WELL CONTROL MANUAL

By Prof Dr. Sc., PhD **Elnur Amirov** at the Departments of Petroleum Engineering (Baku Higher Oil School, Khazar University and Heriot Watt University). M/LWD Log Analyst (Sr. Tech Prof Sperry Petrophysicist) at SS Drilling Services.
e-mails: e.amirov@hw.ac.uk ; eamirov@khazar.org ; elnuramirov@outlook.com ; amire3@bp.com

WELL CONTROL

The ultimate objective of well control in the petroleum industry is the technique used in oil and gas operations such as drilling, well work over, and well completions to maintaining the fluid column hydrostatic pressure and formation pressure to prevent influx of formation fluids into the wellbore. This technique involves the estimation of formation fluid pressures, the strength of the subsurface formations and the use of casing and mud density to offset those pressures in a predictable way/manner. Understanding of pressure and pressure relationships are very important in well control.

BASIC CONCEPTS

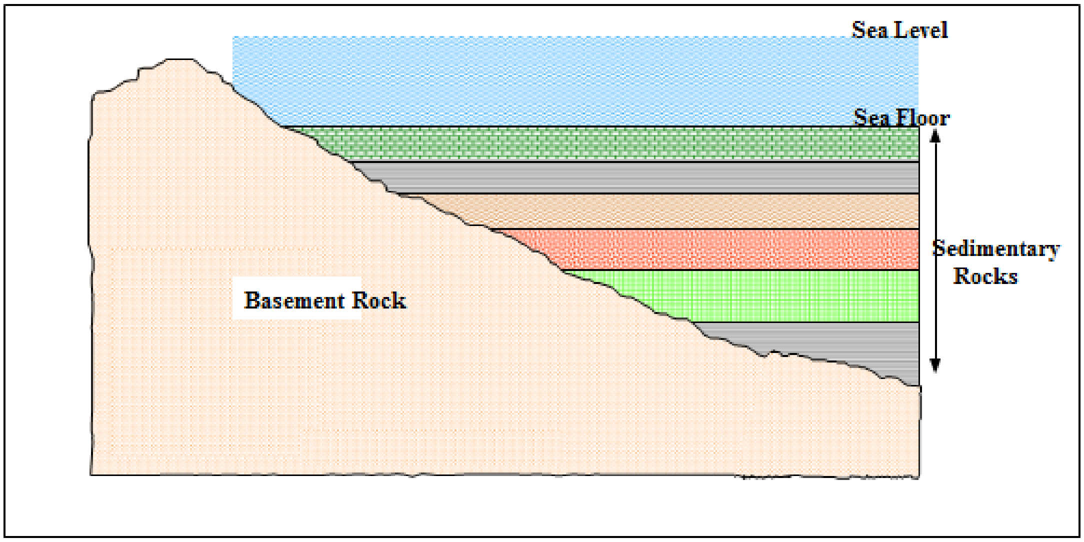
Drilling fluid commonly called mud. Mud is the vital factor in creating hydrostatic pressure and therefore primary well control. We need to look at mud in more detail. Mud is a mixture of liquid and solids and performs a number of functions during the drilling operation.

GEOLOGY

Geology is the study of rocks. Oil industry tends to call rocks by formation name. For example, a sand formation or a limestone formation.

The majority of rocks we drill are called sedimentary rocks meaning that they were deposited as sediments, mostly in water e.g. lakes and seas.

Sediments are mostly made up of tiny grains of material washed down by rivers or by salts that settle out of the seawater or by the remains of sea animals. As each individual grain of material settles to the bottom of the sea, it helps form a layer of sediment (see below). This is a very simple diagram of what you would see in a section through the earth.

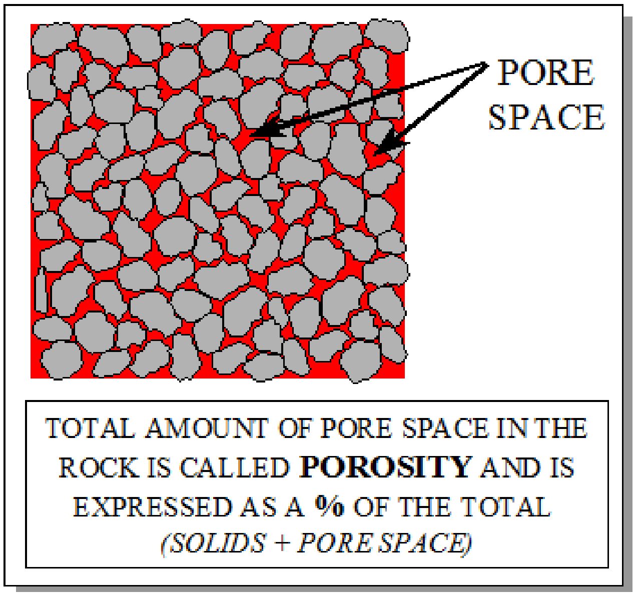


The sediment consists of all the grains plus tiny spaces between that are filled with water. An example of this would be to drop a lot of glass beads in a glass of water. Although each bead is touching the one next to it, there is a space between filled with water.

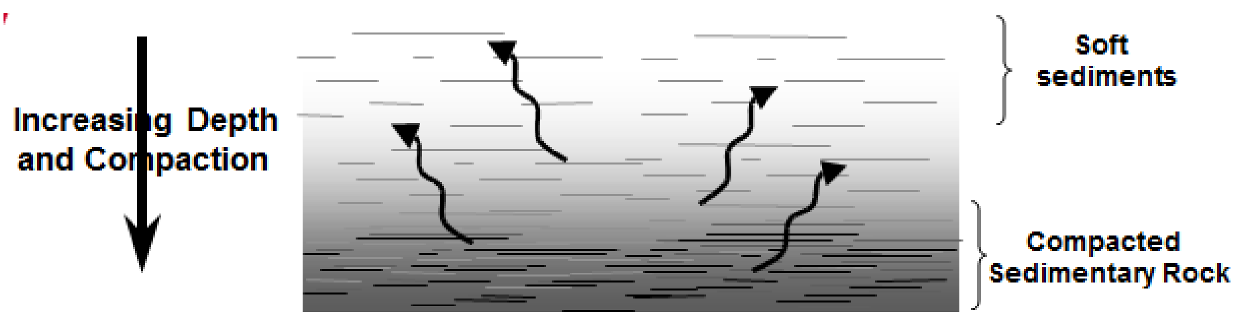
This space is called a pore space.

It is normally filled with water - pore fluid.

The amount of pore space is called the POROSITY and is usually expressed as a % of the total volume of rock grains and water. A porosity of 20% means that the sediment is 20% space (filled with water) and 80% rock grains.



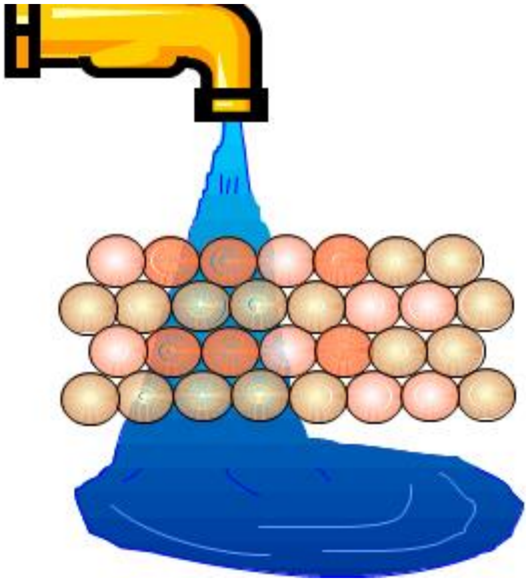
As more and more sediment is deposited, the weight causes the underneath to be squashed (compacted). This compaction causes the pore fluid (formation fluid) to be squeezed out and the porosity to decrease. The sediment also gets harder and denser.



PERMEABILITY

For the pore fluids to get squeezed out it means that the fluid migrates upward along and through the pore spaces until it reaches the surface.

This means that the pore spaces are normally connected in order to allow the fluid to be squeezed out. How easy it is for fluids to migrate depends on how easy it is to move from one pore space to the next. This property is called the permeability.



CONCEPT OF BALANCE

Formation fluid present in the pore spaces of the rock. To hold formation fluids back, the mud hydrostatic pressure must at least be equal the formation fluid pressure.

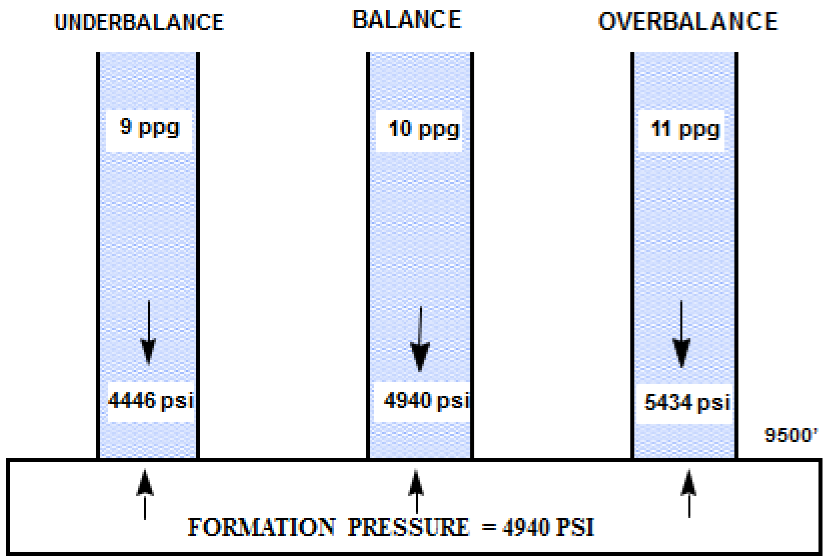
Mud Hydrostatic = Formation Fluid Pressure (Balanced)

Mud Hydrostatic greater than Formation Fluid Pressure (Overbalanced)

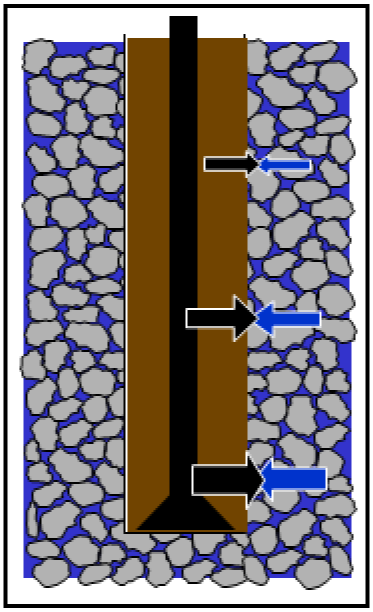
Mud Hydrostatic less than Formation Fluid Pressure (Underbalanced)

KICKS CAN HAPPEN WHEN UNDERBALANCED

The diagram below shows the three conditions.



OVERBALANCE

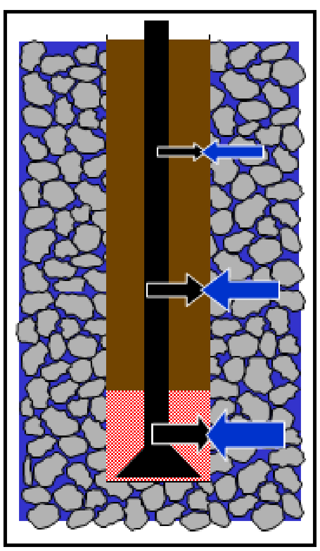


Mud Hydrostatic > Formation Pressure

To hold formation fluids back, the mud hydrostatic pressure must at least BALANCE the formation fluid pressure. Common drilling practice is to drill slightly OVERBALANCE.

UNDERBALANCE

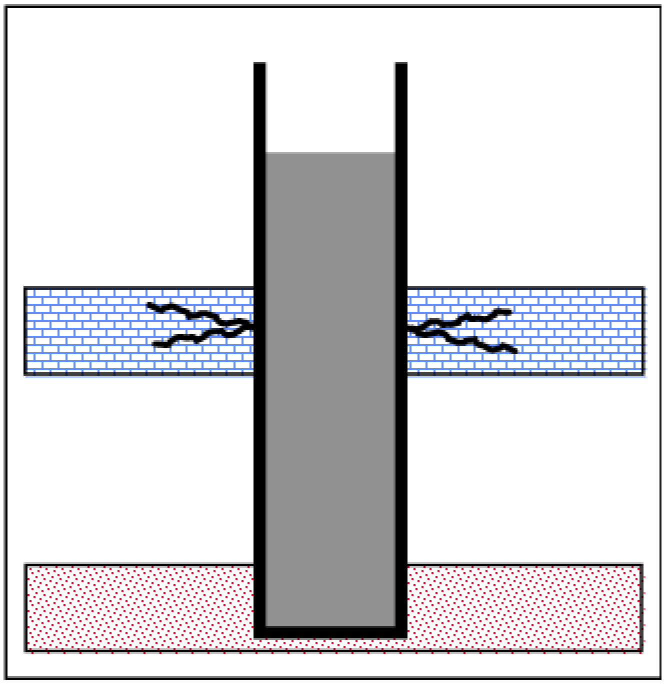
Causes of underbalance are: 1) reduction in mud hydrostatic pressure and 2) increase in formation fluid pressure.



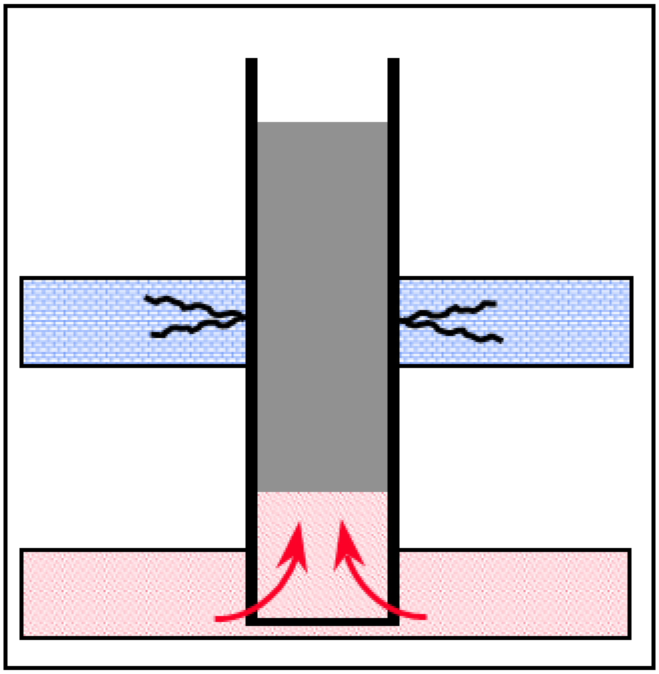
Mud Hydrostatic < Formation Pressure

FORMATION FRACTURE

All formations have strength: but some are stronger than others. Strength relates to the formations ability to handle pressure applied from the mud or other sources e.g. pressure from the pumps with the well shut in. The strength of the formation depends on the rock type, amount of compaction and natural fractures that may exist in the rock. In most cases the deeper we drill the greater the compaction and the greater the strength. If too much force is put on a formation then it will fracture. Drilling Fluid will then drain away into the fracture.



If this happens the danger would be a reduction in mud hydrostatic pressure (Primary Control) that could cause the well to start flowing (kick). For this reason we must try to avoid creating losses by use of good drilling practice. As long as sections of open hole have to be drilled there will always be the risk of formation fracture and lost circulation. If the drilling personnel know how much force is required to fracture the formation then such forces can be avoided. Knowledge of fracture pressures can be gained by performing Leak-Off Tests or Pressure Integrity Tests or by studying offset wells and the problems encountered. However much information there is available to drilling personnel there is always the possibility of drilling into a naturally weak formation.

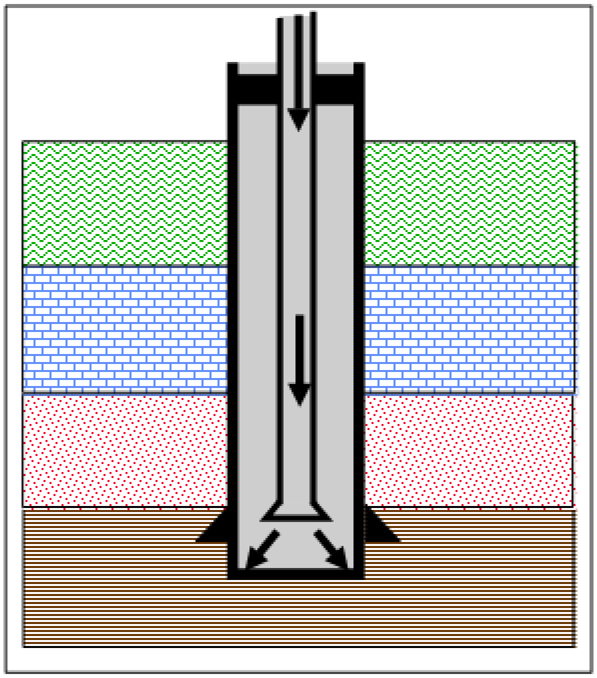


LEAK OFF TEST

A Leak-Off Test is performed on the open formation immediately below the casing shoe. A shallow 'rat-hole' is drilled below the shoe, say 5-25 ft (1.5-7.5m), to give open hole for performing the test.

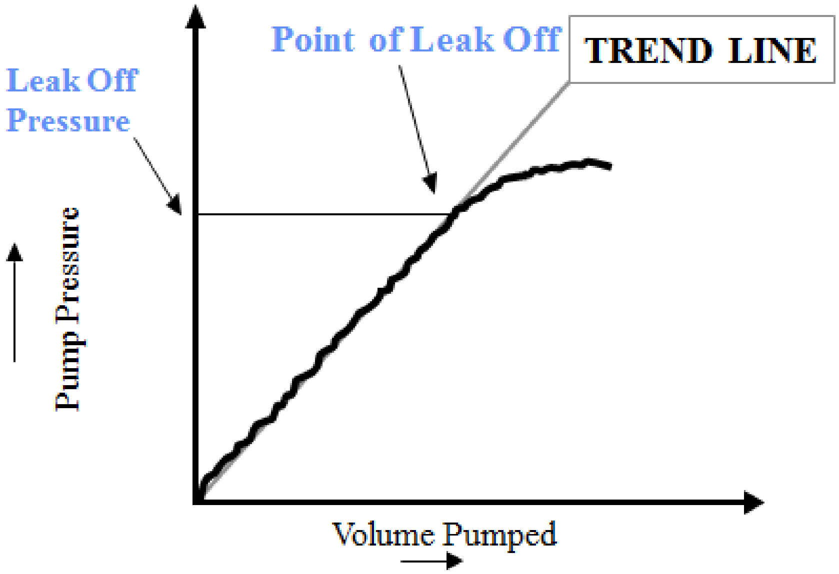
The logic behind testing the formation just below the shoe is that it is most likely to be the weakest. Compaction and hardening of rock increases with depth, therefore, the shallowest open hole formation should be the weakest.

Testing can be done by closing in the annulus using the BOP and slowly pumping mud down the drill pipe to pressure up the well bore. Pumping down the kill line with the well shut-in at surface is another method.



For a LEAK OFF TEST (LOT) the wellbore is pressured up until the formation takes mud or "leaks-off". The diagram (see below) shows a graph of pump pressure plotted against volume pumped. The point at when the line moves away from the trend is taken as the point of 'leak off'.

The information gained will tell you the approximate Fracture Pressure, by how much you can increase the pressure on Shoe Formation and whether that pressure is greater than or less than anticipated mud weight required as we drill deeper.

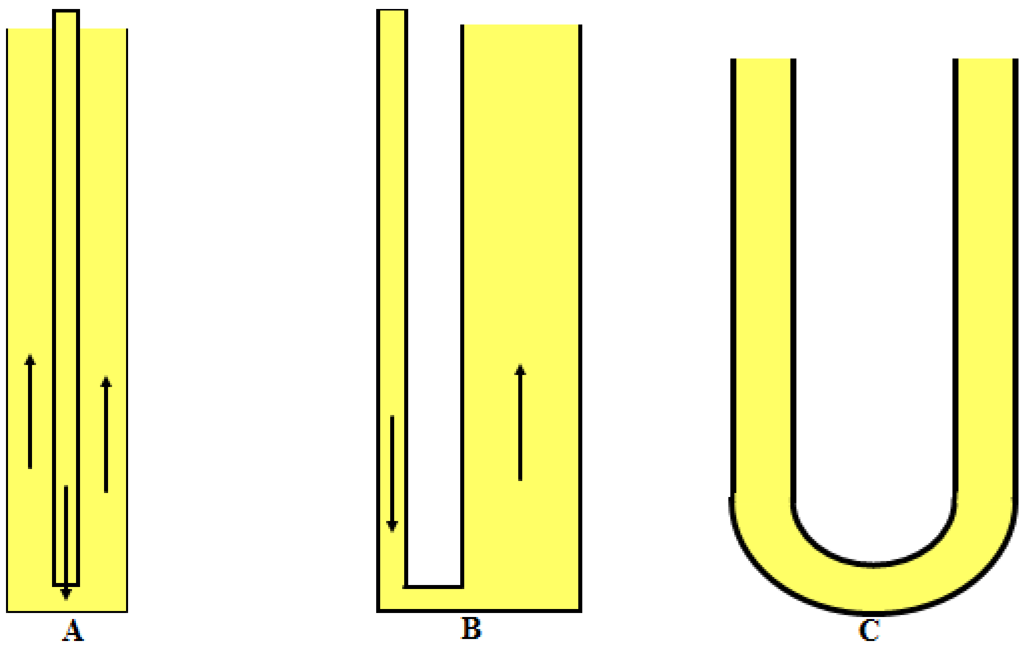


U-TUBE

Understanding how a U-Tube works is essential knowledge for anyone studying well control. Before explaining further, the hole needs to be represented as a U-Tube.

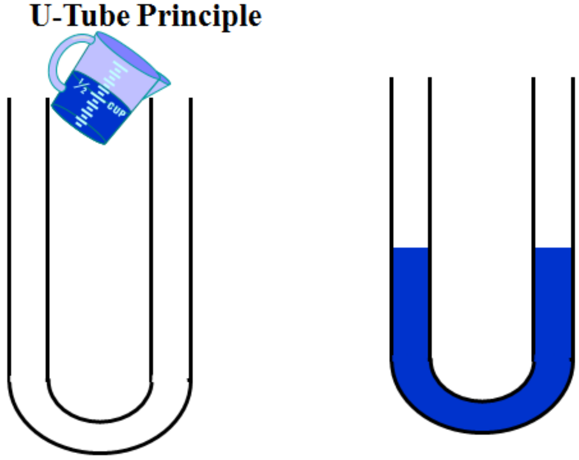
Diagram A is the normal diagram for a well, showing drillpipe and Annulus. If the drillpipe is moved outside as shown in Diagram B we have a typical representation.

Diagram C shows another way to show a U-Tube.

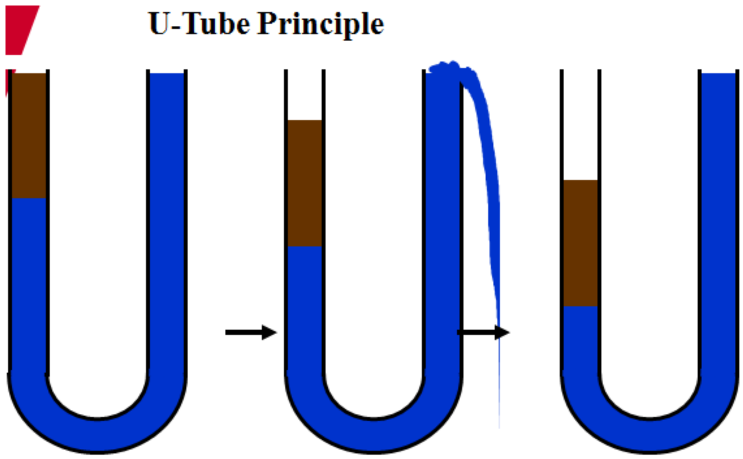


The U-Tube on the right is to be partly filled with water. What will happen once the water is in the U-Tube? The water in the U-Tube has balanced with the same height on either side. The reason for this is that the hydrostatic pressures for each side are the same because the fluid (water) and heights are identical.

U-Tube Principle



Following the three diagrams below from left to right, the first diagram has some heavy fluid added (brown). The heavy fluid increases the hydrostatic pressure on the left side and causes the water to u-tube out (middle diagram). Once stabilized it can be seen that the levels are different. The u-tube is balanced so the hydrostatic pressures on left and right side are the same (balanced).

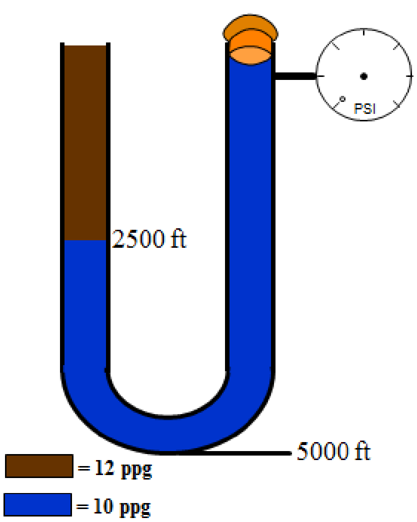


To complete this introduction to the U-Tube the left hand side is half filled with a heavy mud and the right hand side is plugged.

The hydrostatics are not balanced due to the heavy mud, making the left hand hydrostatic greater.

This imbalance will want to cause the u-tube to balance but this is prevented by the plug.

There is pressure acting against the plug that is equal to the difference in hydrostatics. So if the left hand side has a hydrostatic pressure 100 psi greater, then the pressure underneath the plug will be 100 psi.



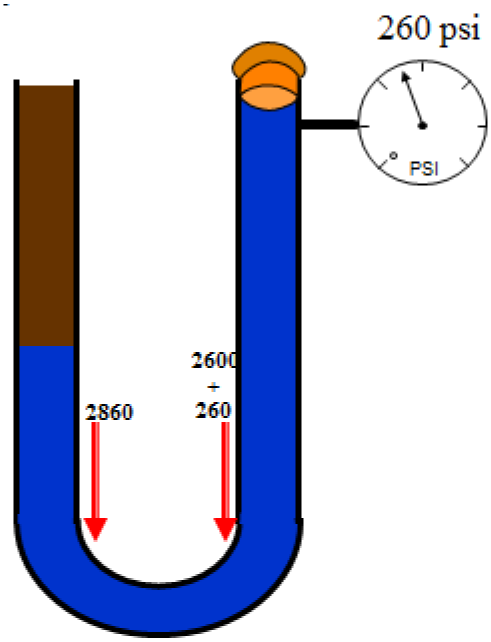
The procedure is to calculate the hydrostatic for both side then find the difference.

The calculation is shown below:

12 x 0.052 x 2500 = 2860 psi

10 x .052 x 5000 = 2600 psi

2860 - 2600 = 260 psi



FRICTIONAL PRESSURE LOSSES

Where does Pump Pressure come from??

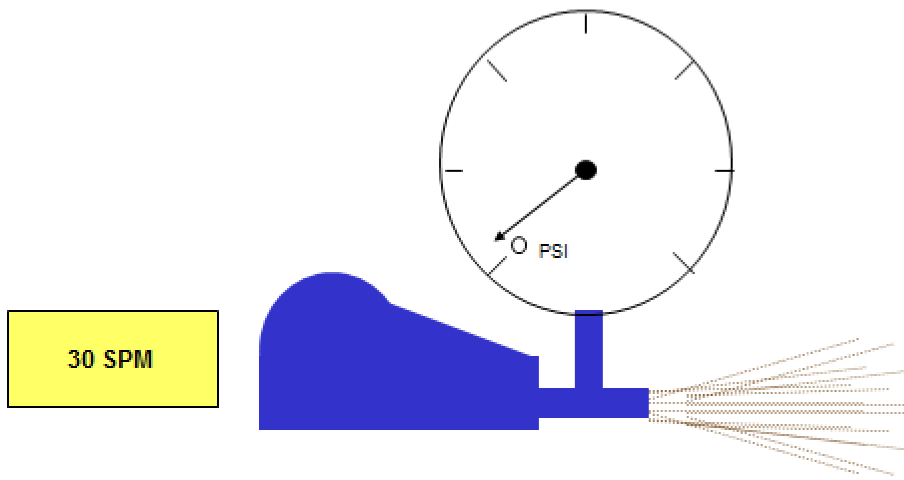
Pump pressure is the result of friction caused by pumping a fluid (mud) around the circulating system.

Friction is caused by the mud rubbing against the wall of the pipe/hole and also by the solids in the mud rubbing against each other.

Friction will increase if:

-the size of pipe/hole is decreased (narrower)
-length of system is increased (longer)
-solids in mud are high (thicker)
-flow rate is increased (faster)

Pressure Losses in the Circulating System



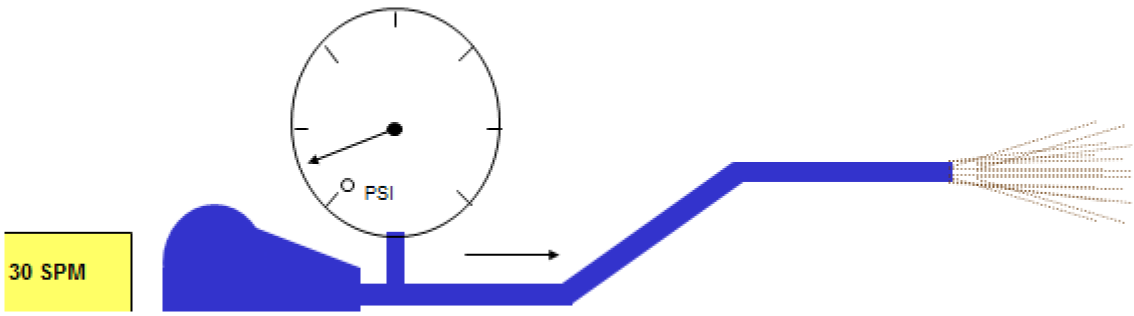
In this diagram the pump has been connected to the pipework that runs up to the rig floor.

With the increased length of pipe the friction generated by pumping at 30 SPM has increased.

This accumulated friction in the system is seen at the pressure gauge.

The pump therefore has to work harder to maintain the same pump rate.

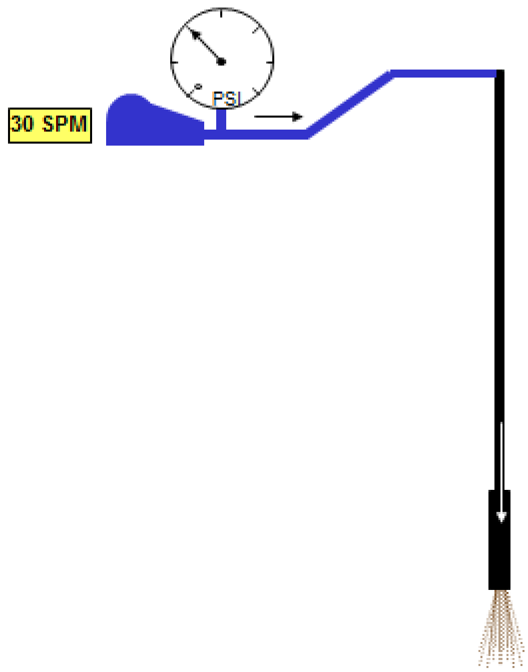
Pressure Losses in the Circulating System



The drillstring has been connected.
The drillstring has increased the length of the system and may have reduced the ID. Both will increase the amount of friction generated at 30 SPM.

The accumulated friction in the system is seen at the pressure gauge.

Pressure Losses in the Circulating System

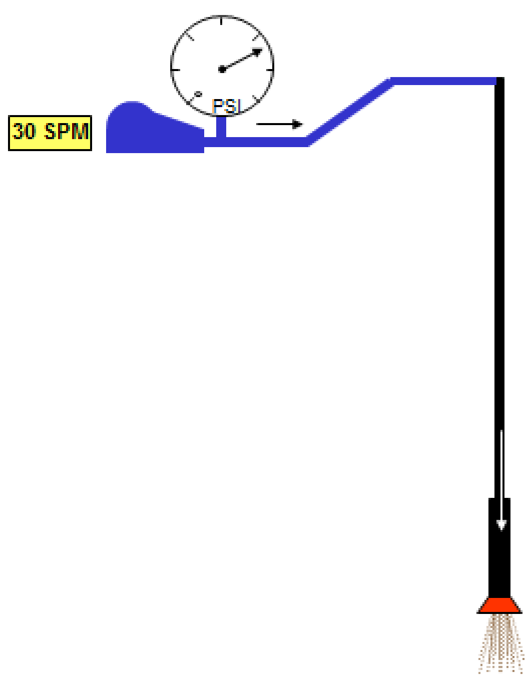


The drillstring has been connected.

The drillstring has increased the length of the system and may have reduced the ID. Both will increase the amount of friction generated at 30 SPM.

The accumulated friction in the system is seen at the pressure gauge.

Pressure Losses in the Circulating System



The Bit has now been connected.

