale and both behave differently to a limestone) they will all react to applied force in a similar manner to the plastic ruler.

That is, when force is applied they will flex and then fracture.



This means that there is always an upper limit to the amount of pressure which can be applied to a formation before the formation fractures.

#### Fracture pressure

The pressure at which fractures are initiated in a formation and the formation accepts whole fluid from the well bore.

# **Measuring fracture pressure**

During the process of drilling a well, it is necessary to measure the fracture pressure. This will allow us to know the upper limits of mud weights and pressures that the formation can be safely exposed to.

Fracture pressure is measured by performing a *leak off test* (LOT).

# Of interest - Leak off tests

A leak off test is normally performed just below each casing shoe and is carried out by shutting in the well, applying a pressure at surface and monitoring when the formation begins to fracture.

Another type of test is a formation integrity test (FIT) or limit test which tests the formation to a pre-determined pressure and not to the point when fracture takes place.

These tests are carried out to measure the strength of the formation below the last casing shoe. We need this information to be able to calculate, amongst other things, the maximum mud density we will be able to use.

We carry out the test by closing in the well and applying additional pressure at surface. By careful monitoring of the surface pressure, we can tell when the formation begins to fracture.



Once we have measured the surface pressure at which fracture takes place, we can calculate the actual pressure on the formation when the fracture takes place (fracture pressure). The fracture pressure will be equal to the mud hydrostatic <u>plus</u> the surface pressure.



Once we have calculated the fracture pressure in psi we can perform calculations in exactly the same way as any other hydrostatic pressure calculations. We can calculate;

- the fracture gradient in psi/ft
- the fracture or maximum mud weight in ppg.

Example	
A leak off test has been carried ou	It just below the $9^{5}/_{8}$ inch casing shoe (set at 10000 feet).
I ne mud weight for the test was I Leak off took place at a surface pr	0.0 ppg.
Leak off took place at a surface pl	
Calculate the fracture pressure.	
The fracture pressure is the sum o pressure.	f the mud hydrostatic at the shoe and the surface leak off
Fracture pressure =	mud hydrostatic + LOT pressure
- =	$(10 \times 0.052 \times 10000) + 1000$
=	5200 + 1000
=	<u>6200 psi</u>
What would this be as a fracture g	gradient?

Fracture gradient (psi/ft) = Fracture pressure (psi)  $\div$  TVD shoe (feet) = 6,200  $\div$  10,000 = 0.62 psi/ft

We can now calculate the theoretical maximum mud weight that could be used i.e. the fracture mud weight.

To do this we can simply convert the fracture gradient to a mud weight.

Fracture mud weight (ppg) =  $\frac{\text{LOT pressure}}{\text{ShoeTVD } \times 0.052} + \text{LOT mud weight}$ =  $\frac{1,000}{10,000 \times 0.052} + 10$ = 11.92 ppg

Another way to calculate the fracture mud weight would be from the original LOT data.

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So in the example the theoretical maximum mud weight or the mud weight that will cause the formation to fracture is 11.92 ppg.

We now therefore have the upper limit on what our mud weight can be.

Try some yourself Exercise	e 3.14
Well data	
Shoe depth (TVD):Mud weight:LOT pressure:	12000 ft 13.0 ppg 1500 psi
Calculate:	
1. The mud hydrostatic at the	he shoe.
	psi
2. The fracture pressure of	the formation
	psi
3. The fracture gradient of	the formation
	psi/ft
4. The fracture mud weight	t
	ppg

# Section 3: The Circulating System

In the previous sections we have examined the pressures exerted by columns of fluid at rest (hydrostatic pressure). We must now look at what happens when these fluids are moving. This section discusses the pressure created when a fluid is moved.

Objectives

- To explain what causes pressure when a fluid is moved.
- To discuss the circulating system on a rig and the pressures within it.
- To calculate the effects of different pump rates and fluid densities.
- To explain and calculate the effect of circulating pressures on the well.
- To discuss why and how circulating rates differ between drilling and well control operations.

Try thes	e first Exercise 3.15
1.	When circulating at 150 spm the pump pressure is 4650 psi. What would the pump pressure be at 75 spm?
	<ul> <li>a. 2325 psi</li> <li>b. 1162 psi</li> <li>c. 4650 psi</li> <li>d. 1550 psi</li> </ul>
2.	<ul><li>When circulating around the well at 90 spm with 11 ppg mud the pump pressure is 2500 psi. What would the pump pressure be if the mud weight was raised to 13 ppg?</li><li>a. 2115 psi</li></ul>
	<ul> <li>b. 1790 psi</li> <li>c. 3492 psi</li> <li>d. 2955 psi</li> </ul>

Exerc	cise 3.15 continued				
	$\mathbf{P}$				
3.	While circulating at 60 spm the pressure losses around the circulating system are:				
	Surface lines 100 psi				
	Drill string 600 psi				
	Bit 700 psi				
	Annulus 50 psi				
	a. Calculate the pump pressure.				
	psi				
	b. What would the gauge on the standpipe manifold read?				
	nci				
	psi				
4.	Well data				
	Depth (TVD) : 12000 feet				
	Mud weight : 11 ppg				
	While circulating at 75 spm the pressure losses in the system are;				
	Surface lines 150 psi				
	Drill string 1000 psi				
	Bit 1200 psi				
	Annulus 250 psi				
	Calculate:				
	a. I ne static bottom hole pressure (BHP).				
	psi				
	h The bottom hele size ulating measure (DUCD)				
	b. The bottom hole circulating pressure (BHCP)				
	psi				
	c. The equivalent circulating density (ECD).				
	ppg				

Exercise 3.15 continued . . .

- 5. Select the reasons why a kick is circulated out at a slow circulating rate. (Four answers)
  - a. Minimise wear of the pump.
  - b. Minimise the pressure exerted on the formation.
  - c. Allow correct operation of the choke.
  - d. Prevent cuttings settling.
  - e. Mud mixing capabilities.
  - f. Pressure limitations of the mud gas separator.
- 6. When are slow circulating rates normally taken (four answers)?
  - a. When mud properties change.
  - b. After each connection.
  - c. Every shift/tour.
  - d. After a long section of hole has been drilled.
  - e. When the bit or BHA is changed.
  - f. Prior to a leak off test.

# **3.1** What happens when a fluid moves? (What is pump pressure?)

Lets examine what happens when a fluid is moved or pumped along a pipe.



As we start to pump fluid will move along the pipe. To make this happen we must overcome the fluids resistance to flow. This is caused by the friction of the fluid against the pipe and the viscosity of the fluid.

For example, the more viscous the fluid or the smaller the pipe, the more resistance to flow. To overcome this resistance will require a pressure to be exerted at the pump.



Now the mud is flowing at a constant rate of 100gpm, we should see a steady pressure at the pump. This "Pump Pressure" is equal to the amount of friction that must be overcome to move the fluid along the pipe at this flow rate.

This pressure would change if any of the following change;

- flow rate
- fluid properties (viscosity, density)
- pipe diameter
- pipe length

Increasing the flow rate, fluid viscosity, fluid density and length of the pipe would all cause an *increase* in pump pressure.

Increasing the diameter of the pipe would cause a *decrease* in the pump pressure.



Note that whilst there is a pressure at the pump (pump pressure) of 500 psi, the fluid is leaving the pipe at 0 psi gauge pressure (the gauge will not show atmospheric pressure). There is therefore a *pressure loss* or *pressure drop* across this section of pipe.

As in this example we only have one section of pipe, this pressure loss is the same as the pump pressure.

Of interest –	Pressure	Gauges
		$\mathcal{O}$

Pressure gauges do not normally show atmospheric pressure – that is, they read zero at atmospheric pressure.

You might therefore see pressures written in two ways;

psia - absolute pressure where atmospheric pressure is approximately 14.7 psi.
psig - gauge pressure where atmospheric pressure is zero.

When you see a pressure written simply as psi it means the pressure you would see on a gauge.

Take three different pieces of pipe and pump fluid along them at a constant rate of 100 gpm.



Each pipe has a different pressure loss depending on the dimensions of the pipe.



What if we join the pipes together end to end?

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The pump pressure (Gauge 1) would show the sum of the pressure losses;



Pressure Loss 50 psi Pressure Loss 100 psi Pressure Loss 150 psi

What would the other gauges read?

Gauge 2 would show the sum of the pressure losses from itself through the rest of the system;



Note that gauge 2 shows 50 psi *less* than the pump pressure. This is because it does not show the pressure required to move the mud along pipe A.

Gauge 3 would show only the pressure losses from itself through the rest of the system.



Note that Gauge 3 does not show the pressure losses in pipe A or pipe B.

A circulating system can be thought of as a series of pipe (or annulus) sections each with its associated pressure losses.

The pump pressure required to move fluid around the system will be equal to the sum of all the individual pressure losses.

# 3.2 The Circulating System

When looking at circulating pressures we can split the circulating system into four component parts.



Surface lines	-	from the mud pump to the top drive or kelly.
Drill string	-	the drill string including drill pipe, HWDP and drill collars.
Bit	-	the nozzles or flow path through the bit.
Annulus	-	from the bit back up to surface including, for example; drill collar in open hole drill pipe in open hole drill pipe in casing

When we pump mud around the circulating system, each section of the system will have an associated pressure loss. The sum of these pressure losses will be seen at the pump as the *pump pressure*.

