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Acknowledgment

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I would also like to thank Silje Ramvik and Espen Simonsen for their moral support and good company during this last semester. It would have been a longer semester without them and I wish them all the best for their future, hope to see them in the industry sometime in the years to come!

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Summary

Well control can in short words be described as the core for human safety on board a platform or a rig. It includes a variety of elements that go under the name barrier elements that are in place to prevent an unwanted inflow of formation fluids. They need to be functional in order to fulfil their purpose. Elements are made, controlled and replaced by people, it is therefore vital that the people working with them knows how they work in order to detect failure so they can be repaired or replaced as soon as possible. It is also important that everyone working in a drilling operation knows what well control is and the different scenarios that can develop if one should emerge.

On the Norwegian Continental Shelf the number one priority from the authorities are safety, this is what the industry chases in pursuit for black gold and high rewards. To secure their investment guidelines, procedures and standards are provided to the industry and it is required that the people working there knows what they say, understand them and work according to them. In this way everything is done to make sure that all operations are successful operations. This high safety focus ensures that workers can go home from work in the same physical condition as when they went to work in the morning, or when they left for their offshore period 14 days earlier.

The different well control methods are used for different situations depending on a variety of factors. This might be what depth the incident happened at, drill string position, personnel competence, and platform capacities to mention a few. For the Driller`s method (DM) and Weight and Wait (W&W) method, in many ways they use the same operational procedures when killing the well, but the thing that separates them from each other are when kill mud gets introduced into the system. Time consumption are also another aspect that separates them, where W&W uses less time compare to DM. W&W can also have an positive advantage, if the kill mud enters the annulus before the kick reaches the casing shoe, then it will be able to reduce the pressure from the kick acting on the casing shoe due to its heavier weight.

The Volumetric method and Bullheading method may be the best choice if the drill string is high up or out of the well, if the competence among the personnel is too low to perform a conventional kill method (DM and W&W), or if there are limitation within the equipment to

handle the kick on surface etc. In these cases the Volumetric or Bullheading method may be the best choice when killing a well.

The selection of mud in the system is also an element related to well control, and knowing the different behaviour between WBM and OBM in the event of a kick is crucial and very important. To know the behaviour increases the chances of detecting a kick early and before it escalates into a large kick. In WBM, when a gas kick enter the wellbore it will occupy annulus space which can be observed at surface as pit gain. However, there is another process developing in the OBM, here the gas gets dissolved into the OBM and the chances of detecting this at surface are small. Also, also if the mud is stationary the kick will also be stationary until circulation starts up again.

When the circulation starts up the dissolved gas moves upwards in the annulus together with the mud, nothing happens, not until the well pressure gets reduced to the extent that it reaches the boiling pressure of the gas, or the flash point. What happen is that gas goes out of suspension and back into free gas, this will lead to a rapid displacement of mud, and the result can lead to, if they are unable to trap it in the well and it moves past the BOP, a surface blowout with unpleasant consequences.

With today`s search for more and remote black gold, drilling gets deeper along with more complex well paths which reduces the margins for errors. This increases focus and requirements to personnel`s experience and knowledge, and are one of the most important factor in terms of reducing the risk and consequence if an incident should happen.

One intention with this thesis is to shed light on different elements related to well control, in this way it is possible to increase the overall understanding a bit more. The second intention with the thesis is to give a broader understanding of four well control methods used today. Two of them will have a higher focus than the rest. Also the importance of knowing and understanding well control calculations is elaborated by calculation examples for several different well scenarios. Also different platform types are used for distinguishing between the different methods. Hopefully the thesis will contribute to a broader understanding of well control.

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Nomenclature

$\Delta P_{friction,cl}$ = Frictional pressure loss in the choke line

P_{PP_T} = Total pore pressure

g_{kt} = the kick tolerance gradient

g_P = the pore pressure gradient

g_m = the hydrostatic gradient of the existing mud

BHP = bottom hole pressure

ρ_{kill} = density of kill mud

ρ_{old} = density of already in place mud

TVD = True Vertical Depth

ICP = Initial circulating pressure

SM = Safety margin

FCP = Final Circulating Pressure

SR_1 = Circulation pressure up riser (friction) – pump pressure

SR_2 = Full circulation through the choke line instead of riser

ΔP_{CL} = Frictional pressure loss in choke line

$P_{friction,DP\ bit}$ = Frictional pressure loss through drill pipe and bit

$\Delta P_{friction,Annulus}$ = Frictional pressure loss thorough the annulus

$(\rho gh)_{Annulus}$ = hydrostatic pressure in annulus

$(\rho gh)_{DP}$ = hydrostatic pressure in drill pipe

$(\rho gh)_{Cl}$ = hydrostatic pressure in choke line

SIDPP = Shut in Drill Pipe Pressure

SICP = Shut in casing pressure

SM = Safety margin (to make sure we are above the formation pressure)

P_{bottom} = Hydrostatic bottom hole pressure when BOP is closed

$\rho_{mud}gh$ = Hydrostatic pressure of the mud between bottom and casing shoe

$\rho_{gas}gh$ = Hydrostatic pressure of the gas between bottom and casing shoe

$\rho_{kill\ mud}gh$ = Hydrostatic pressure of the kill mud between bottom and casing shoe

α, β, γ = is the mixing fraction – the space percentage each substance occupies in the annulus)

$\Delta P_{choke\ line}$ = Choke line pressure

$\Delta P_{kill\ line}$ = Kill line pressure

P_{BH} = Bottom hole pressure

P_{res} = Reservoir pressure

P_{over} = Overpressure

HS_{CSG} = Hydrostatic pressure in casing

$HS_{C\&K}$ = Hydrostatic pressure in the choke line and kill line

MACSPI = Maximum Allowable Casing Shoe Pressure Increase

MAIP = Maximum Allowable Injection Pressure

CLFPL = Choke line frictional pressure loss

P_{over} = Overbalance pressure

FPL_{OH} = Frictional Pressure Loss in the open hole

1 Introduction

In terms of drilling and well control, the industry faces more and bigger challenges as wells are drilled in more remote areas and in larger depths, all these elements reduces the margins within well control. Also when drilling in already producing fields where e.g. depleted zones can lead to an unwanted situation, this raises challenges when the high focus is on overall safety.

In the light of BP`s Macondo well catastrophe, the focus on safety and avoiding unwanted situations have led to a tightening up of existing procedures and making new ones that forces the industry to make changes to show their motivation on safety. The focus towards the industry is high and there are no room for errors if they want to stay in the game. Therefore, it is important that adequate procedures exist and that a high focus on well control is integrated into the work culture. In this way the risk of a new BP`s Macondo can be reduced or prevented.

If safety is not taken seriously there is a risk that something will happen to the personnel on board, to the surrounding environment or to material goods, none of these outcomes are good for the company`s reputation, and in addition it puts a bad reputation to the industry as a whole. Companies are judged by their records, and to stay in the game these records needs to be more or less spotless in order to get renewed confidence and new work contracts. If the records are filled up with small incidents, outwards it will not seem like safety is the company`s number one priority and this will give them a bad reputation. The result can be that they are excluded from participating when new licenses are awarded. If a service company do not show good records with respect to focusing on preventing incidents, they will not get renewed their contracts or win a new contract from an operating company. The negative side of judging companies by records is that it can led to an unfortunate work culture, meaning that no one reports HSE to maintain a clean record and prevent bad reputation.

The focus on having qualified personnel in drilling operation has never been higher. The company spends a lot of money on educating personnel, this creates a positive company reputation, but most important the risk of an unwanted situation is heavily reduced.

In some companies, for new employees one requirement is that they need to take higher education beside job, and only if this is accepted they may be offered a position there. Another requirement, new employee needs to have oil related education in order to get offshore work (given drilling related work). For not many years ago this was not a requirement, and then a certificate would be enough to be qualified for a job offshore. The requirements are created with the intention to increase focus and raise the overall awareness towards safety, and also to raise the expertise within the workforce.

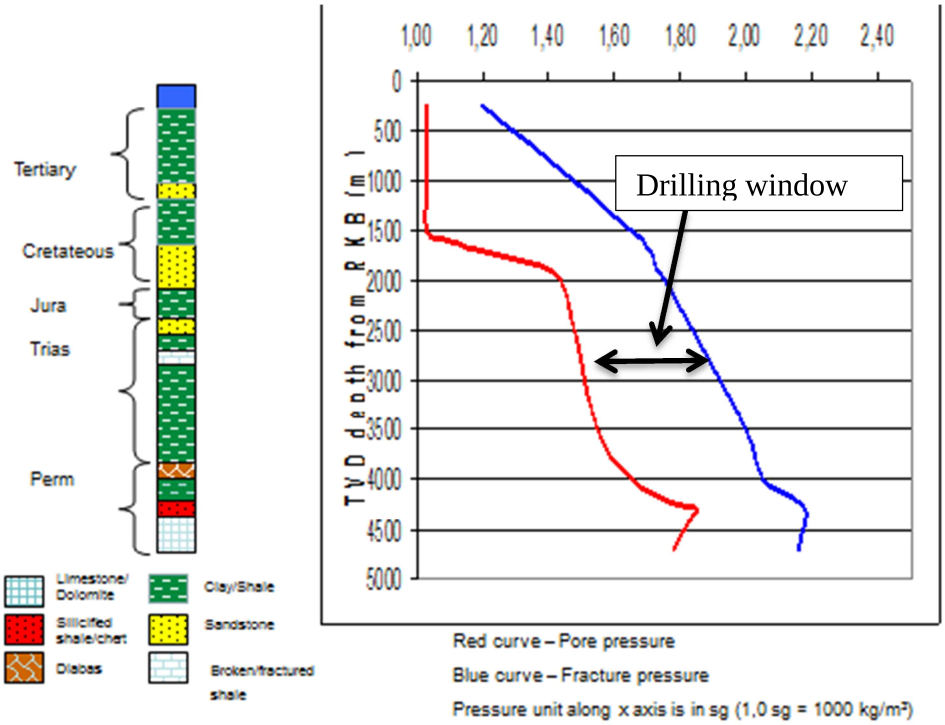


Figure 1.1 – Shows the lithology profile and the pore pressure plot or the drilling window as it also is called [1].

The objective with this thesis is to cover the main well control methods currently in use. The objective is also to highlight their positive and negative sides and increase the understanding on how they work and how they are performed. Calculations examples are used to increase the understanding on how they are carried out, how they are calculated and to show the difference between them. The examples in section 5 focus on the two main well control methods, which is Driller`s method and Wait and Weight method.

The thesis is divided into 6 sections, each with the purpose to enhance well control understanding and the elements needed to maintain a stable and controlled well kill operation. The well control methods considered in the thesis are:

- Driller`s method
- W&W method
- Bullheading
- Volumetric

As mentioned, the main focus will be on Driller`s method and the W&W method.

The well control methods are developed to re-establish the well`s primary barrier. During a drilling operation the fluid column is the primary well barrier, and its intension is to control the well pressures during drilling, balance or stay between the pore pressure (blue line in Figure 1.1) and the fracture pressure (red line in Figure 1.1). Drilling fluid is the well`s primary well barrier, and if this barrier should fail, meaning that fluid volume is lost to the formation or it has to low pressure to balance the well pressure, actions needs to be carried out to fix it. If the hydrostatic fluid pressure is to low the formation pressure will be dominant, the result will then be inflow of formation fluids into the wellbore which can lead to a well control situation. With the use of well control methods the aim is to re-establish the fluid column in such a way that it can balance the formation pressures on its own. How this is done is discussed in more detail in the sections to come.

During a well control situation the well pressure goes either above the fracture pressure or below the pore pressure. Loosing drilling fluid is then a potential result if the pressure goes above, mud height is reduced which leads to a hydrostatic pressure below the formation pressure. The wellbore then gets influx of wellbore fluids and a kick is in progress, which is a well control situation that requires proper procedures and experienced personnel to fix. During a drilling phase the aim is to keep the pressure between the blue and red curve in Figure 1.1 (above), by doing so it will ensure a safe operation and reduce the risk of a well control situation. These curves are also known as the drilling window, and a successful operation depends on staying between them to prevent a well control situation.

2 Well control in general

The main focus during a drilling operation is to keep the wellbore pressure stable and prevent any type of influx of formation fluids. Inflow of formation fluid is what is called a well control situation. In every well stage e.g. drilling, completion, production, intervention etc. barriers are the most important system to prevent an unwanted situation. Their intention is to avoid a catastrophe and to have the ability to regain well control if a situation should arise and escalate. All operations must be planned and conducted in a way that no uncontrolled inflow of formation fluid enters the wellbore, e.g. in the drilling phase one want to avoid kicks [2].

According to the NORSOK STANDARD D-010 section 3.1.47, well control is defined as:

Well Control
"*Collective expression for all measures that can be applied to prevent uncontrolled release of well bore effluents to the external environment or uncontrolled underground flow*" [2].

2.1 Well barriers

A barrier has the intention to reduce or avoid the consequence of an unwanted situation or accident. This includes both technical, human and organisational barriers [3].

If we look at well barriers, it consists of one or several barrier elements that form a continuous and protective envelope around the wellbore. Its purpose is to prevent an uncontrolled and unintentionally gas or fluid flow into another formation or to surface [2]. The well barrier ensures the overall safety on board a platform and it also prevents contamination of wellbore fluids into the environment. Should a barrier or a barrier element however fail, actions to replace and reinstate the failed barrier or barrier element should be number one priority, all other well related activities should temporarily be stopped until the barrier or barrier element is fixed and reinstated [4].

Barriers regulations are not a world vision and it varies from country to country. Also the focus on them and the governmental control towards the industry are not a common practice around the world. In Norway the NORSOK Standards are heavily used, they are a guideline for the industry, and the company are required to follow up on the minimum requirements defined there. The regulations given by the Petroleum Safety Authorities Norway states [4]:

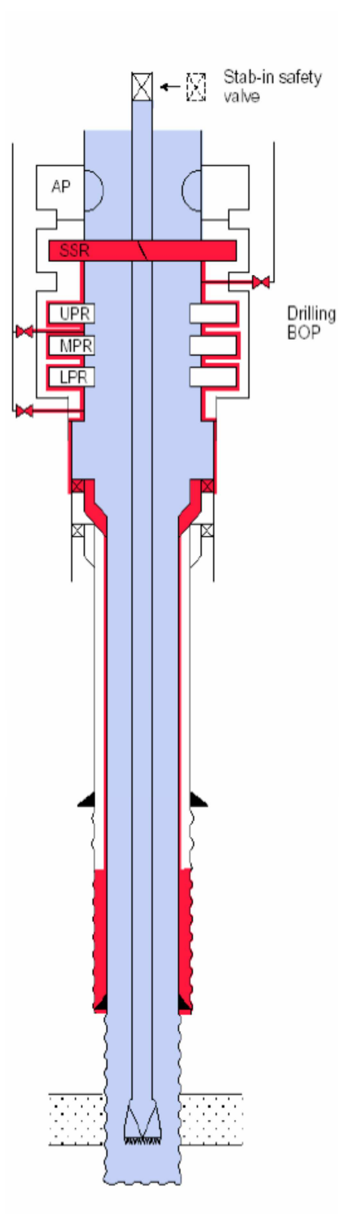
"*We should always have minimum two independent and tested barriers. The barrier requirement should be organized in a way that allows for a quick turn around, and that a failed barrier is repaired as quickly as possible*"

2.1.1 Barrier element

A barrier element is a part of the barrier envelope that stops unwanted inflow of formation fluid reaching the surface. To stop a flow from one side to the other several barrier elements are needed to close the envelope, one single barrier element are not sufficient to stop the flow on its own as can be seen from the barrier schematics in Figure 2.1. Here barriers during drilling operations are shown. Similar drawings can be found for other well phases and activities like: completion, production and intervention operations [2].