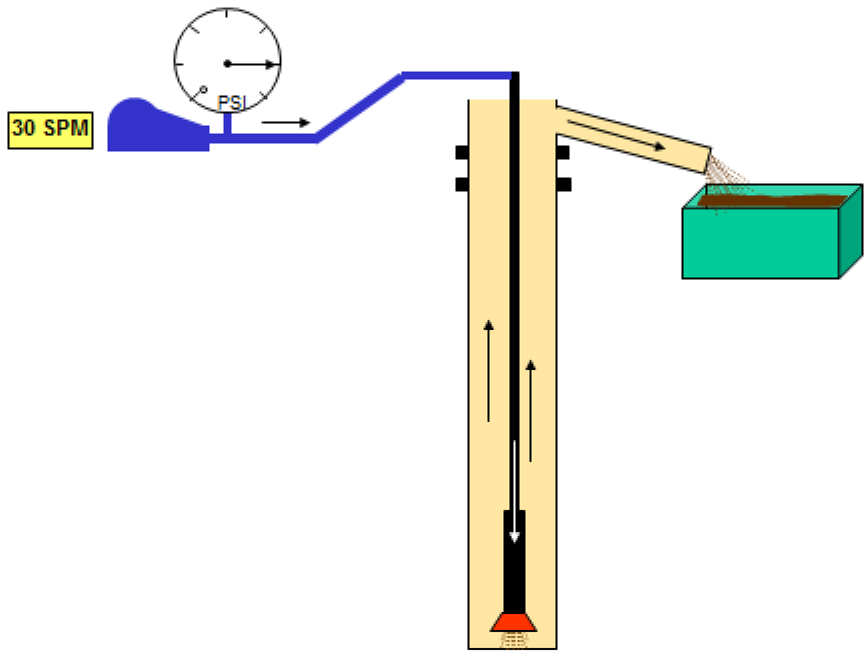
The bit only adds a very small amount of length to the overall system but the pump pressure has increased significantly.

This is due to the small size of nozzles (jets) installed in the bit. This is done to create a jetting action that cleans cuttings from the bottom of the hole.

This restriction in ID increases the amount of friction generated at 30 SPM.

The accumulated friction in the system is seen at the pressure gauge.

Pressure Losses in the Circulating System



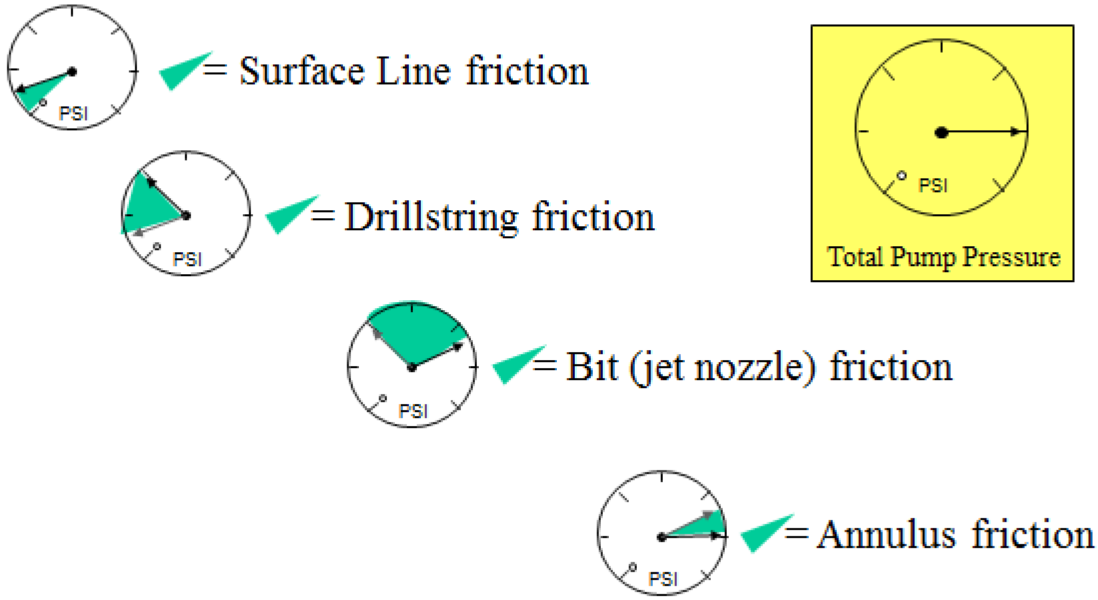
Finally there is the Annulus.

The annulus has increased the length of the system but it has a larger diameter so will not generate high amounts of friction.

The friction in the system has increased but only by a small amount

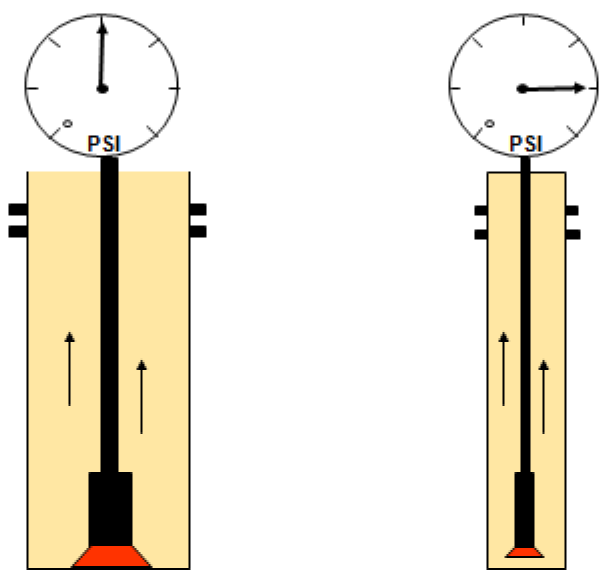
The accumulated friction in the system is seen at the pressure gauge.

Pressure Losses in the Circulating System



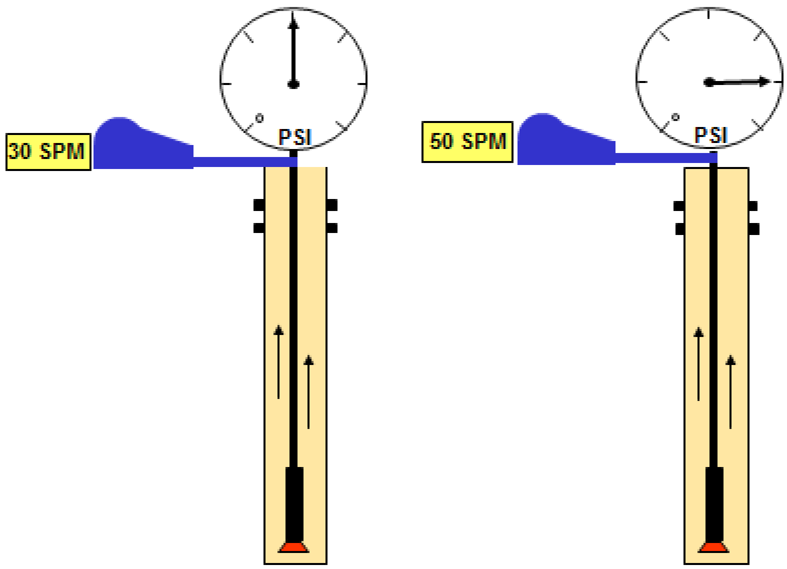
This diagram shows the increase in friction generated by each part of the circulating system. The addition of each part results in the total pump pressure seen at the pump. The following pages review what can affect pump pressure.

Review of Friction Losses



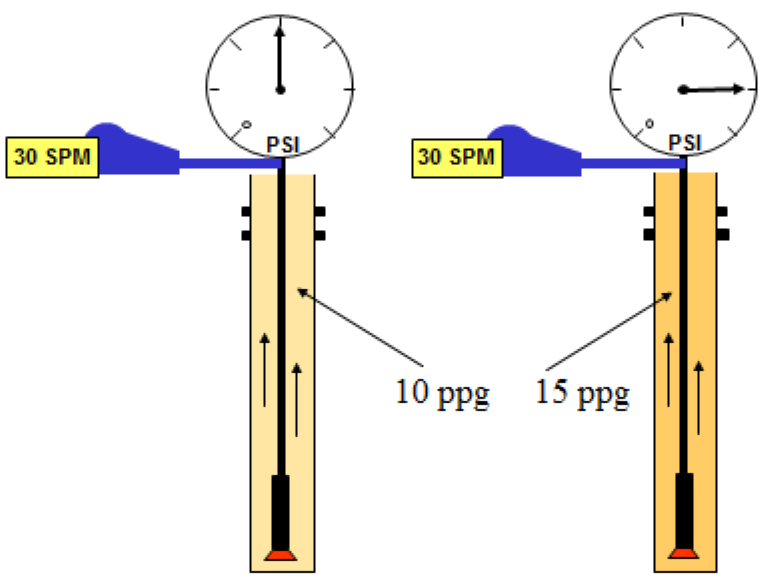
Friction is generated as mud is pumped around the circulating system. The geometry of the system will affect pressure. This could be Diameter (see right) or Length.

Review of Friction Losses



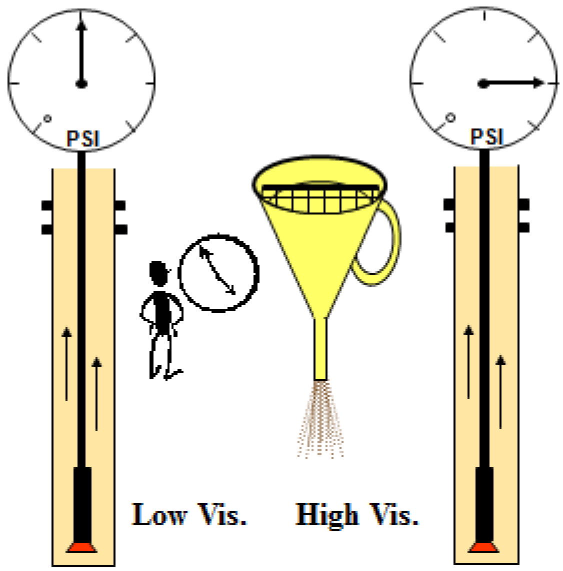
Here the geometry of the system is the same but the SPM has been increased giving a greater pump pressure.

Review of Friction Losses



Here the geometry of the system is the same and the SPM is the same but the mud weight has been increased. With increased mud weight there is an increase in solids that results in a higher pump pressure. The opposite effect will take place as mud weight is decreased.

Review of Friction Losses



Here the geometry of the system, the SPM and the mud weight are the same but the viscosity has been increased. Increased viscosity means that the solids in the mud are more tightly bound together making it thicker and harder to move. This creates more friction and a higher pump pressure. The opposite effect will occur if mud viscosity is decreased.

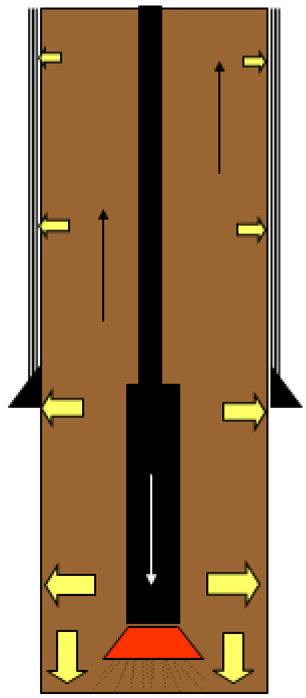
Friction generated acts against the walls of the circulating system. For example the friction loss inside the drillstring acts against the wall of the pipe. As the pipe is made from steel this pressure has little effect, but if pipe were made from rubber it would cause it to expand.

The friction generated in the annulus acts against the wall of the hole (Casing and Open Hole). If the friction pressure were high it could damage the open hole formations and lead to a fracture.

Usually this Annulus friction pressure is quite small compared to other parts of the circulating system. The Annular Friction Loss is normally in the order of 50 -200 psi and may not damage the hole, but in some wells it can be high and will affect drilling practice.

The yellow arrows in the diagram (right) shows the effect of annular friction loss on the hole wall. Note that the effect increases with depth so an annular friction loss of 100 psi is the total extra pressure on bottom. Friction loss in the annulus may also be called Annular pressure Loss (APL).

Effect on Bottom Hole Pressure

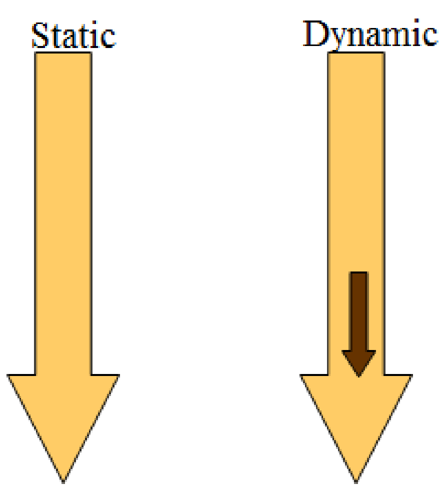


The pressure acting on the bottom of the hole is therefore the sum of the mud hydrostatic plus and additional friction (pressure) losses.

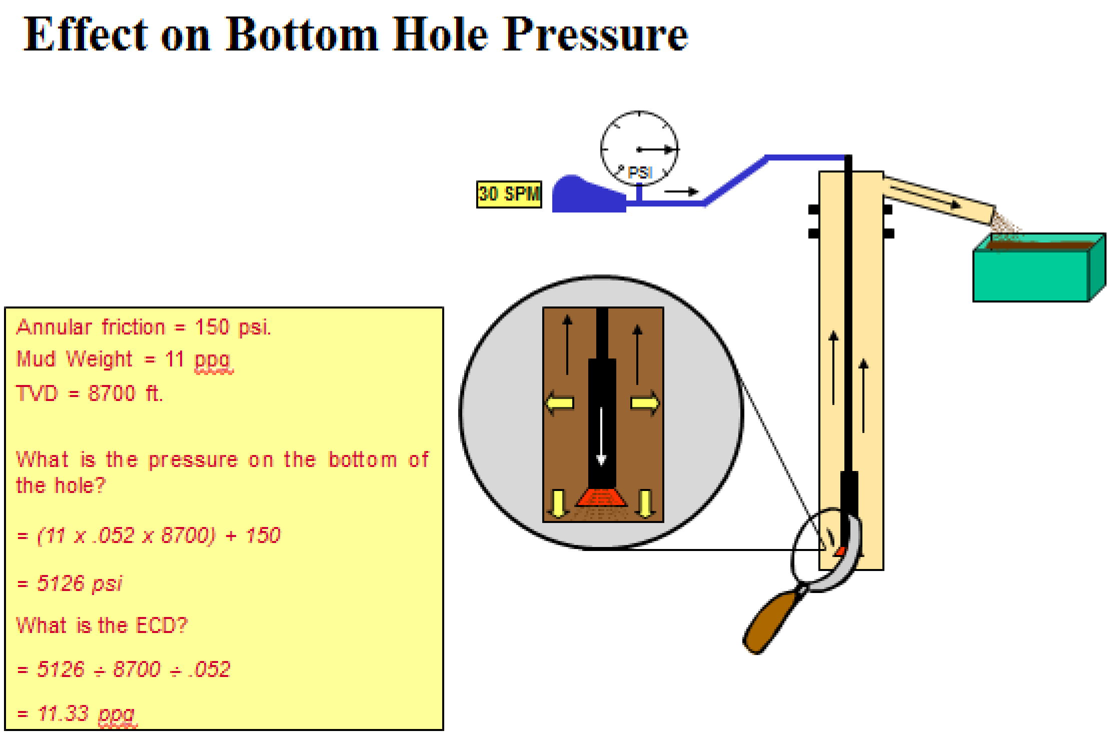
The diagram shows the static and dynamic pressures. Note the dynamic pressure includes the friction losses (brown arrow).

The friction loss is normally calculated by the Drilling Engineer using standard industry equations. By knowing this value the effective or equivalent mud density (ECD) can be calculated.

Effect on Bottom Hole Pressure



The diagram shows the friction pressure acting on the bottom of the hole. To calculate the equivalent circulating density (ECD) the calculation below is used:



11.33ppg/8.345=1.35SG

INTRODUCTION AND DEFINITIONS

In oil & gas industry an “out of control” well is the biggest threat to life, equipment and the environment. A well that is “out of control” is called a BLOWOUT. The picture below is a blowout. The derrick has gone but the substructure is still standing.

We open up the formation (various lithology layers) while we drill the borehole for the first time since it was deposited millions of years ago. If hydrocarbons are there, we are the first to see them at the surface.

If the formations we drill have high pressure and we are not able to contain them, then a Blowout is likely to occur.

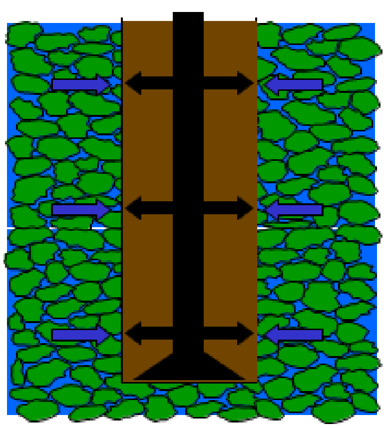
A Blowout means we have lost control over the well, which cause the fluids in the formation (gas, oil or water) are escaping up the wellbore all the way to the surface.

If these formation fluids are flammable and/or toxic the rig is likely to burn down, people would be killed and damage to the environment will take place. The greatest exposure to the risk is with Blowouts. Preventing Blowouts is therefore an essential part of the day-to-day operations. As we can see from the picture below the consequences can be catastrophic.

Our first line of defense against a Blowout is the pressure exerted by the drilling mud (called MUD HYDROSTATIC PRESSURE).

It is this pressure that acts against the fluids in the formation, preventing them from entering the wellbore. In the diagram the mud hydrostatic is holding back the formation fluids.

We call this our PRIMARY means of Well Control.



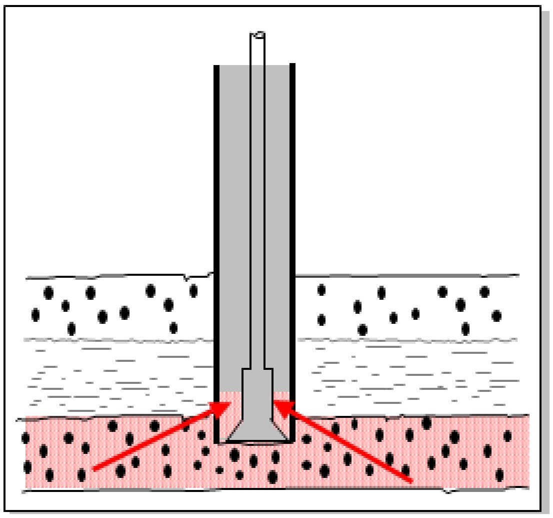
KICK

If we underestimate the formation fluid pressure, the mud hydrostatic will not be enough to control the well.

In this case it is very likely that the formation fluids will force their way into the wellbore causing mud to be pushed out of the hole at the surface.

If this happens the well is said to be ‘kicking’.

In other words, we have taken a KICK.

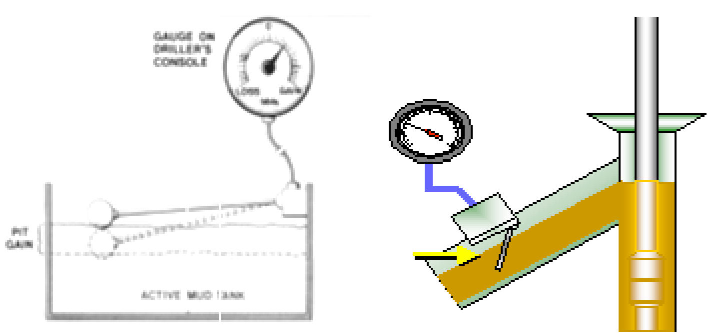


Because the kick is displacing (pushing) mud out at the surface we should be able to detect this by watching both the mud flow rate from the well and the level of mud in the mud pits. If either increase then it is a sign (indication) that a kick could be happening downhole.

We therefore have to continuously monitor Flow Rate and Pit Level and set high and low alarms to warn us of any changes.

A slow response to these indications will lead to a larger kick, which will increase pressures in the well making it more hazardous to kill the well and a greater amount of lost operating time.

Kick Indicator



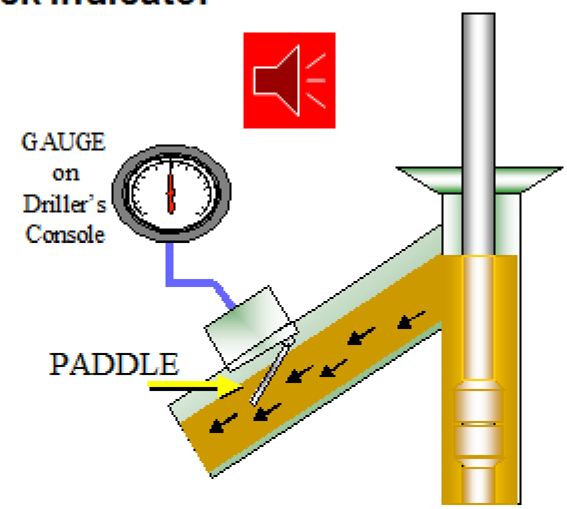
Note the increase in flow from the well

- the paddle is deflected more

- the gauge reading increases

- the alarm is heard

Kick Indicator

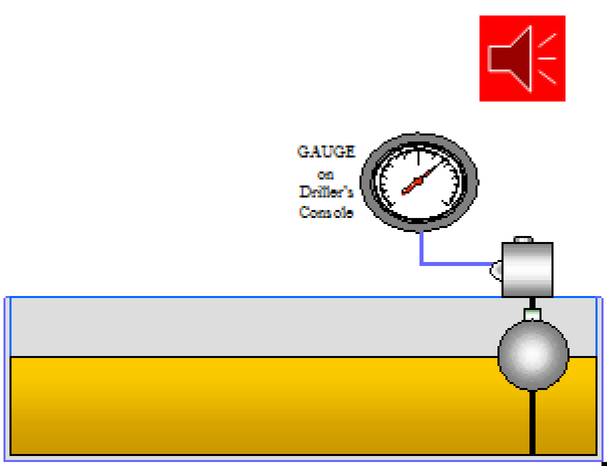


The pit level will increase

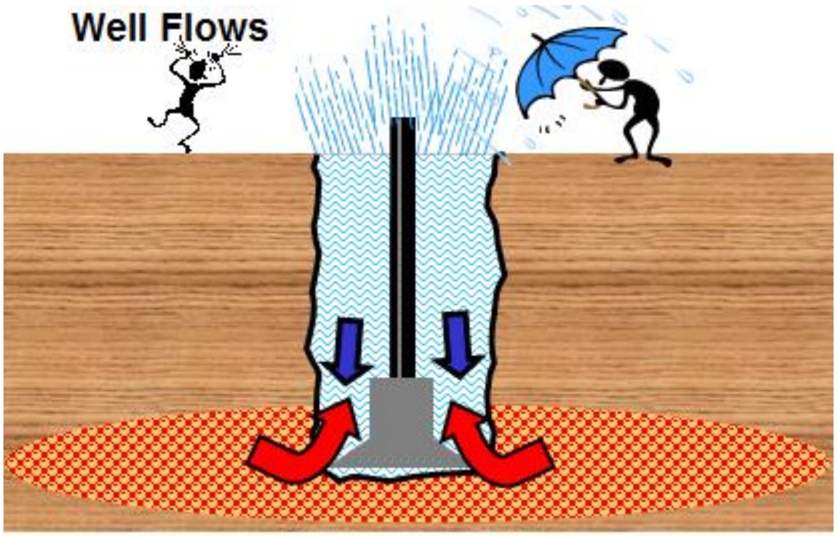
The gauge reading will increase

The alarm is heard

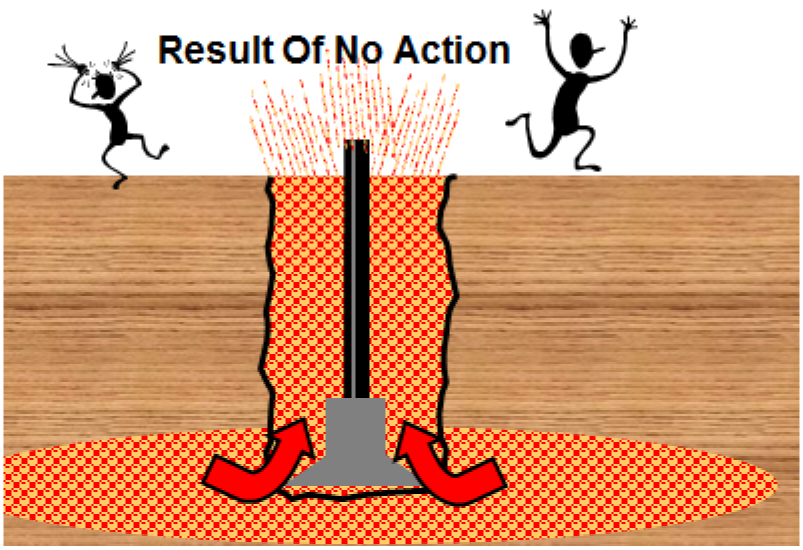
Kick Indicator



Having recognised something may be going wrong downhole, we prepare to shut the well in.

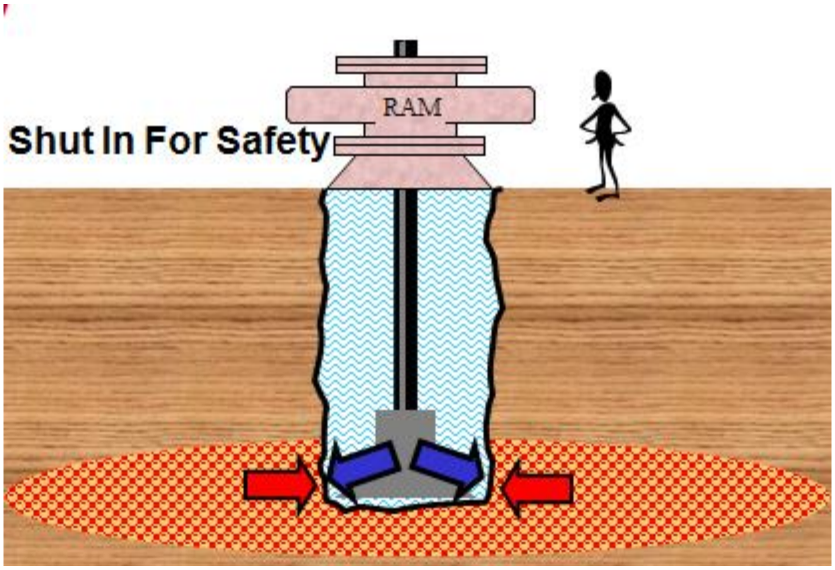


If we did nothing at this stage, all the mud would eventually be pushed out of the hole and a blowout would occur. This could lead to a fire, pollution or a release of poisonous gases such as H2S.



To shut in the well, we stop drilling,
- raise the bit off bottom
- shut off the mud pump
- check to see if the well is flowing on it's own (that is, without the pumps running)
- if Yes, then we shut the well

If it is flowing then we assume there is a kick.



PRIMARY & SECONDARY CONTROL

PRIMARY Control = Mud Hydrostatic
SECONDARY Control = BOPs

In this section the terms Primary and Secondary are used.

PRIMARY Control = Mud Hydrostatic
SECONDARY Control = BOPs
We therefore start with two lines of defence. If we take a kick we only have one line of defence - the BOPs. If they fail, then a blowout will soon follow. Both lines of defence are vital. We must make every effort to prevent a kick by having the correct mud in the hole and to stop a kick becoming a blowout we must keep the BOPs in first class working condition AT ALL TIMES!!! Therefore, care of the mud and care of the BOPs must have the highest operational priority on the rig.

Well Control Equipment

KILLING THE WELL (RESTORE PRIMARY CONTROL)

PRIMARY control has to be restored!

If we take a kick and shut the well in then the next step is to 'kill the well'. This means raising the mud weight to a value that will restore PRIMARY control and pumping it around the well so that it replaces old mud. If the kill is carried out correctly then the well will be dead; we can open up the BOPs and mud hydrostatic will hold back the formation fluids.

PRIMARY control is therefore restored. Response to a kick must be quick as the larger the kick the more problems we can encounter during the kill operation.

Brief Review

-A Blowout is a well that is out of control.
-Blowouts kill people, damage the environment and burn rigs.
-The Mud Hydrostatic is the Primary means of well control.
-A Kick is an influx of formation fluid into the wellbore.
-The Pit Level and Flow Rate instruments help detect a kick.
-We Shut in the well with the BOP's to contain the kick.
-BOPs are the Secondary means of control.
-After shut in we Kill the well, this restores primary control.

A Blowout is a well that is out of control. Blowouts kill people, damage the environment and burn rigs. Blowouts are the company's greatest exposure to risk. The Mud Hydrostatic is the Primary means of well control. A Kick is an influx of formation fluid into the wellbore. The Pit Level and Flow Rate instruments help detect a kick. We shut in the well with the BOP's to contain the kick. BOPs are the Secondary means of control. Care and maintenance of BOPs is vital. After shut in we Kill the well, this restores primary control.

CAUSES OF KICKS

A - REDUCTION IN HYDROSTATIC

or

B - INCREASE IN FORMATION FLUID PRESSURE (Abnormal Pressure).

A kick will occur if the well goes underbalance. The main causes of underbalance are 1) reduction in hydrostatic or 2) increase in formation fluid pressure (Abnormal Pressure).

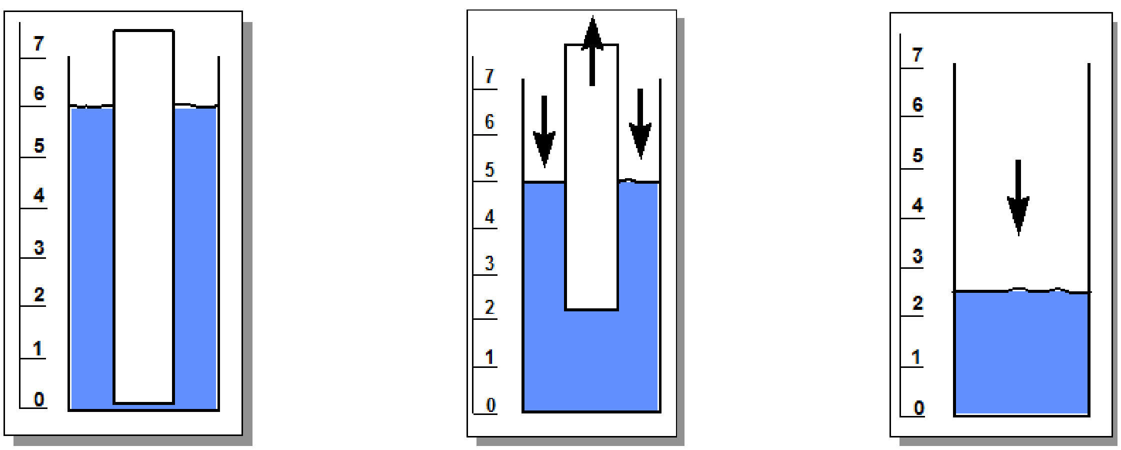
Reduction In Mud Hydrostatic Pressure
Pressure, psi = Mud Density, ppg x 0.052 x Vertical Depth, ft
(*Pressure = Mud Density x Constant x Vertical Depth*)
Mud density must decrease or vertical depth must decrease (more precisely vertical length of mud in hole must decrease).

From the above it can be stated that a reduction in hydrostatic pressure can be caused in three (3) main ways:

1. DROP IN LEVEL OF MUD IN THE HOLE
a. failure to fill the hole
b. losses to the formation
c. equipment leaks
2. DROP IN MUD DENSITY
a. dilution by water or base oil
b. removal/settling of Barite
c. pumping lightweight pills or whole mud
d. cleaning cuttings from hole
e. Cementing
3. LOW DENSITY FORMATION FLUIDS ENTERING THE WELLBORE
a. gas cut mud
b. swabbing

One of the most common causes of Kicks and Blowouts is: FAILURE TO KEEP THE HOLE FULL WHEN PULLING OUT (drop in mud level due to failure to fill the hole).

Effect On Mud Level Due To Pulling Pipe Out.



When pulling out of the hole to change the Bit or for any other reason, the mud level in the hole will drop due to the pipe removed.

Before discussing the items above an explanation is given as to what happens when pipe is pulled from the well (work from left to right).

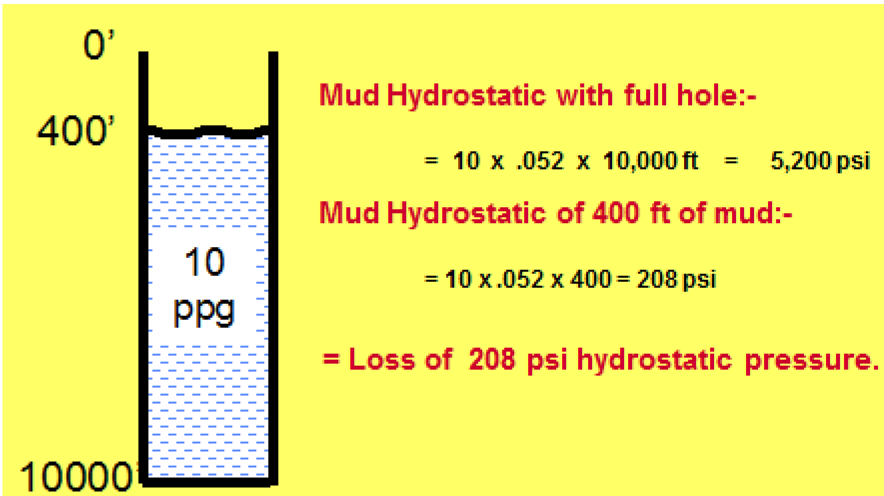
The container on the left has a rod placed inside and the level of fluid can be read against the scale as 6.

When the rod is partly removed from the container, (see right) it can be seen that the fluid level has dropped 1 unit to 5 on the scale.

The rod takes up space (volume), therefore when it is removed fluid fills the space left and hence the level drops.

After the rod has been removed completely (see far right) the level has dropped a total of 3.5 units to 2.5 on the scale.