# Pump pressure

The sum of all the pressure losses in the system from the pump back to surface.



In the previous example, the gauge on the pump itself would show 2,300 psi. What would the gauge on the standpipe manifold on the rig floor read?

Standpipe Manifold	
A manifold on the rig floor allowing mud to be directed from the pumps to different places but normally to the kelly or top drive via the standpipe.	

#### There are two ways to look at this.

#### Either, 1

Starting from the pump where the pressure is 2300 psi. By the time the mud reaches the standpipe manifold, 150 psi will have been "lost" overcoming the friction in the surface lines (i.e. the surface lines have a pressure loss of 150 psi).

The gauge on the standpipe will therefore show 150 psi less than the pump pressure.

The pressure on the standpipe gauge would be;

2300 – 150 = 2150 psi

#### Or, 2

If we add up the pressure losses from the standpipe around the rest of the system this should be the pressure on the standpipe gauge.

Drill string	950 psi
Bit	1000 psi
Annulus	<u>200</u> psi
Standpipe pressure	2150 psi

Whichever method we use, the pressure shown on the standpipe gauge will be 150 psi less than that on the pump because of the pressure loss between the two gauges.

Try some y	ourself Exerc	vise 3.16	
1. While	e circulating at 80 sj	om the pressure losses aroun	d the circulating system are:
a.	Surface lines Drill string Bit Annulus Calculate the pun	125 psi 750 psi 850 psi 75 psi	
b.	What would the p	psi ressure gauge on the rig floc psi	or standpipe read?

# 3.3 Changes in pump rate

In the previous example we were circulating at 100 spm (strokes per minute).



At 100 spm the pump pressure is 2300 psi.

If we change the pump rate then the pump pressure will also change.





Increasing the spm will cause the pressure to increase.



Decreasing the spm will cause the pressure to decrease.

This will apply to any of the friction losses in the system individually or as a whole.

The actual pressure for a new pump rate can be *estimated* using the following formula;

New pressure = Old pressure 
$$\times \left(\frac{\text{New spm}}{\text{Old spm}}\right)^2$$

It must be stressed that this is an *approximate* calculation. The actual pressures will depend very much on the mud system in use.





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Try s	some y	yourself ]	Exercise 3.17			
1.	Pumj Pumj	p rate p pressure	140 spm 3750 psi			
	Calco (Rou	ulate the new p nd answers to	oump pressure at; nearest psi)			
	a.	30 spm		psi		
	b.	50 spm		psi		
	c.	120 spm		psi		
	d.	160 spm		psi		
2.	Pumj Pumj	p rate p pressure	50 spm 600 psi			
	Calculate the new pump pressure at; (Round answers to nearest psi)					
	a.	150 spm		psi		
	b.	120 spm		psi		
	c.	70 spm		psi		
	d.	15 spm		psi		

# 3.4 Changes in mud weight



Increasing the mud weight will cause the pressure to increase



Decreasing the mud weight will cause the pressure to decrease



This effect can also be calculated using the formula;

New pressure = Old pressure  $\times \frac{\text{New mud weight}}{\text{Old mud weight}}$ 

# Example

When circulating with a mud weight of 10 ppg the pump pressure is 3000 psi. What would the pump pressure be if the mud weight was increased to 12 ppg?

New pressure (psi) = Old pressure (psi)  $\times \frac{\text{New mud weight}}{\text{Old mud weight}}$ 

New pressure (psi) =  $3000 \times \frac{12}{10}$ 

New pressure (psi) = 3600 psi

The pump pressure with 12 ppg mud would be 3600 psi.

Try some yourself Exercise 3.18				
<u>Data</u> : Mud weight Pump pressure		14 ppg 2750 psi		
What would the new pump pressure be if the mud weight was changed to; (Round answers to nearest psi)				
1.	15 ppg		psi	
2.	16 ppg		psi	
3.	9 ppg	-	psi	
4.	11 ppg		psi	
5.	17 ppg		psi	

# **3.5** The effect of circulating pressures on bottom hole pressure

Lets now look further and see how circulating pressures might affect Bottom Hole Pressure (BHP).



As discussed previously, 150 psi is lost in the surface lines, 950 psi down the string, 1,000 psi across the bit and 200 psi in the annulus. Starting from the pump;

	Pump pressure	2300 psi
-	Surface line loss	<u> </u>
	Standpipe pressure	2150 psi
-	Drill string loss	<u>950</u> psi
	Pressure behind bit	1200 psi
-	Bit pressure loss	<u>1000</u> psi
	Pressure after bit	200 psi

As you can see, if we start with the pump pressure and subtract each individual pressure loss in turn, this will show us the circulating pressure at different points in the system.

The important pressure to note here is that there is 200 psi remaining to move the mud up the annulus. This pressure loss in the annulus is usually termed the Annular Pressure Loss (APL).

Looking back at the circulating system it can be seen that most of the pressure losses take place prior to the mud reaching the bit. In fact the only pressure loss remaining in the open hole is the annular pressure loss (APL). Thus the APL is the only pressure which will have any effect on Bottom Hole Pressure (BHP).

So when the mud is being circulated, a pressure equal to the APL acts on the bottom of the hole. This will have the effect of increasing BHP.

Annular pressure loss acts on the bottom of the hole, increasing bottom hole pressure.

# 3.6 The effect of annular pressure loss on bottom hole pressure



In our example it requires a force of 200 psi to overcome the friction and move the mud up the annulus. i.e. the APL is 200 psi



According to the Newton's laws of motion, this *must* exert an equal force downwards on the bottom of the hole.









Try s	some yourself	. Exercise 3.19	
1.	Well data Depth (TVD) : Mud weight :	11250 feet 13.2 ppg	
	Pump pressure at 80 Annular pressure los	3750 psi 175 psi	
	Calculate;		
	a. Static BHP		psi
	b. BHCP		psi
2.	Well data		
	Depth (TVD) : Mud weight :	7950 feet 11.9 ppg	
	Pressure losses at 10		
	Surface lines :	75 psi	
	Drill string :	725 psi	
	Bit :	850 psi	
	Annulus :	100 psi	
	Calculate;		
	a. Static BHP		psi
	b. BHCP		psi
	c. Pump pressu	re	psi

# 3.7 Equivalent circulating density

We have seen that bottom hole pressure increases when circulating by the amount of the annular pressure losses (APL).

So while circulating the bottom hole circulation pressure (BHCP) is higher than the mud hydrostatic.

BHCP can be expressed as a value in pounds per gallon (ppg), this is known as the Equivalent Circulating Density (ECD).

ECD can be calculated from the bottom hole circulating pressure by converting this to an equivalent mud density.

$$ECD(ppg) = \frac{BHCP(psi)}{TVD(ft) \times 0.052}$$

Another more common formula used to calculate ECD uses the annular pressure loss and the original mud weight.

$$ECD (ppg) = \frac{APL (psi)}{TVD (ft) \times 0.052} + Mud weight (ppg)$$

#### Example

Well data:

Depth (TVD) : 10000 feet Mud weight : 10 ppg

1. Calculate the BHP when static.

BHP (psi)	=	mud hydrostatic
	=	mud weight (ppg) x 0.052 x TVD (feet)
	=	10 x 0.052 x 10000
	=	<u>5200 psi</u>

2. When circulating at 100 spm the annular pressure losses are 260 psi. Calculate the bottom hole circulating pressure (BHCP).

> BHCP (psi) = mud hydrostatic + APL = 5200 + 260= 5460 psi

3. Calculate the Equivalent Circulating Density (ECD).

ECD (ppg) = 
$$\frac{\text{APL (ps1)}}{\text{TVD (ft)} \times 0.052} + \text{Mud weight (ppg)}$$
  
=  $\frac{260}{10,000 \times 0.052} + 10$   
= 10.5 ppg

As we can see from the example, bottom hole pressure increases by 240 psi to 5,460 psi when circulating. This is equivalent to a mud weight of 10.5 ppg (i.e. the ECD is 10.5 ppg).

Try	some y	ourself Ex	ercise 3.20				
		Mud weight	Depth TVD	APL	BHCP	ECD	
		(ppg)	(feet)	(psi)	(psi)	(ppg)	
	a.	10	10000	300	5500	10.6	
	b.	12	10000	200	6440		
	c.	11	12000	250	7114		
	d.	9.5	8500	150			
	e.	17.3	16500	375			

# 3.8 Circulating out a kick

When drilling we normally use high flow rates and therefore high pump rates to maximize penetration rates and for hole cleaning. Different considerations apply once the well is shut in – we would not normally consider circulating a kick out at the same circulating rate used when drilling.

These considerations include;

- minimising the extra pressures exerted on the well bore (e.g. APL);
- reaction time of the choke operator;
- our ability to maintain mud properties;
- pressure limitations of the mud gas separator (poorboy degasser).



For these and other reasons we would normally circulate a kick out at a much slower pump rate. These slower rates are known as Slow Circulating Rates or SCRs.

Slow circulating rates have traditionally been in the range  $\frac{1}{3}$  to  $\frac{1}{2}$  of the rate used when drilling, but nowadays would be even slower than this.