2.1.2 Well barrier schematics

5) Drilling, coring or tripping – Shearable drill string



1) Well barrier elements	See Table *2)*	*3)* Comments
Primary well barrier		
1. Fluid column	1	
Secondary wellbarrier		
1. Casing cement	22	
2. Casing	2	Last casing set
3. Wellhead	5	
4. High pressure riser	26	If installed
5. Drilling BOP	4	

4) Note

Legend:

1. *This describes the name of the WBE(s)*
2. *A complete description of general acceptance criteria for this WBE is found in Clause 15 which contains a library of WBE acceptance criteri tables.*
3. *This table column is used to describe comments.*
4. *The place can be used for describing additional requirements and guidelines. For example a description of compensative measures if the exist common WBEs.*
5. *The illustration shows the primary well barrier in its normal working sta while the secondary well barrier is shown in its ultimate stage. This sta often described with a closed shearing device.*

Figure 2.1 – Taken from the Norwegian NORSOK D-010 standard

In Figure 2.1 it is shown the different barrier elements that together form an entire envelop. The fluid column forms the primary barrier, and even if it is a single barrier element it is classified as a well barrier envelope.

2.1.3 Primary barrier during drilling

The primary well barrier is the first barrier envelope and the first line of defence against unwanted formation inflow. It surrounds the entire wellbore, holding back the pressure and preventing formation fluids from flowing in. The primary well barrier is the mud column and outlined in blue in the NORSOK STANDARD D-010 drawings. As a primary barrier its main purpose is to keep the well pressure between the formation pressure and fracture pressure.

2.1.4 Secondary well barrier during drilling

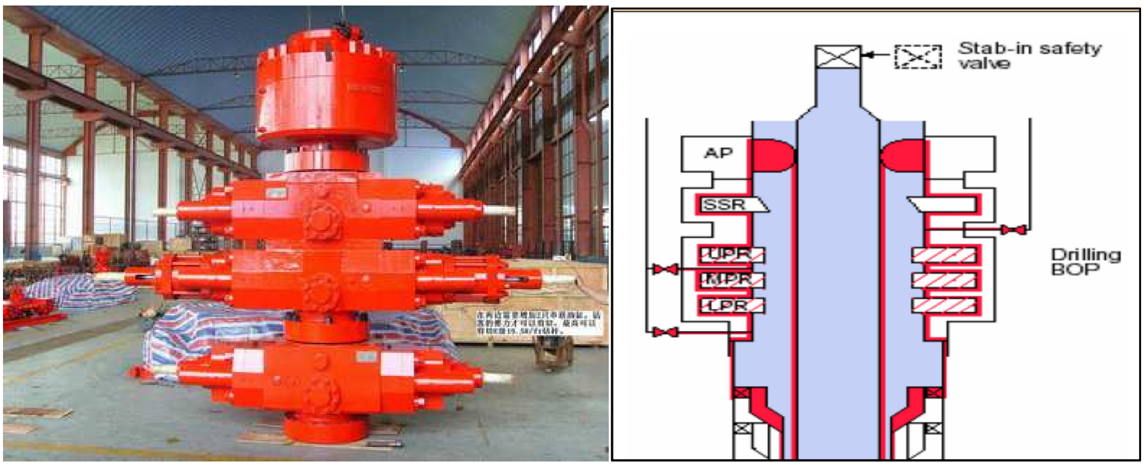


Figure 2.2 – Shows a BOP and a schematic showing the functions. Pictures are retrieved from [2, 5]

Here the annular preventer is the barrier highest up, then when moving down one see the shear and seal ram, upper variable pipe ram, middle variable pipe ram and lowest the lower variable piper ram. The left picture shows a BOP standing on a warehouse floor.

If not the primary well barrier holds, the secondary barrier shall be the next obstruction point the influx fluid meets, its main function is to stop it from reaching the surface and getting out of control. If the primary barrier is the inner envelope surrounding the well bore, then the secondary well barrier is the envelope that closes around both the primary barrier and the well bore. From Figure 2.1 the secondary well barrier consists of casing cement, casing, wellhead, high pressure riser and the BOP.

As mentioned in the section above, the BOP in Figure 2.2 holds different defence mechanisms that prevent unwanted flow to pass by having several closing rams. The first ram that is activated if an unwanted situation occurs is an annular preventer which is a rubber seal that closes around the drill pipe, collars and BHA preventing flow to pass it. The optimal scenario during a kick circulation is to have the drill string as close to the bottom as possible, stripping to desired location is not a problem with the annular preventer due to the rubber seal that allows variable diameter passing thorough it while closed. The other rams in the BOP is the upper pipe ram, middle pipe ram and lower pipe ram which is designed to close around a fixed pipe size. As a redundancy measure if all other thing fails there is a shear and seal ram. This cuts the drill string, closes the entire annulus space and prevents leaks.

2.2 Reasons for kick

There are several factors that affect the extent of a kick, these are the differential pressure between the wellbore and formation. Also the formation properties like porosity and permeability are important. In order to get a kick the pushing force from the formation and into the wellbore must be higher than the force holding formation fluid back or containing it in its original place. When the hydrostatic wellbore force is not able to hold back the formation pressure it will lead to inflow of formation fluids, this is what we call a kick situation. As mentioned the formation properties are also important factors with respect to the kicks magnitude.

If the formation has a high permeability the rocks ability to allow fluid flow is high, as it is in sand formations. However, if the permeability is low the fluid flow within the rock is low and shale is a rock with low permeability.

Porosity is how much empty space there is in a rock. Like a sponge, it has high porosity meaning it can contain large amount of water in its pore space. The same goes for a rock and even if the pores are much smaller compared to a sponge the rock volume is much larger. An example of high porosity formations can be sand deposits, and formations with low porosity can be shale deposits. A kick taken from a sand formation with high porosity and high permeability has a much bigger impact than a kick taken in a shale formation with low porosity and permeability [6].

But in order to get the fluid moving differential pressure is needed. The differential pressure is the pressure from the formation – the difference between the force that wants to push the fluids out of the rock, and the hydrostatic column from the mud that tries to hold back the formation fluid from entering the wellbore. The larger the negative differential pressure between wellbore and formation gets, the higher the inflow – if the formation also have high permeability and porosity inflow will accelerate [6].

There are however several reasons that can lead to a kick, these are retrieved from [6]:

- Insufficient mud weight
- Improper hole fill-up on trips
- Swabbing
- Gas cut mud
- Lost circulation

2.2.1 Insufficient mud weight

Kick will occur if the pressure from the formation is higher than the hydrostatic pressure from the mud column in the well. Therefore it is important to have a mud weight that will exceed the formation pressure but still be within the drilling window – lower than the fracture pressure and higher than the pore pressure. Insufficient mud weight is often related to unexpected pore pressures in a zone which may lead to a well control situation [6, 7].

2.2.2 Improper hole fill-up on trips

Improper hole fill-ups is another cause of kick. It is important to pay attention when tripping out because this may lead to a kick situation. Tripping is when drill pipe is pulled out of or in to a well. When tripping out drill pipe steel volume will be replaced with mud, this will reduce the height of the annular mud column with the result of a lower bottom hole pressure. It is therefore very important to pay careful attention when tripping to avoid a kick. The trip tank is used to refill the well if needed [6, 7].

This is what happens when mud height is reduced due to removal of steel volume, or by mud lost to the formation leading to column height reduction

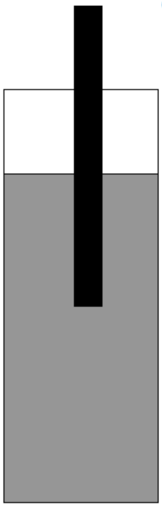


Figure 2.3 - A picture showing reduced annulus mud height after losses [8]

Swabbing is another effect that may cause a kick. When pulling the pipe there will be a piston type force between the drill pipe and the wellbore walls, this creates a pressure reduction beneath the drill pipe/bit which reduces the effective hydrostatic bottom hole pressure. If the effective hydrostatic pressure is reduced below formation pressure a kick situation may be the outcome. It is therefore important that certain parameters are carefully monitored, such as tripping speed, hole configurations, mud properties, and the effect of "balled" equipment. Balled equipment is when clay, sandstone etc. sticks to the pipe or bit and makes a larger outer diameter of the equipment. This increases the swab effect [6, 7, 9].

2.2.3 Gas cut mud

Kick caused by gas cut mud are not common. When drilling formations containing hydrocarbons, small amounts of gas from the drilled out formation will be present in the well. The gas within the cuttings will on its way up to the surface be released and it expands and reduces the hydrostatic pressure and this can lead to a kick.

2.2.4 Lost circulation

Lost circulation may also lead to a kick scenario. One outcome is loss of drilling fluid when entering a zone with high permeability, this happens because the formation is unable to prevent drilling fluid from entering the permeable zone. E.g. a mitigation action in such a case can be to add lost circulation pills (LCM) in the mud that will build a filter cake on the bore walls and prevent further losses. Another aspect is if the weight of drilling mud is too high compared to the formation strength. The increased hydrostatic pressure may exceed the fracture pressure creating cracks where mud can be lost. For both cases above, mud level in the annulus will fall with the result that bottom hole pressure is reduced. Should the hydrostatic pressure in the wellbore go beneath the formation pressure, influx of formation fluids will be a result and a kick is in progress. The severity of the kick will depend on the amount of wellbore fluid lost to the formation and how low the wellbore pressure gets compare to the formation pressure (differential pressure). Another aspect, should formation fluids be able to enter the wellbore it will reduce the mud density by mixing formation fluid with the wellbore fluids, with decreasing bottom hole pressure more formation fluids will enter the wellbore and a negative spiral is in progress.

Maintaining an overall control over any situation that may develop and avoiding a well control situation puts a lot of responsibility on the personnel. For this reason, it is very important that they are well trained and educated in their job, having good routines and procedures to handle any situations that may occur in a potential loss environment (e.g. leading to kick). E.g. of some precautions that might be initiated, and taken from [10]:

1. All involved personnel should attend a safety meeting where they discuss what may happen prior to entering a potential loss zone. All scenarios should be discussed and actions related to different outcomes must be established. E.g. routes of probable loss, consequences of well control, what consequences mud loss will have on the operation, areas of responsibility, line of communication are some of the issues to be addressed.
2. The trip tank should be filled up with mud, base oil or water to get the annulus volumes back up to its initial height if losses occur.
3. If three mud pumps are available, there should be a discussion if one of them should be directly connected to the annulus for redundancy.
4. If heavy losses are encountered, it is important to have access to pre-mixed gunk pills to get the losses under control.

Depleted reservoir pressures in immature fields that have been producing for some time is also a concern, it is therefore important to take it into account when drilling into depleted risk zones. If using too high mud weight the result may be fracturing of the formation, leading to significant losses and a well control situation. When drilling into depleted reservoirs it is important to determine the last casing setting depth, it should be set above and as close to the reservoir as possible since it has a much higher fracture pressure. Determining the setting depth can be challenging, and there is a risk that the drilling operation is performed with too high mud weight into a weak reservoir which can lead to losses [10].

Other causes of mud losses are retrieved from [10]:

1. Formation is naturally fractured
2. Subnormal formation pressures – which is pressures less than the normal formation pressure
3. Surge pressures when running the drill string or casing can lead to formation fractures (induced fractures)
4. Drilling pack off in the annulus, e.g. caused by poor cuttings transport
5. The gel strength of mud is too high, i.e. large pressure peaks are induced when resuming circulation (has to break circulation by first starting rotation)
6. Casing cement around casing shoe has poor quality
7. Extensive pressure losses in the annulus leading to too high ECD

2.3 Warning signs of a kick

Drilling operations are not without risk, and the one with high focus is kick detection. There are some key warning signs that a kick is in progress, these are retrieved from [6]:

- Flow rate increase
- Pit volume increase
- Flowing well with pumps off
- Decreasing pump pressure and increasing pump strokes
- Improper hole fill-up on trips
- String weight change
- Drilling break – e.g. when drilling into an open hole which increase the ROP significantly

During a drilling operation each crew member is responsible for carefully monitoring the different kick indicators which are listed above. It is their responsibility to take actions if any indicator shows that an unwanted situation is under development. There are on the other hand not all indications of a kick that actually lead to a kick, e.g. an increase in pit volume when taking connections may be because of temperature effects, and should be monitored by "fingerprinting" each connection – this means identifying the volume increase in the pit tank for every connections to monitor the trend. If there are any anomalies in the "prints" this may indicate a real kick.

If a kick is taken in OBM it can be difficult to detect on surface, the gas will be dissolved in the oil and no expansion will be observed in the pit tank. During the time it takes before some changes are observed at surface, there is a risk that large volumes of formation fluid have entered the wellbore. And when this reaches the flash point it will boil out of suspension creating a large kick. The flash point needs to be below the BOP where it can be contained.

Finger printing

Down towards the reservoir the formation temperature will increase with depth. This temperature increase can be quantified to a gradient of about 3 degrees in Celsius per 100 meters (3^0C/100 m). In a drilling operation a new connections happens every 30 meters, or one stand (which consist of 3 drill pipe lengths). During circulation/ drilling the well will have a temperature profile which is near equal to the geothermal gradient. The mud will be hotter at the surface and cooler at the bottom. However, when taking a connection the mud pumps are turned off and there is no mud flow, it is in static conditions. This enables the shallow formation to cool down the mud up in the well, and the deep formations to heat it up further down. If there is a net temperature increase, the result will be a decrease in the mud weight due to mud expansion. This expansion can be observed on the surface as pit gains and can resemble a kick to be in progress, but it is only the temperature effects on the mud during connection that is causing this. Monitoring the volume changes during connections is what is called fingerprinting. By monitoring each connections, one can identify deviations from the normal trend which could warn about a real kick in progress [11]. Below is a figure showing how the temperature down in the well affects the mud temperature.