Hydrostatic Effect Of Mud Level Drop



As an example:

5" OD Drill Pipe has a steel volume of approximately 0.7 bbls per 90 ft stand. Therefore as each stand is pulled from the well 0.7 bbls of steel is removed. After 10 stands this would be (10 x 0.7) = 7 bbls.

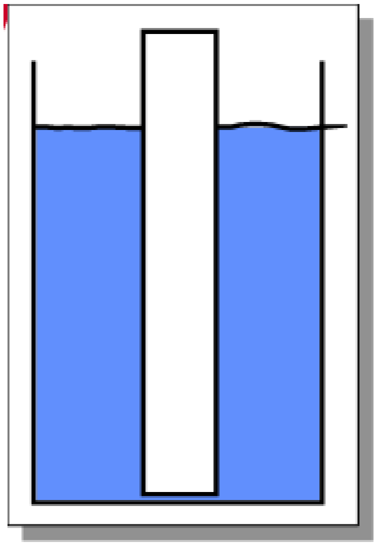
What would be the result if enough pipe was removed to allow the mud level to fall by 400 ft?

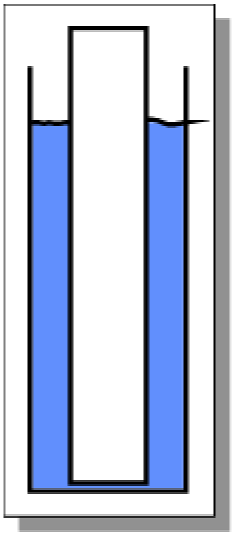
A 400 ft drop in the level of 10 ppg mud will reduce Mud Hydrostatic by:-

Mud Hydrostatic = 10 ppg x .052 x 400 = 208 psi

A DROP IN HYDROSTATIC PRESSURE OF THIS AMOUNT MAY CAUSE THE WELL TO GO UNDERBALANCE AND A KICK IS LIKELY TO OCCUR.

Effect Of Pipe And Wellbore Size





The diagram (see left) shows a large diameter, e.g. 26" well with pipe, e.g. 5". The Annular Volume is large = 0.6326 bbls/ft (or 63 bbls per 100 ft)

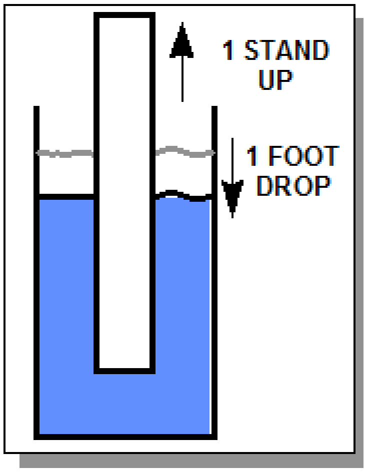
The diagram (see right) shows a small diameter well, e.g. 8-1/2", with 5" pipe. The Annular Volume is small = 0.0459 bbls/ft (or 4.5 bbls per 100 ft)

The annulus in the 26" hole is over 13 times larger than the 8-1/2" hole!!

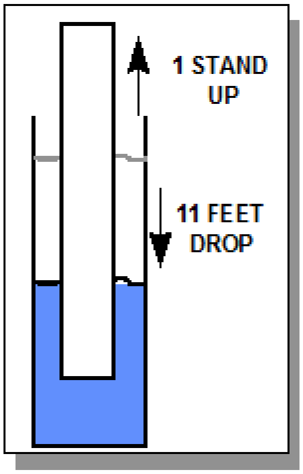
As the 5" drillpipe is pulled out, the drop in level in the 8-1/2" hole (for every stand pulled) would be much greater than in the 26" hole.

Effect Of Pipe And Wellbore Size

Level Drop for 26" hole = 1 foot



Level Drop for $8^1/_2$" hole = 11 feet

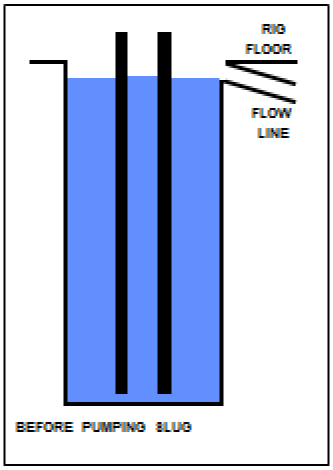


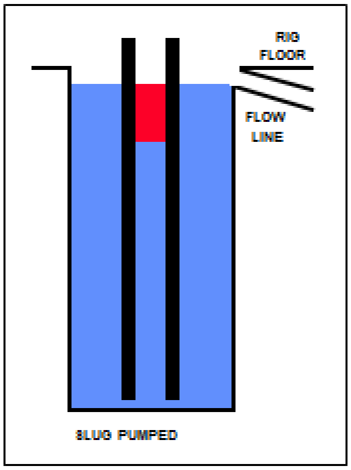
It can be seen from these examples that the geometry of the well is a very important factor in determining the Level Drop.

At surface the hole size is usually the ID of the last casing, unless on a semi-submersible where it would be the Riser ID.

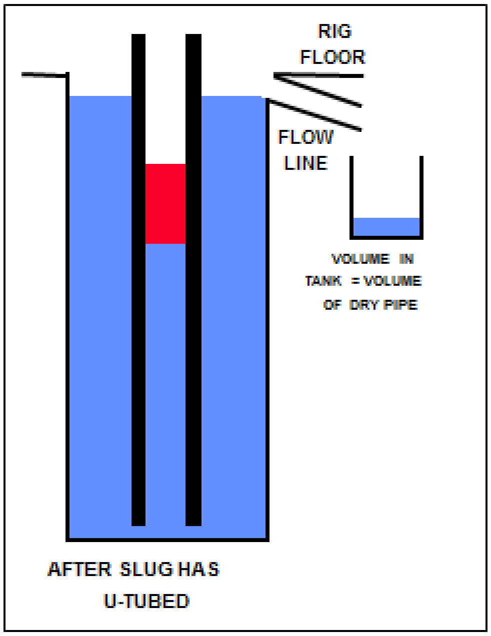
The smaller the diameter of the surface pipe/riser the greater the level drop.

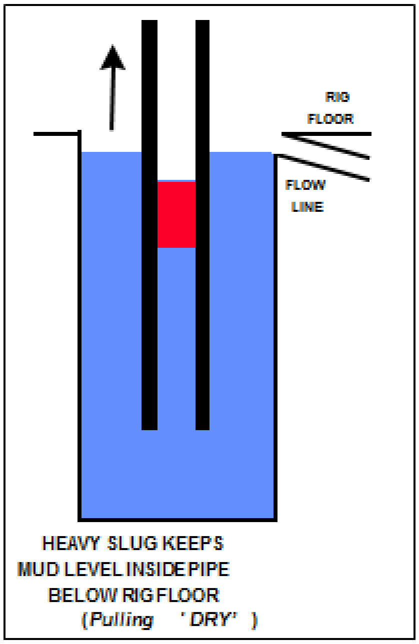
Effect Of Pulling Dry Or Wet





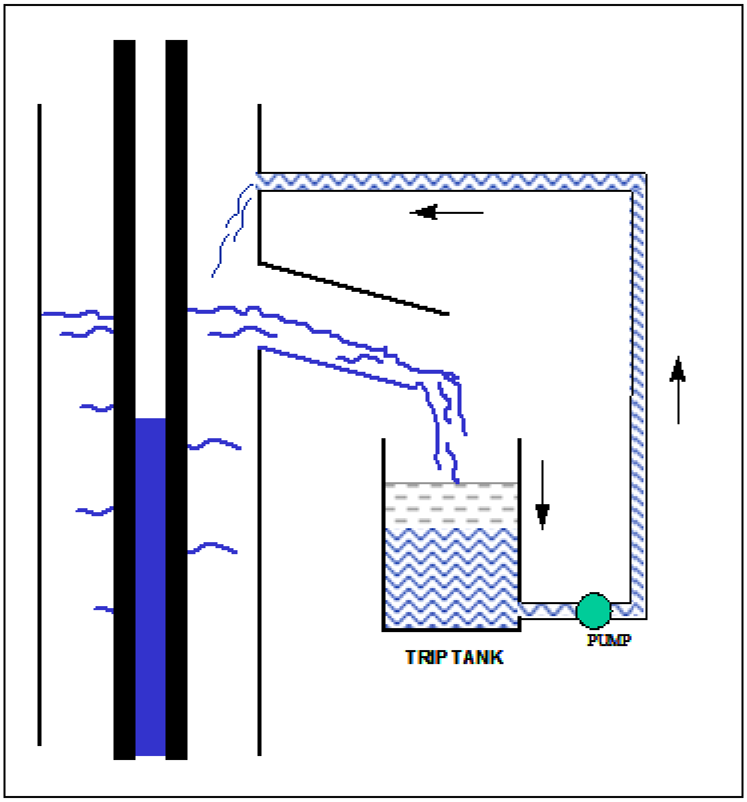
The calculations were done assuming dry pipe. Meaning that a weighted 'slug' was pumped prior to pulling out of the hole.





The effect of the slug is to lower the level inside the pipe to a point below the rotary table - this means that when pipe is pulled, there is no mud inside the pipe that is above the Rig Floor.

Trip Monitoring



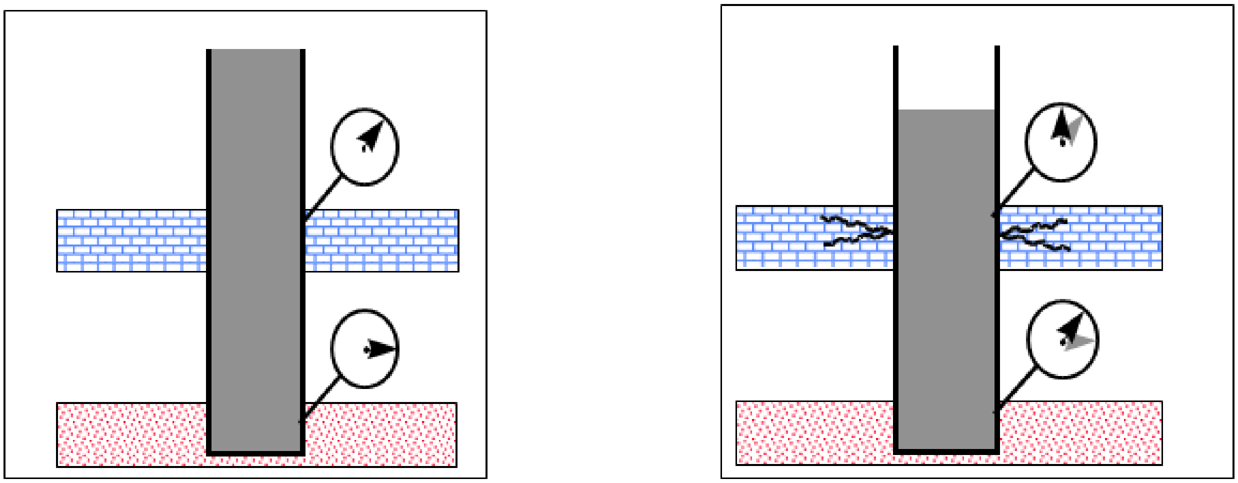
As the string is pulled out of the hole, the level of mud in the hole will drop as a direct result of the volume of steel removed. Therefore, if an amount of steel equal to one barrel was removed from the well, it would require one barrel of mud to re-fill the hole.

Keeping the hole full is essential to maintain full mud hydrostatic BUT checking to see that the hole is being filled with the CORRECT amount of mud is the basis of TRIP MONITORING.

The reason for monitoring hole fill is to check for either Swabbing or Losses. When pulling out of the hole, it is normal to monitor for Swabbing.

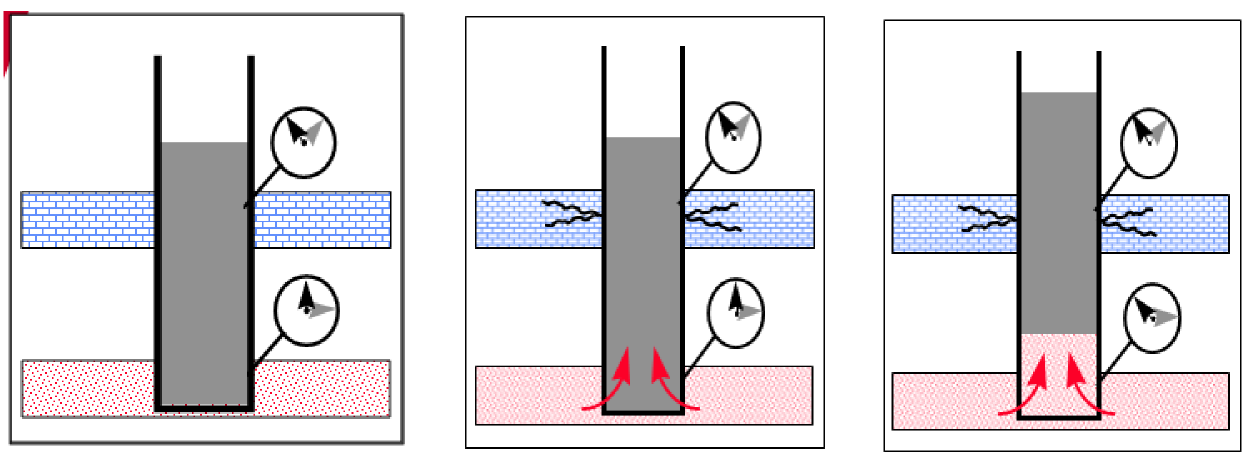
When running in the hole, it is normal to monitor for losses due to surging. Both Swabbing and Surging are explained later in this section.

Losses To The Formation



The density of the mud exerts hydrostatic pressure on the formation. If we purposely pressure the well up, this will add to the mud hydrostatic. The formations only have a limited strength. So if we exceed that strength by placing too much pressure on the formation, then it will fracture (break).

Some rocks are naturally fractured due to geological event that took place in the past. Whether the fracture is natural or imposed, mud will be lost into the formation (this is called LOST CIRCULATION). As mud is lost into the fractures, the level of mud in the well will drop.

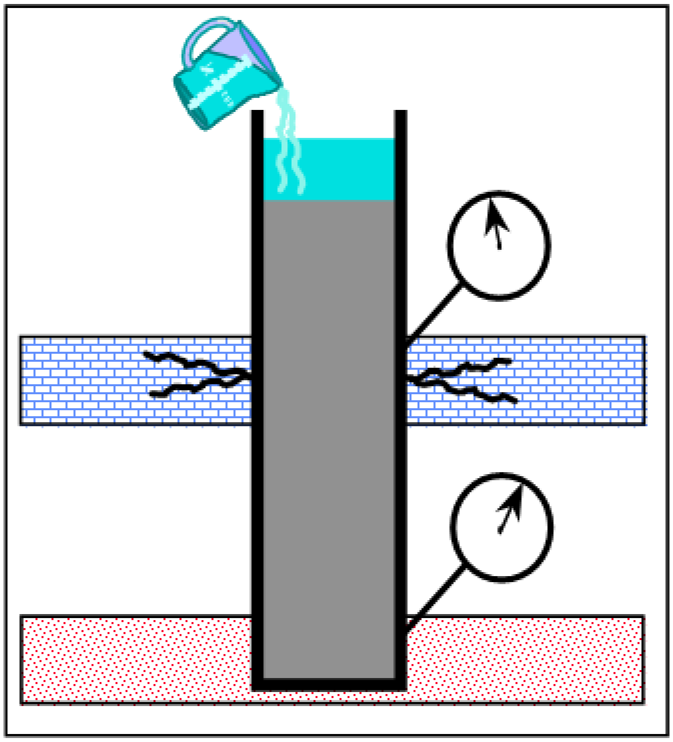


Losses have stopped

This drop in level will reduce the hydrostatic pressure allowing two things to happen.

1. The pressure acting on the loss circulation zone may drop below the fracture pressure. If this happens it is possible that the formation will heal itself (fractures will close) and losses stop (see left). If this does not happen, the losses will continue.

2. Hydrostatic pressure acting on other formations will drop and may allow an 'underbalance' to occur. If the formation is permeable, then a kick is likely to occur from this zone (see right).



What to do? If the mud is not helping to fill the hole, then a light base fluid (water or oil) may need to be used. All the time this is happening, the volume of fluid pumped should be recorded and the well watched closely in case of a kick.

As more and more light fluid is pumped, the hydrostatic pressure will drop to a value equal to the fracture pressure. If the fracture heals at this stage, it may be possible to fill the hole back to surface.

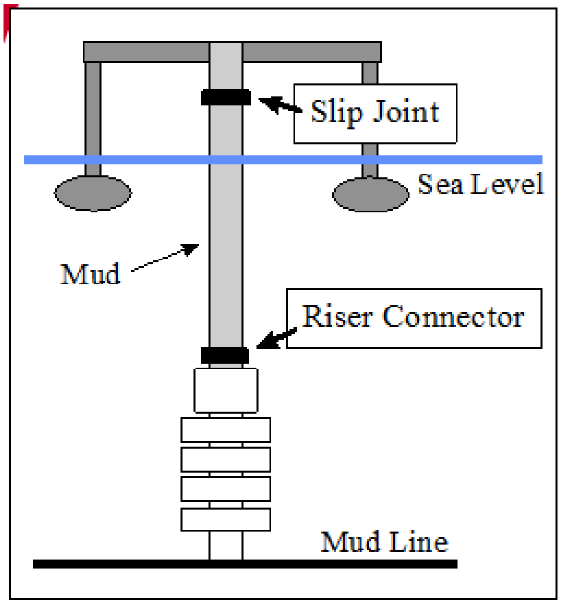
Formations that cannot be repaired may require special techniques to drill or repair, (eg lost circulation material, cement, plugs, etc);

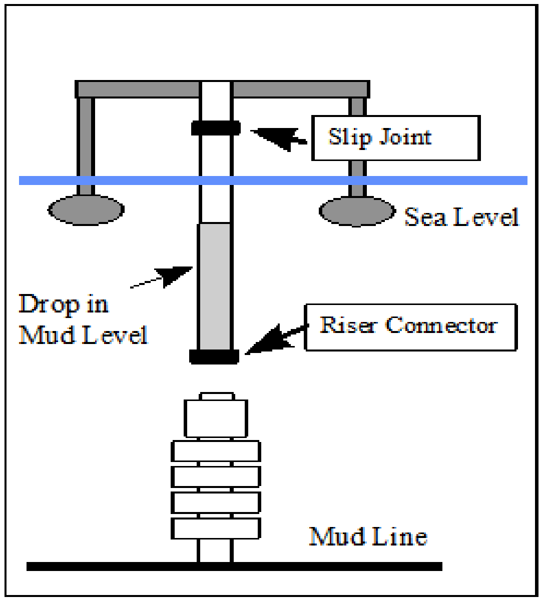
If losses occur and the mud cannot be seen when looking downhole (total losses) it is very important to pump fluid down the annulus in an attempt to fill the hole as soon as possible.

If we can see the mud level then we can monitor for kicks.

The current mud may be pumped at first but probably it will be too heavy.

Equipment Leaks





Mud normally flows from the well at the Bell Nipple and along the Flowline to the Shale Shakers. Any leak to the equipment below the Bell Nipple will cause mud level to drop. Riser connections are the obvious place to lose mud. On floating rigs where the stack is at the sea-bed, the risk is greater due to the long length of riser plus the chance of a riser disconnect.

The diagram (left) shows two critical leak points on a floating rig: the Slip Joint and the Riser Connector.

The diagram (right) shows what happens if the Riser disconnects from the Stack.. The hydrostatic head from the column of mud (rig floor to the Stack) is lost and is replaced by the hydrostatic head of sea water from sea level to the Stack.

Other common leak points are at the, Diverter Lines, and Overshot-Packers (common to integral Diverters e.g. Regan, Hughes).

There is a type of ‘downhole leak’, other than losses, that has been known to cause a kick. This is when a Casing ‘float’ fails.

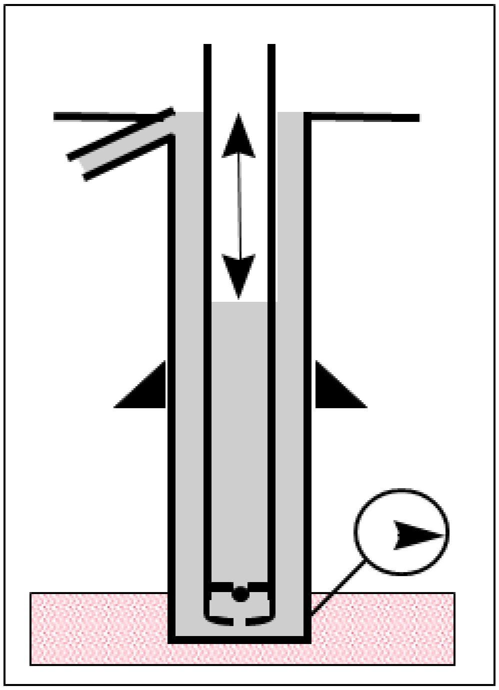
If the Casing is not filled regularly the level of the mud inside the casing will be lower than the level in the annulus. A differential pressure therefore builds up across the float. If the float were to fail at this point, the mud in the annulus will U-tube up inside the casing.

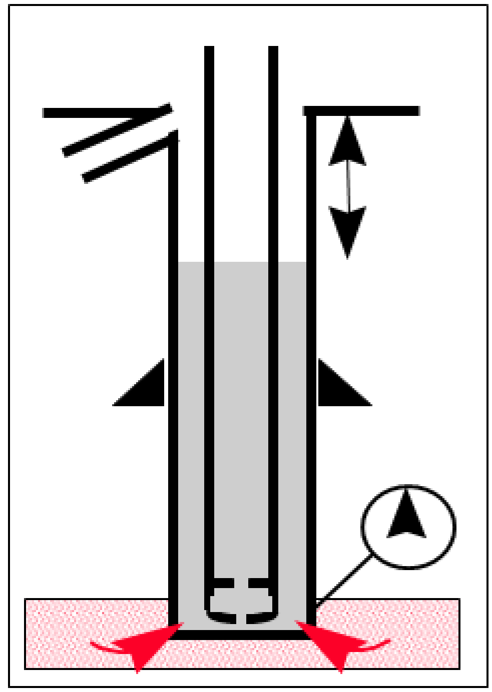
Depending on hole and casing geometry it is possible for the level in the annulus to drop a large distance. This drop may reduce hydrostatic pressure enough to allow the well to flow. The diagrams show this effect.

Note in left hand diagram above:-

- lower level inside casing through not filling.
- full column of mud in annulus
- hydrostatic on bottom is enough to prevent flow.

Note in right hand diagram:-
-mud has U-tubed up inside casing due to float failure
-hydrostatic in annulus has fallen and well is flowing





Review of Drop in Mud Level

This concludes the discussion on the causes of a drop in mud level. The three main causes can be categorised into:

a. failure to fill the hole
b. losses to the formation
c. equipment leaks

Drop In Mud Density

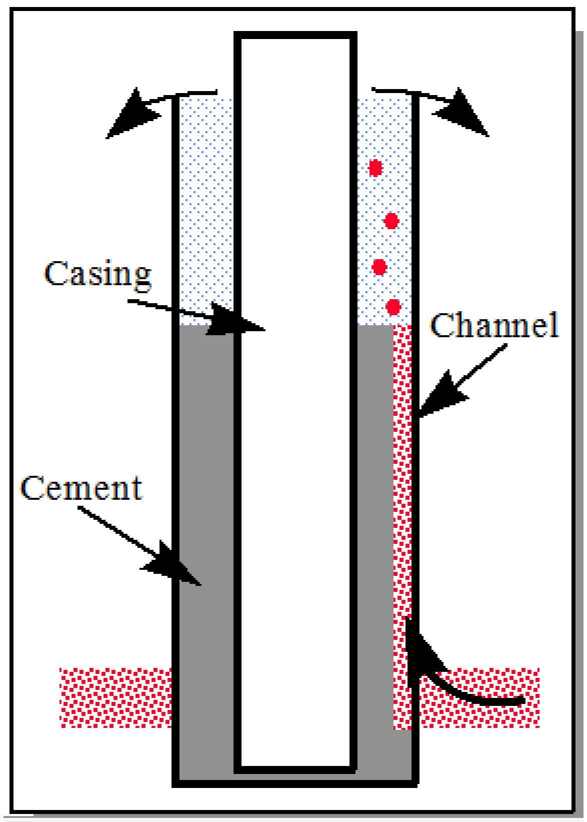
DUE TO:

a. dilution by water or base oil
b. removal/settling of Barite
c. pumping lightweight pills or whole mud
d. cleaning cuttings from hole
e. cementing

As identified earlier, a drop in mud hydrostatic pressure can be caused by a drop in mud level or a drop in mud density or contamination of the mud. This following looks at the DROP IN MUD Density. The main causes of a drop in mud density are:

a. dilution by water or base oil
b. removal/settling of Barite
c. pumping lightweight pills or whole mud
d. cleaning cuttings from hole
e. cementing

Cementing



When cementing there is always a risk that hydrostatic pressure could be affected.

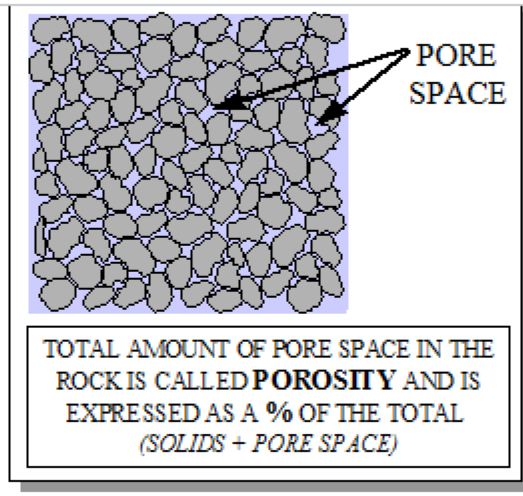
Four possible causes of this are:

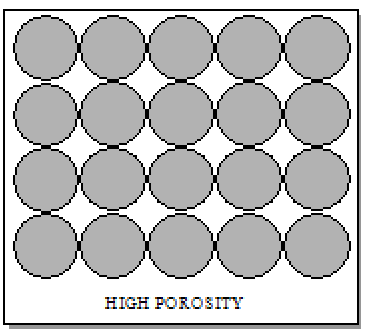
1. Drop in hydrostatic as cement starts to harden
2. Cement Channeling
3. Lightweight Spacer
4. Losses

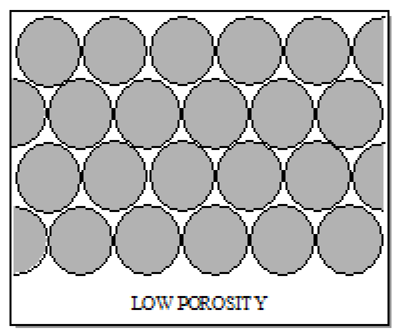
Low Density Formation Fluids Entering The Wellbore

The third major cause of a reduction in hydrostatic pressure is the effect of low density formation fluids entering the wellbore. This can be due to:
a. gas cut mud
b. swabbing

Entry Of Light Weight Fluid Due To Drilling New Formation

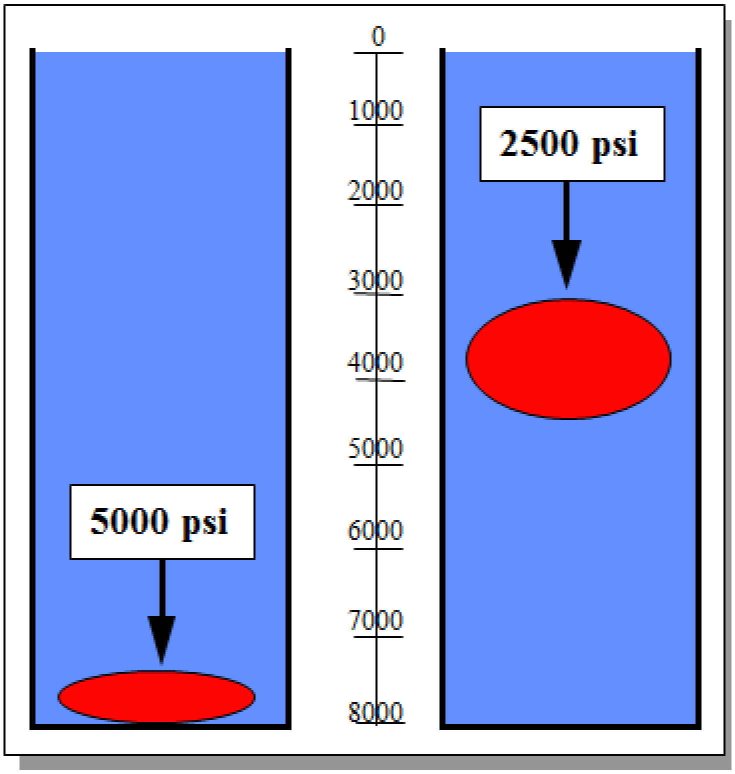






As the bit drills ahead, it is cutting the solid particles of the formation. Formations (rocks) that we drill consist mainly of solid particles and the space between the particles (pore space).

As the bit drills ahead, both cuttings and fluid are released. The amount of both cuttings and fluid depends on the porosity.
Porosity will vary due to size, shape and arrangement of the grains.

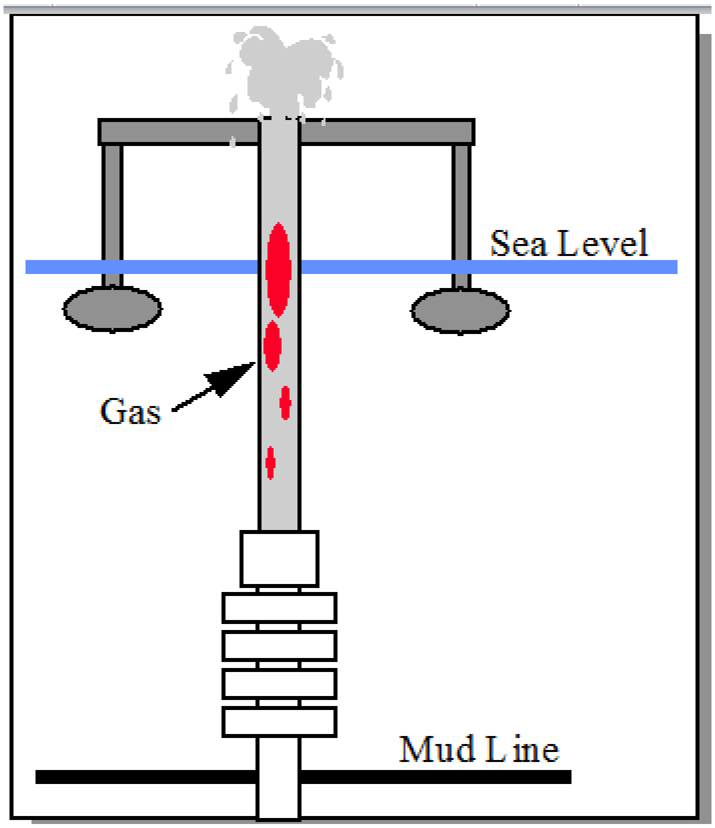


Cuttings act as a solid, (like bentonite or barite) and help to increase the mud density a little.

The formation fluids (gas, oil or water) help to reduce or "cut" the mud density. If the effect is large then the mud hydrostatic may go underbalance. Although all these fluids will reduce mud hydrostatic, gas acts differently to oil and water once in the wellbore.

Oil and water, being liquids, do not show any real expansion as they are circulated up the hole. Any reduction in mud density would occur as the fluid entered the mud stream and would stay fairly constant on its way up hole.

Gas acts differently and expands as pressure is reduced. Therefore, on its way up hole, the hydrostatic pressure of the mud above gets less allowing the gas to expand.



In subsea wells this behavior may mean that a large proportion of gas expansion takes place in the Riser, above the BOP's. If the gas expands rapidly, it can force mud out through the rotary table and create a hazard. In this case the well will need to be diverted to protect the rig floor personnel.

Gas cutting can be reduced by drilling more slowly thereby reducing the volume of formation fluid entering the well per minute.

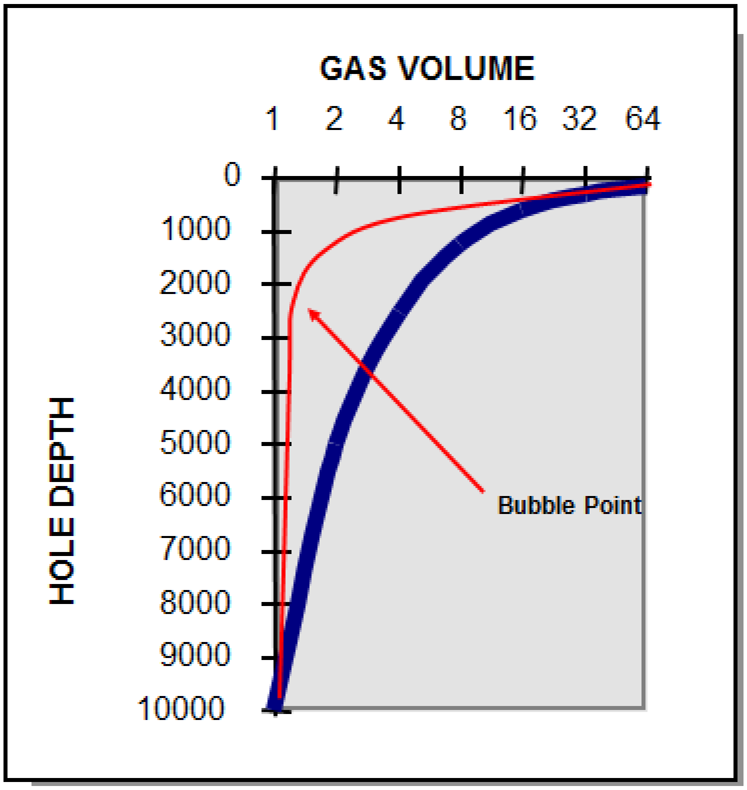
If gas cutting is expected when circulating bottoms up, it is common practice to close the well in and circulate the last part of the well (e.g. 20-25%) through the choke. Any problems caused by the large amounts of gas are therefore handled safely through the mud gas separator and if a kick occurs, it is a simple matter to close the well in.