# Slow Circulating Rates (SCRs)

When we circulate out a kick, we must always ensure that bottom hole pressure is above formation pressure. To do this we must monitor the pressures on surface. In order to accurately monitor the bottom hole pressure, we should know what the pump pressures should be for a range of different rates.

In order to know what pump pressures to expect during well control operations, most Drilling Contractors and Operators carry out slow circulating rates on a regular basis to record the pressures on the mud pumps at different rates.
SCRs are usually taken: -

- every shift;
- when mud properties (including weight) change;
- when the bit or BHA is changed;
- every 500 feet (or 1000 feet);
- change of liner sizes;
  - (in fact whenever anything changes which could affect the pressure).

SCRs are taken: -

- on at least two pumps (in case of a pump failure);
- with at least two different rates (to give a range of options);
- with the bit close to bottom (to give accurate values);
- using the pressure gauge on the choke panel (as this is the gauge that will be used in well control operations).



## Example

The rig is drilling at 16000 feet. Pump pressure is 3500 psi at 100 spm. As the new Driller comes on shift he will normally take some SCRs fairly soon after this.

When taking SCRs he would take them on two mud pumps as a minimum and might record the following information

SCRs at 16000 feet Mud weight 14.8 ppg

Pump 1	spm	Pump 2
130 psi	20	140 psi
320 psi	30	325 psi
550 psi	40	575 psi

Note that the pressures for each pump are slightly different – perhaps due to different efficiency.

These SCRs would be repeated;

- if we drill another 500 feet in this shift;
- if any mud properties change;
- if we the bit or BHA is changed;
- if we change liners.

# **3.9** Significance of annular pressure loss at slow circulating rates

Previously we looked at APLs when drilling and calculated that bottom hole pressure changed significantly between static BHP and BHCP.



However, these annular pressure losses will be much smaller and less significant when the pump rate is slower (e.g. at the SCR).

We should be able to calculate an *approximate* value for the APLs at the SCR using the formula;

New pressure (psi) = Old pressure (psi) x 
$$\left(\frac{\text{New SPM}}{\text{Old SPM}}\right)^2$$

Using the numbers from the previous example, what would the annular pressure loss be at a SCR of 30 spm?



spm is only 18 psi.



The graph shows how pressure loss varies with pump strokes.

From the above example we can make a fairly general statement regarding the effect of annular pressure losses at slow circulating rates on an installation with a surface BOP stack.

In most cases APLs are significant when drilling because of the high pump rates used. When circulating at a SCR however, annular pressure losses are usually so small as to be insignificant.

This will be important in later sections when we discuss the procedures used in well control operations.

# Section 4: Introduction to Well Control (Kick Prevention and Detection)

In previous sections we have discussed normal formation pressure and how to maintain primary well control with the correct mud hydrostatic.

In this section we will discuss abnormal formation pressure, and how to detect it. We will also consider what might happen when primary well control is lost and the methods for ensuring the well is secure.

#### Objectives

- To review primary well control.
- To calculate overbalance and underbalance.
- To define what a kick is.
- To list the causes of kicks
- To discuss reasons for abnormal formation pressure.
- To list the warning signs of abnormal formation pressure.
- To list the positive indicators that a kick is taking place.

Try	these first Exercise 3.21
1.	Well Data:       12500 ft         Depth (TVD)       12500 ft         Mud weight       14.7 ppg         BHA length       680 ft         BHA metal displacement       0.055 bbl/ft         Casing capacity       0.072 bbl/ft         Calculate the drop in BHP if the entire BHA is pulled (dry) without filling the hole.
2.	<ul> <li>Which of the following are warning signs that the well may be approaching balance?</li> <li>(Three answers)</li> <li>a. Increase in size and volume of cuttings.</li> <li>b. Faster ROP.</li> <li>c. Higher torque and drag.</li> <li>d. Reduction in mud chlorides.</li> <li>e. Increase in shale density.</li> </ul>
3.	<ul> <li>Which are the two positive indicators of a kick?</li> <li>a. Decrease in mud flow from the well.</li> <li>b. Increase in mud flow from the well</li> <li>c. Decrease in pit levels</li> <li>d. Increase in pit levels</li> </ul>
4.	<ul> <li>What should the driller do at a drilling break?</li> <li>a. Drill ahead to casing point.</li> <li>b. Stop drilling and pull out.</li> <li>c. Stop drilling and flow check.</li> <li>d. Nothing.</li> </ul>

# 4.1 A review of primary well control

In order to maintain control of the well we must continuously have a mud hydrostatic pressure in the well equal to or above the formation pressure.

This extra pressure is known as an overbalance

Overb	alanced situation		
	Mud hydrostatic	>	Formation pressure
Remember			
<ul><li>&gt; greater than</li><li>= equal to</li><li>&lt; less than</li></ul>			
Example			
	Mud hydrostatic Formation pressure The static overbalan and formation pressu	= = ce is the ure or;	5200 psi 4650 psi difference between the mud hydrostatic
Overbalance (psi)	= Mud hydrost = 5200 - 4650 = <u>550 psi</u>	atic (psi)	) – Formation pressure (psi)

Try	some yourself	. Exercise 3.2	22	
1.	Mud hydrostatic Formation pressure	= 7000 psi = 6850 psi		
	Overbalance	=	psi	
2.	Mud hydrostatic Formation pressure	= 5200 psi = 4950 psi		
	Overbalance	=	psi	

When the mud hydrostatic pressure and formation pressure are equal, that is known as a balance situation or we would say the well is on-balance.

000 000 000 000 000 000 000 000 000 00	On balance		
	Mud hydrostatic	=	Formation pressure

If mud hydrostatic falls below formation pressure we use the term underbalanced.



Example						
	Mud hydrostatic = 5200 psi Formation pressure = 6000 psi					
	Overbalance = -800 psi					
	or the well is 800 psi underbalance					



Example				
Well depth is 10000 feet (TVD) Mud weight is 12 ppg Formation pressure gradient is 0.61 psi/ft				
Is the well overbalanced?				
Firstly we must calculate the mud	hydrostatic.			
Mud hydrostatic (psi) =	Mud weight (ppg) x 0.052 x TVD (ft)			
=	12 x 0.052 x 10000			
=	<u>6240 psi</u>			
Next we must calculate the formation pressure.				
Formation pressure = (psi)	Formation pressure gradient x TVD (psi/ft) (ft)			
=	0.61 x 10000			
=	<u>6100 psi</u>			
Now we can see if the well is overbalanced.				
Mud hydrostatic Formation pressure Overbalance	$ \begin{array}{rcl} = & 6240 \text{ psi} \\ e &= & 6100 \text{ psi} \\ = & 140 \text{ psi} \end{array} $			
So the well is 140 psi overbalanced.				

Try some yourself Exercise 3.24				
In the under	In the following examples calculate whether the well is overbalanced on balance or underbalanced and by how much.			
1.	Depth (TVD) Mud weight Formation pressure	= =	12000 ft 10 ppg 0.465 psi/ft	
2.	Depth (TVD) Mud weight Formation pressure	=	16000 ft 12 ppg 0.75 psi/ft	
3.	Depth (TVD) Mud weight Formation pressure	= = =	17950 ft 17.5 ppg 0.91 psi/ft	
4.	Depth (TVD) Mud weight Formation pressure	= = =	9750 ft 13.5 ppg 0.69 psi/ft	

As discussed in Section 2, whilst maintaining primary well control it is important not to allow the mud hydrostatic to become too great as eventually the pressure will become too high and mud will be lost into the formation. This is known as the fracture pressure and is a measure of the strength of the formation.



Fracture pressures are also measured in the same units as hydrostatic or formation pressures as a gradient in psi/ft or as an equivalent mud weight in ppg.

# Example The fracture pressure in a well is 9100 psi at 10000 feet. So if the mud hydrostatic was above this fluid could be lost into the formation. If we change the fracture pressure to an equivalent mud weight:-Mud gradient (psi/ft) ÷ 0.052 = Mud weight (ppg) 0.91 (psi/ft) ÷ 0.052 = 17.5 (ppg) We see that the equivalent *fracture mud weight* is 17.5 ppg. This now gives us a maximum mud weight which cannot be exceeded. This same information can also be given as a gradient in psi/ft. Fracture gradient (psi/ft) = Fracture pressure (ppg) ÷ TVD (ft) = 9,100 ÷ 10,000 = 0.91 psi/ft

To maintain primary well control we must maintain a mud density which will keep mud hydrostatic pressure above formation pressure but below fracture pressure.