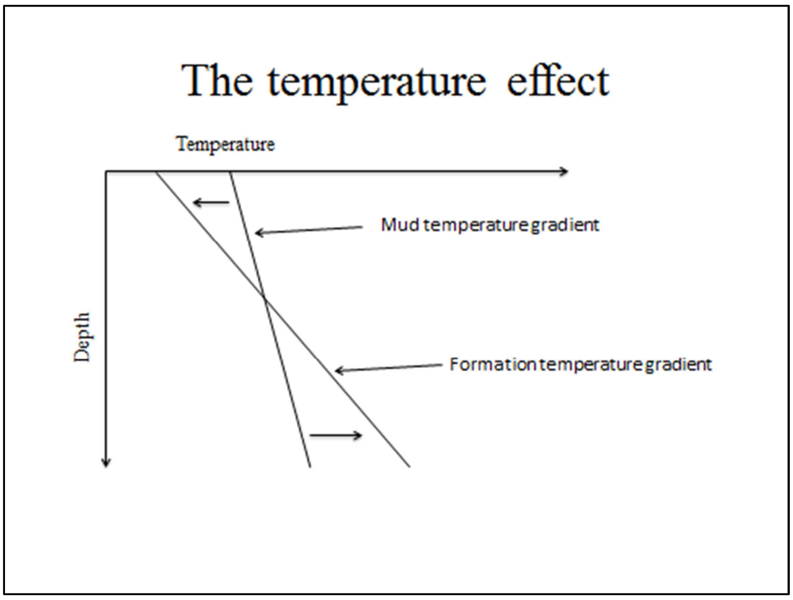


Figure 2.4 – Shows the temperature effect between mud and formation during connection

2.4 General about Well Control procedures

Beneath is an illustration of the well layout with the different components during a drilling operation [8]. There should also be a kill line in Figure 2.5, this do not show in the drawing. This should be equal in length and size as the choke line. The following chapter will give some information about different elements during the drilling process to enhance understanding of the theory presented later in the thesis.

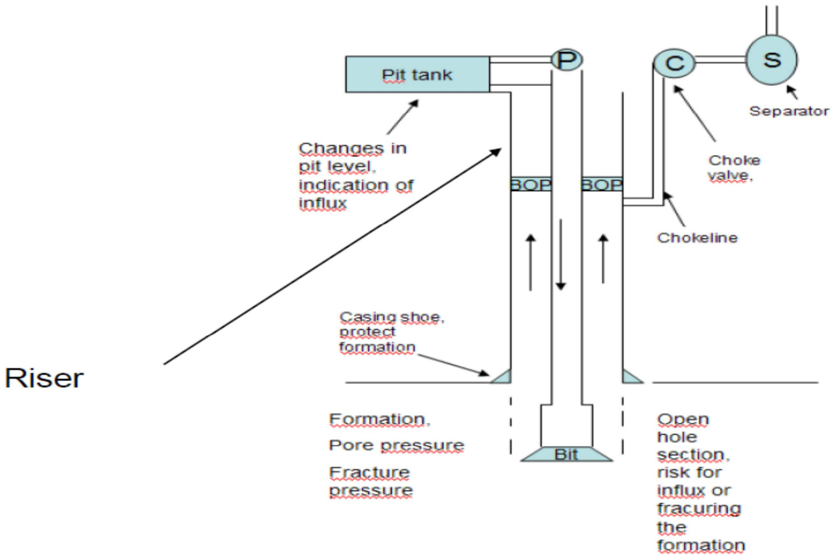


Figure 2.5 – An illustration of the different components in a drilling operation [8]

2.4.1 BOP

The BOP (blow out preventer) is a secondary barrier element and consists of several BOP rams with different purposes. The BOP is placed on top of wellhead as can be showed in the barrier drawing in Figure 2.1.

Annular BOP:

This has a rubber reinforced with steel. It can close around different pipe sizes and allows the pipe to move up and down. It is used as second barrier element when the pipe is non-shearable.

Ram BOP:

The ram BOP consist of the following elements

- Pipe ram
- Shear ram
- Seal ram
- Blind ram.

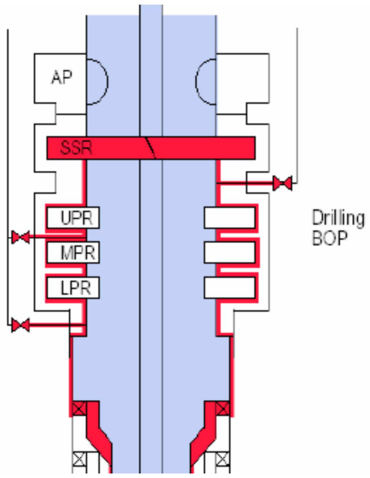


Figure 2.6 – A section of the barrier drawing showing the annular preventer and the different rams [2]

2.4.2 What happens during shut in?

When a kick is in progress there are several actions that must be carried out in order to minimize the kick. Beneath the different steps are listed to what is performed when a kick is in development. The information in this section is retrieved from [8].

- Kick detection
- Stop pumps, rotation of the drill string etc.
- Then close the BOP
- Monitor shut-in pressure – This is used in the calculation of the new kill mud that is to replace the contaminated mud in the well and balance the well
- Then determine which killing method to use
    - Driller method: circulate out the kick before introducing kill mud.
    - Wait and weight: start pumping kill mud while circulating out the kick.
    - Bullheading: revers kill, forcing the kick back into the formation. With this method the choke is not used as it is for the other methods
    - Volumetric method: which opens and closes the choke in steps in order to hold a stable bottom hole pressure during the kill operation. Used when pipe is out of hole
- Open choke line and circulate the kick out through the choke line to the separator or to flare, this is only done for the Driller`s method and W&W method
- Open and close the well during the kill procedure to stay between the formation pressure and fracture pressure, which is done with the Volumetric method
- The kill line can, if needed, be used as a secondary choke line or to pump fluid into the well

After the BOP is closed, the pressure will build up until $P_{well} = P_{pore}$, and influx will stop. By reading the shut-in casing pressure (SICP) and shut-in drill pipe pressure (SIDPP) we can get an indication of kick size and calculate P_{pore}.

More information about the SICP and SIDPP will be given in section SIDPP and SICP 2.4.3.

2.4.3 SIDPP and SICP

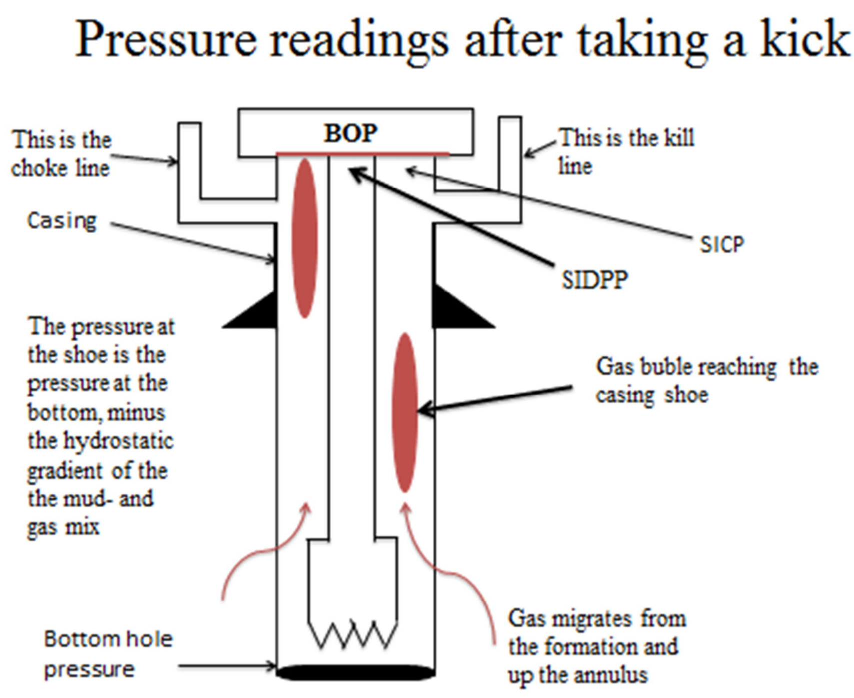


Figure 2.7 - A picture showing SIDPP and SICP.

When the BOP is closed, pressure will start to build up right after a kick is taken. The formation forces fluid into the wellbore which increases the wellbore pressure. This inflow proceeds until the BHP equals the formation pressure, and at this point the SIDPP and SICP are measured. If the well is kept closed for a longer time with WBM in the well, inflow gas will start to move up in the annulus on its own and lead to increasing SICP and SIDPP. In OBM the pressure goes up until it equals the formation pressure, this is because gas is dissolved in the OMB and nothing happens as long as there is no circulation (at least for HPHT conditions). The pressure peek after build up shown in Figure 2.8 is where one reads off the SIDPP and SICP. These values will be used as references when circulating out the kick and when calculating new mud weight.

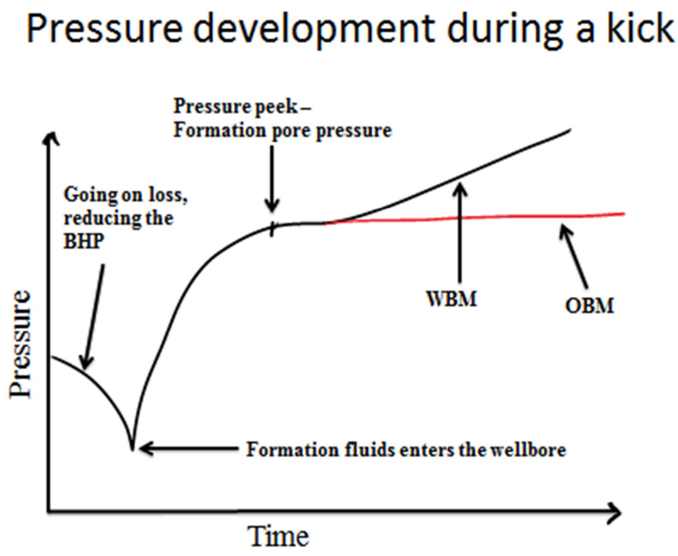


Figure 2.8 – SICP and SIDPP during a kick

It is also possible to determine the pore pressure after measuring the SIDPP. This is performed by the following formula:

$$\mathbf{P_{pore} = SIDPP + \rho_{mud} g h_{TVD}} \qquad \textbf{(2.1)}$$

From the pore pressure, new kill mud weight can be determined and a kill sheet can be worked out. A kill sheet tells the operator which pump pressure one should have in the different stages of the well kill (I.e. pump pressure vs. strokes pumped). In this way a constant bottom hole pressure can be maintained. It is important to monitor a constant BHP above pore pressure during the well kill to avoid a second kick.

As can be seen from Figure 2.7 above the inflow gas migrates upwards in the annulus towards the wellhead. When the well is closed the gas have no possibility to expand (given closed well) and according to Boyle`s law P*V = constant [12], meaning that the gas pressure will be preserved as long as the well is shut in (more about Boyle`s law in section 4.1.3).

The SIDPP is used when calculating ICP (initial circulation pressure) and FCP (final circulation pressure). The pressure difference between the annulus and drill pipe also makes it possible to calculate the density of the inflow fluid.

2.4.4 SR_1 and SR_2

In a subsea well the BOP is placed on the seabed, here the choke line and kill line goes from platform deck and down to the BOP. SR_1 and SR_2 are measured as pump pressures along a given pathway. When circulating through long coke lines, large frictional pressure losses will be experienced which will be reflected in pump pressure. Therefore it is important to know the difference between SR_1 and SR_2 which is explained below. SR denotes well friction during circulation in the whole well. SR_1 indicates that the pump pressure measured when circulation is taken up the riser. The SR_2, however, is the pump pressure when the circulation is performed through the well and up the choke line after the BOP is closed, meaning that no fluid goes up the riser. Beneath a sketch is shown, which includes the different flow paths.

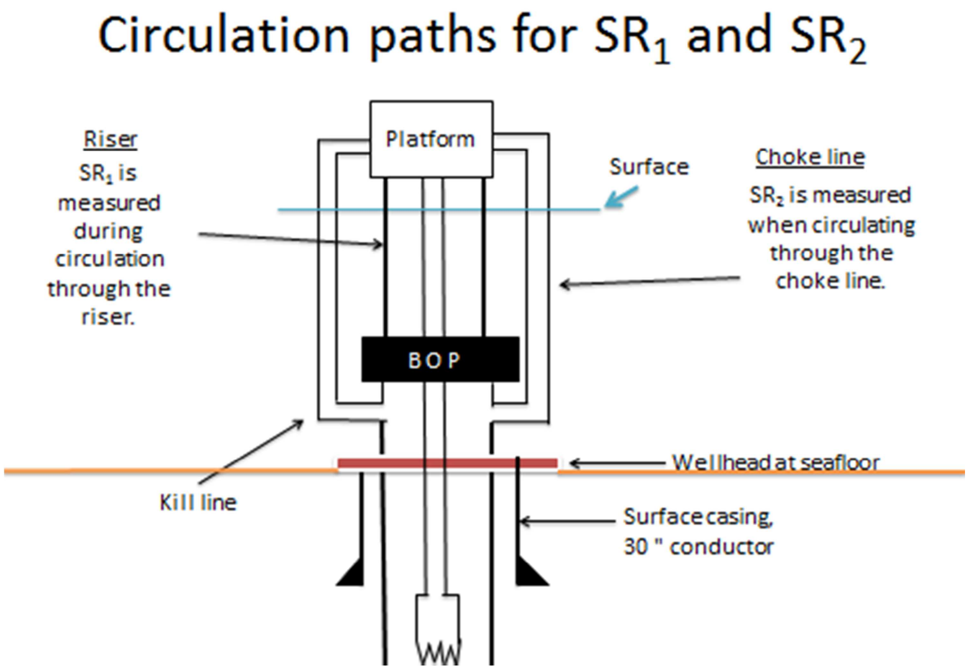


Figure 2.9 - Showing where SR1 and SR2 are measured.

The choke line friction can be calculated by taking the pump pressure (SR_2) minus pump pressure (SR_1), both taken during circulation in the whole well and with the assumption that the riser friction is negligible. The circulation tests are performed regularly using the anticipated kill rate.

$$\Delta P_{friction,cl} = SR_2 - SR_1 \tag{2.2}$$

Where:

$\Delta P_{friction,\ cl}$ = Frictional pressure loss in the choke line

SR_2 = Pump pressure during full circulation through the choke line instead of riser

SR_1 = Pump pressure during full circulation through the riser

2.4.5 A short introduction of Driller`s and W&W method

After taking a kick a well control situation has occurred. In order to regain well control there are established several methods that can be used to regain well control.