Gas and Gas Behaviour

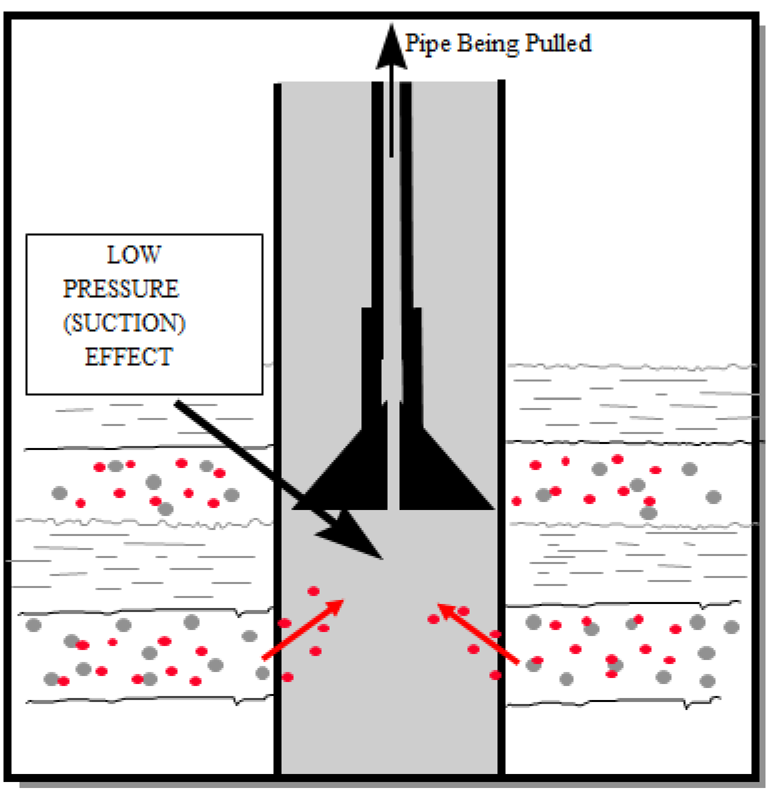
In water based mud the gas begins expanding as it starts circulating uphole. In general it can be said that it doubles in size as pressure is reduced by half. The gas in water based mud is represented by the blue line.

Oil based mud, acts differently. The gas stays in solution and acts in the same way as a liquid until bubble point, then suddenly breaks out and expands. This can be very rapid and may begin to unload the hole.

In the worst case mud can be blown up through the rotary table endangering those working on the rig floor. The red line shows typical gas behavior in an Oil Based Mud.

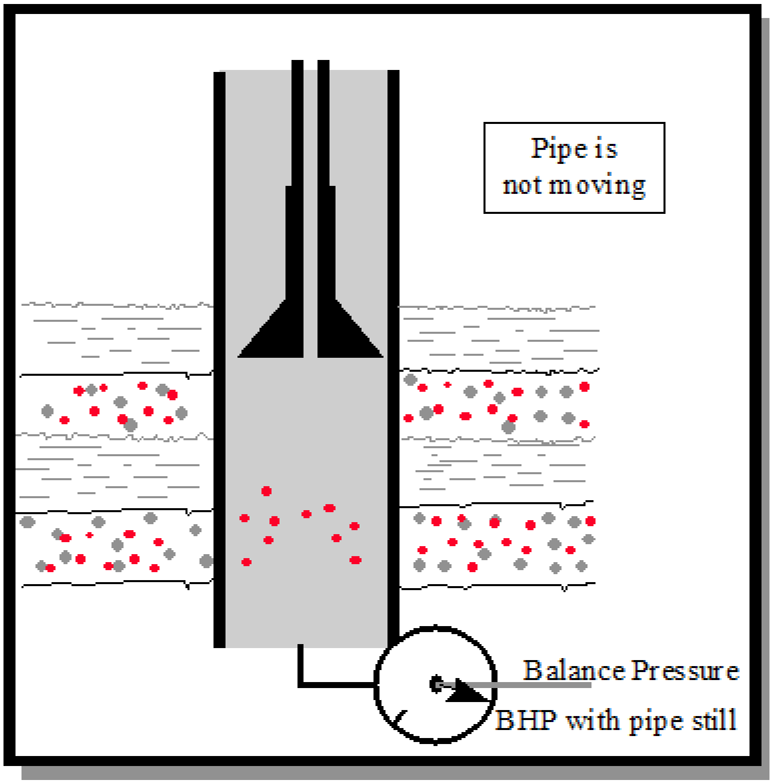

GAS VOLUME
1 2 4 8 16 32 64
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
HOLE DEPTH
Bubble Point

Swabbing


Pipe Being Pulled
LOW PRESSURE (SUCTION) EFFECT

Swabbing and failure to fill the hole on trips are two of the most common causes of kicks. Both occur when pulling out of the hole and are linked to Trip Monitoring.

Swabbing is when formation fluids enter the well bore due to a temporary loss in hydrostatic head below the bit.



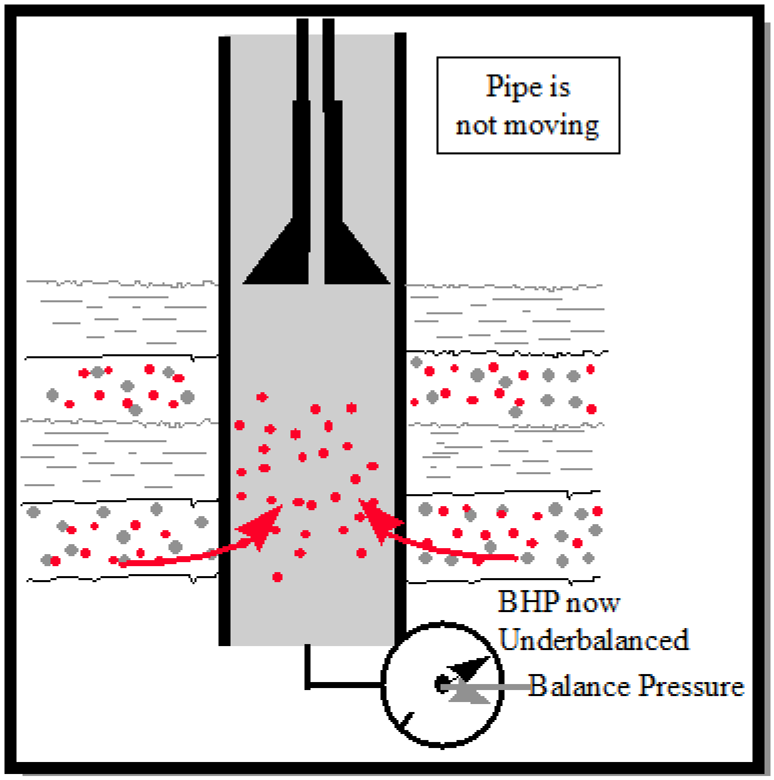
Once pipe movement stops, the hydrostatic head returns to normal.

The only difference is that the "swabbed" formation fluid now reduces the hydrostatic head by a small amount. This means that the safety margin is reduced.

As tripping continues and the well is swabbed each stand, the amount of safety margin is gradually reduced and reduced until all safety margin (overbalance) has gone.

At this stage, the well goes permanently underbalanced and a kick will result.

Swabbing which results in a kick should not happen, so long as we carry out Trip Monitoring procedures. Any formation fluid that does enter the well bore during the trip reduces the amount of mud required to fill the hole. The Driller should have noticed this by monitoring the trip and stopped to assess the situation.



The key to prevent swabbing is to allow mud from above the bit to move down and fill the space below, at the same rate as the string is moved up.

Any practice that can help achieve this would be beneficial.

It takes time for mud to move down around the bit so if we pull too fast it is more likely that the suction (low pressure) effect will occur. Other conditions would be:

narrow Annular clearance
balled Bit or Stabilisers
thick (viscous) mud
tight hole

If we have any of the above conditions downhole then pipe must be pulled at a slower rate.

Key prevention is therefore to pull slowly and monitor hole fill.

Another way to minimize swabbing is to pump out of the hole.

This is becoming very common practice on rigs with a Top Drive, but you still have to be careful. Do not to pull faster than the mud can fill the space below the bit.

Also accurate Trip Monitoring is harder to achieve when pumping out of the hole
- so take care!

Causes Of Kicks
A - REDUCTION IN HYDROSTATIC

or

B - INCREASE IN FORMATION FLUID PRESSURE
(Abnormal Pressure)

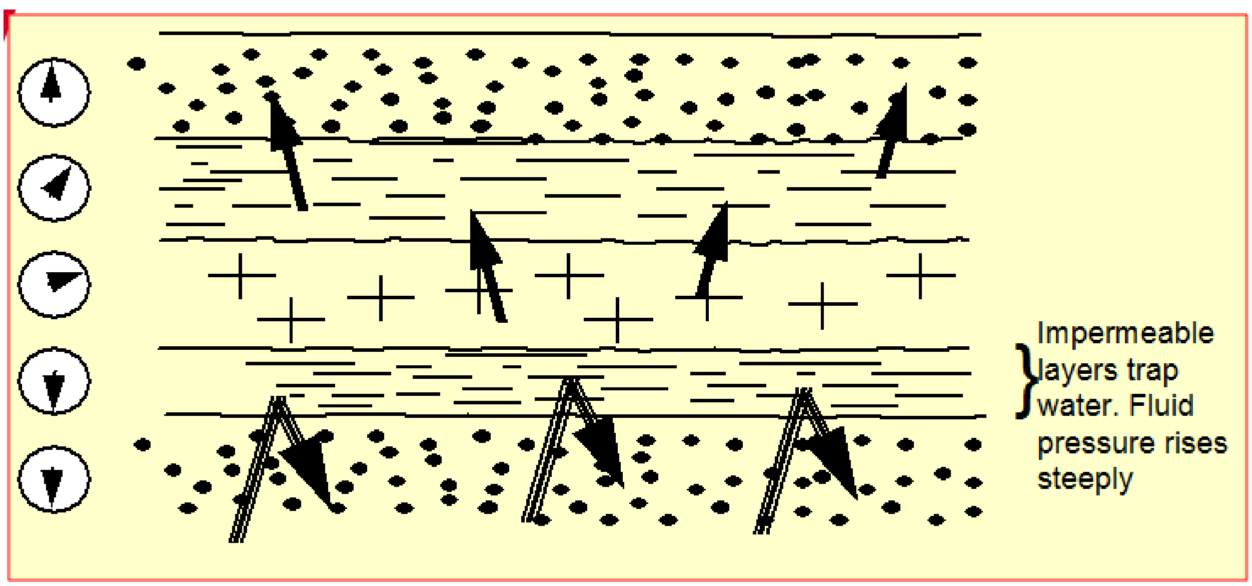
An increase in formation fluid pressure can be caused by:

A - Trapped formation fluids in Shale/Sand formations
B - Salt Domes
C - Artesian Effect
D - Faulting
E - Gas Cap
F - Leaks Around Casing

Definitions
Normal Pressures:
When the gradient of the formation fluid is 0.465 psi/ft
Abnormal Pressures:
When the gradient of the formation fluid is greater than 0.465psi/ft.

Mud densities greater than 9 PPG would be required to BALANCE abnormal formation fluid pressure.

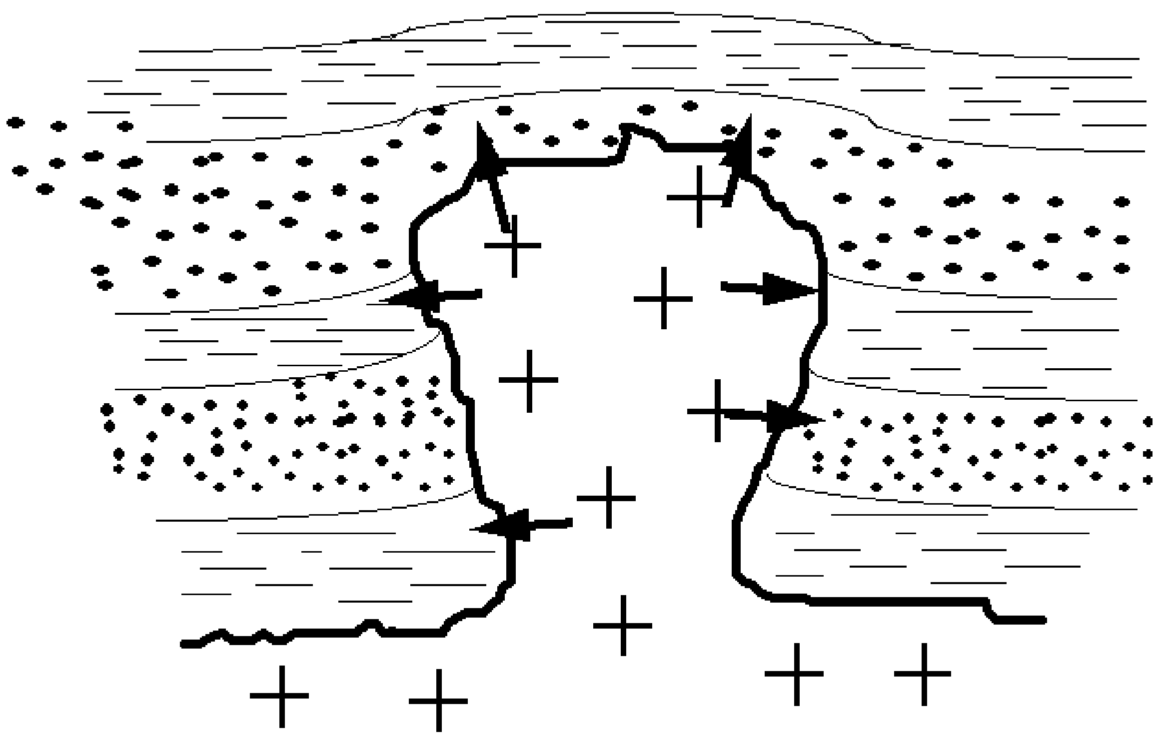
Trapped Formation Fluids



Normal compaction occurs when the Overburden weight acting on the rock successfully squeezes out the water. This means that water can escape through the rock.

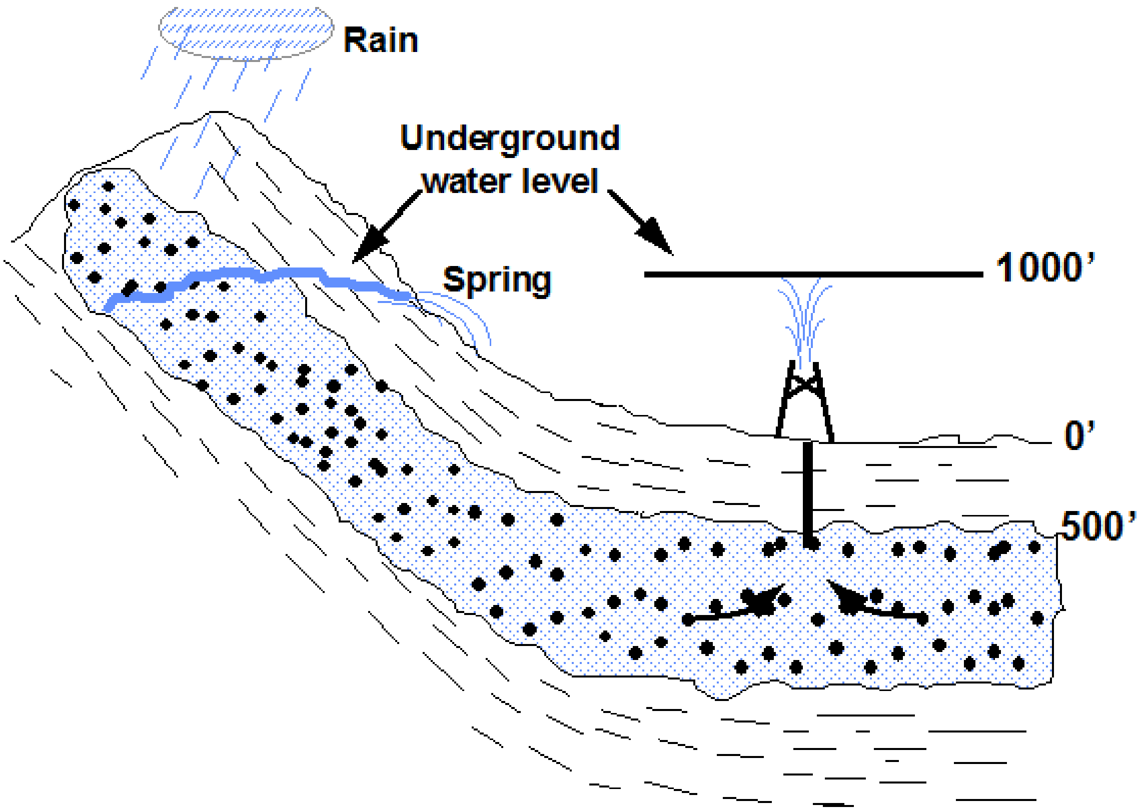
If a layer of rock does not allow water to easily pass (low permeability) then the water is trapped. The Overburden then pressures up this trapped water because water will not compress.
If we drill into this pressured water it is possible that a kick will take place. The pressure of this trapped formation fluid is called Abnormal. Abnormal fluid pressures commonly occur in Shales and any nearby sands. There is always a danger of kicks when drilling through mixed Shale and Sand Formations.
When drilling these formations the Shales tend to drill slower and the sands faster. The increase in ROP, when entering a sand causes a 'drilling break' and, following standard practice, must be flow checked.

Salt Domes



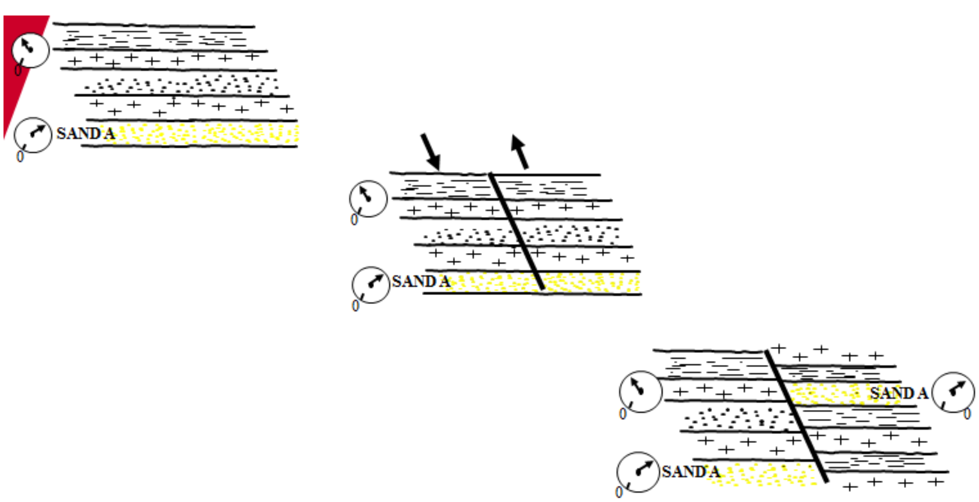
Salt is a low density rock. It tends to rise up through the heavier rocks above, similar to those Novelty lamps with globules of liquid rising and falling. As the salt rises it pressures up fluid in the neighbouring rock. This build up of pressure is more often quicker than the fluid can escape, therefore, the fluids become Abnormally pressured. Sometimes rafts of abnormally pressurized rock may me contained in and drug by salt.

Artesian Effects



These are often a cause of high formation fluid pressures in mountainous areas.

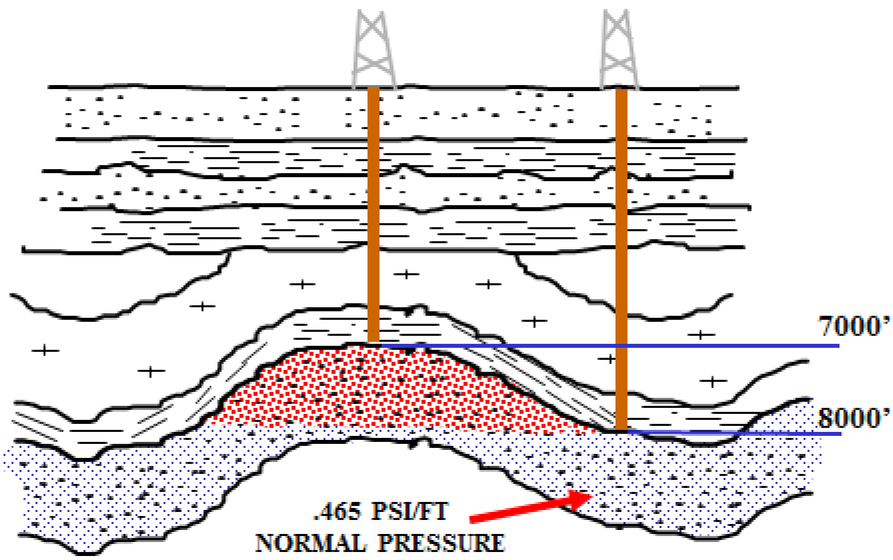
Falting



Faulting can cause Abnormal Pressure. Stresses build up in the earth and often cause the rocks to crack. These are called faults.

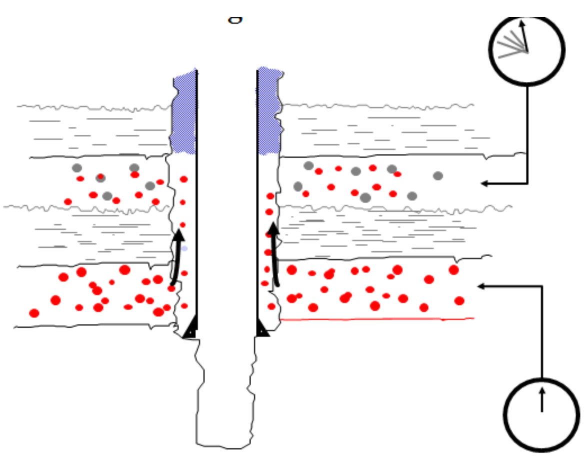
The sequences of diagrams show a fault that causes a layer of rock from deeper in the earth to be moved upward. If the rock maintains the same pressure (does not bleed off along the fault) then the pressure will be abnormal for that depth.

Gas Cap Effect



The position that you drill a reservoir can affect the formation fluid pressure at that point especially when it is a gas reservoir or an oil reservoir with a 'gas cap'.

Leaks Around Casing



Leaks around casing can be a cause of Abnormal Pressure in shallower formations.

Review of Abnormal Pressure

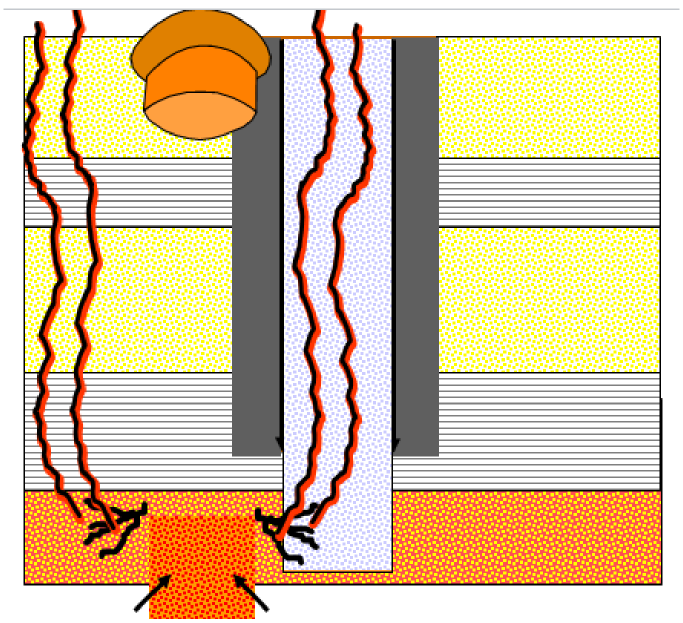
A - Trapped formation fluids in Shale/Sand formations
B - Salt Domes
C - Artesian Effect
D - Faulting
E - Gas Cap
F - Leaks Around Casing

Intentional Kicks

1. Drill String Test
2. Underbalance Drilling

Although we do not want to bring in a kick there comes a time in the overall construction of a well when the formation fluids have to be allowed to enter the wellbore. The two main operations when this happens is during testing and completion work.

Shallow Gas



Shallow Gas is one of the major causes of blowouts and loss of rigs in our industry.

The main problem with shallow gas is that we do not have the BOPs installed and only rely on a Diverter for protection. Installing BOPs and closing the well in is possible but the buildup of shut in pressure will most likely case a breakdown at the Casing Shoe. Diverting is therefore the preferred option to a standard well kill.

Shallow Gas

Causes:
Shallow gas is the result of the decay of organic material in the sediments. It can accumulate in porous sand formations. These formations may or may not be pressured.

Drilling Procedures:

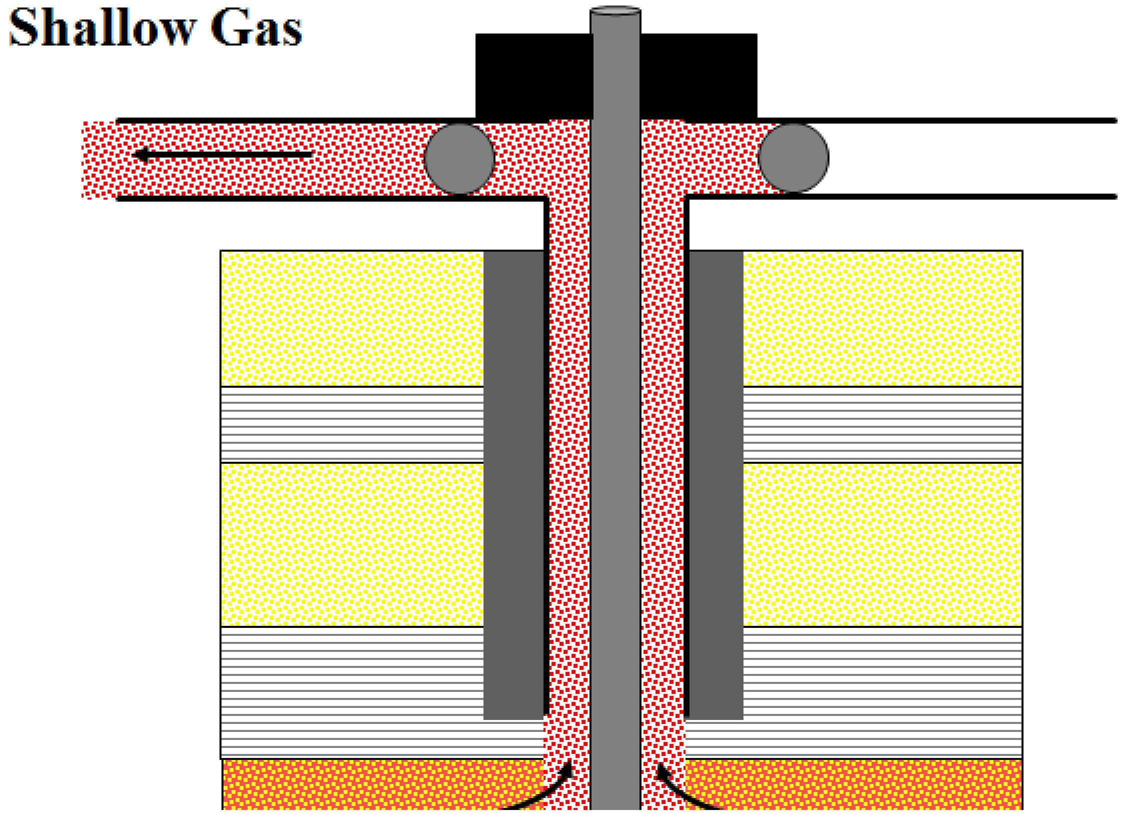
- drilling Pilot Holes to minimise flow rate and time to fill with kill mud.
- installing Diverter equipment
- drilling Riserless on a Floater or using a Floater instead of a Jack Up
- Pumping out of the hole to minimise swabbing
- control drill to avoid lost circulation due to too many cuttings
- installing a Float Valve in the drillstring

Actions:
If the well kicks then the diverter vent lines are opened and the Diverter closed. At this stage the crews are put on immediate evacuation standby and steps taken to try and kill the well.

Kill attempts include:

- pumping at high rates

- pumping kill mud weight

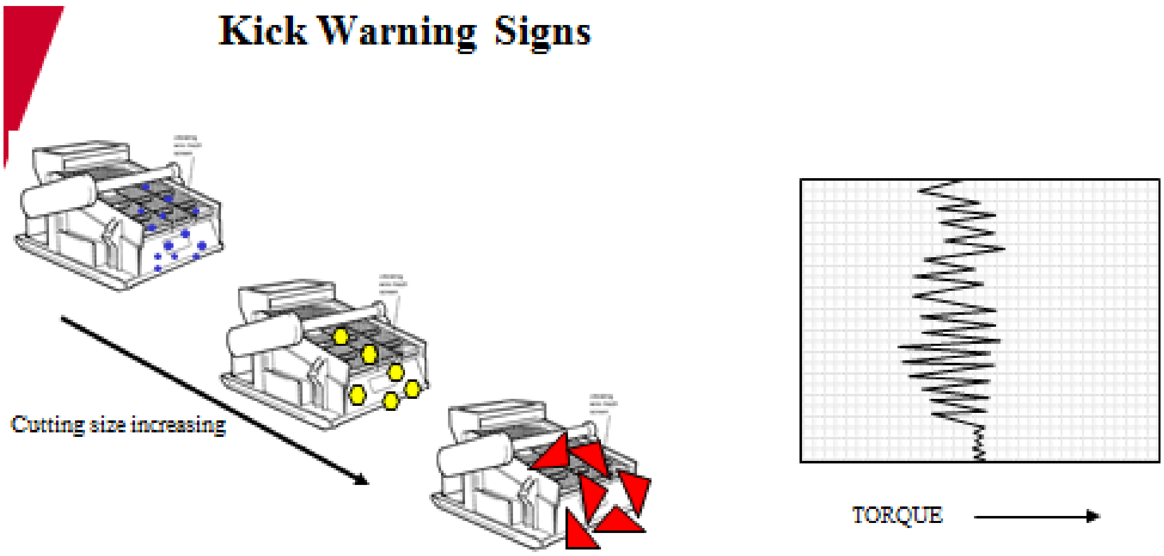


Knowing what causes a kick can help us avoid those practices that reduce overbalance on the bottom of the hole.

Prevention is the key and a simple operation like monitoring the mud weight going in the hole will drastically reduce the occurrence of kicks.

KICK WARNING SIGNS

Kicks rarely happen 'just like that' without any warning. In most cases there is information coming from the well that tells you conditions are changing downhole. These changes may be warning you of an increase in formation pressure or of a decrease in the stability of the hole wall, or of a formation change. Two examples are shown cuttings size change (left) and drillstring torque (right).



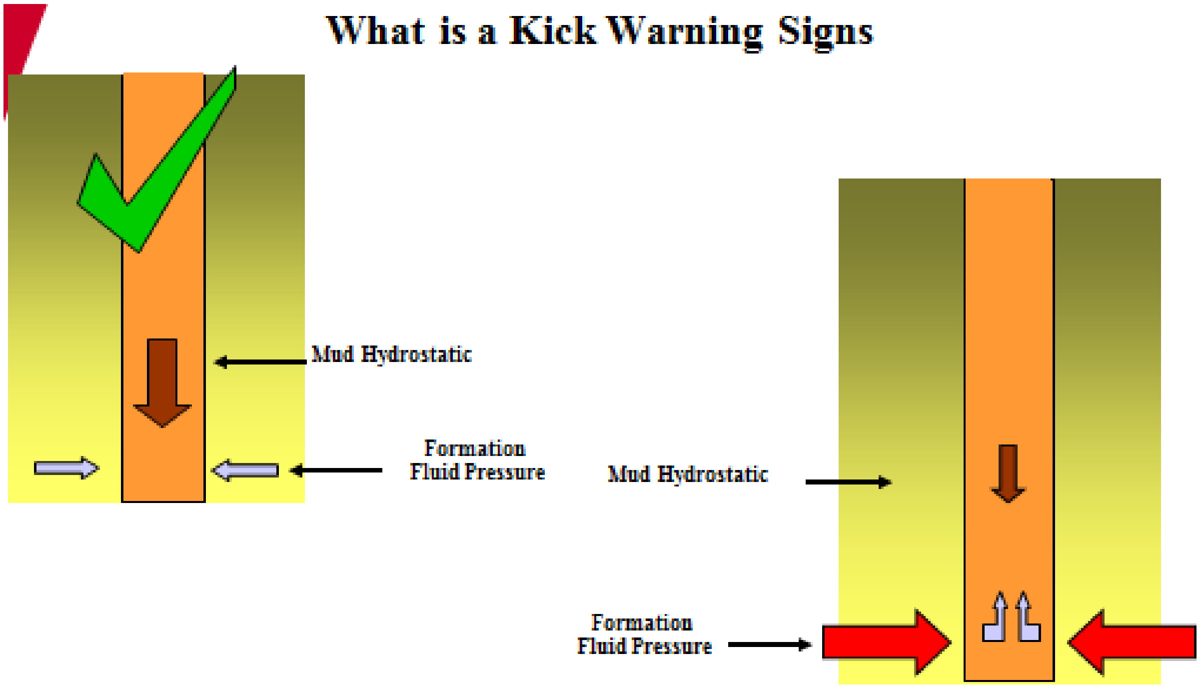
So what is a Kick Warning Sign?