Remember				
Primary well control				
Controlling formation pore pressures with the hydrostatic pressure of the drilling fluid. This is achieved by maintaining a mud hydrostatic above the formation pressure but below the fracture pressure of the formation.				
Formation pressure < Mud hydrostatic < Fracture pressure				
<b>Overbalanced</b> Mud hydrostatic pressure above formation pressure.				
Mud hydrostatic > Formation pressure				
<b>Balanced</b> Mud hydrostatic pressure equal to formation pressure.				
Mud hydrostatic = Formation pressure				
Underbalanced Mud hydrostatic pressure less than formation pressure				
Mud hydrostatic < Formation pressure				

Well data Depth (TVD) : 125	
Formation pressure gradient : 0.6 Fracture pressure gradient : 0.9 Calculate:	500 ft 24 psi/ft 36 psi/ft
a. The minimum mud weight requir	ed.
nng	
PPS	14
b. The maximum or fracture mud w	eight.
ppg	
Well data Depth (TVD) : 900 Formation pressure gradient : 0.6 Fracture pressure gradient : 0.7 Calculate: a. The formation pressure at 9000 fe b. The fracture pressure at 9000 fee	00 ft 8 psi/ft 5 psi/ft eet.
	Depth (TVD)       :       125         Formation pressure gradient       :       0.60         Fracture pressure gradient       :       0.90         Calculate:       .       .       .         a.       The minimum mud weight require

# 4.2 What happens if we lose primary well control?

If primary well control is lost (i.e. the well becomes underbalance), several outcomes are possible, these include:-



a kick;

the drill string becoming stuck because the formation squeezes into the well bore.



# **Definition of a kick**

If the well is underbalance then the potential exists for formation fluids to flow from the formation into the well bore.



It is important to note that for this to happen the formation must be permeable.

### Remember

**Permeability** – a measure of the ease in which a fluid flows through a rock formation.

### Remember

Kick: an unintentional flow of formation fluids into the well bore

**Influx:** the volume of fluid which has entered the well bore.

**Note:** the terms influx and kick are often used interchangeably. In this document we will use the terms as above – the *kick* being the process of an *influx* entering the well bore from the formation.

# 4.3 Causes of kicks

In order for a kick to take place the following situation must exist:-

The well must be underbalance with a permeable formation exposed in the well bore.



For the well to become underbalance one of only two things must happen, either;

1. mud hydrostatic **DECREASES** 

or

2. formation pressure **INCREASES** 

That is, abnormal formation pressure.

## Example

Well depth	10000 ft
Mud weight	10 ppg
Formation pressure (Normal)	0.465 psi/ft

What is the overbalance at this stage?

Mud hydrostatic =	:	Mud weight (ppg) x 0.052 x TVD (ft)
=	:	10 x 0.052 x 10000
=	:	<u>5200 psi</u>
Formation pressure =	:	Formation pressure gradient (psi/ft) x TVD (ft)
=	:	0.465 x 10000
=	:	<u>4650 psi</u>

So the well is currently 550 psi overbalance.

If we drilled into a new formation with a formation pressure of more than 5200 psi we would become *underbalance*.

If the mud hydrostatic were allowed to drop below 4650 psi we would become *underbalance*.

In either case we have a potential kick situation.

We can now separate causes of kicks into two distinct categories: -

- reduction in hydrostatic pressure;
- increase in formation pressure (i.e. Abnormal formation pressure).

Let's now look at the individual causes in turn.

# 4.3.1 Reduction in hydrostatic pressure

There are a variety of reasons why the hydrostatic or bottom hole pressure might decrease. These might include:-

## **Reduction in mud weight**

If the mud weight falls then the bottom hole pressure will fall. A reduction in mud weight could be caused by;

Accidental dilution A valve left open, water or base oil diluting the system.

Small amounts of gas entering the well bore will cause a reduction in





Gas cutting

mud weight.

# **Barite settling** If the barite (the material used to increase the mud weight) settles during periods of no circulation the mud weight will fall.





Example – Reduction in mud weight			
A well is 15000 feet (TVD). The formation pressure gradient at this depth is 0.7 psi/ft. The current mud weight is 14.2 ppg			
a.	Calculate the overbalance		
	Overbalance (psi) = mud hydrostatic – Formation pressure = $(14.2 \times 15000 \times 0.052) - (0.7 \times 15000)$ = $11076 - 10500$ = $576 \text{ psi}$		
b.	If the mud weight was reduced by 1 ppg what would the drop in bottom hole pressure (BHP) be?		
	The easiest way to calculate the reduction is to work out the <u>loss</u> in hydrostatic of 15000 feet of 1 ppg.		
	Loss of hydrostatic = mud weight drop x $0.052$ x TVD = $1 \times 0.052 \times 15000$ = $\underline{780 \text{ psi}}$		
	The drop in BHP would be 780 psi.		
с.	Would the well now be overbalance or underbalance?		
	If we started with an overbalance of 576 psi and lose 780 psi we would now be;		
	Underbalance = $780 - 576 \text{ psi}$ = $204 \text{ psi}$		

Example –	Gas cut mud		
The well is 95 Current mud v	00 feet (TVD). veight is 11 ppg		
It is estimated	that the top 1000 feet of the well contains gas cut mud weighing 9.5 ppg.		
a.	What is the bottom hole pressure (BHP) when the hole is full of 11 ppg mud?		
	BHP = Mud weight (ppg) x $0.052$ x TVD (ft)		
	= 11 x 0.052 x 9500		
	= 5434  psi		
b.	What will be the reduction in BHP due to the gas cut mud?		
If we have 1000 feet of mud which <i>should be</i> 11 ppg but is actually 9.5 ppg then the drop in mud weight is;			
	Reduction in mud weight (ppg) = $11 - 9.5$		
	= 1.5 ppg		
	We can now calculate the reduction in BHP.		
Reduction in BHP (psi) = Mud weight reduction (ppg) x $0.052$ x TVD (ft)			
	= 1.5 x 0.052 x 1000		
	= <u>78 psi</u>		
	So the gas cutting of the mud will cause a reduction in bottom hole pressure of 78 psi.		

Try s	ome yourself Exercise 3.26
1.	Well depth : 18115 feet Mud weight : 16.3 ppg
	The mud weight is reduced by 1.5 ppg.
	Calculate the reduction in BHP.
	psi
2.	Well depth:11090 feetMud weight:13.8 ppg
	2000 feet of the well contains gas cut mud with a weight of 12 ppg.
	Calculate the reduction in BHP.
	psi

### Not keeping the hole full when down hole losses are encountered



If a weak formation is drilled into we may start to lose mud into that formation.

If the mud level is allowed to fall, the mud hydrostatic will fall, potentially causing the well to become underbalance and a kick taken.

When losses are encountered it is of paramount importance that the well is kept full.

#### Example – Losses

When drilling a new formation is penetrated at 16500 feet. Major losses occur.

The level of mud is estimated to have dropped 400 feet down the annulus.

Mud weight is 13 ppg.

Calculate the drop in BHP.

The drop in BHP is due to the loss of 400 feet of 13 ppg mud.

Drop in BHP (psi)

= Mud weight (ppg) x 0.052 x TVD (ft) = 13 x 0.052 x 400 = 270.4 psi (270 psi)

So the losses would cause a drop in BHP of 270 psi.

### Not filling the hole with the correct amount of fluid when tripping

If we pull one stand of pipe with a volume of 2 bbl out of the hole, we must put in 2 bbl of mud to keep the hole full.

If the level of mud is allowed to fall, the hydrostatic pressure will fall, potentially causing a kick.

It is important that we monitor trips <u>very</u> carefully to ensure that fluid additions or displacements during a trip are <u>correct</u>.

Return to Part 2 section 8 for a complete description of trip monitoring and the use of the trip tank and trip sheets.



#### Example – Not filling the hole

The entire bottom hole assembly (BHA) is pulled from the hole dry. If the hole is not filled at all, calculate the drop in BHP.

Well data

Length of BHA	=	500 ft
Metal displacement of BHA	=	0.054 bbl/ft
Casing capacity	=	0.15 bbl/ft
Mud weight	=	11 ppg

Firstly we must calculate the volume of the metal in the BHA pulled out of the hole.

BHA metal volume	=	500 x 0.054
	=	27 bbl

So the top of the well is empty by 27 barrels.

Next we must calculate the level drop.

Level drop = Volume  $\div$  Casing capacity = 27  $\div$  0.15 = 180 feet

So the level of mud will have dropped by 180 feet.

Now we can calculate the pressure drop.

Pressure drop $=$	Mud weight x 0.052 x level drop
=	11 x 0.052 x 180
=	<u>103 psi</u>

Therefore pulling the entire BHA without filling the hole will cause a drop in BHP of 103 psi.

Try s	some yourself Exercise 3.27			
1.	In a well with a mud weight of 18.5 ppg, the mud level falls by 230 feet.			
	Calculate the drop in BHP.			
	psi			
2.	Well data Length of BHA = 800 ft <b>Metal displacement of BHA = 0.035 bbl/ft</b> Casing capacity = 0.073 bbl/ft			
	Mud weight = 9.8 ppg			
	Calculate the drop in BHP if the entire BHA is pulled dry.			
3.	Losses of 5bbl/30mins are encountered when drilling. Drilling is stopped and the hole monitored for one hour.			
	Mud weight : 12.5 ppg Annular capacity : 0.125 bbl/ft *Assuming the same losses occur while the well is being monitored. Calculate:			
	a How much mud would be lost in one hour?			
	bbl			
	b. How far would the mud level drop in the annulus?			
	ft			
	c. What would be the reduction in BHP?			
	psi			

#### Swabbing

Imagine the drill string down the hole to be similar to a piston in a cylinder.



If the drill string is raised, mud must move past the string down the hole to keep the hole full below the bit.