Driller`s method is a two circulation method. After a kick is taken and the BOP is closed, the pressures in the annulus and drill pipe are read and written down. Based on these pressures new kill mud can be weighted up, the main purpose of the new mud is to balance the formation pressure after the kick has been circulated out of the well. In the first circulation stage inflow fluid is circulated out of the well. Since the BOP is closed the return flow has to go through the choke line, which is a line on the outside of the riser and up to surface. At the end of the choke line there is placed a choke valve. This can be regulated between open and closed position. The choke enables regulation which is used to hold and maintain a constant bottom hole pressure during the entire kill operation. The bottom hole pressure is kept equal to the pore pressure plus a safety margin to make sure the pressure is above the formation pressure. The second circulation stage is when the new kill mud is introduced to the well and circulated down the drill pipe and up annulus. After the second stage, the entire well is filled with new kill mud and it is now able to balance the formation pressure on its own and drilling can proceed as intended before the kick started.

The Wait and Weigh (W&W) method is also known as the one circulation method [10]. When a kick is taken and BOP has been closed, pressures are noted, and new kill mud is pumped simultaneously as the kick is circulated out. This is different from Driller`s method that uses two circulation stages, the first to get the kick out of the well using old mud and the second to replace old mud with new kill mud. The Driller`s method and the W&W method uses the same choke line with the ability to regulate the choke. The goal is to maintain a constant bottom hole pressure between the formation and fracture pressure window. With this method it is more difficult to carry out the operation as the columns in both drill pipe and annulus will change as kill process is carried out.

The various calculations done by hand are difficult for both methods, and for this reason the industry uses advanced simulators to take into account all variables during the entire kill operation. In this way they are able to create a visual image of the situation. Calculating the choke pressures by hand for the operation are not common, however, the goal is to regulate the choke such that the pump pressure schedule given by the kill sheet is followed as precisely as possible. In the annulus the inflow fluid will change the hydrostatic pressure, and the new kill mud will do the same when entering the drill pipe. If W&W is a better option than the Driller`s method will be discussed in chapter 6.

2.5 Kick tolerances and well design

In this section there will be an introduction of what kick tolerances is and what effect it will have on the well design. It will also cover a short introduction to well design.

2.5.1 Kick tolerances

During kill circulation using Driller`s method (DM) and W&W, the bottom hole pressure will be kept constant above the pore pressure. The pressure at the casing shoe will be given by the formula:

$$\mathbf{P_{max,cs} = P_{BHP} + SM - \rho_{mix} g h_{TVD} - friction} \quad \textbf{(2.3)}$$

Where:

P_{BHP} = Bottom hole pressure
SM = Safety margin

The casing shoe pressure is equal to the constant bottom hole pressure minus the hydrostatic pressure of the mixed mud and gas between bottom and the casing shoe.

The density of the mixture is affected by the mud and gas density and the fraction of mud vs. gas. The formula above shows that a large kick will give a large maximum casing shoe pressure and one must ensure that this pressure does not exceed the fracture pressure at the weakest point in the well (usually the casing shoe). Also, the distribution and location of the kick has an effect. A kick situated around the BHA, will e.g. have a larger height and consequently lead to a higher maximum casing shoe pressure. We also note that a larger mud weight will lead to reduced casing shoe pressure.

Kick tolerances is about evaluating how large kick a hole section can take without casing breakdown at the shoe. From the discussion above we see that the kick tolerances will depend on variables such as pore pressure, safety margin chosen, kick volume, mud density and kick distribution. It can be interesting to note that the formula indicates that the well friction in this case has a positive effect in the sense that it gives a reduced maximum pressure at the shoe. Table 2.1 shows what typical kick sizes the well should be able to handle in the different well sections without breaking the shoe. For instance, if we consider a 12 ¼" hole section and observe that a 25 bbl kick from TD will induce a too large casing shoe pressure, the planned depth of the 12 ¼" hole section must be revised.

The table below is retrieved from [13], this is a table from various operators that lists up typical values of kick tolerances in a well.

Table 2.1 - Shows typical values of kick tolerances from various operators [13]

Hole size **[in]**	**Kick Volume** **[bbl]**
6 inch and smaller	10-20
8.5	25-50
12.25	50-100
17.5	100-150
26	250

In [12] the kick tolerance is defined as:
"The maximum kick intensity that a well can tolerate before lost circulation is experienced at the last casing seat."

If the kick intensity is expressed as a gradient, this will give the equation:

$$\mathbf{g_{kt} = g_P - g_m} \qquad \textbf{(2.4)[12]}$$

Where:

g_{kt} = the kick tolerance gradient
g_P = the pore pressure gradient
g_m = the hydrostatic gradient of the existing mud

As a requirement, the formation beneath the last casing shoe at a giving depth should have a fracture pressure that is equal to or higher than the potential kick pressure at this point [12].

For the well design, kick tolerance is a key factor when determining the optimal setting depth for a casing section. The evaluation of kick tolerance is important to establish, in the event of a kick the length of the open hole section and the effect the kick will have on it must be taken in considerations to avoid the casing shoe from breaking down. Seeing this from an economic point of view, a long casing section is desirable as this will be more cost efficient than many short sections. By using kick tolerance in both the well design phase and during the drilling process, the risk of an incident will be reduced together with the consequence if one should occur [9].

2.5.2 Well design

Well design wraps all processes related to the well in a particular phase together as a whole. This might include choice of materials or grading on steel, kick tolerances, pressure grading on the wellhead, casing setting depth, choice of mud type (OBM vs. WBM), contingency plan etc. in addition to much more related to the well`s life. Considerations to pressure in different well sections, stress and strain in the wellbore rock and on the drill pipe, these are important factors to be taken seriously in the planning phase. Several other considerations and evaluations like temperature exposure of material in the well, formation fluid contamination that corrode the steel and equipment, what mud to use and the additives it shall contain to minimize wear etc. also needs to be evaluated. By taking all these issues into consideration the risk of an unwanted situation is heavily reduced, and in the event of an incident the well will be able to handle the challenges during its lifetime. These issues are also included in the casing design and in the casing setting depth evaluation.

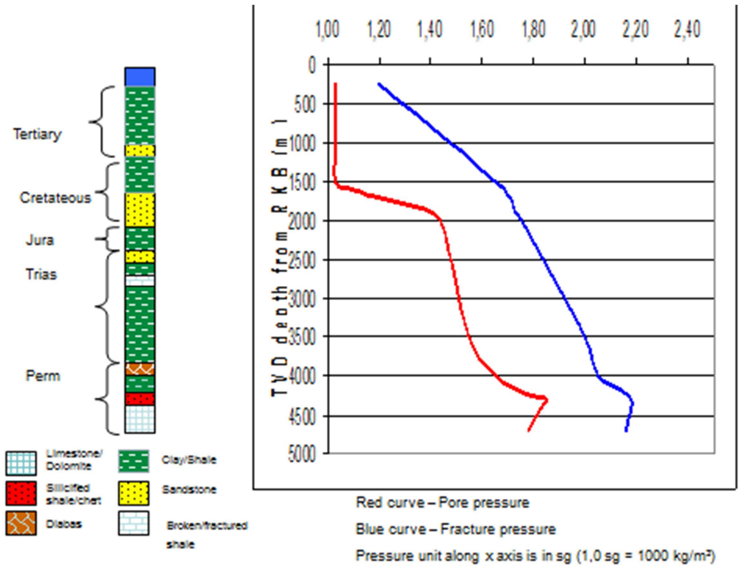


Figure 2.10 - Lithology and pressure prognosis [1]

In the pre stages of drilling the geologists have conducted a thorough investigation of the lithology. Based on the seismic readings and their knowledge they are able to form a lithology profile together with the pressure prognosis of the different formation zones down to target depth. With this information the engineers together with a multidisciplinary team are able to design the well from scratch. Decisions are made for long time purposes and with the intention to extract as much hydrocarbons as possible. Completion and intervention also need to be in mind in the well`s design phase. This is to make sure that all options are evaluated for a long time perspective. It is also important to look at different technologies and decide which alternative will serve the best purpose for that particular well in terms of long time costs and flexibility.

Some issues that needs to be addressed in the well design phase:

- Well profile
- Casing setting depth
- Mud type, weight and additives
- Type of bit for the different sections
- Torque and drag profile
- Casing design with safety factors
- Kick tolerances
- etc.

These are some of the issues that need to be addressed in the well design phase in order to have the most cost efficient and safe operation as possible.

2.5.2.1 Casing design

In the casing design, burst loading is the inside pressure minus the outside pressure. These loads can be pressures that may be encountered while drilling, e.g. a kick will give a large pressure load on top of casing and a cement job can give a large collapse load at the casing shoe. If the load on the casing is exceeded by the burst or collapse strength of the casing, then the casings are approved. This is one element that needs to be in place in order to have full well integrity. To have full well integrity the critical fracture pressure beneath the casing shoe must be higher than the inside well pressure. Since the well design dominates the high burst load and high critical fracture pressure means that the well, the open hole interval and the casing, have full well integrity. As a requirement the last casing before the production tubing is installed needs to have full well integrity. Both the casing and open hole must be able to withstand full reservoir pressure from a gas reservoir in order to meet the requirement of full well integrity [14].

Another terminology is reduced well integrity, which means that all casing strings are designed with reduced well integrity, except for the production casing. Should however the well be filled with gas during shut in it will not be capable of handling these pressures. In this case, the place that gets the highest pressure and face bursting is just beneath the wellhead. Bursting at this location is not an option in the design due to the consequence this might yield, e.g. a blowout on surface can be fatal for human and disastrous for the environment and equipment. In order to eliminate the possibility of a casing burst under the wellhead the design must make sure that the weakest point is just beneath the last casing shoe. A leak of test (LOT) is used to define or check fracture gradients at this location before drilling the next section. Then kick tolerance for each section must be estimated and the casing setting depth for each casing section must be determined. If the tolerance is too low, the next casing shoe must be placed further up. If the pressures gets too high in the event of a kick, a failure in the rock can lead to a underground blowout, and it is therefore desirable to have the weak point just below the casing shoe [14]. It is also important that the casing shoes are placed in stable formations like shale or other stable formations that can withstand the pressures when further drilling or when casing are cemented in place.

For a reduced well integrity case, the following design considerations need to be considered. These are retrieved from [14]:

- The minimum fracture gradient required when placing a casing at a particular depth
- The weak point should be below the casing shoe and what can the maximum allowable fracture gradient be
- If a kick event is to happen, one needs to know the maximum kick size the well can handle without fracturing below the casing

Wells are designed with a maximum kick size in mind, for example a kick size of 4 m^3. Should however this maximum anticipated kick be higher than expected, then the well integrity may be heavily reduced.

2.6 Blowout potential

A blowout is when a kick goes out of control and passes the well barriers and makes its way to the surface. In terms of severity the blowout is one of the worst. Looking back at BP`s Macondo accident in the Gulf of Mexico April 2010, a well control situation resulted in a subsea blowout, 11 people lost their lives and the environmental consequences of the oil spill were enormous. It took BP several months to stop the leak from the uncontrolled well, over 4,9 million barrels of oil were spilled out into the ocean and the clean-up job was immense and tedious [15].

In the light of this event, the focus on the well control procedures, barrier elements and the equipment were set on the agenda. All should be designed to prevent a blowout if a kick situation should develop, and there should be no possibility for personnel to bypass important steps in the process e.g. the cementing phase or the testing phase. Safety shall be number one priority and this has changed the focus on well control globally. Also in Norway several well incident have happened, one of them at the Statoil`s Gullfaks field in 2010. They had a casing breach in a production well that was about to be completed in the final circulation phase. Mud was lost to the formation and gas from the formation flowed into the well bore and was detected on surface. Normal safety measures was performed, subsequent mustering of personnel, and circulation to re-establish the well barrier was performed according to procedures [16].

For safety, a well is required to have two independent well barriers that surround the entire well [2]. The risk of a blowout is reduced and it can only occur when both of the barriers are breached. However, there are several elements that affect the blow out potential. To name a few:

- Shallow gas zones – in the open zone, before the riser and BOP is in place
- Poor cement quality – there can be pathways in the cement, which can occur as mud mixes with cement
- BOP failure – not able to close the BOP in time
- OBM instead of WBM – gas dissolves in the oil based mud making it hard to see a kick developing before it is too late. It can therefore go out of solution and flash when the pressure is reduced to a certain point. The expansion is so severe that within seconds the kick can be out of control
- Casing design – the formation pressure is higher than expected and the casing quality is not designed for these pressure forces

When taking a kick there is always a potential of blowout, the only thing that prevents one from happening are the primary and secondary well barriers. Also good detection and action procedures from the rig personnel on board are required to prevent and deal with incidents when they happen. The importance of good routines and procedures are crucial, they are designed to re-establish well control, stop the kick and prevent it from escalating into a blowout.

3 Presentation of example wells to be used in calculation examples

In this section two example wells will be presented. These examples are to be used in some calculation examples in chapter 5 for the different well kill methods (i.e. Driller`s method and Wait & Weight).

3.1 Deviated well example, subsea well

In this example the choke- and kill- line are attached to the riser and have a length corresponding to the water depth of 500 meter. For some well kill operations one is circulating the kick out through the choke line, and in this case we have to account for choke line friction pressure losses. This will be explained more in detail when going through an example in relation to presentation of the W&W.