Normally we drill with a small OVERBALANCE (see left) that allows us enough safety margin to pull out of the hole (trip or safety margin).

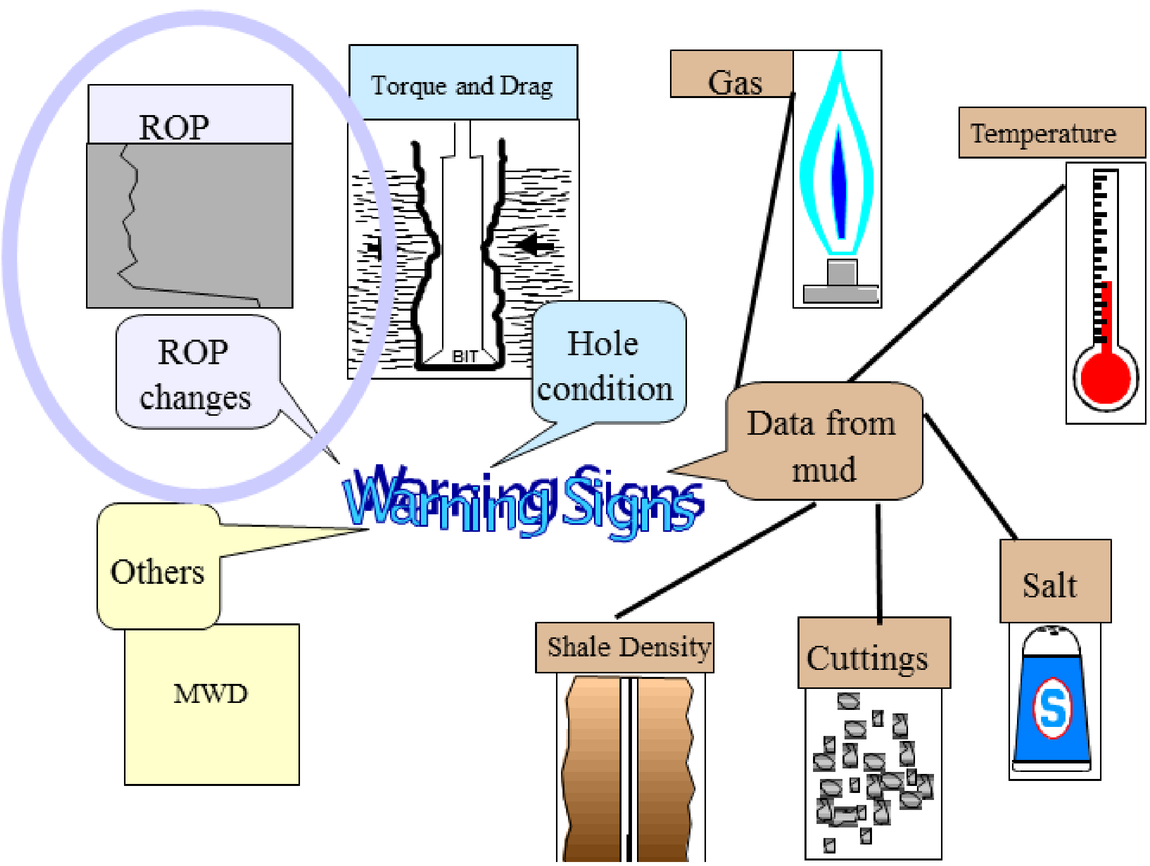
A KICK WARNING SIGN therefore tells you that the well may be going UNDERBALANCED or your SAFETY MARGIN is decreasing.

If we can recognise these Kick Warning Signs then action can be taken to re-establish safe **PRIMARY CONTROL**. This would normally be achieved by raising mud weight a small amount.

What is a Kick Warning Signs



ROP Changes

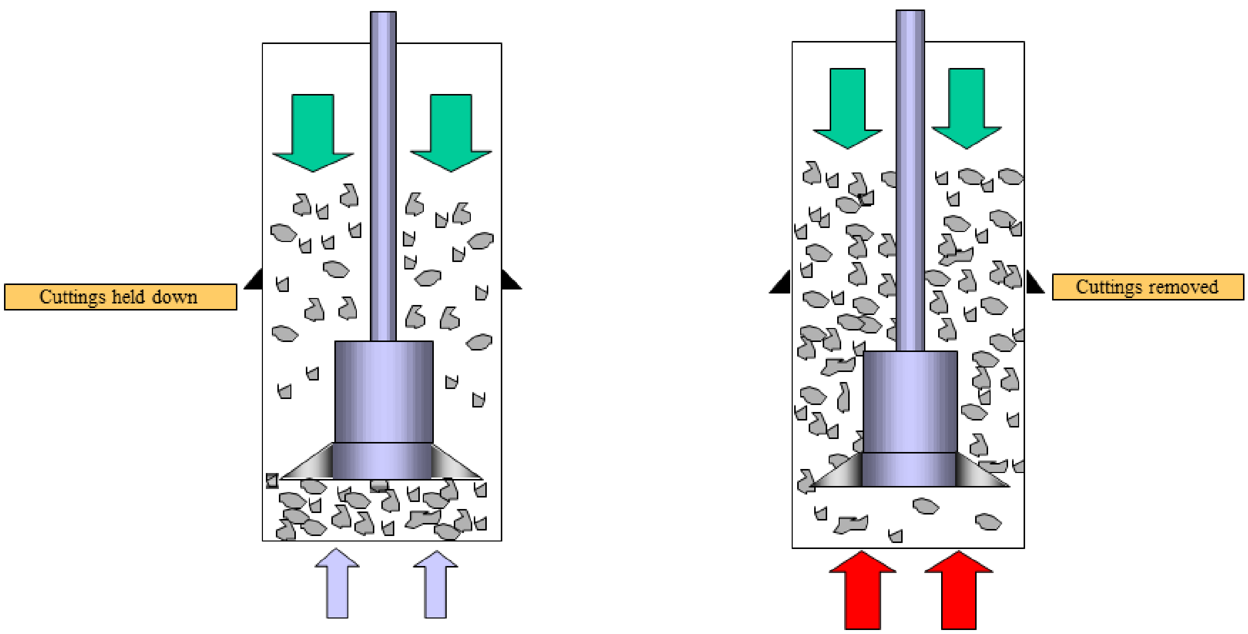


What happens to cause this ROP change?

The overbalance creates a differential pressure on the bottom of the hole which makes it harder for the chips of rock (cut by the bit) to be released. The bit may therefore have to cut the same piece of rock a number of times before the chips (cuttings) break away and are carried up the annulus by the mud stream. This is called the 'Chip Hold Down' effect (see left).

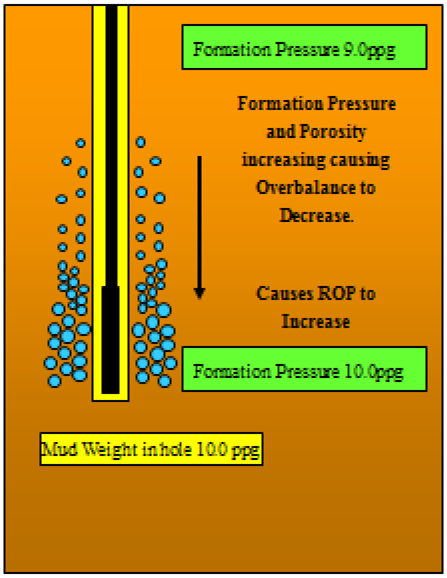
The closer we get to balance the easier it is for cuttings to be released, thus the ROP increases (see right).

ROP- Overbalance Effect

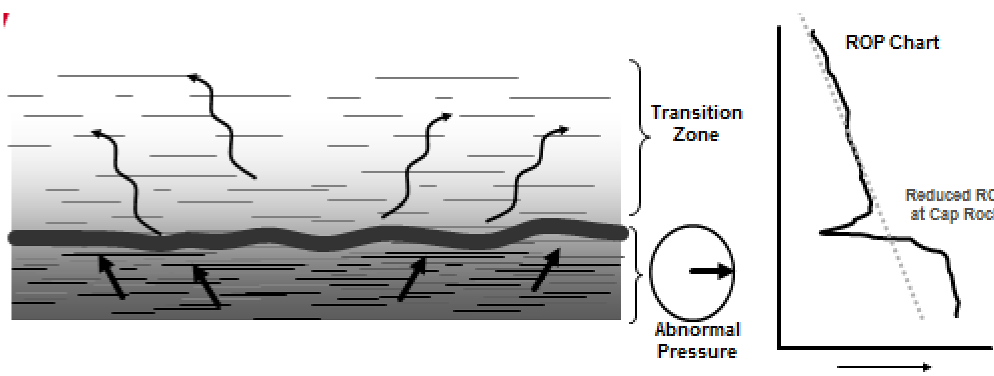


What happens when we drill a Transition Zone?
A transition zone is a zone where the pressure of the fluids in the formation (formation fluid pressure) is increasing. If we drill toward a high-pressure formation those rocks above may exhibit an increasing pressure.
This is common in clay based rocks such as claystone and shale.
As we drill through the transition zone there is a gradual increase in ROP due to a reduction in the amount of overbalance. This is due mainly to two factors - overbalance and porosity effects.

ROP- Transition Zone



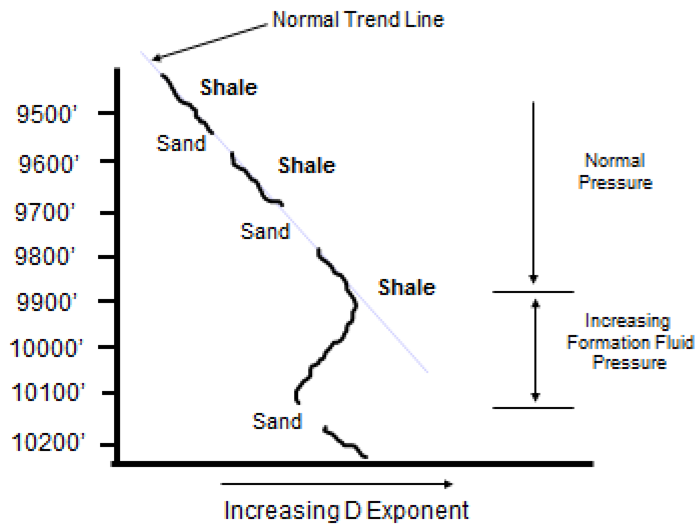
The formation fluid trapped in the pore spaces cannot escape therefore compaction is slowed down. The formation with trapped water therefore has a greater porosity or less amount of rock per unit volume of formation.
Because the drill bit cuts rock, not water, the ROP will be faster than expected (less rock to cut). As we drill from normally pressured formations the amount of trapped water gradually increases (the porosity increases and rock percentage decreases).
This, together with a reduction in overbalance, causes a gradual increase in ROP (see below). This change in porosity not only affects ROP. Other kick warning signs (to be discussed later) are also related to porosity changes in the transition zone.



Analysis of ROP

Here the D Exponent increases with normal compaction of the Shales. In Abnormal zones the trend reverses.

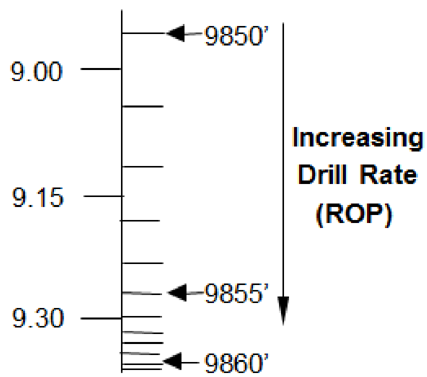
ROP- D Exponent



Drilling Breaks

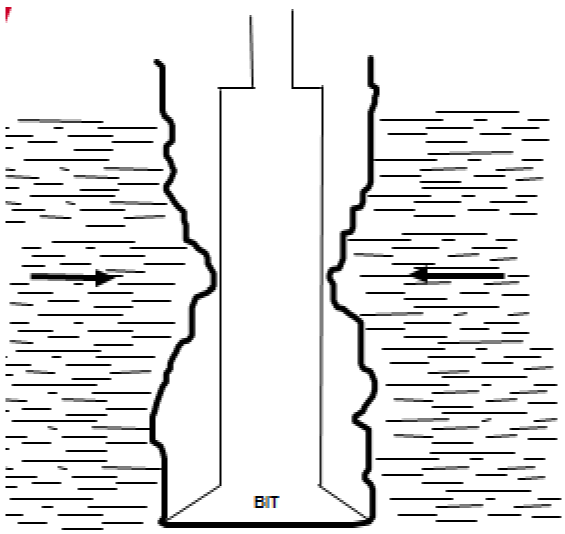
A drilling break is a sudden increase in the ROP.
This is normally due to a change in the type of formation being drilled.
A faster drilling formation is likely to be softer and may have an increased POROSITY and PERMEABILITY.
Historically many kicks have occurred following a drilling break, therefore it is standard practice to stop drilling and watch the well (check flow).
a 50% increase is a good guideline.
Local experience is also very important in deciding when to flow check.
Drilling breaks are not normally checked immediately. Usually 3 to 5 feet of formation is drilled at the increased ROP before flow checking.
In some areas a DECREASE may signal a possible high-pressure formation. Local knowledge will help decide if a 'reverse' drilling break needs to be flow checked.

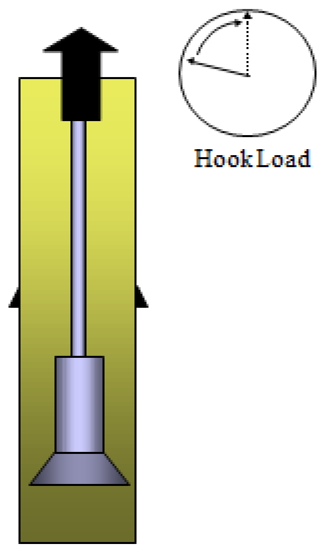
ROP- Drilling Break



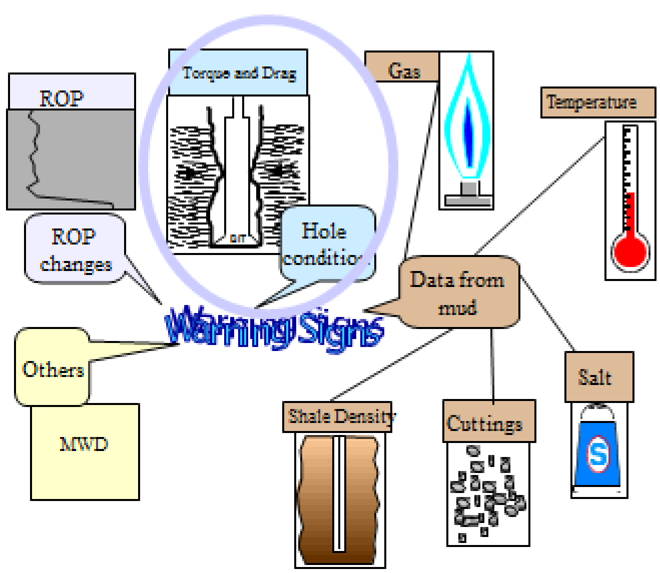
GEOLOGRAPH CHART

Hole Condition. The largest OD part of the drill string is the BHA. Any increased friction between it and the hole wall will increase torque. This may be due to a large amount of cuttings or cavings from the hole wall but it may also be due to the hole wall itself squeezing in a very small amount. This may be due to the pressure of the formation or just instability of the wellbore hole wall.
It is not a convincing warning sign of a reduction in overbalance, but it is trying to tell you that conditions downhole are changing. The question we have to ask ourselves is WHY?
If the hole is getting tighter then it is likely that 'drag' will be seen when moving the pipe up and down. Drag is noticed by an increase in hook load when raising the pipe and a reduction when lowering the pipe.





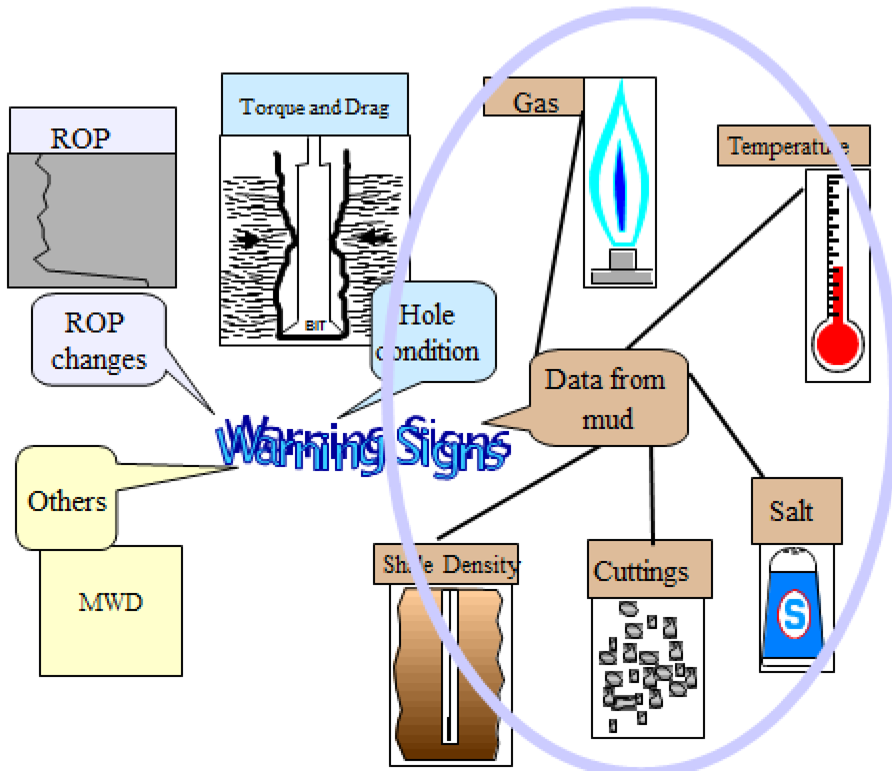
Hole Condition - Torque and Drag



There are a number of kick warning signs in this category that help us decide if overbalance is being reduced. These are:

Gas level in the Mud
Connection Gas
Cutting Size and Shape
Mud Temperature
Mud Resistivity
Shale Density.

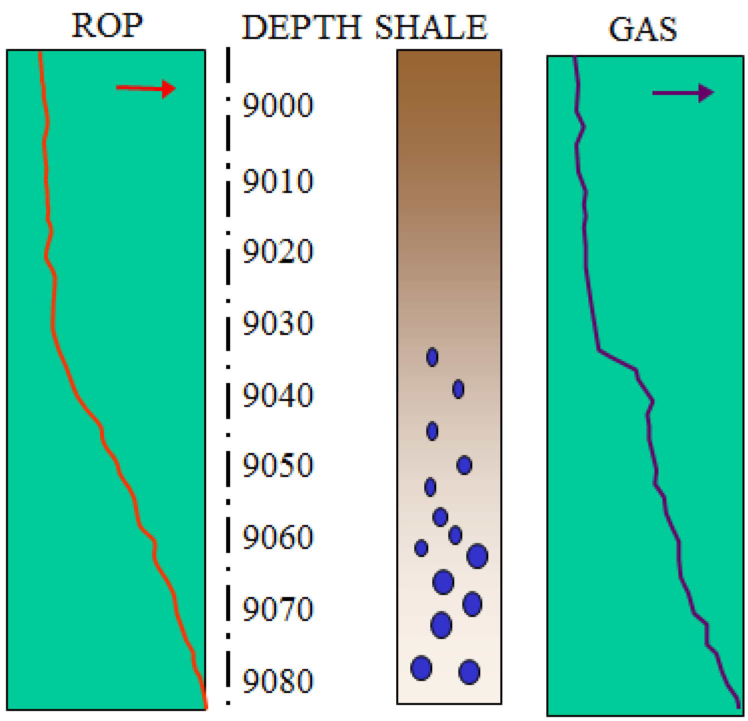
Data from the Mud



Changes to gas levels in the mud are a sign of conditions changing downhole. It may indicate a change in formation pressure, but maybe not. If seen with other warning signs, like ROP (see left) then it is likely that formation fluid pressure is increasing.

Increased gas levels require rig site supervisors to discuss what is happening downhole.

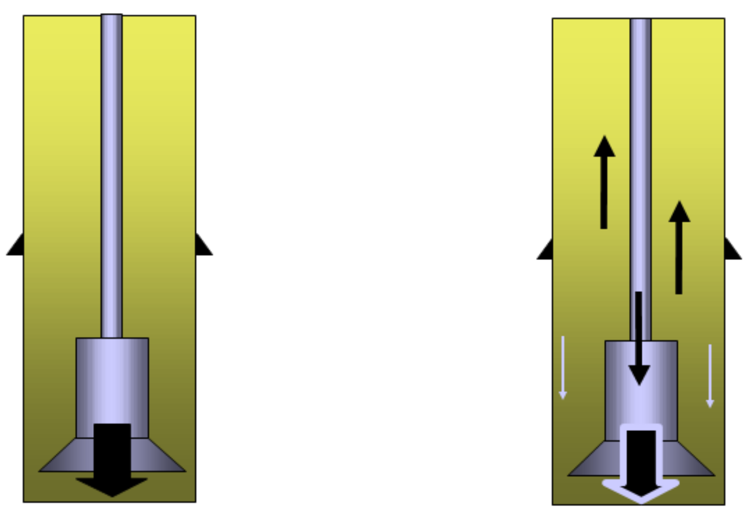
Gas Levels in Mud



When pumping mud, a ‘dynamic’ effect is seen. Fluid moving up the annulus generates a friction pressure. That friction pressure acts downward and against the wall of the hole. The extra pressure is known either as Annular Friction Loss or Annular Pressure Loss.

When circulating mud around the system the circulating bottom hole pressure is therefore greater than static bottom hole pressure. In the diagram this extra pressure due to friction is represented by the red line surrounding the big black arrow. The difference is called the Annular Pressure Loss (APL).

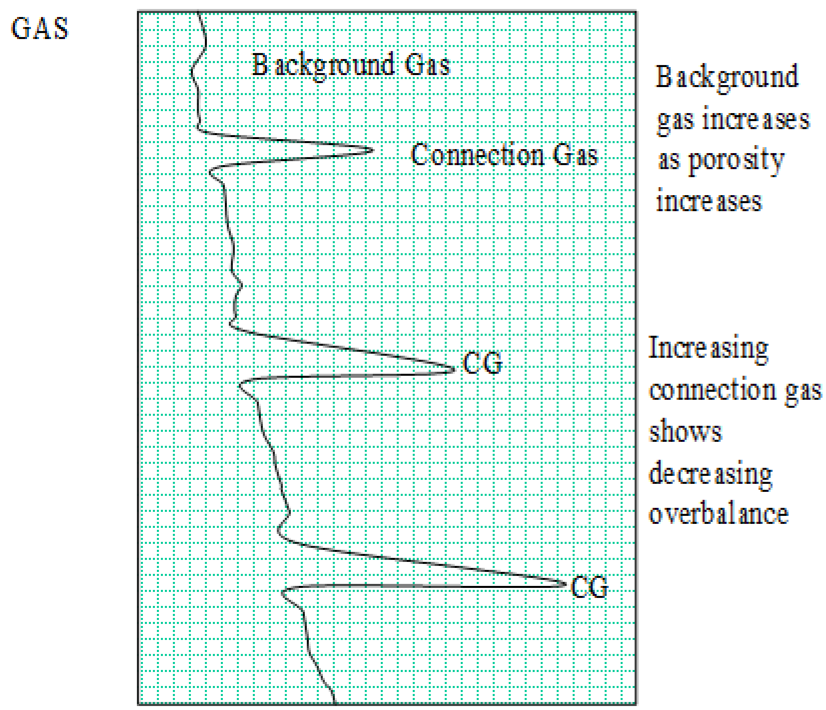
Connection Gas



To review:

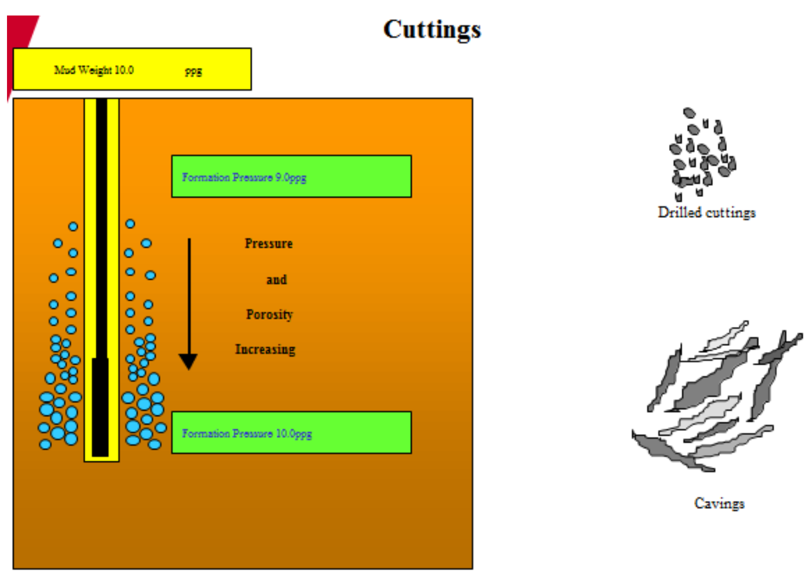
If the minor influx contains gas, then it may be detected when it reaches the surface. This would be seen by a small peak of gas above background levels that related back in time to when the connection was made.

Connection Gas



Cutting Size and Amount

A common kick warning sign in Shales is a change in the size and amount of formation coming back over the Shakers. This can also be a sign of wellbore instability.

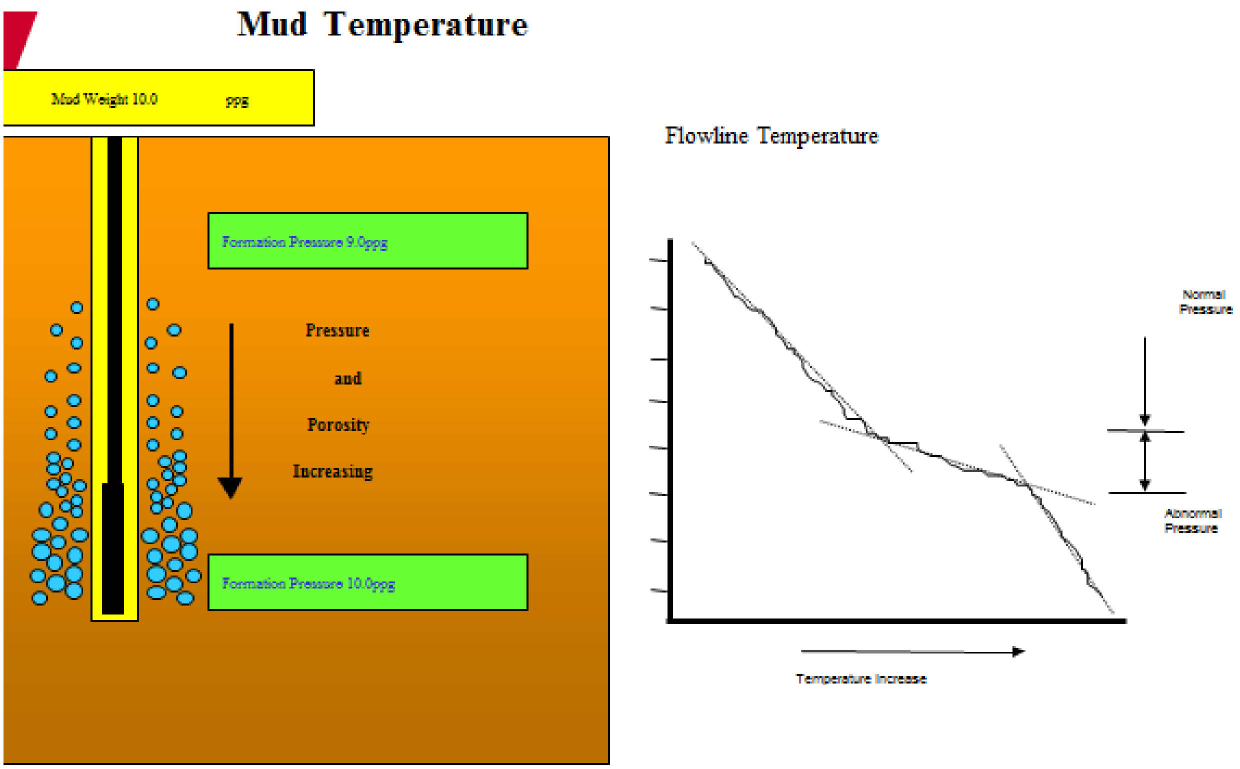


Mud Temperature

As we drill deeper, the formations increase in temperature because of the heating effect from the earth's core. Temperatures can get up to 300ºF + in certain areas.

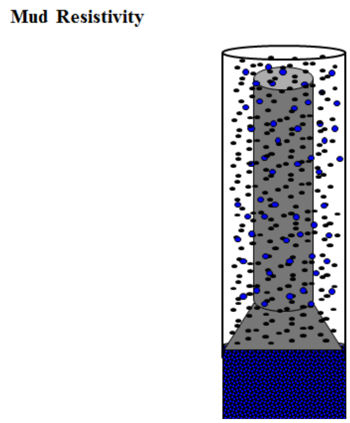
The downhole temperatures heat the mud on its way round the system. Temperature sensors inserted in the pits and shale shakers detect temperature in and out of the hole.

Abnormally pressured zones tend to be hotter due to their increased porosity and water content, the water traps and stores heat.



Mud Resistivity

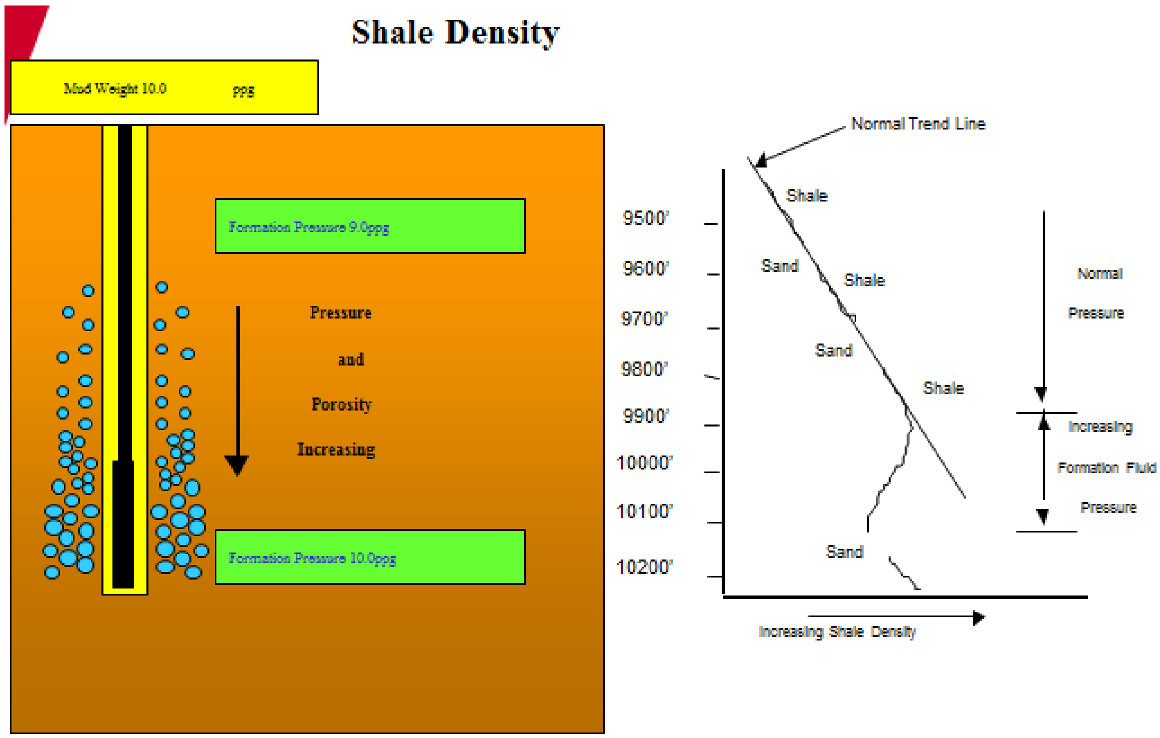
When drilling abnormally pressured formations, the porosity may be higher and more formation fluid is released into the mud per foot of rock cut, thus affecting chloride levels in the mud.