This relative movement of string and mud will inevitably cause a temporary drop in bottom hole pressure (BHP) *while the string is moving*. Once the string is static, BHP will return to normal.



If this drop in BHP is great enough, the well may be temporarily underbalance causing an influx of formation fluid into the well bore.

### Surging

Surging can be thought of as the opposite of swabbing – moving the drill string into the hole causes a temporary increase in bottom hole pressure (BHP).

This increase may be sufficient to cause minor losses to the formation eventually leading to an influx. (The actual mechanisms for this are complex and outwith the scope of this book.)

Factors, which increase both swab and surge pressures:

- increased pipe speed
- increased mud viscosity
- smaller annular clearances
- longer pipe lengths.





It should be noted that *any* movement of anything in the well (including open ended pipe or even wireline) will cause a change in BHP. Only the magnitude of the change will vary.

Upward movement causes a drop in BHP = Swabbing Downward movement causes an increase in BHP = Surging

Swabbing and surging can only be detected by the accurate monitoring of hole fill during trips.

To do this properly, it is essential that we use the trip tank and trip sheets correctly. Again see Part 2 section 8.

Try some yourself Exercise 3.28			
1. Swabbing	g is due to?		
a.	An increase in BHP while tripping		
b.	A decrease in BHP while tripping.		
с.	Lost circulation.		
d.	Not filling the hole.		
2. Select the factors that will increase the risk of swabbing. (Three answers)			
a.	High viscosity mud.		
b.	Low viscosity mud.		
с.	Balled up stabilisers.		
d.	Pulling out of the hole quickly.		
e.	Pulling out of the hole slowly.		

# 4.3.2 Causes of abnormal formation pressure

For formation pressure to increase there must be a change in the formation. This might occur within a formation or as we drill into a new formation. Thus a kick due to abnormal formation pressure can only really occur while we are drilling ahead.



For example, if the new formation penetrated is abnormally pressured, the well may be underbalance and we might take a kick.

The causes of abnormal formation pressure are many and varied. Some of the more common reasons we encounter abnormal pressures while drilling include;

- undercompacted shales
- faults
- salt domes
- aquifers
- gas caps
- communication between formations.

### **Undercompacted shales**



Shales are rocks formed from mud deposited in a marine basin, which has undergone a process of compaction and dewatering due to its burial beneath more layers of mud. This process of deposition is continuous in a typical marine basin.

To picture the process of compaction and

dewatering, remember what happened when we compressed the sponge – the porosity is reduced and the water is forced out of the sponge.





When this process of compaction and dewatering takes place over a sufficient period of geological time, the formations will be normally pressured because formation fluids will be able to migrate and thus pressure will not be trapped.

Normally pressured

- shales have undergone the process slowly
- porosity will decrease with depth
- density will increase with depth
- the shale becomes more compact, dense and less porous.
- The drilling rate should decrease with depth.

In areas of the North Sea and the Gulf of Mexico, this process of compaction is still taking place. This is due to the rapid (geologically speaking) deposition of the muds.

Because this process is still taking place, the porosity will be greater for a given depth and the fluid pressure higher than normal. Because of the higher porosity and fluid content the formations will be less dense than expected for a given depth.

Abnormally pressured

- porosity higher than expected
- density lower than expected
- drilling rate faster than expected.

Because this mechanism causes a gradual or *transitional* increase in formation pressure with depth, changes or *warning signs* will be seen while drilling.

These warning signs will be detailed in section 4.4.

#### Faulting

When earth movements have taken place in the geological past, they may have caused shearing and relative movements of formations. This is known as faulting.



These movements can cause abnormal formation pressures.







Any uplifted formation where fluid is trapped may be abnormally pressured.



## Salt domes



**Artesian effect** 

Formations in and around salt domes are often abnormally pressured due to uplifting as the salt forces its way through the surrounding formations.

Very high formation pressures can be encountered in the formations within the salt itself.

H

When drilling near high ground it is possible to encounter formations carrying a much higher hydrostatic head of water than anticipated.

In the example we would be trying to balance a water height H with a mud height h.

Thus the formation we are drilling through will be abnormally pressured.

#### Gas caps



Because the gas in the reservoir is less dense than the water in the surrounding formations, the top of the reservoir will be abnormally pressured.

Example	5000 ft		
	6000 ft Gas/Water contact	Gas	
The gas reservoir is at 5000 feet TVD.			
The gas /water contact is	s at 6000 feet TVD		
The gas gradient is 0.1 p	osi/ft		
The whole area surrounding the reservoir is normally pressured with a gradient of 0.465 psi/ft.			
Firstly calculate the formation pressure 10 feet above the top of the reservoir (at 4990			
feet) this being normally pressured.			
Formation pressu	n pressure = Formation pressure gradient x TVD		
(psi) at 4990 feet	t	(psi/ft)	(ft)
	= 0.465	x 4990	
	= 2320	osi	





Try some yourself Exercise 3.29			
1. When drilling the top of a gas reservoir penetrated is penetrated at 4500 feet.			
<u>Well Data</u> :			
Reservoir top Gas/water contact	:	4500 ft 6000 ft	
Normal formation pressure		0.465 psi/ft	
If the area outside the reservoir is normally pressured calculate:			
a. The formation pressure at the top of the reservoir.			
psi			
b. The mud weight required to balance the formation.			
ppg			

# 4.4 Warning signs

In some cases when drilling towards an abnormally pressured formation, there will be a variety of changes which take place. If we monitor the well carefully, these changes will warn us of the increasing formation pressure – hence the name warning signs.

Warning signs of abnormal pressure (or of decreasing overbalance) can be related to a number of things, including;

- changes in drilling parameters
- hole condition
- gas levels
- cuttings properties
- mud properties

### Warning sign

A warning sign is information from the well telling us that formation pressure is increasing or that the well is becoming closer to balance.

One way to picture what is happening and why these signs occur is to consider what happens when we drill through a long sequence of shales where the formation pressure is increasing (i.e. undercompacted shales).

As we start to drill the formation is normally pressured. If we were drilling with a mud weight of 10 ppg we would have an overbalance of approximately 1 ppg.



\_

\_

As we drill deeper the formation pressure increases. If we maintain the mud weight at 10 ppg, the overbalance will be decreasing.



This decreasing overbalance may cause changes in;

- drilling rate (rate of penetration)
- hole condition
- gas levels
- cuttings
  - mud properties

# Increased rate of penetration (ROP)

Assuming constant drilling parameters we would expect the ROP to decrease with depth in normally pressured formation.



In an abnormally pressured formation, the ROP would increase due to;

- decreasing overbalance
- increasing porosity
- decreasing density (softer rock drills faster)

#### Hole condition

As the formation pressure increases, the plastic clay will start to "squeeze" into the well bore, causing increased torque and drag.



#### **Gas levels**

If the formation porosity is increasing and the pore spaces contain gas, background gas may increase.





Connection gas may also occur as the well approaches balance.

Connection gas is a slight increase in gas levels a lag time after a connection, caused by the drop in bottom hole pressure when the pumps are switched off. It indicates that the well is very close to balance.

### **Cuttings size and shape**

Normal drilled shale cuttings tend to have a specific shape depending on the bit.

A rock bit tends to produce small, round or flat cuttings with rounded edges.

A Polycrystalline Diamond Compact bit (PDC) tends to produce cuttings which look like "shavings".



As the formation pressure increases and overbalance decreases, the cuttings start to become long and splintery with angular edges.

As the well approaches balance, cuttings start to explode off the sides of the hole by themselves – known as *cavings*.

### **Cuttings or shale density**

Mud Weight 10.0 ppg

Shale density should normally increase with depth.



The increased porosity and fluid content of the overpressured zone will cause shale density to be less than expected.

#### **Flowline temperature**

Formation temperature normally increases as we drill deeper (i.e. there is a geothermal gradient). This is due to the heat flow from the Earth's core (the closer we get to the core, the hotter the temperature). This means we usually see an increase in temperature as we drill deeper.



The trapped fluid in an abnormally pressured formation causes a disturbance in this geothermal gradient, because water conducts heat less effectively than rock.



Thus an abnormally pressured formation may show a higher geothermal gradient – shown by an increase in mud temperature.

The practical limitations of measuring mud temperature at the flowline often mask these effects completely.

#### Chlorides content of the mud

Because the overpressured zone has an increased porosity, if the formation fluid was salt water, it can contaminate the mud, causing the chloride content to increase.



A combination of the above warning signs tells us that formation pressure is increasing (or that the overbalance is decreasing).


## What should we do?

If the mud weight is increased slightly then everything should return to normal.

## What if we ignore them?

Mud Weig	nt 100 ppg
	Porosity Increasing Formation Pressure 10.0ppg Formation Pressure 10.1ppg

The formation pressure is now higher than the mud weight i.e. the well is underbalance.

## What will happen?

With the well underbalance, we might take a kick or we might get stuck.

#### In a shale

As shale has very low permeability, the formation cannot flow, so the hole will collapse and the string becomes stuck.



### In a permeable formation



If we had penetrated a permeable formation whilst underbalanced, we would take a kick.



# 4.5 Drilling breaks

In the previous section we examined the warning signs that we would see as we drilled through a continuous shale where formation pressure was increasing. In many cases, these warnings might be absent, for example, when drilling into a faulted zone.