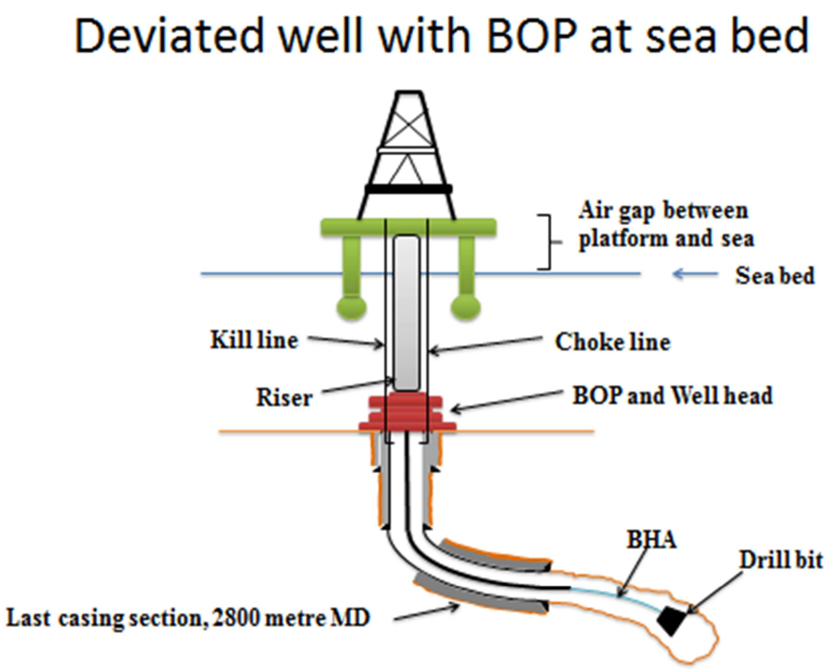


Figure 3.1 – Shows a floating rig, a deviated well with BOP on seabed

In a directional well, at 4580 meters MD and 4120 meters TVD a kick is taken. Old mud density is 1,73 sg. In order to know the choke line friction, kill circulation tests have been performed in advance. These where performed with 35 strokes per minute (spm). The result was 35 bar when the circulation up riser and 49 bar when circulating up through the choke line. The shut in pressures after taking the kick was measured at surface. The SIDPP = 43 bar, and in the annulus the SICP = 57 bar. The safety margin of 10 bar will be set for the well kill operation.

- Well profile
  - Water depth of 500 meters
  - Vertical well down to 1800 m
  - 55° from 1800 m TVD to 3500 m (MD), 2775 m (TVD)
  - 42° from 3500 m (MD) to 4580 m (MD), 3578 m (TVD)
- Drill pipe geometry
  - 5 " DP down to 4380 m MD/3429 m TVD with capacity 9,15 l/m
  - 6 ½" Drill Collar of 200 meters with capacity 4,01 l/m.
- Mud density 1,73 sg
- Pump capacity 17,2 l/stroke
- Annular capacity

DP/Csg	24,2	l/m
DP/OH	23.6	l/m
DC/OH	15,2	l/m

OH – Open hole

DP – Drill Pipe

Csg – Casing

3.2 Vertical well profile example

This is a vertical well with a TVD deep of 4300 meter. The last casing shoe was placed at 2800 meters. This is a platform well and therefore the BOP is located on the rig.

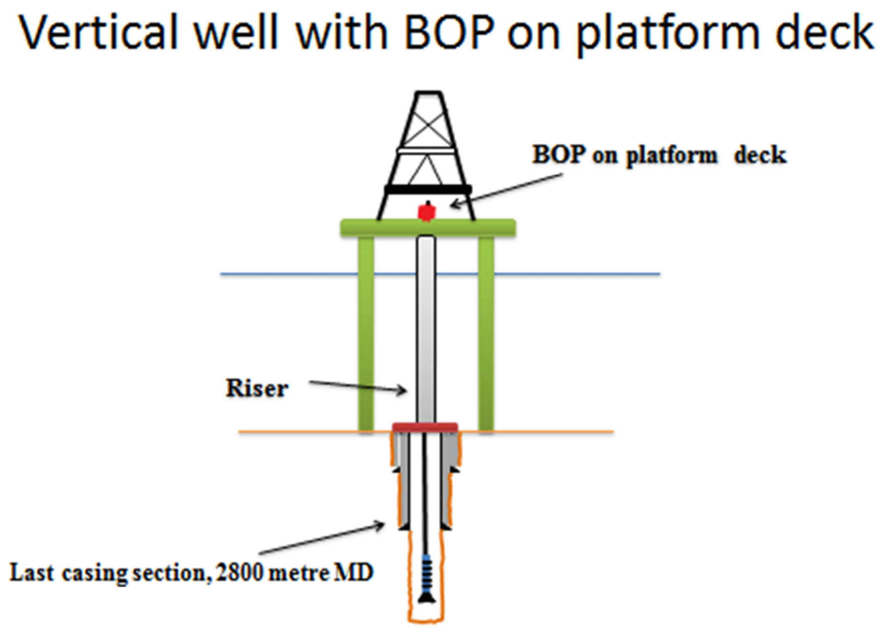


Figure 3.2 – Shows a fixed platform, a vertical well with BOP on platform deck

The drill collar section is 280 meters long.

Drill pipe inner capacity 9,15 l/m

Drill collar (DC) inner capacity 4,0 l/m

Annular capacity:

DP/Csg	24,2	l/m
DP/OH	23,6	l/m
DC/OH	15,2	l/m

During the kill operation, the kill pump delivers 17,5 l per strokes. The operation shall be carried out with 34 strokes per minute (spm) and a kill rate of 595 l/min. Pump pressure (well friction) was measured to 18 bar, it was performed when pumping at kill rate. The old mud that is going to be replaced is 1,52 sg.

After the kick is taken and the BOP is closed the pressures are read. The pressures are SIDPP

$(P_D) = 40$ bar, and the SICP $(P_A) = 48$ bar. As a safety assurance, a safety margin of 10 bar is added for the kill mud density calculations and to the bottom hole pressure during the well kill. This is done to make sure that the bottom hole pressure stays safely above the formation pressure avoiding a secondary kick, but one should not exceed fracture pressure.

4 Well Control Procedures

There are many ways of killing a well as will be further discussed in this chapter. This will depend on the particular situation. Factors like drill pipe position in the well and whether the drill string is in the well or not are important factors. Another important factor is where the drill string is located in the well, i.e. near the bottom or high up in the well. These different elements will indicate which method to use in order to kill the well in the safest and most efficient way possible[10].

This chapter focus on the following killing methods:

1. Driller`s Method
2. Wait and Weight
3. Bullheading
4. Volumetric Method

The placing of the drill string determines which method is the best for killing the well. In order to use methods 1 and 2 the drill string must be on bottom, the two other methods (3 and 4) becomes an alternative if the drill string is way off bottom with no possibility to get down to TD [10] or drill pipe circulation has been obstructed. Bullheading, however, is also an alternative if the drill string is on bottom.

Having a near to constant bottom hole pressure when killing the well is a common practice for both Driller`s method and W&W method, for Volumetric method and Bullheading the bottom hole pressure can vary more during the well kill operation. This means that the pump pressure from the surface, plus the hydrostatic mud pressure is equal to or preferably higher than the formation pressure without exceeding the fracture pressure during the well kill operation. By maintaining constant bottom hole pressure and assuming that the well is able to take the circulation, no more formation fluid are able to enter the wellbore and escalate the situation. Bottom hole pressure is controlled by regulating the choke pressure at surface, it enables bottom hole pressure control between the pore- and fracture pressure. Then, re-establishing well control should go safe and according to plan [10].

Before the various killing methods are introduced, the next topic will be to elaborate on the formulas used when taking a kick.

Pump pressure when circulation starts is the ICP (Initial Circulation Pressure), and when kill mud enters the annulus it is the FCP (Final Circulation Pressure) that is used in the kill sheet. The kill sheet is the pump pressure the driller has to maintain during the well kill. In this way the bottom hole pressure is maintained constant.

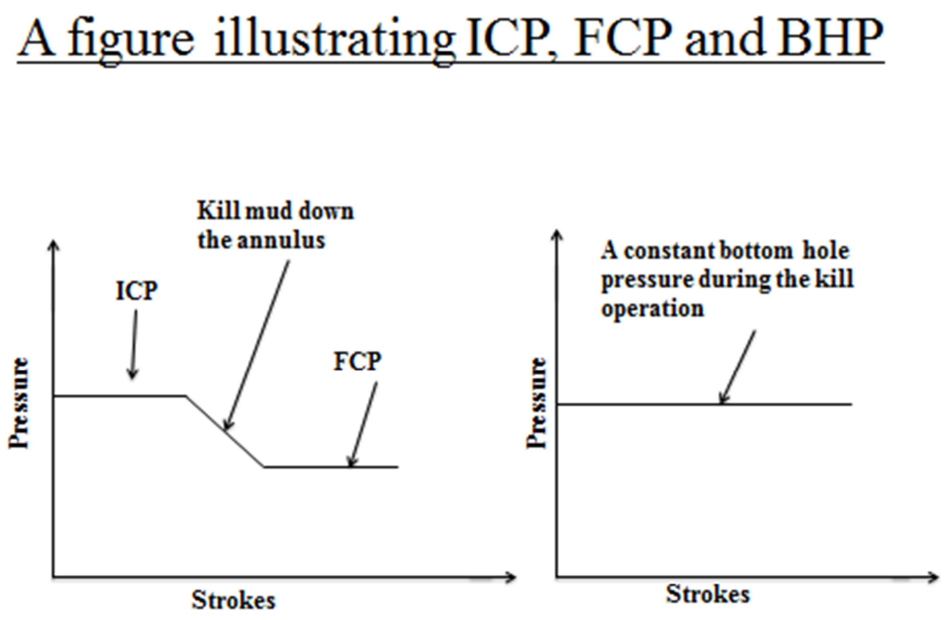


Figure 4.1 – Shows how bottom hole pressure is related to ICP and FCP

As can be seen from Figure 4.1, if the kill operation process follows the pressure curve in the kill sheet the bottom hole pressure will remain constant. Holding a stable bottom hole pressure is preferred since this will avoid a second kick during the operation and also prevent fracturing the formation.

4.1 Common well control formulas that are used when facing a kick scenario

When a kick is in progress there are several formulas that are needed in order to re-establish the well barrier. This section has the goal to include the various formulas used during a kill calculation and enhance the understanding of them. These formulas will later be used in the calculation examples in section 5.

After a kick is taken, the gauges will indicate the pressure build up in the annulus and in the drill pipe. When this is known the bottom hole pressure can be calculated and new kill mud can be found.

Bottom hole pressure is found by:

$$\mathbf{BHP = SIDPP + (\rho_{mud} g h_{TVD})} \tag{4.1}$$

This will be the same as the pore pressure at shut in conditions when the inflow has stopped and pressure build up has stopped.

The kill mud weight can be determined from the following formula:

$$\boldsymbol{\rho_{\text{kill mud}} = \rho_{\text{old mud}} + \frac{SIDPP+SM}{0{,}0981 \times TVD_{well}}}$$ **(4.2) [10]**

Where:

BHP = bottom hole pressure [bar]

ρ_{kill} = density of kill mud [sg]

ρ_{old} = density of already in place mud [sg]

SIDPP = Shut in Drill Pipe Pressure [bar]

SM = Safety margin [bar]

TVD = True Vertical Depth [m]

When taking a kick the gas will move up in the annulus, Figure 4.4 illustrates the gas as a single bubble and the location of where the SIDPP and SICP are measured. With the use of calculations it is possible to find ICP and FCP.

How the ICP is calculated is showed in the formula below. It will be the same for both platform and subsea well. ICP is the initial circulation pressure, which is the starting pump pressure in a kill operation (and kill sheet). The goal is to balance out the formation pressure during circulation by keeping it a bit above the formation pressure to reduce the risk of further influx. The risk is reduced by adding a safety margin (SM) to the ICP calculations in order to stay above the pore pressure during the operation.

ICP is defined as:

$$\mathbf{ICP = SIDPP + SM + \boldsymbol{SR_1}} \qquad \textbf{(4.3)[10]}$$

Where:

ICP = Initial circulating pressure

SIDPP = Shut in Drill Pipe Pressure

SM = Safety margin

The FCP is defined as:

$$\mathbf{FCP = SR_1 \times \frac{\rho_{kill\ mud}}{\rho_{old\ mud}}} \qquad \textbf{(4.4) [10]}$$

Where:

FCP = Final Circulating Pressure

SR_1 = Circulation pressure up riser (friction) – pump pressure

Take notice that the SICP + SM is equal to the initial choke pressure when circulating out a kick with the use of Driller`s method and W&W method when considering a platform well.

When taking a kick the gauges record the pressure development in the annulus and in the drill pipe. The relation between the pump pressure and the bottom hole pressure is determined by the hydrostatic gradient in the drill pipe.

When the kill mud has reached the bottom of the annulus, one has reached the final circulation pressure in the kill sheet. Calculating the FCP is done to balance the friction forces with the new well pressure and the new kill mud in order to re-establish well control. When the kill mud reaches the bit and moves into the annulus the FCP is initiated. This pressure is held until the entire well is filled up with kill mud and the choke can be regulated to fully open. When the well is completely filled with kill mud it is capable of withstanding the well pressure on its own.

In the following case with a deep water well and choke line friction, it is showed how these formulas changes.

4.1.1 For a deep water case:

At shut in, the pressure on top annulus is the SICP, and this is the annular top pressure needed to balance the pore pressure. To avoid a second kick a safety margin of 10 bar is added which gives:

SICP + SM

In this way the risk of having a circulation pressure that goes beneath the pore pressure is reduced significantly. For this reason it is natural that the choke pressure has this initial value. It is valid for both a platform well where the choke line friction is negligible.

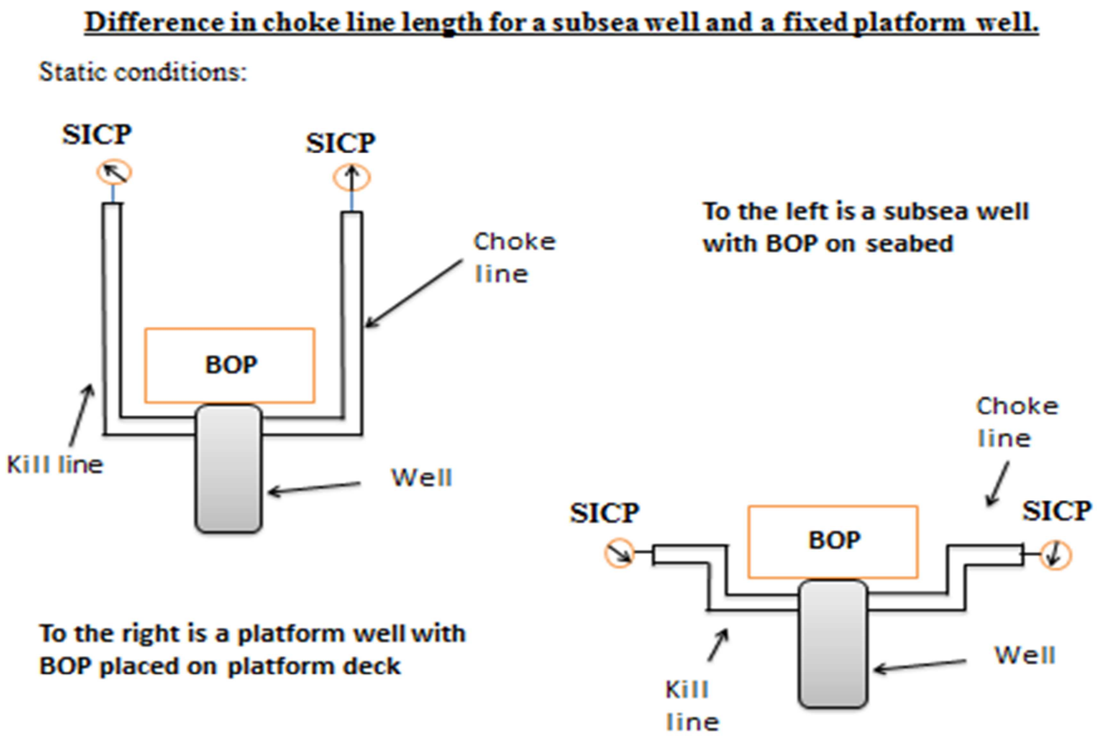


Figure 4.2 – Shows the difference in choke- and kill line length on a subsea well and a platform well at static conditions

Figure 4.2 shows the shut in choke and kill line pressure in a platform well vs. a subsea well. The well is static meaning there is now fluid flow movement in the well. Wellhead pressure is read as SICP after a shut in.