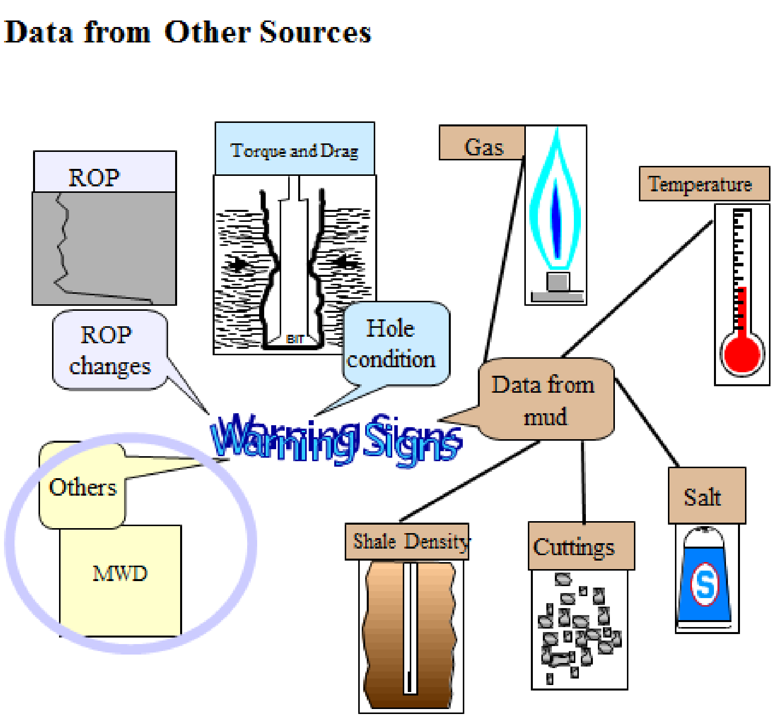


Decreasing Shale Density

The deeper you drill the more compact and dense the shale.

Abnormally pressured zones tend to have trapped water, a greater porosity (therefore more fluid) and less evidence of progressive compaction. Therefore abnormally pressured zones exhibit a Shale Density less than it should be for that depth.





KICK INDICATORS

When a kick starts it must be controlled quickly. Failure can lead to a larger influx, that in turn leads to higher pressures that make the kill more hazardous which, if not handly with care may lead to a loss of control- a BLOWOUT.

Fortunately a KICK will INDICATE itself at the SURFACE.

SURFACE INDICATORS OF A KICK ARE:

1. Excess flow from the well when tripping.
2. Return flow rate increase when pumping.
3. Pit gain.
4. Decreased pump pressure/increased SPM.
5. Flow from well with pumps off.

The question is "Is it a kick or a false indicator?" Unless you can be absolutely sure, treat it as a kick. Remember ……SPEED OF KICK DETECTION IS ESSENTIAL!

The longer the well is allowed to kick, the more dangerous it is to kill.

If in doubt…..SHUT IT IN!

False Indicators

Flow:

- ✓ change in pump speed
- ✓ U-tubing due to heavier mud in the pipe
- ✓ Ballooning Shales

Pit gain:

- ✓ Moving mud
- ✓ Adding fluid

"Secondary Control" comes into the play once the well is kicking. That means the formation fluids are entering the wellbore, and if not controlled will lead to a BLOWOUT.

"Secondary Control" is performed by the Blowout Preventer and the chosen Well Kill Method.

FIRST - use Blowout Preventers to close in the well.

SECOND - choose and use a Kill Method to restore the Mud Hydrostatic Pressure to a level that re-establishes Primary Control.

Kill Methods

1. Principles of Kill Methods
2. Basic Procedures
   - Drillers Method
   - Wait and Weight Method
3. Practical Application of Kill Methods

Considerations During Well Control

Pressure Profiles

Comparison of Main Methods
Problems and Bad Practices

The reason we have a kick in the hole is because the mud hydrostatic (primary control) was too low (see diagram bottom left).

To return to primary control we have to 'kill' the well.

Therefore the objective of any kill operation is to restore primary control.

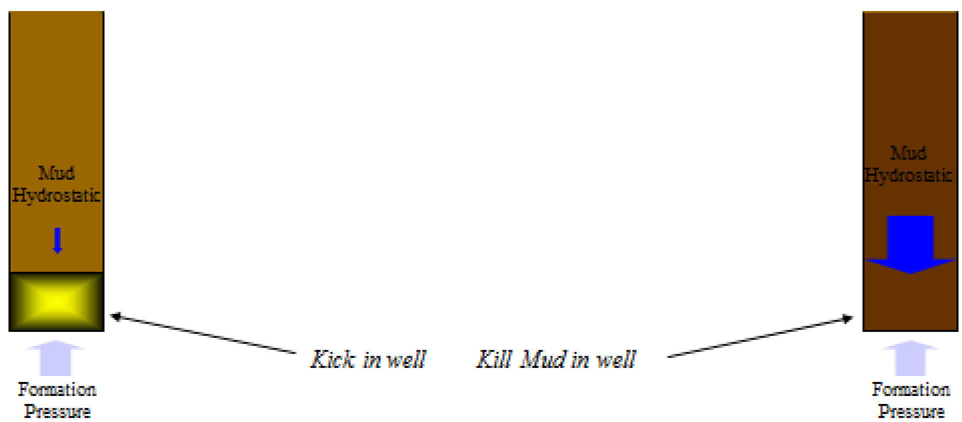
In order to do this it is necessary to:

-Remove the influx

-Replace the original mud with kill mud

(see diagram bottom right)

Objectives of The Kill Operation



To successfully kill the well the correct bottom hole pressure (BHP) must be maintained constant throughout the operation. This is because:

- too low a BHP may result in further influx.
- too high a BHP may result in losses.

That is: BHP must be maintained above Formation Pressure but less than Fracture Pressure.

It is therefore necessary to use a kill method that maintains both constant and correct bottom hole pressure.
There are two commonly used constant BHP methods of well control. These are:

- Drillers
- Wait and Weight

The Drillers Method uses two circulations:

1st circulation to clean the influx from the well

2nd circulation to circulate Kill mud

The Wait and Weight Method is carried out in one circulation. You wait until you have weighted up the mud then pump the kill mud around the well at the same time as the influx.
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 require pressure to be maintained at certain values during the kill process.

Principles of Kill Methods

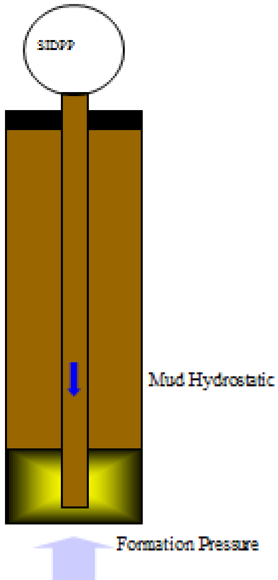
Constant BOTTOM HOLE PRESSURE
Drillers
Wait and Weight
Slower Pump Rate
Constant Pump Rate
Correct surface pressure for strokes pumped
Correct Mud Weight

Starting Up The Kill Operation
The Start-Up procedure can be seen as a technique to get the pumps up to kill speed AT THE SAME TIME ensuring the bottom hole pressure (BHP) is correct – not too high and not too low.

The following slides will look at the procedure starting first with a review of Shut In Pressures (SIDPP and SICP) and their relation to BHP.

Once the well has been shut in and allowed to stabilise, there are two pressures which can be observed.
What do these pressures represent?
SIDPP: is the difference between the Formation Pressure (FP) and the Hydrostatic Pressure in the drill pipe.
It is the amount of underbalance inside the drillstring!

Shut in and Stabilised



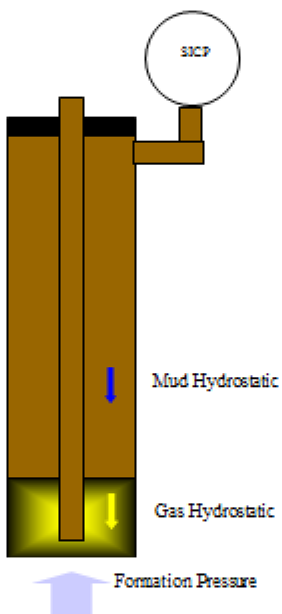
SIDPP = FP - Hydrostatic in drill pipe

SICP: is the difference between the formation pressure and the hydrostatic pressure in the annulus.

It is the amount of underbalance inside the annulus!

The hydrostatic pressure in the annulus is due to mud and the influx.

Shut in and Stabilised



SICP = FP - (mud hydrostatic + influx hydrostatic)

Start Up Procedure

HOLD THE CASING PRESSURE CONSTANT AS THE PUMP IS BROUGHT UP TO KILL SPEED.

Once the pump is at kill rate then the Start Up procedure is over.

A key part to any constant BHP method of well control is the start up procedure.

It is necessary to bring the pump to speed, opening the choke whilst maintaining constant BHP.

The standard procedure is:
HOLD THE CASING PRESSURE CONSTANT AS THE PUMP IS BROUGHT UP TO KILL SPEED

This procedure varies on Subsea wells and will be covered later in this section.

The behaviour of pressures in the well bore during start up is demonstrated on the following pages.

Slow Pump Rates

The well is killed at a slower rate for a number of reasons:

- ✓ gives choke operator more time to react to pressure changes
- ✓ gives more time to maintain correct mud weight
- ✓ minimises friction losses in the annulus
- ✓ minimises pumping pressures if close to maximum pump pressure
- ✓ less risk of overloading the mud gas separator (poor-boy degasser)

The slow pump rate is normally taken at outputs between 2 and 5 bbls per minute. This is usually between 15 and 50 SPM depending on pump Liner size.

They are normally taken every 12 hours or at selected depth intervals, whichever come first. The depth intervals vary but every 500 ft is common.

With these SCRPs the Toolpusher can calculate expected pumping pressures for a kill. How these are used will become more clear as each kill method is discussed.

Drillers Method

Two circulations as follows:

First circulation: remove the influx.

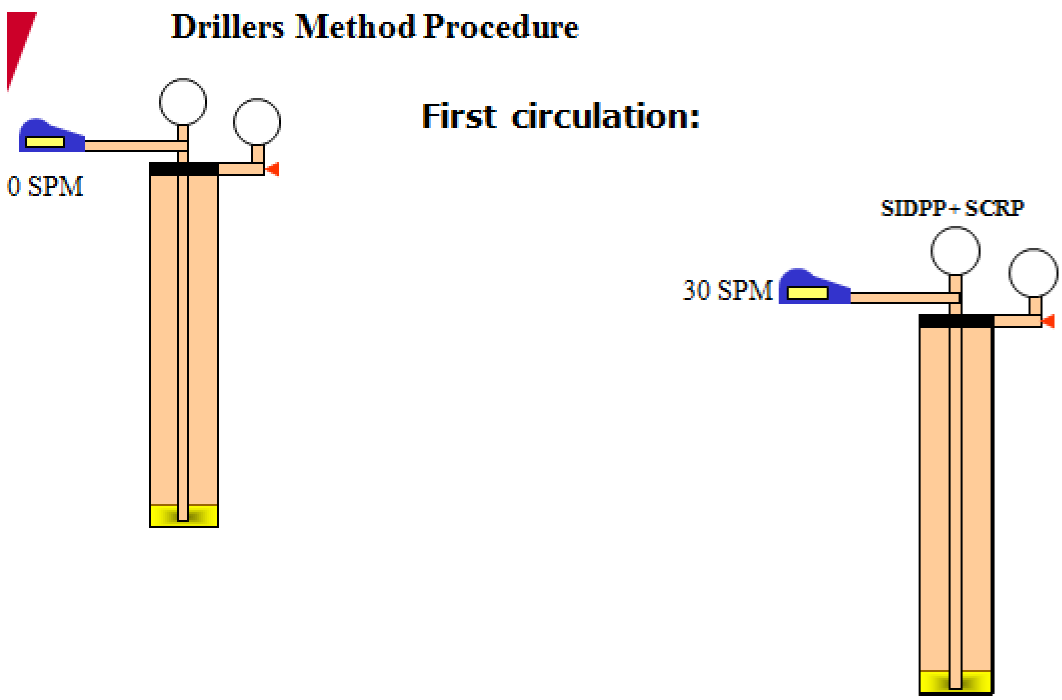
Second circulation: circulate kill weight mud around the well.

Primary Well Control is the correct use of mud hydrostatic i.e. a mud weight high enough to balance formation pressure, but not so high as to cause losses.

1. Bring the pump to kill rate, opening the choke using correct start up procedure. Pump only the original mud weight.

2. Once at kill rate, look at the drill pipe pressure which should be: **SIDPP + SCRP**.

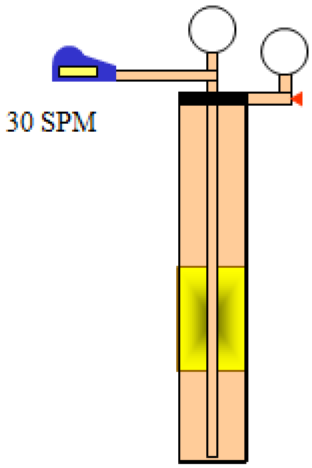
Note: As hole conditions may vary from the time the SCRP was taken, the ACTUAL pressure may be different from the calculated. Go with the actual pressure. More detail on this subject will be covered later.



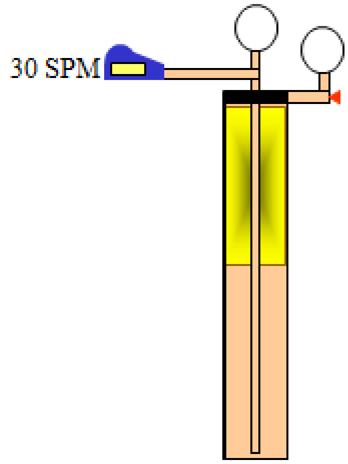
3. Drill pipe pressure is now held constant at **ICP** until the influx is removed (see left). If the influx is gas the casing pressure will normally rise as the gas expands on its way up the annulus. Should the drillpipe pressure vary then the choke must be used to maintain it constant.

4. The casing pressure will continue to rise as gas is circulated closer to surface (see right).

It is important to remember that it is the drill pipe pressure which is being held constant until the influx is removed.



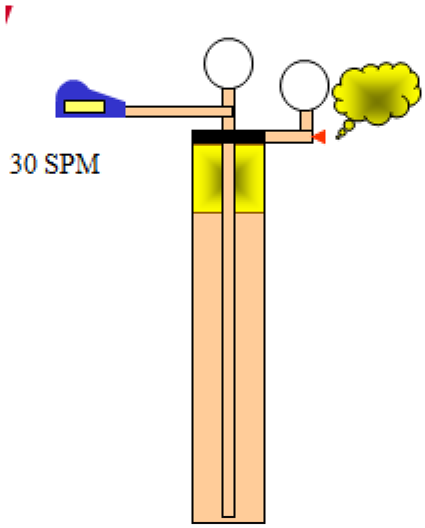
Drillers Method Procedure



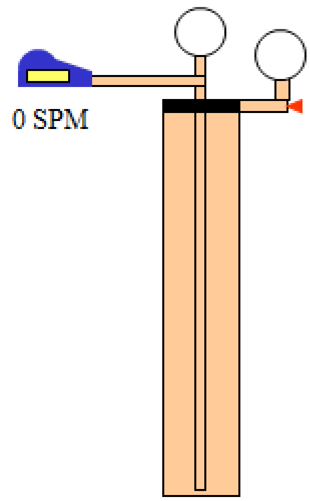
4. As the influx is removed, the casing pressure will start to fall (see left). Remember that it is the still drill pipe pressure which is being held constant.

5. 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** because the mud weight is now the same on both sides of the U Tube i.e. same as original mud weight at time of kick.

To recap on the 1st circulation; Start Up then maintain Drillpipe pressure at start up value until the influx has been circulated out.
Having completed the first circulation it is now time to pump the kill mud, but before we can do this we must be sure that the SICP is equal to the SIDPP. If not (SICP higher) there may still be some influx in the annulus that is causing the SICP to be higher.
There are two procedures for the second circulation . The standard driller's method that assumes a clean annulus and a modified version that can be used if the annulus is still contaminated with influx.
The following description of the Drillers 2nd circulation assumes the annulus is clean and describes the standard method. The modified version is cover later.

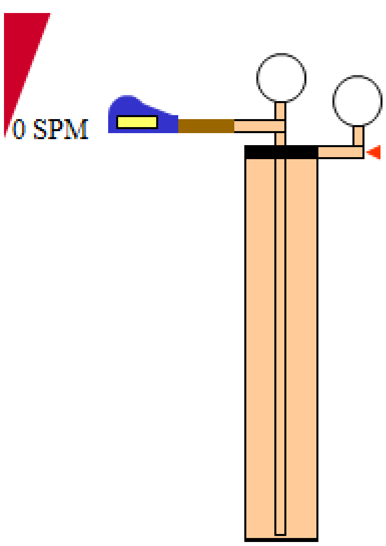


Drillers Method Procedure

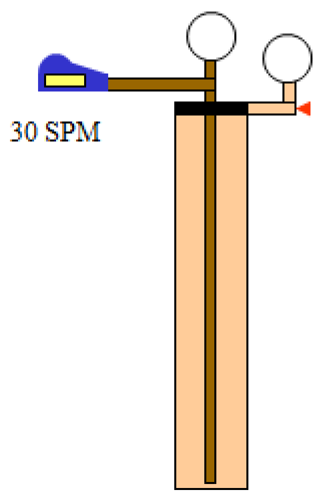


1. With the pump lined up on kill mud, bring the pump to speed, opening the choke, using the correct start up procedure.

2. Once at kill rate, hold casing pressure constant until kill mud reaches the bit (see right). (This can only be done successfully if the annulus is clean). During this process the drill pipe will fall by an amount approximately equal to the **SIDPP**.

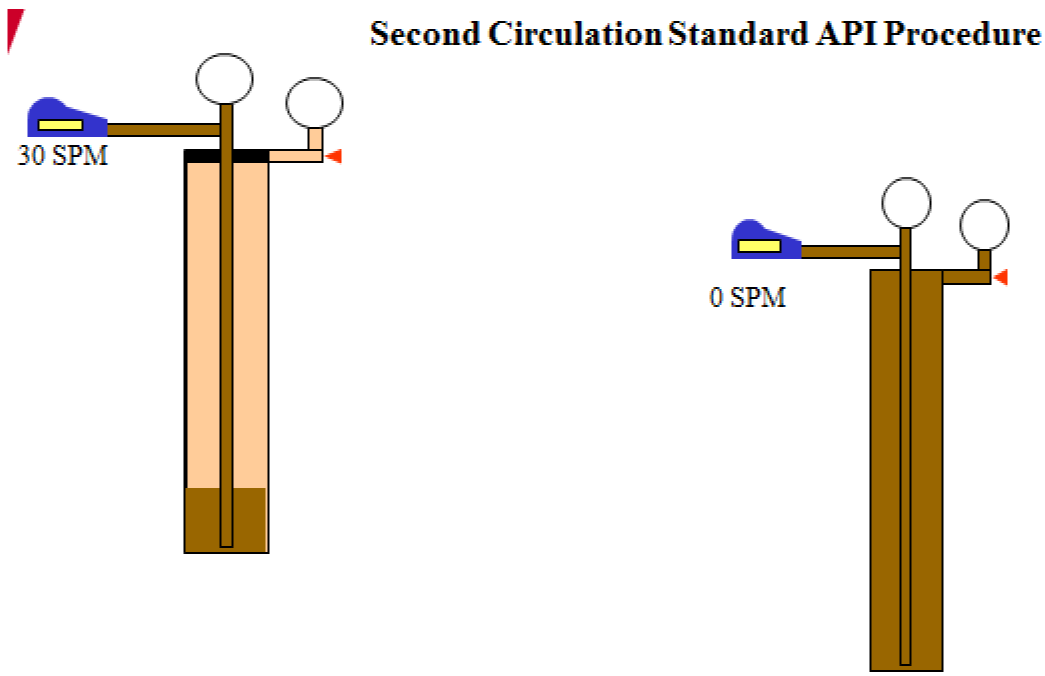


Second Circulation Standard API Procedure



3. As kill mud enters the annulus, switch over to the drillpipe pressure and maintain this constant until kill mud reaches the surface (see right).

4. When kill mud is back to the surface, shut in the well. The **SIDPP** and **SICP** should be zero and there should be no flow.



Wait and Weight Method

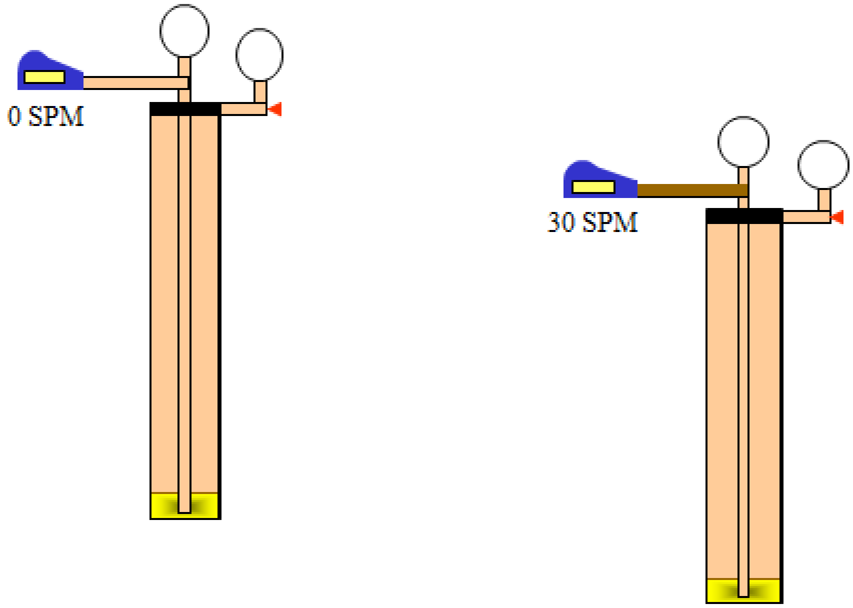
The Wait and Weight method, (named because we WAIT until the kill mud is WEIGHTed before starting the operation) requires only a single circulation during which heavy mud is circulated around the well at the same time as the influx is circulated out.

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

2. Once at kill rate switch to drill pipe pressure which should read the **Initial Circulating Pressure** (**ICP**):

ICP = SIDPP + SCRP

Procedure



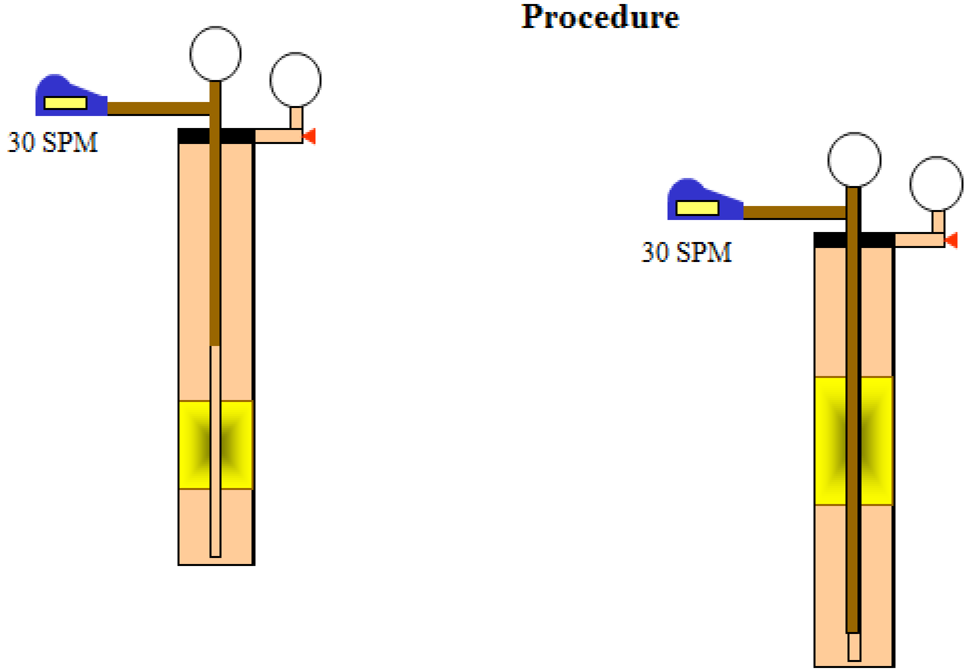
3. As kill mud is pumped to the bit the drill pipe pressure must be allowed to fall from ICP to balance the increasing hydrostatic in the drillpipe,

e.g. if the hydrostatic increases by 100 psi then the drillpipe pressure must be allowed to fall be 100 psi.

4. By the time kill mud has reached the bit, the drill pipe pressure will only be that required to pump. i.e. approximately the SCRP.

In fact, due to the heavier mud in the drillpipe it will be a little harder to pump, so the actual pressure will be higher than the SCRP. This pressure is known as **Final Circulating Pressure (FCP)** and is calculated prior to starting the kill.

Procedure

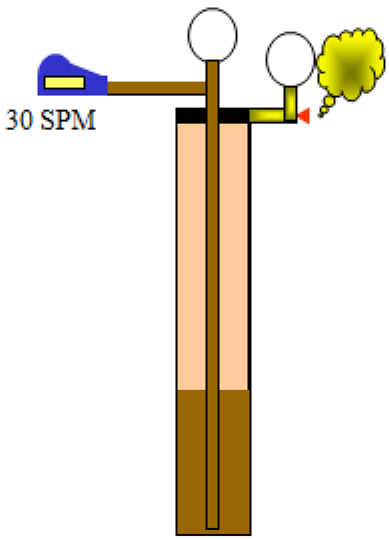


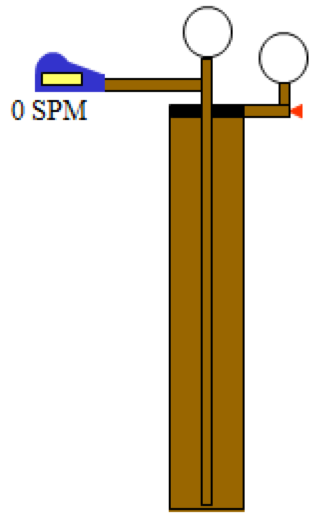
5. Once kill mud has entered the annulus, FCP is held constant until kill mud is back to the surface.

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 no flow from the well.

Procedure





To recap the Wait and Weight method, Start Up and once up to speed the drillpipe pressure should read the calculated ICP. Allow Drillpipe pressure to fall steadily from ICP to FCP as kill mud is pumped to the Bit. Once kill mud is at the Bit hold Drillpipe pressure constant at FCP until Kill Mud returns at surface.

At this stage shut down and monitor pressures. If pressures are zero check for flow through the choke. If OK then prepare to open the BOP and do a full flow check.

If the well is not dead, further circulation may be required and mud weight may need to be increased again.

Start Up
Drillpipe should read calculated ICP.
Drillpipe pressure to fall steadily from ICP to FCP as kill mud is pumped to the Bit.
Once kill mud is at the Bit hold Drillpipe pressure constant at FCP until Kill Mud returns at surface.
Shut down and monitor pressures.
If zero check for flow through the choke.
If OK then prepare to open the BOP and do a full flow check.

If the well is not dead, further circulation may be required and mud weight may need to be increased again.

Driller's Second Circulation (Modified Method)
This, as stated earlier is essentially the Wait & Weight method. Although you will be following a Step Down chart the values on the gauges will basically be the same as the standard 2nd circulation.

During the kill the two pressures we monitor are Drillpipe and Casing. The following pages look at how these pressures react during a normal well kill, starting with the Drillers Method.

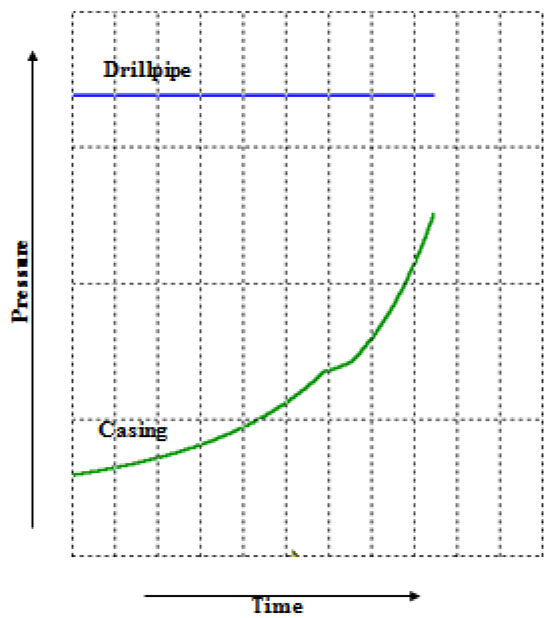
Drillers:

1st Circulation- After start up the drillpipe pressure is held constant until the influx is out of the hole.

In this case we will see no change to the Drillpipe pressure, if it begins to vary the we have to adjust the choke to maintain it constant. If we plotted this pressure on a graph it would be a straight line (see next page).

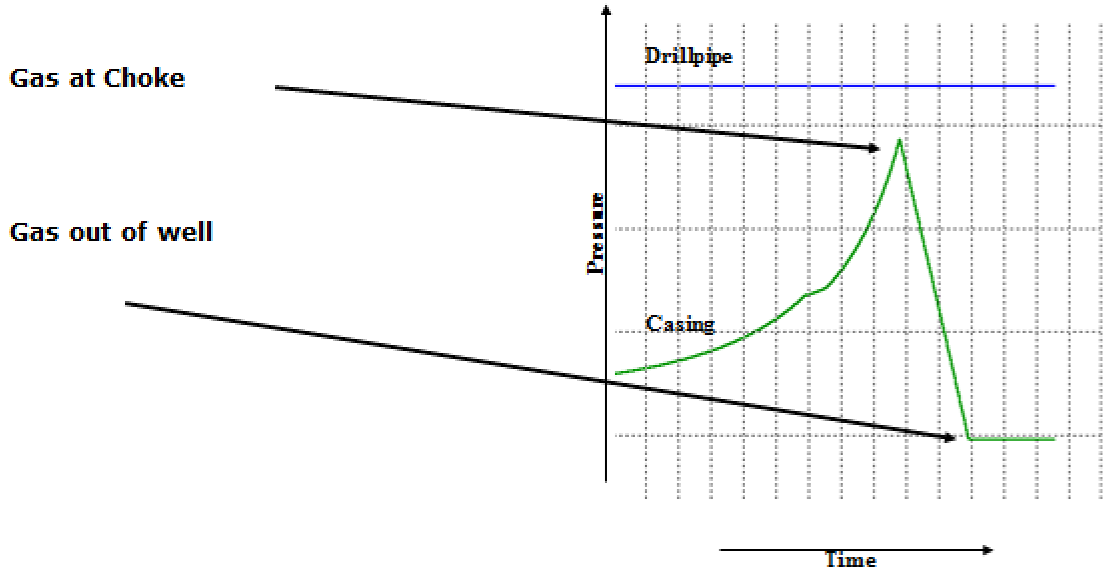
The Annulus is different. The influx as it is circulated up may expand (if gas) and affect the overall hydrostatic pressure in the Annulus.

Wellbore Pressures
Drillpipe and Casing.
Drillers: 1st Circulation.



When the gas reaches the choke and starts to exit the well the hydrostatic pressure begins to increase and the surface Casing pressure starts to decrease (see right).

Once all the gas is out the pressure should read the same as the original SIDPP.

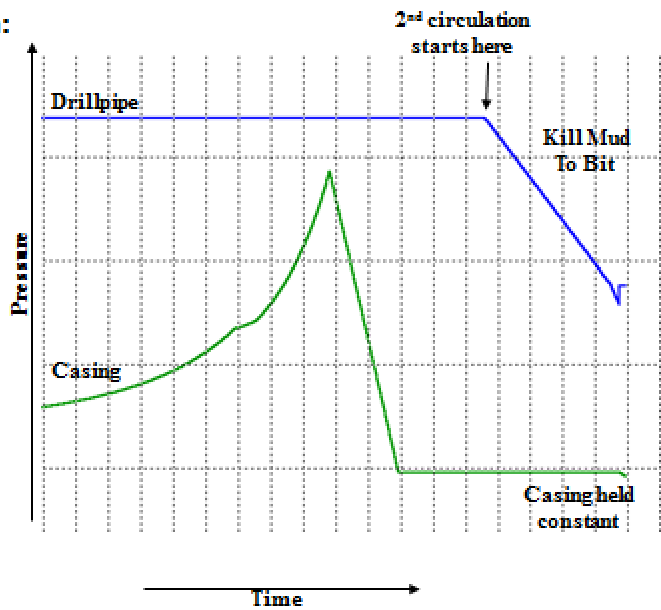


2nd Circulation:
Here the Casing pressure is held constant at start up value until the kill mud reaches the bit. At this point the drillpipe pressure is now held constant.

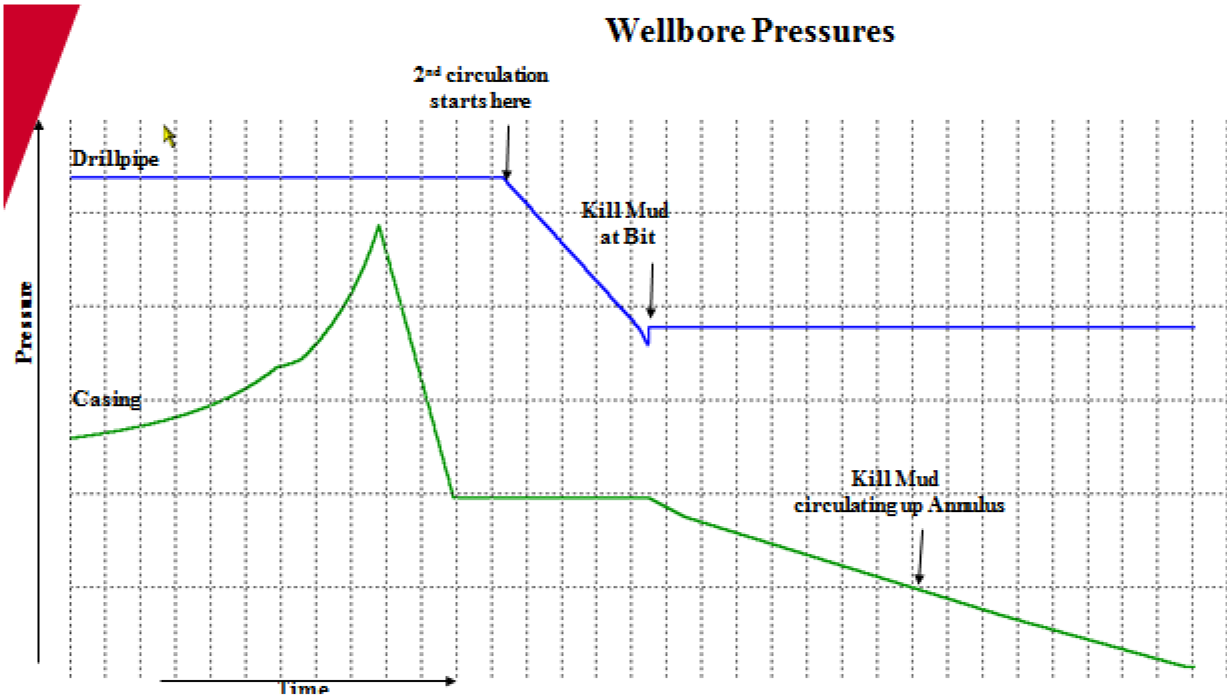
The diagram shows Casing pressure being held constant by the choke operator as kill mud is pumped to the bit. Inside the string the kill mud causes the hydrostatic to rise. In order to maintain constant BHP the drillpipe pressure decreases, e.g. as string hydrostatic increases by 100 psi the Drillpipe pressure decreases by 100 psi.