What will happen when the new formation is penetrated?

We might see a change in drilling parameters, for example rate of penetration (ROP) and torque.



In this case ROP has increased significantly. This change is known as a drilling break.

It is also possible that the ROP slows down, for example, when a harder formation is penetrated.





This is also a *drilling break*.

# Drilling break A drilling break is a significant change in the rate of penetration (ROP) or any other drilling

A drilling break is a *significant* change in the rate of penetration (ROP) or any other drilling parameters.

When a drilling break is encountered the correct procedure is to stop drilling and check that the well is not flowing (i.e. we are not taking a kick). The term for this procedure is flow check.

## Flow check

Stopping all drilling (or tripping) activity and monitoring the well for flow. This is usually done using the trip tank.

A drilling break is an indicator that we have penetrated a new formation, not necessarily that we are taking a kick.

If the well is flowing (i.e. we are taking a kick) there will be further indications.

# 4.6 Kick indicators

When a kick is actually taking place there will be certain positive indications on surface. These include;

- increase in mud flow from the well;
- increase in pit levels.

### Increase in mud flow

As formation fluid flows into the well bore an increase in flow will be seen on surface.



## Increase in pit levels

As this extra flow from the formation increases the volume in the well, an increase in volume will be seen on surface.





When positive indications of a kick are identified, it is important to secure the well **promptly**. This is carried out by closing one of the blow out preventers i.e. *shutting in* the well.

Try s	some yourself Exercise 3.31
1.	What is a drilling break?
	<ul> <li>a. A gradual small increase in ROP.</li> <li>b. A gradual small decrease in ROP.</li> <li>c. A significant change in the ROP.</li> </ul>
2.	What is the correct action if a drilling break is observed?
	<ul> <li>a. Continue, but let the Company Man know that the ROP has picked up.</li> <li>b. Drill up to 5 feet, stop drilling, pick up, shut down the pumps and flow check.</li> <li>c. Continue drilling with a reduced pump rate to observe the well better.</li> <li>d. Nothing - a high ROP is exactly what we want.</li> </ul>
3.	The main indicators that the well is flowing are: (Two answers)
	<ul> <li>a. Increased flow rate.</li> <li>b. Drilling break.</li> <li>c. Pit gain.</li> <li>d. Increase in pump pressure.</li> </ul>
4.	Shutting in the well quickly is essential as a delay may lead to a more serious well control situation. From the list below, identify the practices most likely to cause a large influx. (Three answers)
	<ul> <li>a. Not setting the flow meter alarms.</li> <li>b. Having the choke manifold lined up correctly.</li> <li>c. Drilling a further 15 feet after a drilling break, before flow checking.</li> <li>d. Practice regular pit drills for crew.</li> <li>e. Maintaining and testing stab-in valves.</li> <li>f. Calling Toolpusher to drill floor prior to shutting in the well.</li> </ul>

## 4.7 The importance of monitoring trends

Throughout this section we have discussed warning signs and kick indicators. Without careful monitoring of a whole range of drilling and other parameters we would never be able to spot the warning signs, or even not detect that we were taking a kick.

It is vitally important to the safety of the whole drilling operation that control of the well is maintained. In order to do this all relevant parameters must be monitored and recorded.

When drilling these parameters would include :

Drilling parameters

- Rate of Penetration (ROP)
- Torque
- Overpull and drag
- Pump pressure

### Mud related parameters

- Mud weights
- Gas levels
- Mud chlorides
- Mud temperature

#### **Cuttings related parameters**

- Size, shape and volume of cuttings
- Shale density

#### Measurement While Drilling (MWD) tools.

#### Pressure While Drilling (PWD) tools.

Logging While Drilling (LWD) tools.

#### In fact, ANYTHING that gives us information about downhole conditions

## Trends

For many of the above parameters it is not the actual value that matters, but how it changes over time.

If we can monitor how something behaves when normal, we can detect when the situation starts to change.



- It is the deviation from the *Normal Trend* that is important – we should be able to account for <u>any</u> changes.

One example of the importance of identifying the *Normal* trend is seen when monitoring pit levels. While we often refer to a pit level as being "constant", this would not in fact be true when we are drilling. The pit levels should actually fall as we make new hole.

Example . . . If we are drilling at 100 ft/hr we will be creating 100 ft of new hole each hour. This new hole volume will contain a volume of mud, causing the pit level to fall. If the hole size was 12 <sup>1</sup>/<sub>4</sub> inches this would equal:  $=\frac{12.25^2}{1029.4}$  bbl/ft = 0.146 bbl/ftSo the extra 100 ft of hole would require a mud volume of:  $= 0.146 \times 100$ = 14.6 bbls However, for each 100 ft we drill we must, of course, add 100 ft of drill pipe at the surface. The metal displacement of this drill pipe = 0.0065 bbl/ft So we add 100 x 0.0065 = 0.65 bbls of steel Taking both these volumes into account, the new volume created for each 100 feet drilled would be = 14.6 - 0.65= 13.95 bbls

So we would actually expect the pit levels to fall by approximately 14 bbls per 100 ft drilled. In this case that would be 14 bbls/hr. A level drop of anything less than this might indicate that we were taking a kick.

Try s	some yourself Exercise 3.32 We are drilling 8 ½ inch hole at an	average ROP of 50 ft/hr.	
	Drillpipe metal displacement Calculate the drop in pit level over	0.0065 bbl/ft :	
	a. 1 hour	bbl	
	b. 6 hours	bbl	

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# Section 5: Secondary Well Control An introduction to Kill Methods

In the previous section we looked at the reasons we take kicks. This section gives an introduction to the methods we use to regain primary well control. The procedures are classified as secondary well control.

### Objectives

- To discuss the principles involved in all kill methods
- To outline the basic procedures involved in the Drillers Method and the Wait and Weight Method
- To be able to carry out the calculations required for the above methods

Try these first Exercise 3.33			
1.	For each of the following statements, tick which method the statement best describes.		
	a.	a. Drill pipe pressure maintained at ICP for the first circulation.	
		Driller's	Wait and Weight
	b.	Kill mud pumped during seco	ond circulation.
		Driller's	Wait and Weight
	c. Kill mud pumped as influx circulated out.		irculated out.
		Driller's	Wait and Weight
	d.	Influx circulated out prior to	pumping kill mud.
		Driller's	Wait and Weight

Exer	cise 3.	.33 continued
2.	. Which of the following statements is true when starting to kill a well?	
	a.	Maintain the drill pipe pressure constant when bringing the pump up to kill speed.
	b.	Maintain the casing pressure constant when bringing the pump up to kill speed.
3. Final Circulating Pressure (FCP) is maintained constant:		Circulating Pressure (FCP) is maintained constant:
	a.	Once the influx is out of the well.
	b.	Once kill mud has reached the bit.
	c.	Once kill mud reaches the casing shoe.
	d.	When pumping kill mud down to the bit.

## 5.1 Principles of kill methods

## Objectives of the kill operation

The objective of any kill operation is to restore primary well control. In order to do this it is necessary to:

- remove the influx
- replace the original mud with a heavier mud



Only once all the influx is removed and the well circulated with a mud weight which will balance formation pressure will we have regained *primary well control*.

This procedure is called *killing the well*. The methods used are "kill methods". The increased mud weight to balance formation pressure is called "kill mud".

To successfully kill the well the correct bottom hole pressure (BHP) must be maintained throughout the operation.

If BHP is too low the well will be underbalanced and a further kick will be taken.

If BHP is allowed to become to high then we may fracture the formation resulting in losses.

So just as we do in primary well control, in secondary well control or "killing the well" BHP must be maintained above formation pressure but below fracture pressure.

It is necessary that the kill methods we use maintain both a *constant* and *correct* BHP, that is, at least equal to or slightly greater than formation pressure.

## **Constant BHP kill methods**

There are two commonly used constant BHP methods of well control. These are:

- Drillers
- Wait and Weight

Both methods have many things in common, for example:

- both will be carried out at a constant pump rate.
- both will be carried out at a slower pump rate than used while drilling.
- both use the same methods to monitor and control BHP.
- both use the choke to maintain constant BHP.

### Selection of pump rates

To be able to monitor and control bottom hole pressure it is imperative that we circulate out a kick at a constant pump rate. The actual pump rate used will usually be selected from the range of slow circulating rates (SCRs).

To monitor BHP during the kill operation the pressure gauges on the surface must be used:

- Drill pipe pressure
- Casing pressure

Correct interpretation of these gauges will indicate what is happening downhole.

Further information can be gained by close monitoring of pit levels and mud weights.

Control of BHP is achieved by manipulation of the choke whilst circulating at a constant rate.

### Try some yourself – Exercise 3.34

- 1. The principle involved in constant bottom hole pressure methods of well control is to maintain a pressure that is:
  - a. Equal to the slow rate circulating pressure.
  - b. At least equal to formation pressure.
  - c. Equal to the shut in drill pipe pressure.
  - d. At least equal to the shut in casing pressure.
- 2. What is the main purpose of a choke during well control operations?
  - a. To shut in the well
  - b. To create a back pressure
  - c. To prevent hydrate formation



## **Interpretation of pressures**

### Well shut in and stabilised

Once the well has been shut in i.e. circulation has been stopped and the BOP closed, and allowed to stabilise, there are two pressures which can be observed: -

Shut in drill pipe pressure	-	SIDPP
Shut in casing pressure	-	SICP

What do these pressures represent?