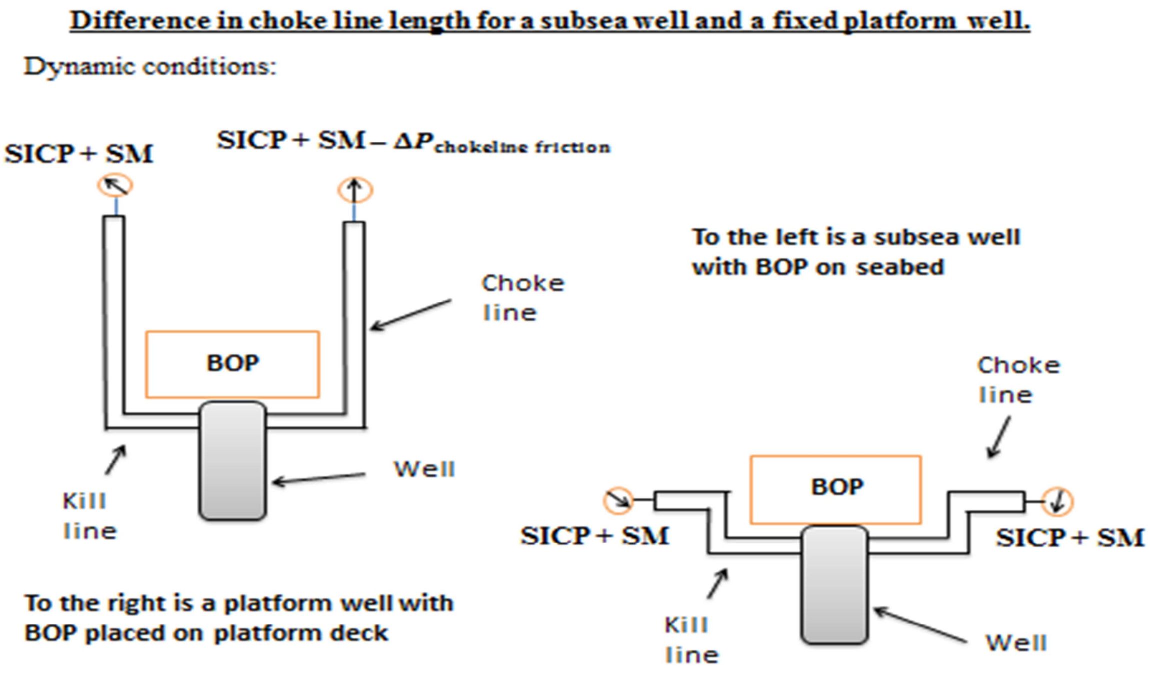


Figure 4.3 - Shows the difference in choke- and kill line length on a subsea well and a platform well at dynamic conditions

When the kill operation has started, Figure 4.3, there is fluid moving in the choke line. For a subsea well with long choke lines the friction needs to be taken into account in order to hold a stable bottom hole pressure. As can be seen in the picture the initial choke pressure is **SICP + SM – ΔP$_{\text{choke friction}}$.** This will give the same BHP as in the platform case since the kill line pressure is a measure of the pressure in the well.

The figures above show how pressures are read before and during a kill operation. The static conditions are shown in Figure 4.2 and the dynamic conditions are shown in Figure 4.3. The only thing that changes is the friction in the choke line from the measurements between the static and dynamic conditions for a subsea well.

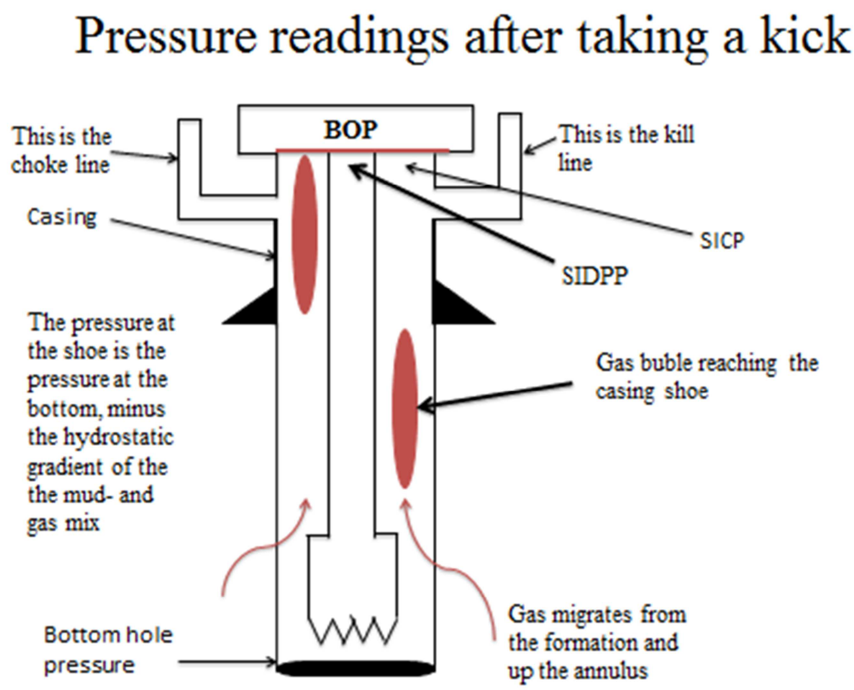


Figure 4.4 - Shows a schematic of where the SIDPP and SICP are measured

In the following it will be shown that the ICP formula for a deep water case is the same as a case where the choke line friction is negligible.

The following relations between shut in surface pressures and pore pressures are valid [8]:

$$\mathbf{P_{pore} = \rho g h_{annulus} + SICP} \tag{4.5}$$

$$\mathbf{P_{pore} = \rho g h_{DP} + SIDPP} \tag{4.6}$$

Above are two expressions that determine the pore pressure, one where the drill pipe is used, and the other where the annulus and choke line is used. When taking a kick the hydrostatic difference can be showed beneath.

Express hydrostatic difference due to kick, using equation (4.5) and (4.6):

$$\mathbf{SICP - SIDPP = \rho g h_{DP} - \rho g h_{Annulus} - \rho g h_{cl}} \qquad \textbf{(4.7)}$$

Calculating pressures from the inlet of the well (pump) until outlet (choke), the following formulas are achieved:

$$\mathbf{ICP + (\rho g h)_{DP} - \Delta P_{friction,DP\ bit} - (\rho g h)_{Annulus} - \Delta P_{friction,Annulus} - (\rho g h)_{Cl} - \Delta P_{CL} = SICP + SM - \Delta P_{Cl}} \qquad \textbf{(4.8)}$$

This leads to:

$$\mathbf{ICP + (\cancel{SICP} - SIDPP) = \cancel{SICP} + SM + \underbrace{\Delta P_{friction,DP\ bit} + \Delta P_{friction,Annulus}}_{\text{SR}_1\text{ (when circulating up riser, neglecting riser friction)}}} \qquad \textbf{(4.9)}$$

The result from eq. (4.9) becomes:

$$\mathbf{ICP = SIDPP + SM + \mathit{SR}_1} \qquad \textbf{(4.10) [10]}$$

Where:

ICP = Initial Circulating Pressure

ΔP_{CL} = Frictional pressure loss in choke line

$\Delta P_{friction,DP\ bit}$ = Frictional pressure loss through drill pipe and bit

$\Delta P_{friction,Annulus}$ = Frictional pressure loss through the annulus

$(\rho g h)_{Annulus}$ = hydrostatic pressure in annulus

$(\rho g h)_{DP}$ = hydrostatic pressure in drill pipe

$(\rho g h)_{Cl}$ = hydrostatic pressure in choke line

SIDPP = Shut in Drill Pipe Pressure

SICP = Shut in casing pressure

SM = Safety margin (to make sure we are above the formation pressure)

SR_1 = Circulation friction/ pump pressure up riser

Hence, equation (4.10) is valid both for a fixed platform with BOP on deck and for a semisubmersible with BOP on seafloor.

For deep-water well, when starting to circulate kick the choke pressure must be regulated according to the kill line pressure. In the start when ramping up the pumps the kill line pressure is used as a guide to hold a stable bottom hole pressure. After this the choke pressure is monitored in such a way that the kill sheet is followed.

If it is a floating rig in deep waters with BOP on seabed, the bottom hole pressure is regulated to the initial choke line pressure. Due to the depth the choke line friction will be much higher compare to the short choke lines on fixed platforms. In cases with long choke lines the initial choke line pressure should be:

$$\textbf{Initial choke line pressure} = \mathbf{SICP + SM - \Delta P_{friction,cl}} \qquad \textbf{(4.11)[8]}$$

This pressure is what the operator uses as a guideline when holding the bottom hole pressure constant in the initial stage of the kill circulation. The initial phase is when mud pumps starts to ramp up to specified flow rate. Afterwards the choke will be regulated such that the pump pressure follows the predicted kill sheet.

In order to ensure that the choke line friction is neglected one makes sure that the kill line pressure is equal to SICP + SM during start-up of kill circulation. During an operation the initial kill line pressure is:

$$\textbf{Initial kill line pressure} = \mathbf{SICP + SM} \qquad \textbf{(4.12)[8]}$$

Another aspect of using rigs with BOP on seabed is the riser and what will happen if this is removed. In seldom occasions a floater may be forced to leave the area for some time, this can be because of bad weather which makes it dangerous to stay there, this is called temporary abandonment. When leaving/moving the rig the well needs to be closed in and the riser must be disconnected from the wellhead. This means that the hydrostatic column from the seawater on top of the well together with the hydrostatic column in the well together should be sufficient to balance the formation pressure until the rig returns and continue where it had stopped. To avoid any surprises the riser margins needs to be correctly calculated, the riser margin is the extra mud weight needed in the closed in well to compensate for the replacement of water instead of mud in the riser when abandon. If the mud weight left in the closed in well is too low pressures can build up, the result is a pressurised well when it is reopened, just like a shaken soda bottle. This is a very dangerous situation, but with the right knowledge and understanding this will not be an issue if the calculations are done correctly.

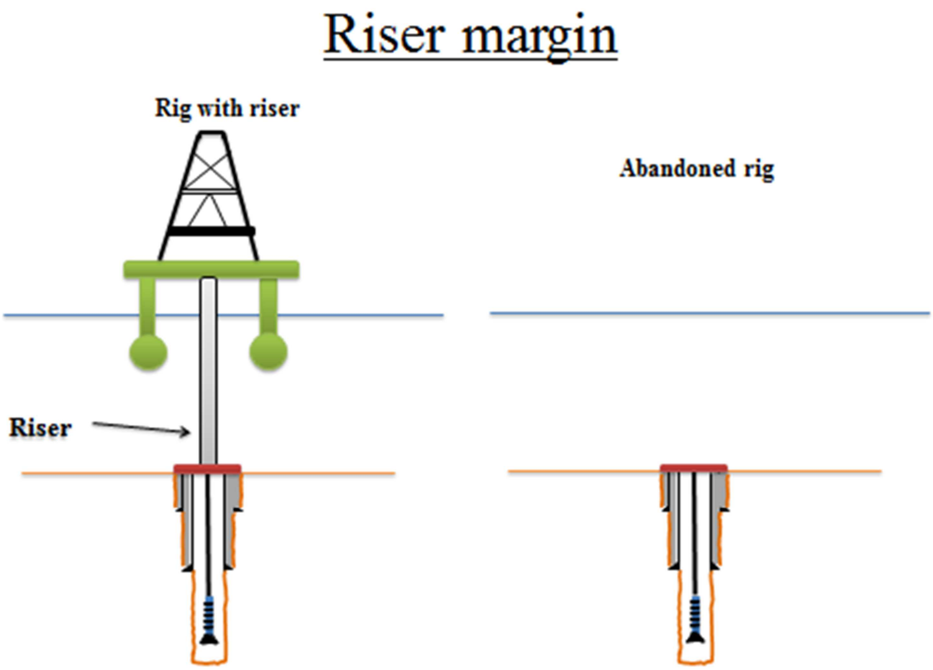


Figure 4.5 – Showing a rig with riser and without riser

Riser margin formulas:

- Without riser margin and with SM

$$P_{pore} + SM + \rho_{mud} g h_{DP} \quad (4.13)$$

$$\rho_{pore} + SM = \rho_{mud} g h_{DP} \quad (4.14)$$

- <u>With riser margin</u>

$$\rho_{mud} g(h_{TVD} - h_{water} - h_{air\ gap}) + \rho_{water} g h_{water} = \rho_{pore} g h_{TVD} + SM \qquad (4.15)$$

Riser margin is found by taking the mud density and subtract the pore pressure density. The difference gives the riser margin:

$$\text{Riser margin} = \rho_{mud} - \rho_{pore} \qquad (4.16)$$

There will be an example with the use of riser margin in section 5.3 in the thesis.

4.1.2 Casing shoe pressure when taking a kick

In a drilling program the weakest point in the well will be in the formation at the casing shoe. Then if a kick is taken the steel would not yield and cause a catastrophe, however, the formation at the shoe will fracture first. Fracture at the casing shoe when taking a kick is called an underground blowout that in worst case if the cement is of poor quality, follow existing casing cements outside and find a way to surface. Calculation of the worst case determines at what depth casing can be placed. In this way if a kick is taken, both the casing shoe and the rest of the well components are able to handle the kick.

When a kick is taken the blowout preventer (BOP) shuts in the well and the effect of the kick is calculated by starting from the bottom and upwards. Then assuming how big the kick might be and its density, the pressure at the shoe can be calculated. The highest pressure on the casing shoe is when the front of the gas reaches the shoe. The gas front will have the highest pressure everywhere it passes which affects all points on its way towards the surface. If the pressure gets too high on the casing shoe, then maybe bullheading is best option for killing the well.