Wellbore Pressures

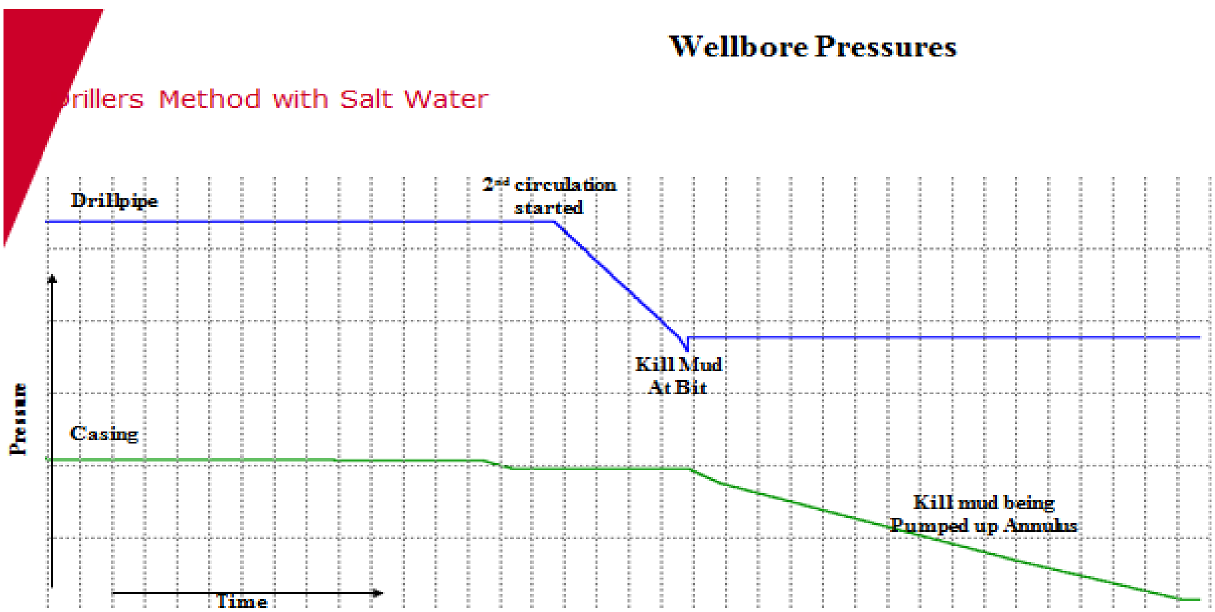
2nd Circulation:



With a drillstring full of kill mud the hydrostatic will be constant therefore the surface (drillpipe) pressure is held constant. Meanwhile in the Annulus hydrostatic is increasing. This increase is compensated for by a decrease in the backpressure held (casing pressure).

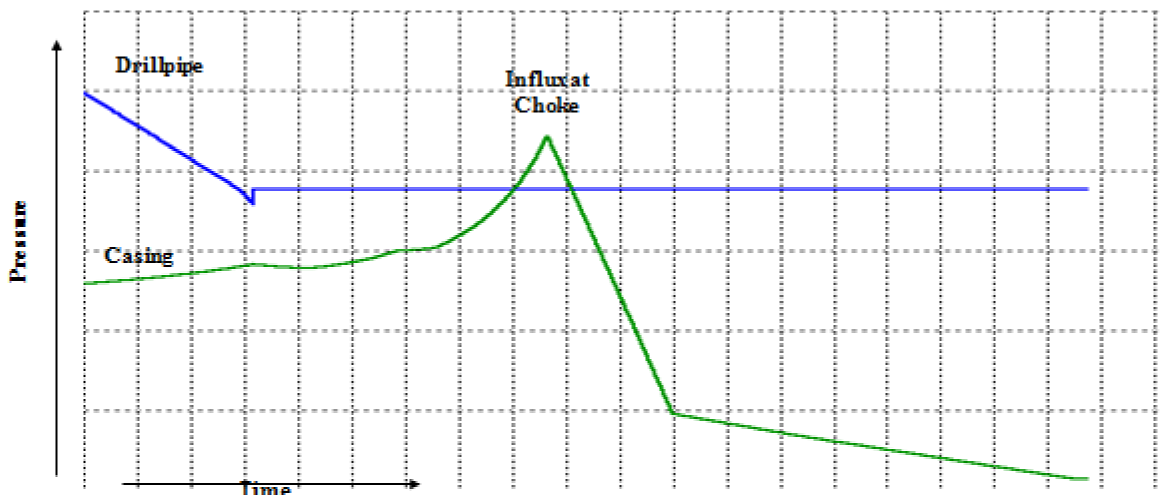


The explanation given and diagrams show what happens to pressure with an expandable influx (gas). If the influx is a liquid like Oil or Water there will be little expansion so the effect is much less. Diagram below shows Drillers method with a Salt Water kick. Note there is no change in Casing pressure until kill mud is circulated up the Annulus.



Here both sides of the U-Tube (drillstring and annulus) are changing. The pressure in the drillstring is increasing as kill mud is pumped to the bit, and the annulus is affected by influx expansion as well as kill mud. The overall pattern can look something like the diagram below (it is likely to vary based on well geometry and size of influx).

Wait and Weight:



Comparison of Main Kill Methods

Drillers Method

Advantages

- Circulation started immediately of benefit if:
- gas migrating,
- risk of stuck pipe

Disadvantages

- Highest Surface pressure
- Highest Annulus/Shoe pressures
- Longest choke time

Wait and Weight Method

Advantages

- Lower Surface pressure
- Lower Shoe pressure (usually)
- Shortest choke time

Disadvantages

- Waiting time prior to circulation commencing (getting stuck).
- Gas Migration

Problems During Well Kill Operations

Problems which may occur include:

- Choke plugging
- Choke washing out
- String plugging
- String washing out
- Annulus packing off
- Hydrate formation
- Stuck pipe
- Lost circulation

It is essential that they are recognised quickly and the correct action taken.

Annulus Packing Off:

The annulus packing off might be recognised by:

- increase in drillpipe pressure.
- no change or reduction in casing pressure.
- drop in flow from annulus.

It may be possible to reduce the problem by using a higher pump rate. The choke should not be opened as this may reduce BHP.

Problems During Well Kill Operations

Hydrate Formation:

- Frozen compounds made up of gas and water.
- May occur when certain gasses are present, with water in between a critical range of temperatures and pressures.

Inhibition of Hydrates:

Inhibition:

-injection of glycol upstream of the choke, starting prior to influx reaching surface.
-addition of glycol based additives to the drilling fluid.

Removal:

-circulation of hot fluids.
-circulation of a solvent such as methanol.

Stuck Pipe:

Kill the well, then attempt to free pipe

Partial Losses:
Reduce BHP to keep up with losses, but never to the point of being underbalanced:
- Remove any pressure safety factors
- Re-establish circulation at a reduced rate

-Stop pumping, shut in and monitor - the losses may cure themselves.
LCM may be added, but care must be taken to avoid plugging the string.

Severe or Total Losses:
- May be underground blowout. Shut the well in and evaluate.
- It will be necessary to cure the losses before continuing to kill the well.

Problems During Well Kill Operations

Summary of Problems:

Well control problem	Drillpipe	Casing	BHP
Choke plugging	↑	↑	↑
Choke washout	↓	↓	↓
Nozzle plugging	↑	—	—
String washout	↓	—	—

Stripping
Volumetric control
Lubricate and Bleed
Bullheading
Off Bottom Kill

SHUT IN AND DATA TO COLLECT

Reasons for Shut In
Shut In Methods

- Hard
- Soft

Shut In While Tripping
Advantages & Disadvantages of both Methods
Special Situations
Diverting
Interpretation of Data
Float in String
Pit Gain
Mud Considerations
Gas Migration

Reasons For Shutting In The Well
Having identified that the well is flowing, it is important to react positively and quickly. In cases where a blow out preventer (BOP) has been installed, the procedure is usually to shut in the well. Performing this action quickly and correctly gives us many advantages.

Shutting in will stop flow and prevent further influx. It will prevent the well becoming a blowout.

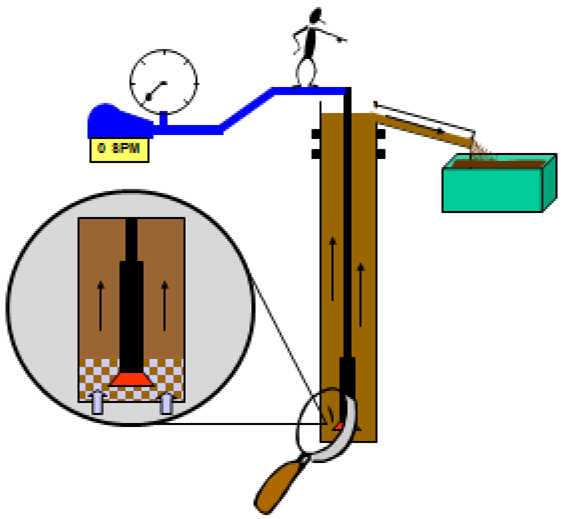
Having the well shut in and under control allows us to safely monitor the pressures at surface
In some cases, e.g. prior to a BOP being installed, it may be necessary to "divert" the flow away from the well to avoid breaking down soft formations at surface and endangering the rig. By diverting the flow we direct formation fluids a safe distance away from the rig while we attempt to regain control.

Shut In Drills are carried out regularly on the rig to ensure everyone is well practised at their shut in procedure. The three main drills are the Trip Drill (securing the well during a trip) and the Pit Drill (securing the well during drilling) and Diverter Drill (for response to Shallow Gas). The company Well Control Policy manual covers the requirement for these to be carried out.

Reasons For Shutting In The Well

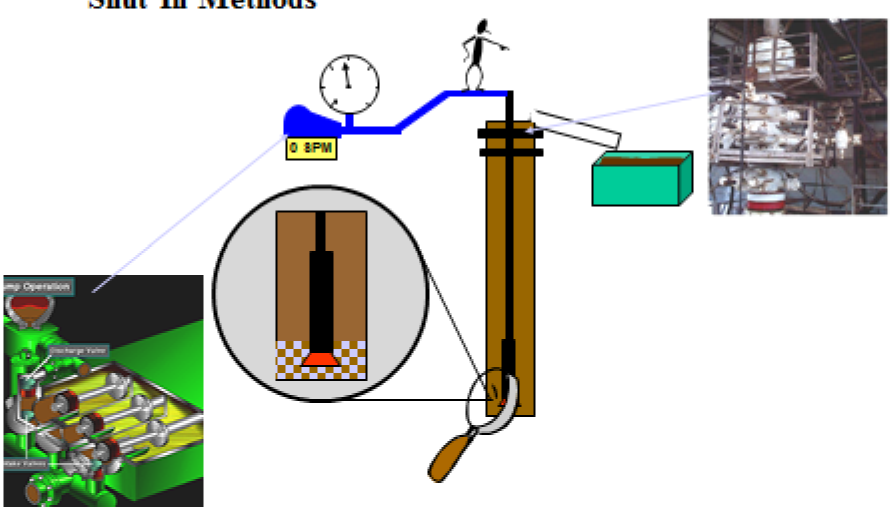
There are two main procedures (methods) used in the industry:
Hard Shut In and Soft Shut In.
Before looking at specific methods we first need to look at a kicking well.
The diagram shows a kick pushing mud out of the Annulus and along the flowline. On bottom the kick is entering the wellbore.
Once it is recognised that the well is flowing we need to seal off the annulus. This is done by closing the BOP’s.

Shut In Methods



The BOPs have sealed off the annulus and kick fluid has stopped entering the wellbore.
But what about the inside of the drill pipe? Can mud escape up pipe? This depends on two things.
If the Top Drive or Kelly is installed then the fluid would be contained by the mud pump. The discharge 'valves' on the fluid end of the pump act as non-return valves (see below) and therefore a blowout preventer, preventing backflow. The pressure relief or 'pop-off' valve on the pump must also be considered. If shut in pressure is too high it will 'blow' and allow mud and pressure to be released from the drillstring.
In this case the IBOPs on the Top Drive would be closed.

Shut In Methods



The following is the procedure for the hard shut in while drilling and applies to those rigs with the BOP stack on surface.
Procedure:

Line up with remote choke closed
Check flow - if flowing;
Close BOP*
Open HCR (hydraulic choke line valve)
Monitor well integrity and record pressure   and call Supervisor
Monitoring the well is vital. The Driller has to ensure that the BOP is closed and is <u>not</u> leaking (see diagram for common leak points). Anywhere there is a potential to leak it should be checked. At the same time the Supervisor has to be informed and the pressure build up should be recorded every minute or two (depends on rig procedure).

1. Pick up to space out position
2. Shut down pumps and top drive
3. Check for flow – if flowing
4. Close BOP
5. Open HCR (hydraulic choke line valve)
6. Monitor well integrity and record pressure   and call Supervisor

The following is the procedure for the hard shut in while drilling and applies to those rigs with a subsea BOP stack.
Stop drilling
Pick up to space out position
Shut down pumps
Check flow - if flowing
Close BOP*
Open choke line valves (failsafe)
Monitor well integrity and record pressure
Call supervisor
Prepare to hang off using Heave Compensator
Once hung off activate ram locks
Bleed off pressure between rams and annular if possible.

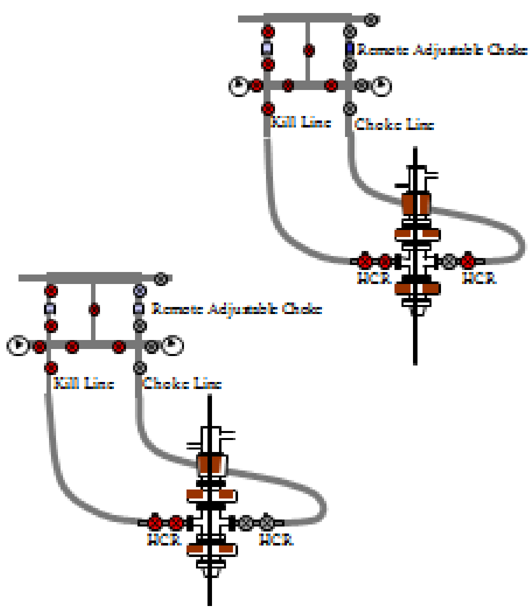
1. Pick up to space out position
2. Shut down pumps and top drive
3. Check for flow - if flowing
4. Close BOP*
5. Open choke line valves (failsafe)
6. Monitor well integrity and record pressure
7. Call supervisor
8. Prepare to hang off using Heave Compensator
9. Once hung off activate ram locks
10. Bleed off pressure between rams and annular if possible.

The following is the procedure for the soft shut in while drilling applies to those rigs with the BOP stack on surface.
Lined up with remote choke open
Pick up to space out position

Shut down pumps
Check flow - if flowing;
Open HCR (hydraulic choke line valve
Close BOP*
Close remote choke
Monitor well integrity and record pressure Call supervisor
*API soft shut in states BOP (ram or annular)

Soft Shut-In While Drilling - Surface BOPs

- Line up with remote choke open
- Pick up to space out position
- Shut down pumps
- Check flow - if flowing: -
- Open HCR (hydraulic choke line valve
- Close BOP*
- Close remote choke
- Monitor well integrity, call supervisor and record pressure



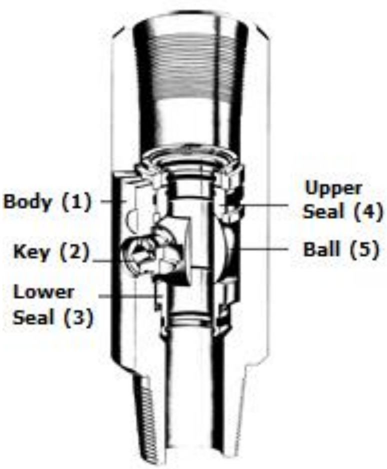
Soft Shut-In While Drilling - Subsea BOPs

- Pick up to space out position
- Shut down pumps
- Check flow - if flowing
- Open choke line valves (failsafes)
- Close BOP
- Close choke
- Monitor well integrity and record pressure
- Call supervisor
- Prepare to hang off using DSC
- Once hung off activate ram locks
- Bleed off pressure between rams and annular

The following is the procedure for the soft shut in while drilling and applies to those rigs with a subsea BOP stack.

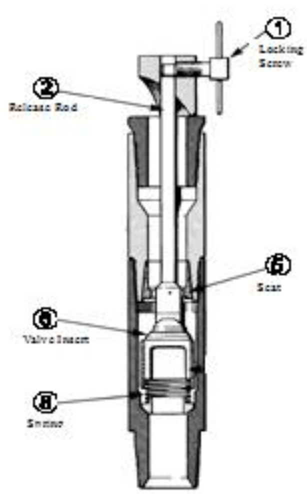
This is an example of a FOSV. They are also called TIWs, Kelly Cocks and SMF valves.
The picture (right) shows the valve with a key. The valve has a lifting ring to help the floorhand stab the valve into the string.
A full opening safety valve is a ball type valve (5) which uses a large key to close (2). It will be easier to stab onto the string during flow due to its full open bore. For this reason it is normally the first valve stabbed onto the string.
A F.O.S.V. is usually installed on top of the string at any time the trip is halted.

Full Opening Safety Valve (FOSV)



This is an example of a non return valve.
Non Return Valves are sometimes Gray Valves.
This type of valve is held open by a rod(2). When released, the spring closes the valve(6). This allows flow downwards through the valve, but not upwards.

Non Return Valve



The only difference between a shut in while drilling and a shut in while tripping is that the FOSV is stabbed, made up, then closed. Once this is done the shut in procedure (Hard or Soft) is exactly the same as when drilling.
What Happens Next?
Once the well is closed in and holding the Top Drive (or Kelly) is made up to the string
The FOSV is then opened and pressures recorded.
The next step is normally to strip the bit to bottom to allow the well to be killed.
In order to do this the Top Drive will need to be removed and the Non Return Valve installed and checked for integrity.

Shut In While Tripping - Surface and Subsea BOPs

Advantages and Disadvantages of Both Methods

HARD	SOFT
- Quicker - Smaller influx - Less risk of exceeding MAASP	- Slower - Larger influx - Less chance of a 'hydraulic' shock

Delays, Checking and Monitoring

Regardless of the differences, the biggest cause for concern in any shut in method is the possibility for delays in shutting in the well. Delays in shutting in the well might include:

- calling the Toolpusher to the rig floor prior to taking action;
- not understanding the correct procedure (e.g. forgetting to close the choke).
- incorrect space out.
- equipment failure.
- not setting Pit/Flow Alarms
- attempting to run in with well flowing
- just not believing that you have a kick
- the mud pump 'pop-off' valve is also a weak point if shut in pressures are high.

Special Situations

- ✓ No pipe in the hole
- ✓ Kicks while running casing
- ✓ Kicks while running wireline
- ✓ Diverting

Kicks While Wireline In The BOPs

A well kick may occur with wireline either in the hole or inside the drill string.
Blind/shear rams should only be used as a last resort as a cut and seal on wireline is not guaranteed and can damage the rams.
If the well kicks with no pipe in the hole then the line should be cut under tension and off bottom (if possible), to ensure line will drop clear of the Blind/Shear Rams. The Blind/Shear Rams are then closed. To ensure a quick close in it is essential to have cutters on the drill floor any time wireline is run.
Any time wireline is run inside the string then a full opening safety valve (FOSV) must be installed. If the well kicks then the wireline is cut (in the same way as above). The FOSV is then closed before closing off the annulus in the normal way (e.g. Hard Shut In).
During wireline operations, the hole must be very carefully monitored. This is the Drillers responsibility and should be done using the trip tank (with alarms set).
During some operations (e.g. well testing, perforating or workover operations) when the rig BOPs rather than drilling fluid hydrostatic are the primary means of control, dedicated pressure control equipment is used. This equipment includes;

- ✓ wireline BOPs;
- ✓ risers;
- ✓ safety valves;
- ✓ grease injection heads
- ✓ Shooting nipples
- ✓ Lubricators.

These are designed to seal around the wireline, or on open hole when the wireline is out of the hole.
Shut In procedures specific to this equipment have to be developed and personnel trained in their use.

Earlier in this section it was stated that the open hole formations below the Casing Shoe must be strong enough to handle pressures created by a kick. If not, then formation breakdown would cause losses.
When drilling top hole formations they are generally weak and are not strong enough to contain a kick. In this case the well is not shut in during a kick, it is Diverted. This is done as stated below using either a large bore Annular e.g. 30" or a purpose built Diverter. As formations are shallow it is vital to recognise flow and respond quickly.
The actual procedure will depend on the equipment but in general the following must be carried out:

1. On recognising a kick stop drilling, but <u>keep</u> pumping.
2. Open the vent line valve that is downwind.

3. Close any valves leading to the flow line and fill up line.
4. Close the Diverter.
5. Inform Supervisor and follow Shallow Gas Emergency Muster procedures.

As stated earlier, the procedure will vary according to the equipment and on some rigs items 2, 3 and 4 above operate automatically with the push of one button. Crews are drilled in the above procedure to ensure a quick response to Shallow Gas.

The Diverting procedure will be very similar when running Casing.

1. On recognising a kick stop runing Casing.
2. Open the vent line valve that is downwind.
3. Close any valves leading to the flow line and fill up line.
4. Close the Diverter.
5. Inform Supervisor and follow Shallow Gas Emergency Muster procedures.

A circulating head should be readily available to install on top of the casing to allow circulation once shut in and to back up the non return valves in the float shoe and collar. Where a circulating seal device (e.g. Tam Packer) is run then these can be used to seal off the casing bore.

While cement is setting it is important to continue monitoring the well for flow. If it flows then the same procedure applies.

As stated earlier, the procedure will vary according to the equipment and on some rigs items 2, 3 and 4 above operate automatically with the push of one button.

As with a kick while drilling crews are drilled in the above procedure to ensure a quick response to Shallow Gas.

Once The Well Is Shut In - What Requires Monitoring

In addition to the initial shutting in of the well, it is the Drillers responsibility to check that the well is secure (e.g. that the BOP used has actually sealed) and that there are no leaks in any manifolds, chokes or valves. The Driller should also record the pressures in the well.

Consideration should be given to monitoring the well <u>above</u> the annular using the trip tank to check for a leaking BOP.

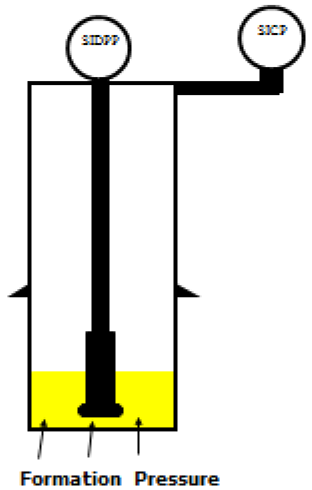
As a minimum, the Driller should record the pit gain and both shut in drill pipe pressure (SIDPP) and shut in casing pressure (SICP) on a regular basis. Readings are taken from the Choke Control Panel because this is where the kill operation is carried out. Usually there are a number of gauges on the rig floor.

If, for any reason, the readings are different then this will affect the accuracy of the kill operation.

SICP - Indicates how much the formation pressure exceeds the hydrostatic in the annulus. This will vary depending on influx size. The smaller the kick size the closer it will be to SIDPP.

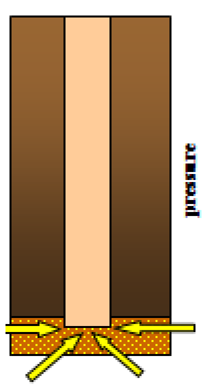
SIDPP - Indicates how much the formation pressure exceeds mud hydrostatic in the drill pipe.

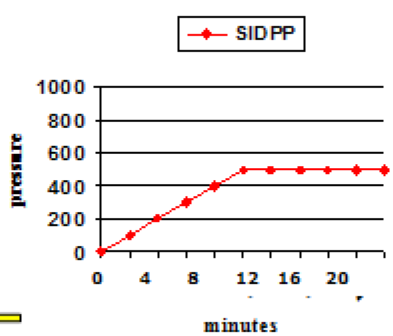
Interpretation Of Data



Once the well is shut in, the flow from the formation continues until the pressure inside the well equals the pressure inside the formation. We can see this 'build up' of pressure by monitoring the SIDPP and SICP.
They must be recorded to allow us to obtain the correct stabilised **SIDPP** and **SICP**.
This may take from several minutes to several hours.
See table showing the build up of both pressures over time.
In the center is the SIDPP plotted onto a graph. It can be seen that the pressure stabilises at 500 psi after 10 minutes. At this point no further influx enters the wellbore.

Stabilisation





Time	SIDPP	SICP
2	100	400
4	200	600
6	300	800
8	400	900
10	500	1000
12	500	1000
14	500	1000
16	500	1000

Once pressures have stabilised it is common to see that the SIDPP is different from the SICP.
The SIDPP shows directly the difference between the formation pressure and the mud hydrostatic in the drill pipe. It is assumed that any influx is in the annulus because the mud was being circulated in this direction when the kick occurred. The drillpipe is full of clean (uncontaminated) mud.
The SICP will depend on what and how much influx has contaminated the mud in the annulus.

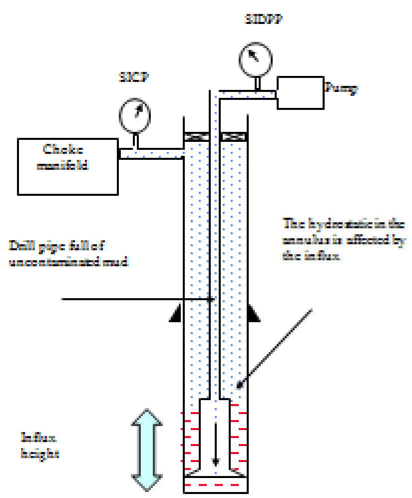
The effect the influx has on the mud hydrostatic in the annulus will depend on;

- size (height of influx);
- type of influx (gas, oil or water).

The greater effect it has (reducing hydrostatic) then the greater the difference between SIDPP and SICP.

Because the influx is normally ALWAYS lighter than the mud, then the hydrostatic in the annulus will be less.

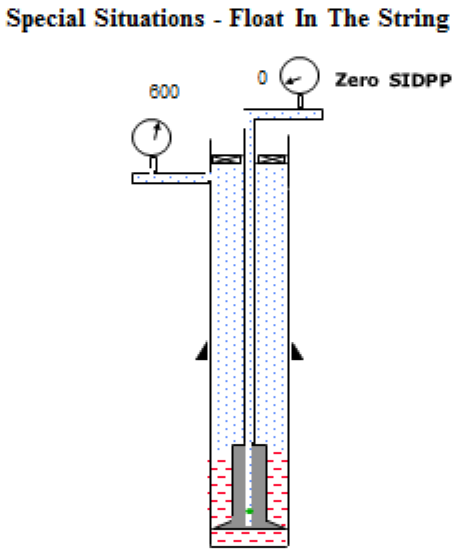
Why Are The Pressures Different?



Floats (non-return valves) are commonly placed in the drillstring (near the Bit) to prevent backflow up the pipe. If one is in the string at the time a kick occurs then it will not allow the kick to pressure-up the drillstring.

A float in the string will cause the SIDPP to read zero.

In order to obtain the correct SIDPP we pump very slowly into the closed well. This causes the drillpipe pressure to rise. When the pressure inside the pipe (above the float) becomes greater than the pressure below, the float will open. How do we recognise this has happened?



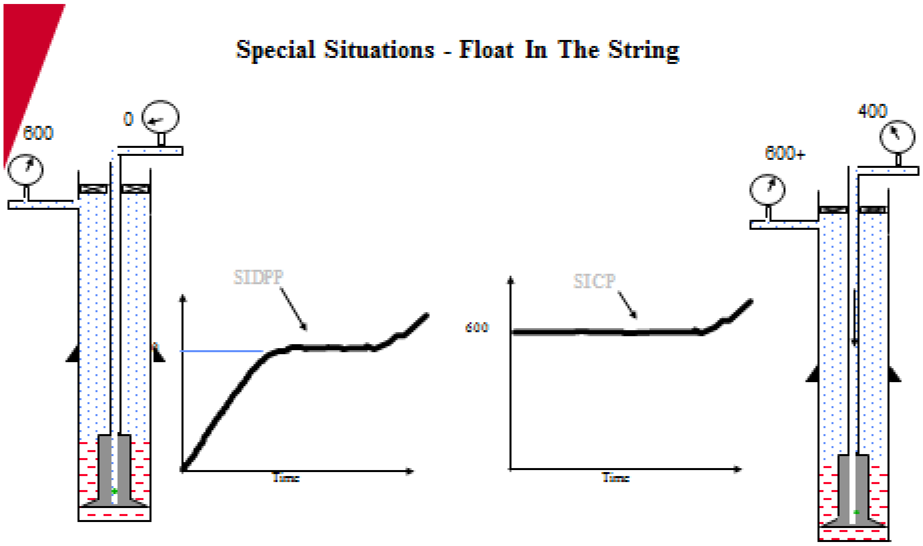
You might see this in two ways:

1st When the float opens the rise in the drillpipe pressure may stop for a while. Once the float is open the pump is now starting to pressure up the annulus. We may not see this for a while due to the amount and type of mud in the Annulus. Some people use the 'flat spot' as evidence that the float is open.

2nd In time the pump will increase pressure in the annulus. This will be seen by both Drillpipe and Casing pressures starting to rise.

This would be evidence that the float is open.

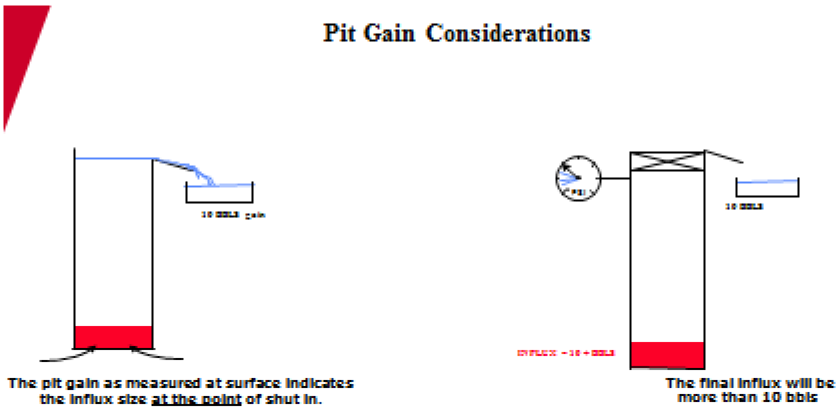
The diagram shows how pressure would behave for both examples above. The left hand graph shows drillpipe pressure build then stabilise. A little later the SICP rises, as does the SIDPP.



When the well is shut in and the mud pits have settled it is possible to record the Pit Gain. The Pit Gain represents the amount of mud seen at surface (see left), e.g.10 bbls.

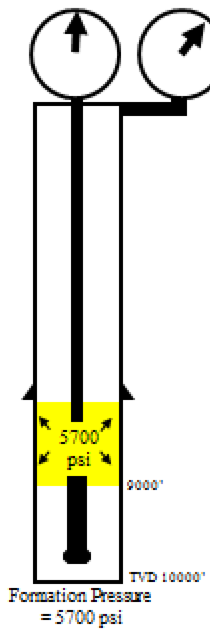
Downhole the formation fluid is still coming into the well as seen during the pressure ‘build up’ phase. The final influx will therefore always be greater than seen on surface (see right).

This may be significant in Oil based muds due to their compressibility. The actual kick could be much larger than expected giving larger than expected



One other topic to consider at this shut in phase (prior to starting the kill) is the effect of gas migration. So what is gas migration?
Gas is lighter than the mud and (due to gravity) will want to rise to the surface. Just as oil will separate to the top when mixed with water.
The rate at which this gas migrates will depend mainly on the type of mud and the angle of the hole. The thinner the mud the faster the gas will migrate. Migration seems to be faster at angles between 40 and 70 degrees but in general migration IS NOT A COMMOM OCCURANCE. Most times the mud viscosity will hold the gas in place. In this case we can continue our preparations without having to react to pressure changes.
If gas does migrate up the Annulus it is unable to expand because the well is closed in. Because the gas cannot expand it maintains the same pressure that it was when on the bottom (i.e. formation pressure) -see right where the gas has migrated from the bottom up to 9000 ft.
This has the effect of increasing the pressure in the well, affecting not only the bottom of the hole but everything above the gas. The following pages will look at this in more detail.