SIDPP shows how much underbalance the well is, i.e. SIDPP is the difference between the formation pressure (FP) and the hydrostatic pressure of the mud in the drill pipe.



#### **Example – SIDPP**

1. Having taken a kick and shut in the well the following pressure is observed on the drill pipe.

SIDPP = 500 psi

The mud weight is 10 ppg and the depth of the well 10000 feet.

What is the formation pressure?

The formation pressure is 500 psi more than the mud hydrostatic pressure in the drill pipe.

Formation pressure (FP) = SIDPP + DP mud hydrostatic

Firstly we must calculate the mud hydrostatic;

Mud hydrostatic = Mud weight (ppg) x 0.052 x TVD (ft) =  $10 \times 0.052 \times 10000$ = 5200 psi

### Example continued-SIDPP

Now calculate the formation pressure;

FP = SIDPP + DP Mud hydrostatic= 500 + 5200 = 5700 psi

What mud weight is required to balance this formation pressure?

Mud weight =  $\frac{\text{Formation pressure}}{\text{TVD} \times 0.052}$  $= \frac{5,700}{10,000 \times 0.052}$ = 10.96 ppg

In practice we would round this up to an accuracy of one decimal place giving a mud weight of 11.0 ppg.

2. While drilling with a mud weight of 12 ppg a new formation is penetrated at 10000 feet. The formation pressure is 7040 psi.

Is the well underbalance or overbalance?

Firstly calculate the mud hydrostatic

Mud hydrostatic (psi) = Mud weight (ppg) x 0.052 x TVD (ft) =  $12 \times 0.052 \times 10000$ =  $\underline{6240 \text{ psi}}$ 

As this is less than the formation pressure the well is underbalance.

When the well is shut in and stabilised what would the SIDPP be?

The SIDPP would show the amount of underbalance or the difference between the formation pressure and the mud hydrostatic.

SIDPP = FP - Mud hydrostatic = 7040 - 6240= 800 psi

The SIDPP gauge would now show 800 psi.

Try some yourself Exercise	se 3.35		
1. After taking a kick and shutting	1. After taking a kick and shutting in the well the following information is recorded.		
Well depth (TVD):Mud weight:SIDPP:	11500 ft 12.5 ppg 650 psi		
a. Calculate the formation pre	essure.		
	psi		
b. Calculate the mud weight required to balance this pressure (round your answer <u>up</u> to one decimal place).			
	ppg		
2. A new formation is penetra If the drilling mud weight i	tted at 6000 feet. The new formation pressure is 3632 psi. s 11 ppg what would the SIDPP read?		
SIDPP =	psi		
SIDPP =	psi		

SICP also indicates the amount of underbalance i.e. SICP is the difference between the formation pressure and they hydrostatic pressure in the annulus.



We must remember however that the annulus is not a full column of clean mud, but also contains the influx.

SICP = FP - (mud hydrostatic + influx hydrostatic).

The SICP will vary depending on the size of the influx i.e. the larger the influx, the higher the SICP.

SICP will also vary depending on the type of influx. For example a 10 barrel gas kick would result in a higher SICP than a 10 barrel water kick because the gas has a lower density.

## To recap:

SIDPP shows the amount of underbalance and depends only on the formation pressure and the mud hydrostatic.



SICP is also indicative of the amount of underbalance but will vary depending on the size of the influx and the type of influx.



Try	some yourself Exercise 3.36	
1.	Which of the following determine the SIDPP? (Two answers)	
	<ul> <li>a. Influx density.</li> <li>b. Influx size.</li> <li>c. Mud density inside the drill string.</li> <li>d. Formation fluid pressure.</li> <li>e. Volume of cuttings in the annulus.</li> </ul>	
2.	Which pressure gauge readings could be used to calculate formation pressure? (Two answers)	
	<ul> <li>a. Accumulator gauge.</li> <li>b. Casing pressure gauge on choke panel.</li> <li>c. Drill pipe pressure gauge at Driller's console.</li> <li>d. Drill pipe pressure gauge on choke panel.</li> </ul>	
3.	In a shut in well, why is the SICP <u>usually</u> higher than the SIDPP?	
	<ul> <li>a. The gauges are at different levels.</li> <li>b. The influx is in the annulus and is lighter than the mud.</li> <li>c. The influx is in the annulus and is heavier than the mud.</li> <li>d. The annulus is loaded with cuttings</li> </ul>	
4.	What would be the difference in SIDPP and SICP for a water kick and a gas kick of the same volume?	
	<ul> <li>a. Difference between shut in pressures are greater for a water kick</li> <li>b. Difference between shut in pressures are greater for a gas kick</li> <li>c. Influx type does not contribute to a difference between shut in pressure</li> </ul>	
5.	When a kick occurs, it is important to get the well shut in as soon as possible to minimise size of influx, because:	
	a. A larger pit gain will result in a higher SIDPP resulting in a heavier kill mud weight?	
	True / False	
	b. A larger pit gain will result in higher SICP but SIDPP will stay the same.	
	True / False	

## Well control methods

Lets now look at the two most common methods of killing the well. They are known as the Drillers method and the Wait and Weight method.

## Start up procedure

One common element of both methods is the way we commence circulating i.e. *the start up procedure*.

What must happen at this point is the pump must be started and gradually brought to the kill rate speed (the selected slow circulating rate). At the same time, the choke must be gradually opened to allow circulation.

Therefore the pump must be brought up to speed, whilst ensuring that a CONSTANT BHP is maintained.

The way this is achieved varies depending on the type of installation (surface or subsea BOPs). On an installation with surface BOPs, the correct start up procedure is to hold CASING PRESSURE CONSTANT.

#### **Start up procedure – Surface BOP**

The pump is gradually brought to the kill rate (slow circulating rate) holding casing pressure constant by gradually opening the choke.

Note;

A modified procedure is used for subsea BOPs (i.e. well control from floating rigs) which is outwith the scope of this document.

Once we are circulating at the correct rate, we change from monitoring the casing pressure to monitoring the drill pipe pressure.

When stopping circulation, gradually close the choke maintaining the casing pressure constant, until the pump rate is reduced to zero.

#### **Pump stroke counters**

As we know from Part 2, the way we monitor positions of fluids in the hole and the stages of a circulation is by monitoring pump strokes.

It is usual to reset the counters to zero at the start of each operation.

## **The Drillers Method**

The Drillers Method of well control requires two circulations as follows:

First circulation: to remove the influx. Second circulation: to circulate heavy mud (or kill mud) around the well.

## **Drillers Method Procedure**

#### **First circulation:**

1. Bring the pump to kill rate, opening the choke using correct start up procedure (HOLDING CASING PRESSURE CONSTANT).





2. Once at kill rate, switch to monitoring the drill pipe pressure which <u>should</u> be equal to the SIDPP plus the slow circulating rate pressure (SCRP). This is known as the initial circulating pressure (ICP)

Initial circulating pressure (ICP) = SIDPP + SCRP

3. Drill pipe pressure is now held constant at ICP until the influx is removed.

The casing pressure will rise as gas expands in the annulus.

Should the drill pipe pressure vary, the choke must be used to maintain it constant.



4. The casing pressure will continue to rise as gas is circulated up the annulus.
It is important to remember that it is the <u>drill pipe</u> pressure which is being held constant until the influx is removed.





5. As the influx is removed, the casing pressure will start to fall

Remember that it is the still <u>drill pipe</u> pressure which is being held constant.

6. Once the influx has been completely removed, the well can again be shut in.

This is carried out by shutting down the pump HOLDING CASING PRESSURE CONSTANT.

If all the influx has been removed the drill pipe pressure and casing pressure should equal the original SIDPP.



## Second Circulation

There are two procedures commonly in use for the second circulation. The original or standard "Driller's method" as documented in API and a "modified" version.

Whilst the standard API method is simple and requires minimal calculations, its success relies on perfect conditions (i.e. total removal of the influx) after the first circulation. It has largely been replaced by the modified version which is more reliable.

In both procedures we should now be lined up on kill mud. In this example the kill mud weight is assumed to be: 11.0ppg.

#### Second Circulation Standard API Procedure

1. With the pump lined up on kill mud and pump stroke counters reset, bring the pump to speed, opening the choke, using the correct start up procedure.



- 2. Once at kill rate, hold casing pressure constant until kill mud reaches the bit. (This can only be done successfully if the annulus is clean.)
- 3. As kill mud enters the annulus, switch over to the drill pipe pressure and maintain this constant until kill mud reaches the surface.



#### Second Circulation (Modified Method)

1. With the pump lined up on kill mud and pump stroke counters reset, bring pump to speed using correct start up procedure.





3. With the pump now at kill rate, the drill pipe pressure should be the initial circulating pressure.

ICP = SCRP + SIDPP

This pressure should be maintained until kill mud reaches the rig floor then the counters reset to zero.



5. Once kill mud has entered the annulus FCP is held constant until the kill mud is back to the surface.



When kill mud is back to surface the well can be shut in. Both SIDPP and SICP should be zero and there should be no flow from the well.