<u>Kick tolerance is calculated by this formula:</u>

$$P_{cs} = P_{bottom} + \rho_{mud} gh * \alpha - \rho_{gas} gh * \beta - \rho_{kill\ mud} gh * \gamma \qquad (4.17)$$

Vertical well:

$$\boldsymbol{\alpha + \beta + \gamma = 1} \qquad \textbf{(4.18)}$$

<u>Where:</u>

P_{bottom} = Constant bottom hole pressure to be maintained during well kill

$\rho_{mud}gh$ = Hydrostatic pressure of the mud between bottom and casing shoe

$\rho_{gas}gh$ = Hydrostatic pressure of the gas between bottom and casing shoe

$\rho_{kill\ mud}gh$ = Hydrostatic pressure of the kill mud between bottom and casing shoe

α, β, γ = is the mixing fraction – the space percentage each substance occupies in the annulus)

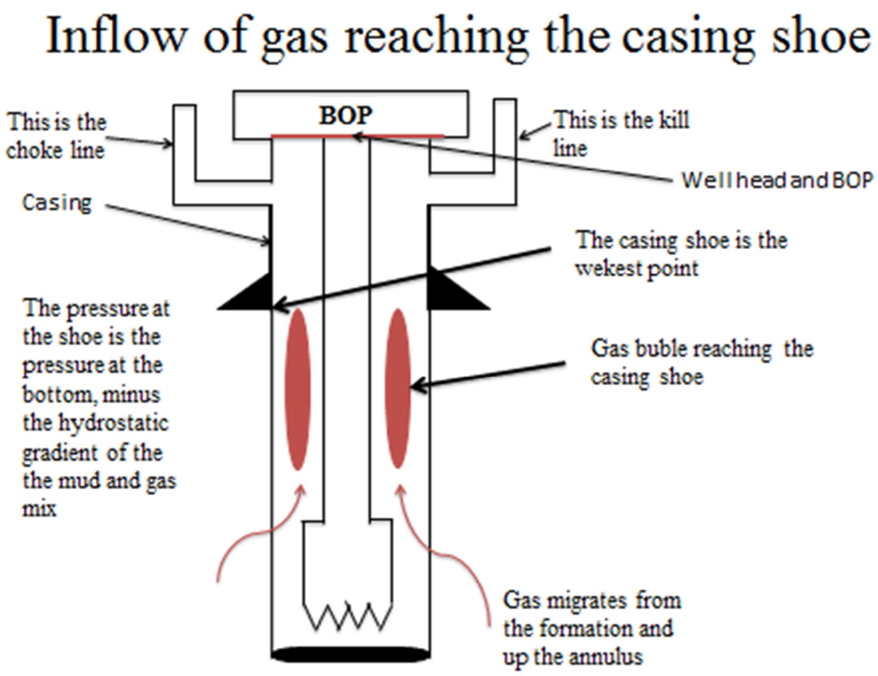


Figure 4.6: Shows a well with gas kick flowing towards the casing shoe

4.1.3 Boyle`s law

This explanation of Boyle`s law is to a large extent retrieved from [12]. The volume/pressure/temperature (PVT) is described by the equation of state (EOS) for a given fluid. Robert Boyle found in the 17th century one of the simplest gas equations during an experiment. What he found was that at constant temperature, the volume of a quantity of gas is inversely proportional to its pressure. The gas law equation can be expressed by:

$$\mathbf{PV = nRT}$$ **(4.19)**

$$\mathbf{\frac{PV}{T} = C}$$ **(4.20)**

$$\mathbf{P_1V_1 = P_2V_2 = Constant}$$ **(4.21)[12]**

(Boyle`s law assuming constant temperature).

The gas pressure and volume are given at two different conditions 1 and 2 in the equation above.

Charles` law explain the direct proportionality between the volume and temperature of a given gas quantity. Here constant pressure is assumed:

$$\mathbf{\frac{V_1}{T_1} = \frac{V_2}{T_2} = constant}$$ **(4.22)[12]**

Gay-Lussac`s law is a development of Charles` law where constant volume is assumed [17].

$$\mathbf{\frac{P_1}{T_1} = \frac{P_2}{T_2} = constant}$$ **(4.23)[17]**

Example on application of Boyle`s law:

A well has a bottom hole pressure of 500 bar and the inflow volume is 4 m^3. At surface we have atmospheric pressure of 1 bar. How much will the gas expand and what will be the volume of the gas at surface conditions? Here we will assume that the temperature is constant.

$P_1 = 500\ bar$
$V_1 = 4\ m^3$
$P_2 = 1\ bar$
$V_2 = ?$

Step I, derive formula:

$$P_1V_1 = P_2V_2 = Constant$$

$$V_2 = \frac{P_1V_1}{P_2}$$

Step II, insert values:

$$V_2 = \frac{500\ bar * 4\ m^3}{1\ bar}$$

$$V_2 = 2000\ m^3$$

The gas bubble has expanded from 4 m^3 and up to 2000 m^3 which is an enormous enlargement. This is why closing the well as soon as possible after detecting a kick is so important, and it will also minimize the potential inflow volume.

Another aspect seen from the Boyle`s law is the bottom hole pressure development as gas moves upwards in a closed in well with WBM (water based mud). If the well is shut in the 4 m^3 gas move upwards in the annulus and it will reach the well head containing its start pressure of 500 bars (given WBM and no circulation), this means that the bottom hole pressure will increase rapidly as the gas moves upwards in the annulus. The bottom hole pressure then becomes gas bubble pressure plus the hydrostatic height of the mud column underneath the migrating gas.

This gives the equation:

$$\mathbf{BHP = P_{gas\ bubble} + \rho_{mud} g h_{height\ under\ bubble\ to\ bottom}} \qquad \textbf{(4.24)}$$

This will also affect the shoe pressure conditions as the gas migrates upwards. When the bubble reaches the shoe the pressure acting on it will be the bubble pressure in the gas, as it moves further up the forces on the shoe is increased due to the hydrostatic mud weight between gas bubble and shoe. This can in worst case create a fracture at the shoe resulting in a leak off and a pre stage to a second kick.

In OBM (oil based mud) the pressure on the bottom will be the same. Gas will be dissolved in the OBM and it will not migrate upwards unless circulation starts. When circulation starts the kick volume will remain the same as the dissolved gas moves towards the surface and nothing is shown in the pit volume. But, the scary fact with OBM and dissolved gas is when the pressure is reduced to the extent that it is not able to contain gas suspended in OBM, it will rapidly flash out of the oil and go back into the gas phase. This means that the volume increase in the well is enormous, which can lead to a blowout with catastrophic consequences if personnel are not able to close the BOP in time. In these situations it is important to know at which point in the well the gas flashes out of the oil. If the well is in deep water with BOP on seabed and the flash point is above the BOP there are no possibilities of closing in the well and preventing the gas from reaching the surface. Therefore knowing the flash depth is important to maintain a controlled situation.

In HPHT wells with low pressure margins there are procedure in place to prevent an incident, when tripping out circulation is maintained to add friction to avoiding a negative pressure as the drill pipe is pulled out. This procedure prevents formation fluid from entering the wellbore and it reduces the risk of a hidden kick in OBM. E.g. can be if a gas kick has developed below or under the bit and follows the trip up towards the surface (given WBM). Or in a situation when oil is fully saturated with gas and it remains at bottom, what will happen is when tripping back down the gas will move upwards as mud is displaced by drill pipe and the circulation is restarted. The gas will be hidden until it flashes out near the surface, if this is above the BOP the result will be a blowout to surface.

Another common procedure in HPHT wells is to close the BOP and circulate bottoms up through choke line in those cases one suspects that a kick is taken and is hidden in the oil based mud. For instance, during tripping into a well after a long period, this procedure is used.

4.2 Drillers Methods

The Driller`s method is one of the oldest well killing methods and it was developed for shallow vertical wells [18]. As time moved on, wells got deeper and went from vertical into more inclined pathways. The method got further developed to overcome the new challenges related to deviated well paths.

Driller's method, also known as the two-circulation method, means that the kick is circulated out in two stages [6]. In this method the drill string needs to be placed at the bottom in order to be fully utilized. In the first stage the objective is to remove the kick from the annulus and re-establish the primary well barrier. This is done by shutting in the well and trapping the kick to minimize inflow, then a couple of calculation steps are performed and the circulation process can begin. The process can also uses a remote controlled choke, its purpose is to control the choke line back pressure to maintain a constant bottom hole pressure during the circulation process. It should also work together with the mud pump(s) in a synchronized manner to maintain the bottom hole pressure constant and preferably above the inflow pressure, but keeping it beneath the formation fracture pressure at the same time during the entire kick circulation process [10]. Old mud is used in the first circulation stage to remove the kick from the wellbore, and there will be no decrease in the drill pipe pressure during this operation. The second stage is to weight up new kill mud and repeat the circulation procedure until the new kill mud have completely filled the wellbore. Now the well is in balance and well control is regained [6].

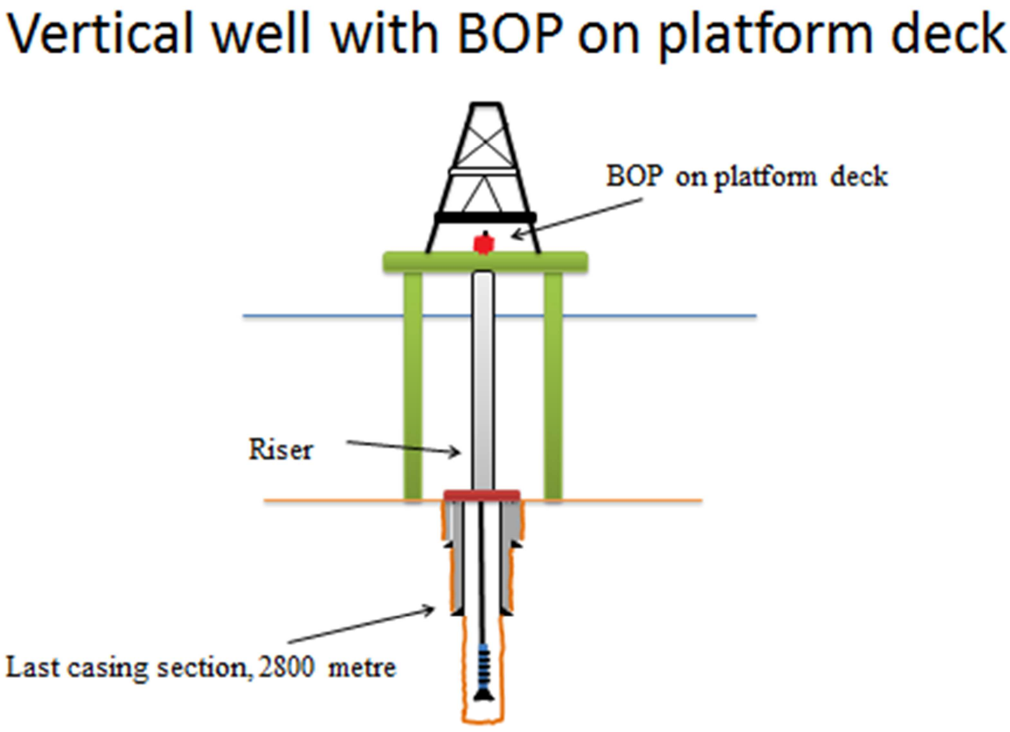


Figure 4.7- Showing the well schematics when drilling a well

Before the Driller`s method can be initiated there are some main steps that shall be followed when suspecting a kick. These are:

- Kick detection
- Stop mud pumps and rotation of the drill string rotation
- Close the BOP
- Monitor the shut-in pressure until it levels out – the wellbore pressure is equal to formation pressure
- Then open choke line and circulate the kick out through the choke line to the separator/flare
    - Driller method: circulate out the kick before introducing kill mud
    - Wait and weight: start pumping kill mud while circulating out the kick
- Another option is to reverse kill or bullhead, this is done by forcing the kick back into the formation (more about bullheading in section 4.4)

In the following section, a description is given on how the Driller`s method is performed. The reference for this is [4] if not stated otherwise.

When unwanted gas flows into the well a kick is in progress. With the BOP closed, the drill string and annulus pressures will increase due to a high pore pressure that forces formation fluid into the wellbore. After taking a kick the drill string pressure is measured at surface, the measured pressure is what is called the shut in drill pipe pressure (SIDPP). The SIDPP is shown in Figure 4.4, where drill string pressure at surface is the bottom hole pressure minus the hydrostatic weight of mud in the drill string. In the annulus the pressure increase will be even higher, this is due to the mix of inflow fluid and mud which reduces the hydrostatic pressure acting on the bottom hole. This pressure is read at well head as the shut in casing pressure (SICP) and shown in Figure 4.4.

Before starting the kill operation the amount of gas that the kick holds is important to evaluate, this because to see if there are any limitations within the equipment. If the equipment holds, the procedure can proceed. If not, then another approach needs to be evaluated.

When gas enters the wellbore with WBM it will meet an uplifting force because gas has a much lower density and weight compared to the mud. As gas rises in the well (given WBM is used) it will maintain its initial pressure as long as the well is kept shut-in, this will also have an effect on the bottom hole pressure which will increase. This means that gas will contain its initial pressure towards the wellhead, given that it migrates in WBM and as long as the well is kept shut in.

When getting a kick the goal is to get it out as fast as possible while maintaining safety as number one priority during the process. A way to get the kick out is with a technique that regulates the choke such that the pump pressure schedule/kill sheet is followed. This ensures a constant bottom hole pressure. And due to constant replenishment of well fluids during circulation, it enables to get the formation fluids to the top and out of the well before initiating the second circulation stage. This is also known as the first circulation stage.

After taking a kick and shutting the BOP the pressure readings in the annulus and drill pipe will not be equal, the SICP will be higher than the SIDPP. The reason for a higher SICP compare to SIDPP is because of the inflow gas mixes with the mud in the annulus which reduces its hydrostatic pressure. The mud in the drill pipe will remain unaffected of the contaminated formation fluids outside it.

Since the formation fluid holds a lower weight compare to mud it will give a lower mud density when these two are mixed together, mixing starts when formation fluids enters the annulus. A reduction of the mud density in the annulus will cause a lower hydrostatic pressure acting on the bottom hole compare to the more dense mud in the drill pipe. During a kick, the pressures on the top needs to be seen from bottom and upwards in order to understand the difference between the two pressures. The readings on the top annulus and drill pipe reflect the hydrostatic column in each section. Because the annulus mud has a lower density and therefore a lower hydrostatic pressure it will have less pressure to withstand the formation pressure which gives a higher pressure on the top compared to the drill pipe pressure.