Gas Migration

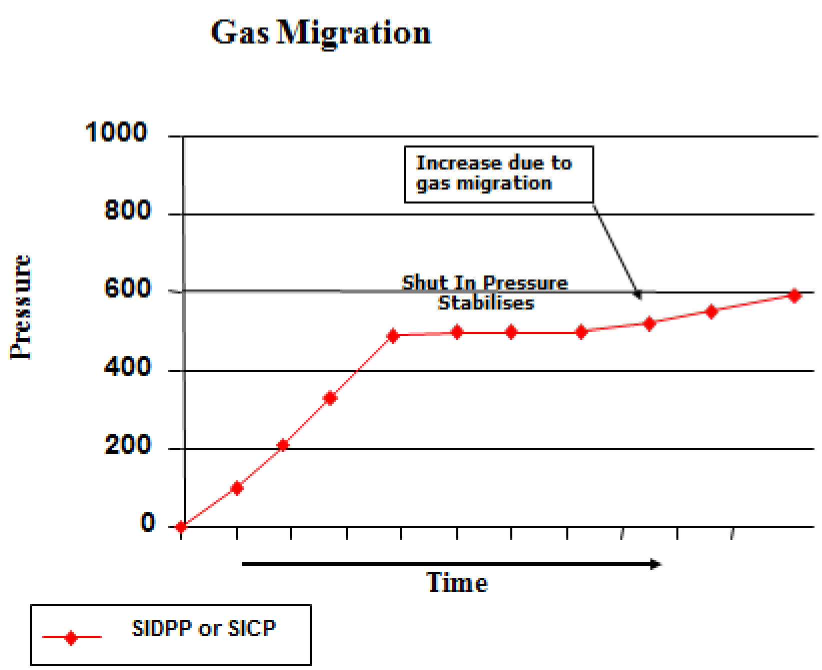


This increase in pressure can be seen on the Casing Gauge (increasing SICP). A pressure increase is also seen on the drillpipe gauge (SIDPP) as it is in communication with the annulus (through the nozzle of the bit).

So to recognise gas migration you will see a gradual rise in both SIDPP and SICP after the well has stabilised. The faster the migration the faster the rise in surface pressure.

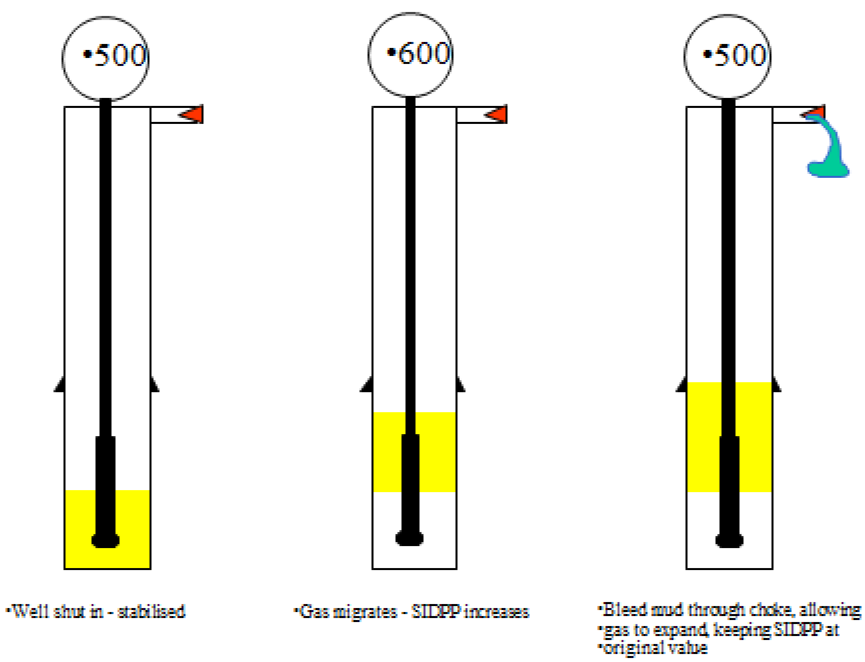
If there is a float in the drillstring then a change will not be seen in SIDPP.

The chart shows what can happen to pressure due to migration.



If gas migration is taking place then what do we do?
We have to do something otherwise the pressure will increase to a point where the formation breaks down. The pressure has to be bled off, but the danger is bleeding too much pressure and letting in more influx.
The procedure is to bleed mud from the choke and reduce the SIDPP back to its original value. Therefore if the original SIDPP = 500 and it now reads 600 you should bleed back to 500.
In practice you are more likely to bleed back to 550, leaving some safety just in case you bleed of too much. This ensures that the bottom hole pressure is maintained at the correct value.
You would continue to do this until ready to kill the well.

Gas Migration - How To Deal With It



Fluid Pressure

Fluid is any substance that flows; e.g. oil, water, gas, and ice are all examples of fluids. Under extreme pressure and temperature almost anything will become fluid. Fluid exerts pressure and this pressure is as a result of the density and the height of the fluid column. Most oil companies usually represent density measurement in pounds per gallon (ppg) or kilograms per cubic meter (kg/m^3) and pressure measurement in pounds per square inch (psi) or bar or pascal (Pa). Pressure increases as the density of the fluid increases. To find out the amount of pressure a fluid of a known density exerts for each unit of length, the pressure gradient is used. A pressure gradient is defined as the pressure increase per unit of the depth due to its density and it is usually measured in pounds per square inch per foot or bars per meter. It is expressed mathematically as; *pressure gradient = fluid density × conversion factor*. The conversion factor used to convert density to pressure is 0.052 in English system and 0.0981 in Metric system.

Hydrostatic pressure

Hydro means water, or fluid, that exerts pressure and static means not moving or at rest. Therefore, hydrostatic pressure is the total fluid pressure created by the weight of a column of fluid, acting on any given point in a well. In oil and gas operations, it is represented mathematically as; *Hydrostatic pressure = pressure gradient × true vertical depth* **or** *Hydrostatic pressure = fluid density × conversion factor × true vertical depth* .

The figure (not shown) shows two wells, well X and Y. Well X has measured depth of 9800 ft and a true vertical depth of 9800 ft while well Y has measured depth of 10380 ft and its true vertical depth is 9800 ft.To calculate the hydrostatic pressure of the bottomhole, the true vertical depth is used because gravity acts (pulls) vertically down the hole. The figure also illustrates the difference between true vertical depth (TVD) and measured depth (MD).

Formation pressure

Formation pressure is the pressure of the fluid within the pore spaces of the formation rock. This pressure can be affected by the weight of the overburden (rock layers) above the formation, which exerts pressure on both the grains and pore fluids. Grains are solid or rock material, and pores are spaces between grains. If pore fluids are free to move, or escape, the grains lose some of their support and move closer together. This process is called consolidation. Depending on the magnitude of the pore pressure, it can be described as being normal, abnormal or subnormal. **Normal pore pressure** or formation pressure is equal to the hydrostatic pressure of formation fluid extending from the surface to the surface formation being considered. In other words, if the formation was opened up and allowed to fill a column whose length is equal to the depth of the formation, then the pressure at the bottom of the column will be equal to the formation pressure and the pressure at surface is equal to zero. Normal pore pressure is not a constant. Its magnitude varies with the concentration of dissolved salts, type of fluid, gases present and temperature gradient.

When a normally pressured formation is raised toward the surface while prevented from losing pore fluid in the process, it will change from normal pressure (at a greater depth) to abnormal pressure (at a shallower depth). When this happens, and then one drill into the formation, mud weights of up to 20 ppg (2397 kg/m ^{3}) may be required for control. This process accounts for many of the shallow, abnormally pressured zones in the world. In areas where faulting is present, salt layers or domes are predicted, or excessive geothermal gradients are known, drilling operations may encounter abnormal pressure. **Abnormal pore pressure** is defined as any pore pressure that is greater than the hydrostatic pressure of the formation fluid occupying the pore space. It is sometimes called overpressure or geopressure. An abnormally pressured formation can often be predicted using well history, surface geology, downhole logs or geophysical surveys. **Subnormal pore pressure** is defined as any formation pressure that is less than the corresponding fluid hydrostatic pressure at a given depth. Subnormally pressured formations have pressure gradients lower than fresh water or less than 0.433 psi/ft (0.0979 bar/m). Naturally occurring subnormal pressure can be developed when the overburden has been stripped away, leaving the formation exposed at the surface. Depletion of original pore fluids through evaporation, capillary action and dilution produces hydrostatic gradients below 0.433 psi/ft (0.0979 bar/m). Subnormal pressures may also be induced through depletion of formation fluids. If Formation Pressure < Hydrostatic pressure then it is under pressured. If Formation Pressure > Hydrostatic pressure then it is over pressured.

Fracture pressure

Fracture pressure is the amount of pressure it takes to permanently deform the rock structure of a formation. Overcoming formation pressure is usually not sufficient to cause fracturing. If pore fluid is free to move, a slow rate of entry into the formation will not cause fractures. If pore fluid cannot move out of the way, fracturing and permanent deformation of the formation can occur. Fracture pressure can be expressed as a gradient (psi/ft), a fluid density equivalent (ppg), or by calculated total pressure at the formation (psi). Fracture gradients normally increase with depth due to increasing overburden pressure. Deep, highly compacted formations can require very high fracture pressures to overcome the existing formation pressure and resisting rock structure. Loosely compacted formations, such as those found offshore in deep water, can fracture at low gradients (a situation exacerbated by the fact that some of total "overburden" up the surface is sea water rather than the heavier rock that would be present in an otherwise-comparable land well). Fracture pressures at any given depth can vary widely because of the geology of the area.

Bottom hole pressure

Bottom hole pressure is used to represent the sum of all the pressures being exerted at the bottom of the hole. Pressure is imposed on the walls of the hole. The hydrostatic fluid column accounts for most of the pressure, but pressure to move fluid up the annulus also acts on the walls. In larger diameters, this annular pressure is small, rarely exceeding 200 psi (13.79 bar). In smaller diameters it can be 400 psi (27.58 bar) or higher. Backpressure or pressure held on the choke also increases bottomhole pressure, which can be estimated by adding up all the known pressures acting in, or on, the annular (casing) side. Bottomhole pressure can be estimated during the following activities:

Static well

If no fluid is moving, the well is static. The bottomhole pressure (BHP) is equal to the hydrostatic pressure (HP) on the annular side. If shut in on a kick, bottomhole pressure is equal to the hydrostatic pressure in the annulus plus the casing (wellhead or surface pressure) pressure.

Normal circulation

During circulation, the bottomhole pressure is equal to the hydrostatic pressure on the annular side plus the annular pressure loss (APL).

Rotating head

During circulating with a rotating head the bottomhole pressure is equal to the hydrostatic pressure on the annular side, plus the annular pressure loss, plus the rotating head backpressure.

Circulating a kick out

Bottomhole pressure is equal to hydrostatic pressure on the annular side, plus annular pressure loss, plus choke (casing) pressure. For subsea, add choke line pressure loss.

Formation integrity test

An accurate evaluation of a casing cement job as well as of the formation is extremely important during the drilling of a well and for subsequent work. The Information resulting from Formation Integrity Tests (FIT) is used throughout the life of the well and also for nearby wells. Casing depths, well control options, formation fracture pressures and limiting fluid weights may be based on this information. To determine the strength and integrity of a formation, a Leak Off Test (LOT) or a Formation Integrity Test (FIT) may be performed. This test is first: a method of checking the cement seal between casing and the formation, and second: determining the pressure and/or fluid weight the test zone below the casing can sustain. Whichever test is performed, some general points should be observed. The fluid in the well should be circulated clean to ensure it is of a known and consistent density. If mud is used for the test, it should be properly conditioned and gel strengths minimized. The pump used should be a high-pressure, low-volume test or cementing pump. Rig pumps can be used if the rig has electric drives on the mud pumps, and they can be slowly rolled over. If the rig pump must be used and the pump cannot be easily controlled at low rates, then the leak-off technique must be modified. It is a good idea to make a graph of the pressure versus time or volume for all leak-off tests.

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

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

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

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

U-tube concepts

It is often helpful to visualize the well as a U-tube as in Figure beside. Column Y of the tube represents the annulus and column X represents the pipe (string) in the well. The bottom of the U-tube represents the bottom of the well. In most cases, there are fluids creating hydrostatic pressures in both the pipe and annulus. Atmospheric pressure can be omitted, since it works the same on both columns. If the fluid in both the pipe and annulus are of the same density, hydrostatic pressures would be equal and the fluid would be static on both sides of the tube. If the fluid in the annulus is heavier, it will exert more pressure downward and will flow into the string, displacing some of the lighter fluid out of the string causing a flow at surface. The fluid level will fall in the annulus, equalizing pressures. When there is a difference in the hydrostatic pressures, the fluid will try to reach balance point. This is called U-tubing, and it explains why there is often flow from the pipe when making connections. This is often evident when drilling fast because the effective density in the annulus is increased by cuttings.

Equivalent circulating densities

The Equivalent Circulating Density (ECD) is defined as the increase in density due to friction and it is normally expressed in pounds per gallon. Equivalent Circulating Density (when forward circulating) is defined as the apparent fluid density which results from adding annular friction to the actual fluid density in the well.

$ECD = MW + \frac{P_a}{0.052 * TVD}$ or ECD = MW +(p/1.4223*TVD(M)

Where; ECD = Equivalent circulating density (ppg), Pa = Annular friction pressure (psi), TVD = True vertical depth (ft), MW = Mud weight (ppg)

Pipe surge/swab

The total pressure acting on the wellbore is affected by pipe movement upwards or downwards. Tripping pipe into and out of a well is one other common operation during completions and workovers. Unfortunately, statistics indicate that most kicks occur during trips. Therefore, understanding the basic concepts of tripping is a major concern in completion/workover operations. Downward movement of tubing (tripping in) creates a pressure that is exerted on the bottom of a well. As the tubing is being run into a well, the fluid in the well must move upward to exit the volume being entered by the tubing. The combination of the downward movement of the tubing and the upward movement of the fluid (or piston effect) results in an increase in pressure at any given point in the well. This increase in pressure is commonly called Surge pressure. Upward movement of the tubing(tripping out) also affects the pressure which is imposed at the bottom of the well. When pulling pipe from the well, fluid must move downward and replace the volume which was occupied by the tubing. The net effect of the upward movement of the tubing and the downward movement of the fluid creates a decrease in bottomhole pressure. This decrease in pressure is referred to as Swab pressure. Both surge and swab pressures are affected by the following parameters:

- Velocity of the pipe, or tripping speed
- Fluid density
- Fluid viscosity
- Fluid gel strength
- Well bore geometry (annular clearance between tools and casing, tubing open ended or closed off)

The faster pipe is tripped, the higher the surge and swab pressure effects will be. Also, the greater the fluid density, viscosity and gel strength, the greater the surge and swab tendency. Finally, the downhole tools such as packers and scrapers, which have small annular clearance, also increase surge and swab pressure effects. Determination of actual surge and swab pressures can be accomplished with the use of special calculator programs or hydraulics manuals.

Differential pressure

In well control, it is defined as the difference between the formation pressure and the bottomhole hydrostatic pressure. These are classified as overbalanced, underbalanced and balanced.

Overbalanced differential pressure

It means the hydrostatic pressure exerted on the bottom of the hole is greater than the formation pressure. i.e. HP > FP

Underbalanced differential pressure

It means the hydrostatic pressure exerted on the bottom of the hole is less than the formation pressure. i.e. HP < FP

Balanced differential pressure

It means the hydrostatic pressure exerted on the bottom of the hole is equal to the formation pressure. i.e. HP = FP

Cuttings change: shape, size, amount, type

Cuttings are rock fragments chipped, scraped or crushed away from a formation by the action of the bit. The size, shape and amount of cuttings depend largely on formation type, weight on the bit, bit dullness and the pressure differential (formation versus fluid hydrostatic pressures). The size of the cuttings usually decreases as the bit dulls during drilling if weight on bit, formation type and the pressure differential, remain constant. However, if the pressure differential changes (formation pressure increase), even a dull bit could cut more effectively, and the size, shape and amount of cuttings could increase.

Kick

Deepwater Horizon drilling rig blowout, 21 April 2010

Kick is defined as an undesirable influx of formation fluid in to the wellbore. If left unchecked, a kick can develop into blowout (an uncontrolled influx of formation fluid in to the wellbore).The result of failing to control a kick leads to loss operation time, loss of well and quite possibly, the loss of the rig and lives of personnel.

Causes of kick

Once the hydrostatic pressure is less than the formation pore pressure, formation fluid can flow into the well. This can happen when one or a combination of the following occurs;

- Not keeping the hole full
- Insufficient Mud density
- Swabbing/Surging
- Lost circulation
- Poor well planning

Not keeping the hole full

When tripping out of the hole, the volume of the steel pipe being removed results in a corresponding decrease in wellbore fluid. Whenever the fluid level in the hole decreases, the hydrostatic pressure exerted by the fluid also decreases and if the decrease in hydrostatic pressure falls below the formation pore pressure, the well may flow. Therefore the hole must be filled to maintain sufficient hydrostatic pressure to control formation pressure. During tripping, the pipe could be dry or wet depending on the conditions. The API7G illustrates the methodology for calculating accurate pipe displacement and gives correct charts and tables. To calculate the volume to fill the well when tripping dry pipe out is given as;

Barrel to fill=pipe displacement(bbl/ft) × length pulled (ft)

To calculate the volume to fill the well when tripping wet pipe out is given as;

Barrel to fill=(pipe displacement(bbls/ft) + pipe capacity(bbls/ft))×length pulled(ft)

In some wells, monitoring fill –up volumes on trips can be complicated by loss through perforations. The wells may stand full of fluid initially, but over a period of time the fluid seeps in to the reservoir. In such wells, the fill up volume will always exceed the calculated or theoretical volume of the steel removed from the well. In some fields, wells have low reservoir pressures and will not support a full column of fluid. In these wells filling the hole with fluid is essentially impossible unless sort of bridging agent is used to temporarily bridge off the subnormally pressured zone. The common practice is to pump the theoretical fill up volume while pulling out of the well.

Insufficient mud (fluid) density

The mud in the wellbore must exert enough hydrostatic pressure to equal the formation pore pressure. If the fluid's hydrostatic pressure is less than formation pressure the well can flow. The most common reason for insufficient fluid density is drilling into unexpected abnormally pressured formations. This situation usually arises when unpredicted geological conditions are encountered. Such as drilling across a fault that abruptly changes the formation being drilled. Mishandling mud at the surface accounts for many instances of insufficient fluid weight. Such as opening wrong valve on the pump suction manifold and allowing a tank of light weight fluid to be pumped; bumping the water valve so more is added than intended; washing off shale shakers; or clean-up operations. All of these can affect mud weight.

Swabbing /Surging

Swabbing is as a result of the upward movement of pipe in a well and results in a decrease in bottomhole pressure. In some cases, the bottomhole pressure reduction can be large enough to cause the well to go underbalanced and allow formation fluids to enter the wellbore. The initial swabbing action compounded by the reduction in hydrostatic pressure(from formation fluids entering the well) can lead to a significant reduction in bottomhole pressure and a larger influx of formation fluids. Therefore, early detection of swabbing on trips is critical to minimizing the size of a kick. Many wellbore conditions increase the likelihood of swabbing on a trip. Swabbing (piston) action is enhanced when pipe is pulled too fast. Poor fluid properties, such as high viscosity and gel strengths, also increase the chances of swabbing a well in. Additionally, large outside diameter (OD) tools (packers, scrapers, fishing tools, etc.) enhance the piston effect. These conditions need to be recognized in order to decrease the likelihood of swabbing a well in during completion/workover operations. As mentioned earlier, there are several computer and calculator programs that can estimate surge and swab pressures. Swabbing is detected by closely monitoring hole fill-up volumes during trips. For example, if three barrels of steel (tubing) are removed from the well and it takes only two barrels of fluid to fill the hole, then a one barrel kick has probably been swabbed into the wellbore. Special attention should be paid to hole fill-up volumes since statistics indicate that most kicks occur on trips.

Lost circulation

Another cause of kick during completion/workover operations is lost circulation. Loss of circulation leads to a drop of both the fluid level and hydrostatic pressure in a well. If the hydrostatic pressure falls below the reservoir pressure, the well kicks. Three main causes of lost circulation are:

- Excessive pressure overbalance
- Excessive surge pressure
- Poor formation integrity

Poor well planning

The fourth cause of kick is poor well planning. The mud and casing programs have a great bearing on well control. These programs must be flexible enough to allow progressively deeper casing strings to be set; otherwise a situation may arise where it is not possible to control kicks or lost circulation. Well control is an important part of well planning.

Well control methods

During drilling operations, kicks are usually killed using the Driller’s, Engineer’s or a combination of both called Concurrent Method while forward circulating. The selection of which to use will depend upon the amount and type of kick fluids that have entered the well, the rig's equipment capabilities, the minimum fracture pressure in the open hole, and the drilling and operating companies well control policies. For workover or completion operations, other methods are often used. Bullheading is a common way to kill a well during workovers and completions operations but is not often used for drilling operations. Reverse circulation is another kill method used for workovers that is not used for drilling.

WELL CONTROL OVERVIEW

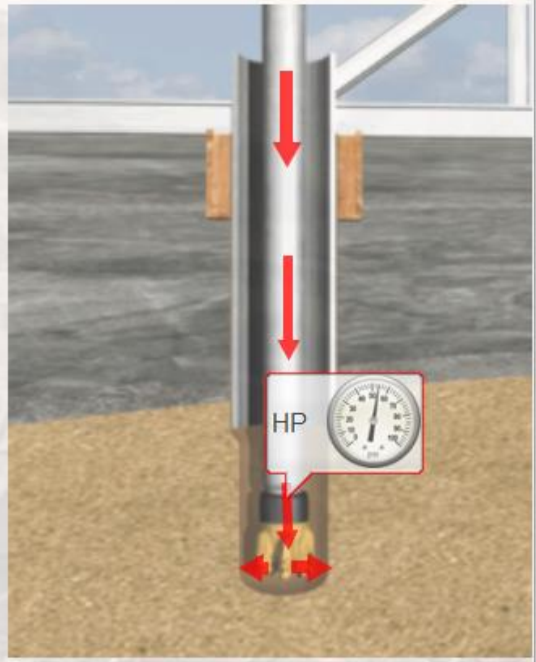
Hydrostatic Pressure

Hydrostatic pressure (HP) is the natural pressure created by the weight of fluids (like the increased pressures at the bottom of a swimming pool).

The formula for HP is as follows:

HP = 0.052 (a constant) × MW (ppg) × TVD (feet)

Therefore, the deeper the well, or the heavier the fluid in the well, the greater the pressure exerted by the fluid will be.



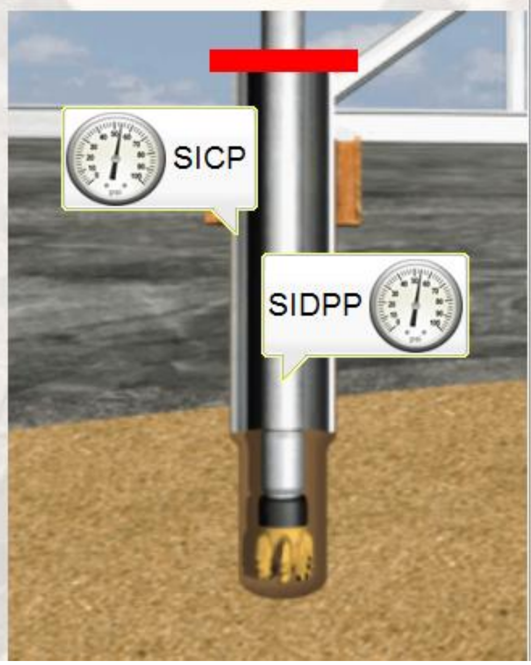
WELL CONTROL OPERATIONS

Shut-in Pressures

Once the well is shut-in, measurements are taken to determine:

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

These measurements help the driller to determine the difference between the hydrostatic pressure and the formation pressure; in order to calculate the required mud weight increase to kill the well.



WELL CONTROL OPERATIONS

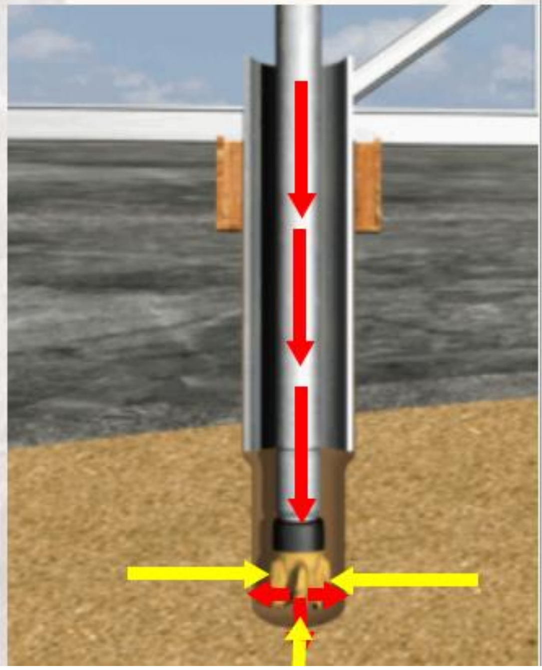
Well Control Methods

Well control methods are the methods used to remove the influx of kick fluids and gas from the well.

There are three primary methods for killing the well, as follows:

- the driller's method
- the wait-and-weight method
- the concurrent method

The three methods differ in how and when kill-weight mud (kill fluid) is pumped into the well.

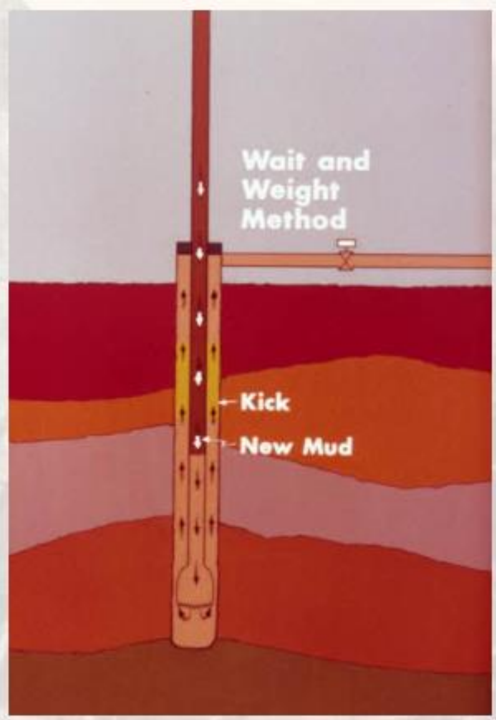


WELL CONTROL OPERATIONS

Wait-and-Weight Method

In the wait-and-weight method:

- The kick is circulated out at the same time that the kill-weight mud is pumped in.



WELL CONTROL OVERVIEW

Well Pressures

Well control is the process of managing pressures in the well and in the formations being drilled.

The pressures in the well are created by the weight of the drilling fluid (called "mud") that is pumped into the well.

The density of the mud is called the mud weight (MW) and is measured in pounds per gallon (ppg).

WELL CONTROL OVERVIEW

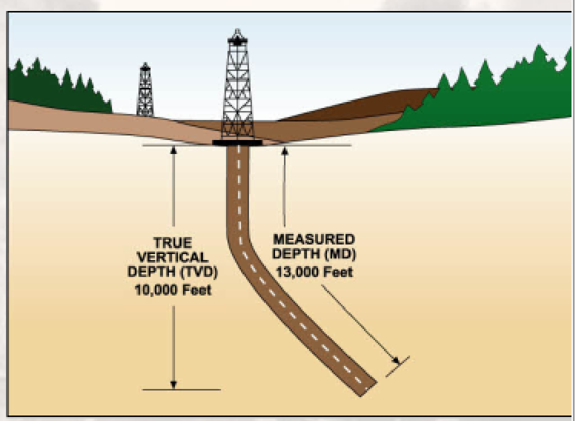
Well Depth

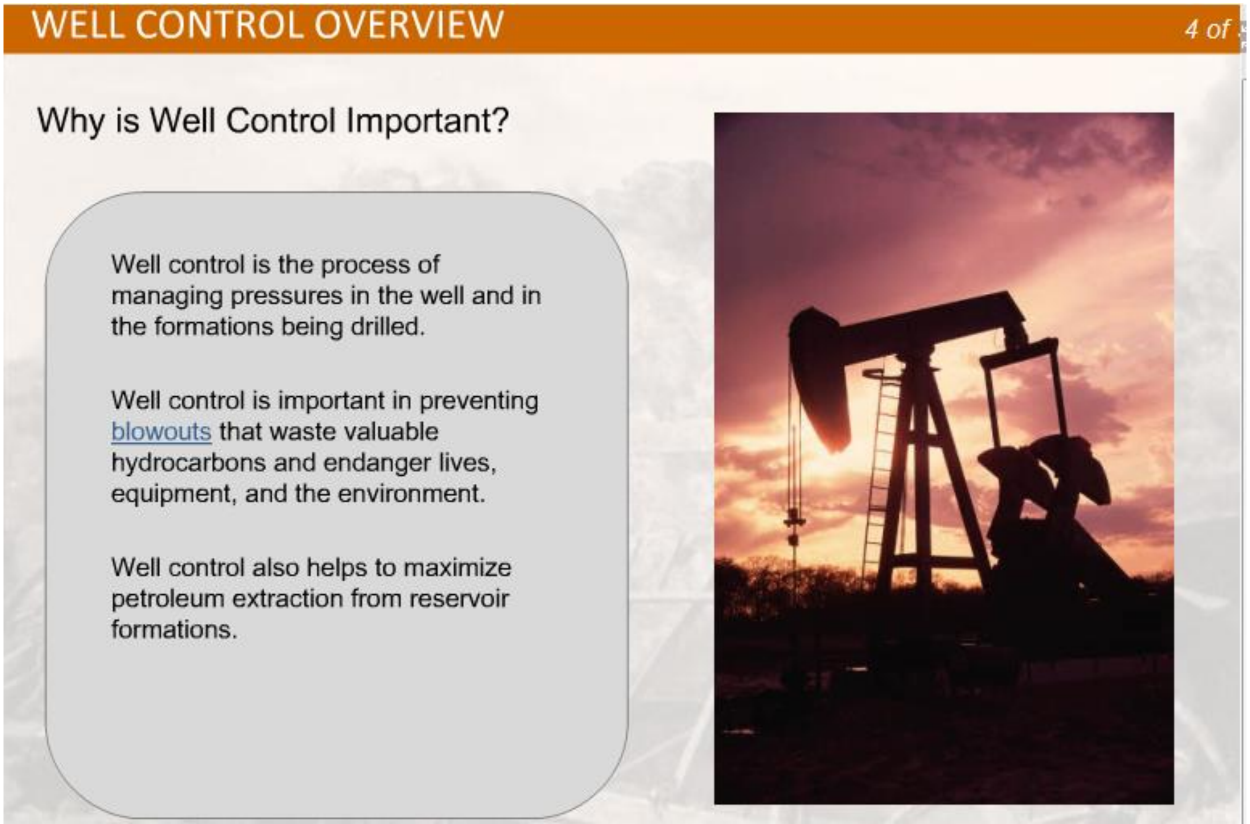
The depth of the well also affects the pressures involved.

There are several ways to measure the depth of a well.

- Measured depth (MD) is the length of the wellbore.
- True vertical depth (TVD) is the actual vertical depth from the surface to the bottom of the well.

If the well is not perfectly vertical, the TVD will be less than the MD.





Conclusion

The aim of oil operations is to complete all tasks in a safe and efficient manner without detrimental effects to the environment. This aim can only be achieved if control of the well is maintained at all times. The understanding of pressure and pressure relationships is important in preventing blowouts. Blowouts are prevented by experienced personnel that are able to detect when the well is kicking and take proper and prompt actions to shut-in the well.

IPIMS

International Human Resources Development Corporation

Awards this Certificate to

Elnur Amirov

BP

For successful completion of the IPIMS e-Learning Program in

Well Planning

Issued on:

Saturday, January 05, 2013

David A.T. Donohue, Ph.D., J.D

IPIMS

International Human Resources Development Corporation

Awards this Certificate to

Elnur Amirov

BP

For successful completion of the IPIMS e-Learning Program in

Drilling Problems and Drilling Optimization

Issued on:

Friday, January 25, 2013

David A.T. Donohue, Ph.D., J.D

IPIMS

International Human Resources Development Corporation

Awards this Certificate to

Elnur Amirov

BP

For successful completion of the IPIMS e-Learning Program in

Drilling and Well Completion

Issued on:

Saturday, June 12, 2010

David A.T. Donohue, Ph.D., J.D

IPIMS

International Human Resources Development Corporation

Awards this Certificate to

Elnur Amirov

BP

For successful completion of the IPIMS e-Learning Program in

Drilling Fluids and the Circulating System

Issued on:

Saturday, January 12, 2013

David A.T. Donohue, Ph.D., J.D

IPIMS

International Human Resources Development Corporation

Awards this Certificate to

Elnur Amirov

BP

For successful completion of the IPIMS e-Learning Program in

Directional and Horizontal Drilling

Issued on:

Sunday, January 20, 2013

David A.T. Donohue, Ph.D., J.D

IPIMS

International Human Resources Development Corporation

Awards this Certificate to

Elnur Amirov

BP

For successful completion of the IPIMS e-Learning Program in

Formation Evaluation Overview

Issued on:

Thursday, January 05, 2012

David A.T. Donohue, Ph.D., J.D