## **Summary of Procedure – Drillers method**

6.



- Bring pump to kill rate, opening choke holding CASING PRESSURE CONSTANT.
- Once at kill rate, switch to drill pipe pressure.
- Drill pipe pressure should be

I.C.P. = SCRP + SIDPP = 300 + 500 = 800 psi

- Hold this pressure constant until the influx is removed
- Shut down holding CASING PRESSURE CONSTANT
- SIDPP should equal SICP

## **First circulation**

Second circulation (modified method)



- Bring pump to kill rate holding CASING PRESSURE CONSTANT.
- Once at kill rate ,switch to drill pipe pressure.
- Drill pipe pressure should be

I.C.P. = 
$$SCRP + SIDPP$$
  
=  $300 + 500$   
=  $800 \text{ psi}$ 

• Allow drill pipe pressure to fall from ICP to FCP as kill mud is circulated to the bit.

Final circulating pressure (FCP) = SCRP  $\times \frac{\text{Kill mud weight}}{\text{Original mud weight}} = 330 \text{ psi}$ 

- Hold FCP until kill mud reaches surface
- Shut down SIDPP = SICP = 0

### Second circulation (the original Drillers)



- When pump to kill rate hold casing pressure constant until kill mud reaches the bit
- Once kill mud enters the annulus, switch to drill pipe pressure and hold constant until kill mud reaches surface

Try some	e yourself Exercise 3.37
1. Wh the (Th	nich of the following statements are correct with regard to the first circulation of Driller's method? hree answers)
a. b. c. d. e. f.	Bring pump up to kill speed holding casing pressure constant. Maintain casing pressure constant until kill mud is at the bit. Maintain drill pipe pressure constant until influx is out. Maintain drill pipe pressure constant until kill mud reaches surface. Shut in well and check both SICP and SIDPP are approximately equal. Shut in well and check for zero shut in pressure.
2. Whof	nich of the following statements are correct with regard to the second circulation the Driller's method. nree answers)
a. b. c. d. e. f.	Bring pump up to kill speed holding casing pressure constant. Allow the drill pipe pressure to fall from ICP to FCP or, maintain casing pressure constant until kill mud is at the bit. Maintain pumping pressure constant until influx is out. Maintain casing pressure constant until kill mud reaches surface. Shut in well and check both SICP and SIDPP are approximately equal to original SIDPP. Maintain drill pipe pressure constant once kill mud is at the bit.

## Wait and Weight Method

The Wait and Weight method, (named because we WAIT until the kill mud is WEIGHTed before starting the operation) requires only a single circulation during which heavy mud is circulated around the well at the same time as the influx is circulated out. So we commence the wait and weight method with the pump lined up on our kill mud.

## Procedure

1. Bring the pump to kill rate using the correct start up procedure.

2. Once at kill rate switch to drill pipe pressure which <u>should</u> be the initial circulating pressure (ICP).

ICP = SIDPP + SCRP

This pressure must be maintained until kill mud reaches the rig floor. The counters are then reset.

3. As kill mud is pumped down the drill string to the bit the drill pipe pressure must be allowed to fall from ICP to FCP.



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4. By the time kill mud has reached the bit, the drill pipe pressure will have fallen to FCP.

5. Once kill mud has entered the annulus,
FCP is held constant until kill mud is back to the surface.
The casing pressure will rise as the gas is circulated up the annulus and will drop as the gas is removed at surface.

6. When the kill mud is back to the surface, the well can be shut in. Both SIDPP and SICP should be zero and there should be now flow from the well.



## Summary of Wait and Weight Method

## Single circulation



- Bring pump to kill rate, holding CASING PRESSURE CONSTANT
- Once at kill rate, switch to drill pipe pressure
- Drill pipe pressure should be I.C.P. = SCRP + SIDP

$$= SCRP + SIDPP$$
$$= 300 + 500$$

• Allow drill pipe pressure to fall. ICP = 800

to

Final circulating pressure (FCP) = SCRP ×  $\frac{\text{Kill mud weight}}{\text{Original mud weight}}$ =  $300 \times \frac{11}{10}$ 

as kill mud is pumped to the bit

- Hold FCP until kill mud reaches surface
- Shut down HOLDING CASING PRESSURE CONSTANT
- SIDPP should equal SICP

Try	some y	yourself Exercise 3.38
1.	Place	the four correct statements relating to the Wait and Weight method in order.
	a. b.	Bring pump up to speed holding drill pipe pressure constant. Allow drill pipe pressure to fall from ICP to FCP as kill mud is pumped to bit.
	c.	Bring pump up to speed holding casing pressure constant.
	d.	Maintain drill pipe pressure constant as kill mud is pumped from bit to surface.
	e.	Maintain casing pressure constant as kill mud is pumped from bit to surface.
	f.	Allow drill pipe pressure to fall gradually from ICP to FCP as kill mud is pumped from suction pit to shakers.
	g.	Shut down and check the well is dead.
	1 <sup>st</sup>	
	$2^{nd}$	
	3 <sup>rd</sup>	
	4 <sup>th</sup>	
2.	Whic Weig	th of the following statements are true or false concerning the Wait and the method?
	a.	In the Wait and Weight method the casing pressure should be kept constant during the second circulation.
		True / False
	b.	Only the Wait and Weight method maintains constant bottom hole pressure.
		True / False
	c.	In the Wait and Weight method the drill pipe pressure is held constant throughout.
		True / False
	d.	The Wait and Weight method requires you to draw a graph or step down chart.
		True / False

## **Calculations required**

Prior to commencing any well control operation, there will be some calculations required. To carry out either of the Drillers or the wait and weight methods some essential calculations are required.

- hole volumes and pump strokes (see Part 2 section 7)
- kill mud weight (KMW)
- initial circulating pressure (ICP)
- final circulating pressure (FCP)
- a step down chart.

## The formulae

#### Abbreviations

KMW	=	kill mud weight (ppg)
OMW	=	original mud weight (ppg)
SIDPP	=	shut in drill pipe pressure (psi)
TVD	=	true vertical depth (ft)
ICP	=	initial circulating pressure
FCP	=	final circulating pressure
SCRP	=	slow circulating rate pressure

$$KMW = \frac{SIDPP}{TVD \times 0.052} + OMW$$

ICP = SIDPP + SCRP

 $FCP = SCRP \times \frac{KMW}{OMW}$ 

Example	
Well data	
Depth (TVD) $=$	10000 ft
Mud weight =	10 ppg
SIDPP =	500 psi
SICP =	900 psi
SCR details	
30 spm	300 psi
Pump strokes	
Surface to bit =	1000 strokes
1. Kill Mud W	Veight (KMW)
	SIDPP
	$KMW = \frac{1}{TVD \times 0.052} + OMW$
	500
	$=\frac{500}{10000}+10$
	$10000 \times 0.052$
	= 0.96 + 10
	= 10.96 ppg
What mud weig	ght should be mixed?
The actual muc must be a weig appropriate KM	l weight must be sufficiently heavy to balance formation pressure but ht that we can mix and measure (i.e. Accurate to 0.1 ppg). The <i>IW</i> is 11.0 ppg.
It is not normal	to add any additional 'Safety Factor' to the mud weight at this stage
2. Initial Circulation	ng Pressure (ICP)
ICP	
ICI	r = 51011 + 5000 $r = 500$ nsi $\pm 300$ nsi
ICI	= 500  psi + 500  psi
ICI	- 000 psi
3. Final Circulatin	g Pressure (FCP)
	$ECP - SCPP \times KMW$
	$1 \text{ CI} - \text{ SCKI} \land \frac{1}{\text{OMW}}$
	11.0
	$=300 \times \frac{100}{100}$
	= 220 mai
	- 220481

## **Example continued**

#### A Step Down Chart

4. In order to allow the drill pipe pressure to fall from ICP to FCP as kill mud is pumped to the bit we must calculate the pressures in between. This is usually done every 100 strokes from surface to bit.

The drill pipe pressure must be allowed must be allowed to fall by 47 PSI per 100 strokes as kill mud is pumped to the bit.



Try some yourself – Exercise 3.39 Well data Depth (TVD) 13500 ft : 12.0 ppg Mud weight : **SIDPP** 750 psi : 1000 psi SICP SCRP @ 30spm 500 psi : Pump strokes from surface to bit : 1500 strokes Calculate: Kill mud weight. 1. 2. Initial circulating pressure 3. Final circulating pressure. Pressure drop per 100 strokes as kill mud is circulated to the bit. 4.

Try some yourself – Exercise 3.40				
Given the following well data:				
Measured Depth		12500	12500 ft	
True Vertical Depth		12000	) ft	
Current mud weight		11.5	ppg	
Slow circulating fate pressure at 40 spin 450 psi			psi	
SIDPP SICP		700	psi psi	
The well is to be killed by the Driller's method.				
Calculate the following.				
1.	Initial circulating pressure to be held for the first circulation.			
	psi			
2.	What should the following pressures read after the first circulation?			
	SIDPPpsi			
	SICPpsi			
3.	The kill mud weight for the second circulation. (Rounded to 1 decimal place.)			
	pp;	g 5		
4.	Final circulating pressure to be held once kill mud is past the bit.			
	psi			