It is also important to know what type of mud that is used. When gas is dissolves in OBM the kick will be stationary until circulation starts up. This will not be the case in WBM where the kick starts its way upwards on its own. For this reason it may be wisely to help the gas to surface when taking a kick, this is performed by the use of mud pumps. It will save a lot of time since gas needs a long time to travel all the way on its own just by the help of buoyancy.

The frictional pressure (pump pressure) is the only difference when circulating the system, it will be added to the gauge pressure together with a safety margin in order to maintain well stability and prevent another influx.

After the first circulation stage when formation fluid is removed, the mud left is not sufficient to maintain and balance the bottom hole pressure. If we were to stop the mud pumps and close the remote choke, the pressure reading would be the same on the top drill pipe before kick circulation started, but it will now also be the same on the top annuli. The reason is equal mud and mud weight in both drill string and annulus. The original mud weight does not give enough hydrostatic pressure to hold back the formation pressure, and for this reason it needs to be replaced with a heavier mud weight in order to re-establish well control.

When SICP and SIDPP are equal, but the mud weight is not sufficient to balance the well pressure it represents an underbalanced situation. This is used as a base when calculation of new mud density is performed.

The second circulation stage is when kill mud moves down the drill string and up annulus. In the first path of the second stage the pump pressure will be reduced as new kill mud moves down the drill string. This reduction in pump pressure will have no effect on the annulus pressure. By keeping the choke pressure equal to **SIDPP + SM** in this period will ensure that the BHP is kept constant while the kill mud travels down the drill pipe.

When circulating kill mud up annulus, a constant pressure can be set at the top of the drill string. This will be the FCP (Final Circulation Pressure). The choke needs to be regulated together with the new kill mud filling the annulus volume in order to maintain a constant bottom hole pressure, but also to avoid exceeding the fracture pressure. The choke pressure will gradually be reduced to zero as the kill mud moves up towards surface.

It is now possible to set a constant pressure at the top of the drill pipe when filling the annulus volume with the new mud. The column in the drill pipe will not change during this process. However, compared to stage one the new pressure needs to be slightly different. The hydrostatic pressure from the new kill mud is now sufficient to balance the formation pressure and there is no need for having a surface pressure support anymore. The pump pressure now only reflects the friction in the system. This is what is called FCP (Final Circulation Pressure). Wells are officially killed when new kill mud occupies the entire well volume and are capable of holding back the formation pressure on its own. Then the coke is set to full open and drilling can proceed as intended before the incident.

Figure 4.8 shows how the drill pipe pressure behaves during the kill circulation throughout the two stages. The constant bottom hole pressure in the annulus during circulation is achieved by tuning the choke pressure such that the pump pressure follows the kill sheet.

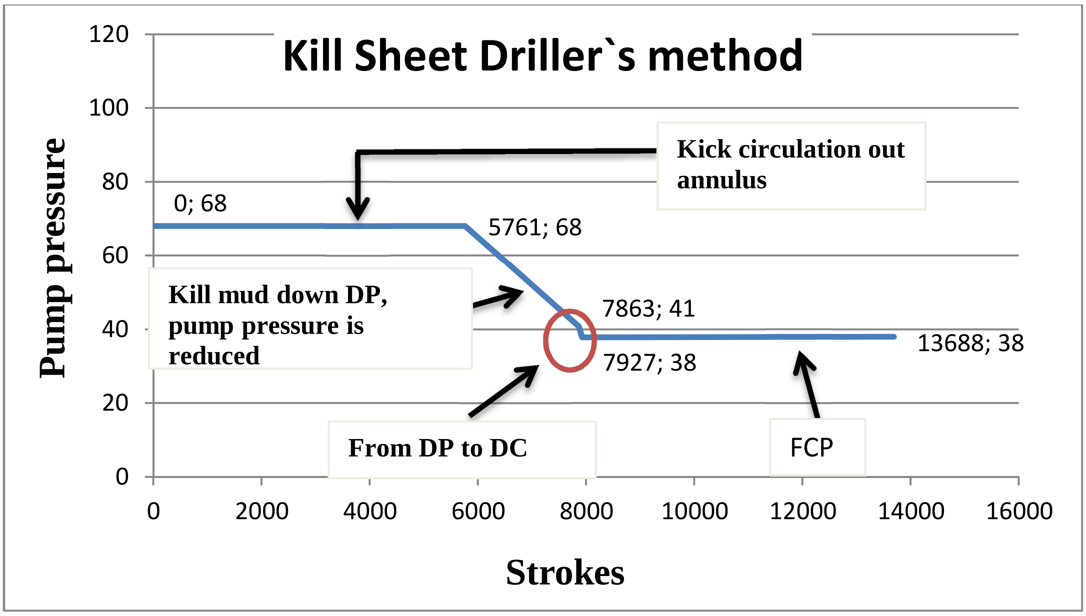


Figure 4.8 – Kill sheet using driller`s method of well control

The first stage in Figure 4.8 is when original mud is used to circulate out the kick, the ICP (Initial Circulating Pressure) is calculated to know which pump pressure one need in order to maintain a bottom hole pressure slightly higher than the formation pressure. When the kick has been circulated out kill mud is introduced, this can be observed when the line goes from a straight line and dips down to a slope. After the new kill mud has displaced the entire drill string and enters the annulus it goes back into another straight section, this section is the FCP (Final Circulating Pressure) stage.

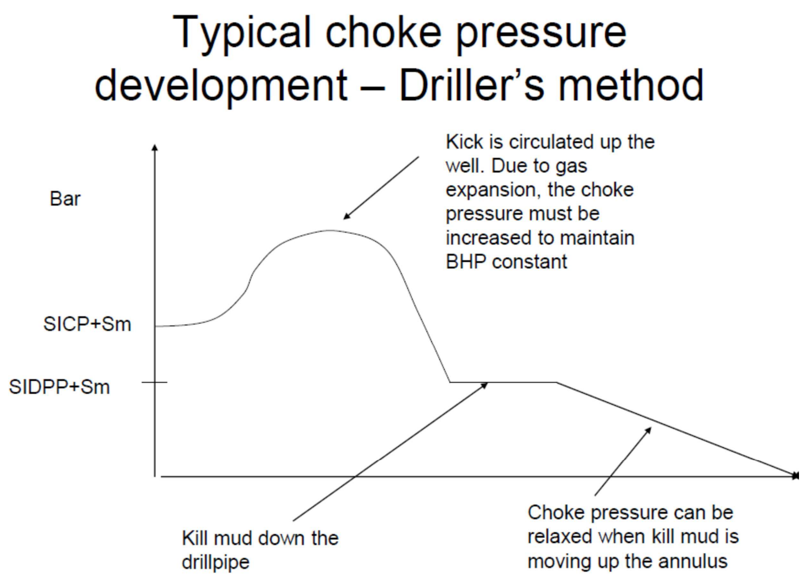


Figure 4.9 – Shows a typical pressure development for Driller`s method [8].

Above is a drawing taken from [8] and shows choke pressure development during a kill operation. It illustrates the choke pressure development during a kick circulation for Driller`s method. It can be used to enhance understanding of how the operation is performed.

We see that the choke pressure will increase until the front of the kick has reached the surface. This represents the situation where we have the largest gas volumes in the well (lowest hydrostatic gradient). Hence, a very high choke pressure is required to maintain a constant bottom hole pressure.

The choke regulates the well pressure during circulation. Here the kill line can be used to pump fluids into the well or it can be used as a secondary choke line, e.g. MEG which is used to avoid hydrates in the choke line during circulation. The main function of the choke line is to circulate out the kick safely and according to procedures.

As an illustration the Driller`s method can be demonstrated by the use of u-tube drawings below, to see what happens when gas (blue square) gets circulated out of the well is a useful way to get an visual overview of the process.

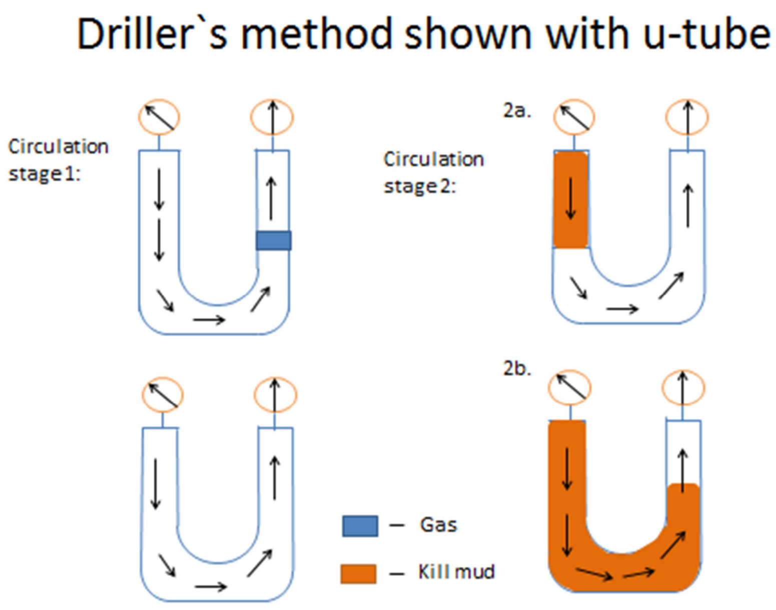


Figure 4.10 – Is retrieved from [4] and shows the Driller`s method during the different phases

The Driller`s method has some advantages and disadvantages, in the table below which is retrieved from [10], these are listed to make it easier to tell them apart:

Table 4.1 Advantages and Disadvantages with the use of Driller`s method [10]

Advantages of the Driller`s method	Disadvantages using Driller`s method
• Not many calculations • It is possible to start the kill circulation at ones if required and possible. However, if the kick is taken in a situation where high mud weight is being used, there is a possibility that the gas intrusion can lead to precipitation of weighting material that falls out of suspension. An example can be barite which can result in a stuck drill string	• Surface equipment is exposed to the highest pressures. The front of gas kick holds the largest pressure due to the reduction of the hydrostatic pressure from the mud column • The well is usually under maximum pressure for a long period since Driller`s method takes long time • Due to long choke exposure time during the two stages, there are some danger of washout

4.3 Wait and Weight

Wait and Weight (W&W) is also known as the Engineering Method [18]. This method was developed some time after the Driller`s method was put into use. It started out from this reasoning: Why use two circulations like the Driller`s method? Why not circulate new kill mud simultaneously as the kick is pumped out? The W&W method is also known as the one circulation method [4].

During this procedure it is still important to have bottom hole pressure (BHP) control, make sure that it is stable and constant during the entire kill operation. The main difference between W&W compared to the Driller`s method is that kill mud is introduced at once in the circulation process with the intention to re-establish the well barrier. In Driller`s method there are always a constant fluid column either in drill string or in annulus, for W&W this is not the case. Here the annulus mud is mixed with inflow fluid with the result of varying hydrostatic column, also for the drill string the hydrostatic column will change. In the drill pipe, when kill mud replaces old mud in the drill pipe it will changes the hydrostatic column, this will affect the pump pressure and it is therefore more important to follow the kill sheet in this method [4].

In the beginning, when mud is replaced simultaneously as kick circulation starts up, there will be no constant mud column in the drill string. Mud column will change as new mud travels down the drill string. Also, inflow fluid in the annulus will change the composition of the mud as it moves upwards in the annulus. This will have an impact on the hydrostatic pressure in the annulus form the mix mud column on the bottom hole pressure, and if needs to be compensated with the choke pressure to avoid it from going below the pore pressure [4]. This is the reason why it is so important that the kill sheet is correctly followed, then mistakes are eliminated and the risk of having a bottom hole pressure either over or underneath the pressure window in the pore and fracture plot are eliminated.

4.3.1 Pressures in the well

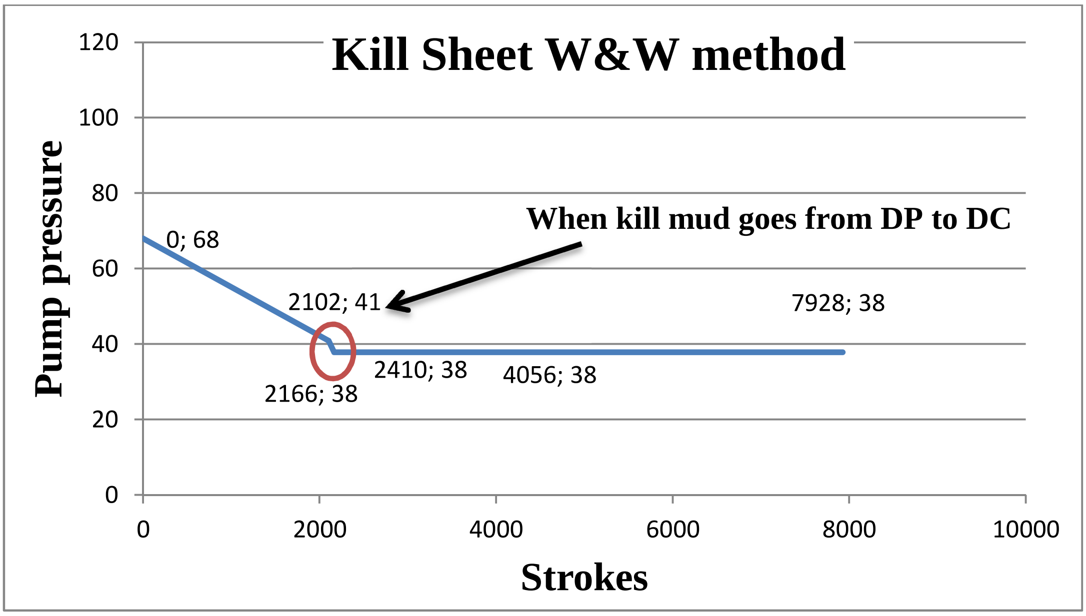


Figure 4.11 – Static drill pipe pressure using Wait and Weight method of well control

In the W&W method we have to wait after the kick is taken. In a shut in well the pressures on top annulus and drill pipe will go up until the BHP and formation pressure has stabilized and inflow has stopped. At this point the SIDPP and SICP are measured, and based on the values the necessary calculations can be performed to find the new mud weight. The operation has the intention to re-establish the primary well barrier and the new kill mud should be able to balance the well conditions on its own. If the W&W method is done correctly the used time will be 2/3 compared to using the Driller`s method [19].

The choke pressure development during a W&W operation is illustrated below, here it can be seen that the max choke pressure is when the front of gas bubble reaches the choke. The figure illustrates a typical choke pressure for a W&W operation and it is retrieved form [8]

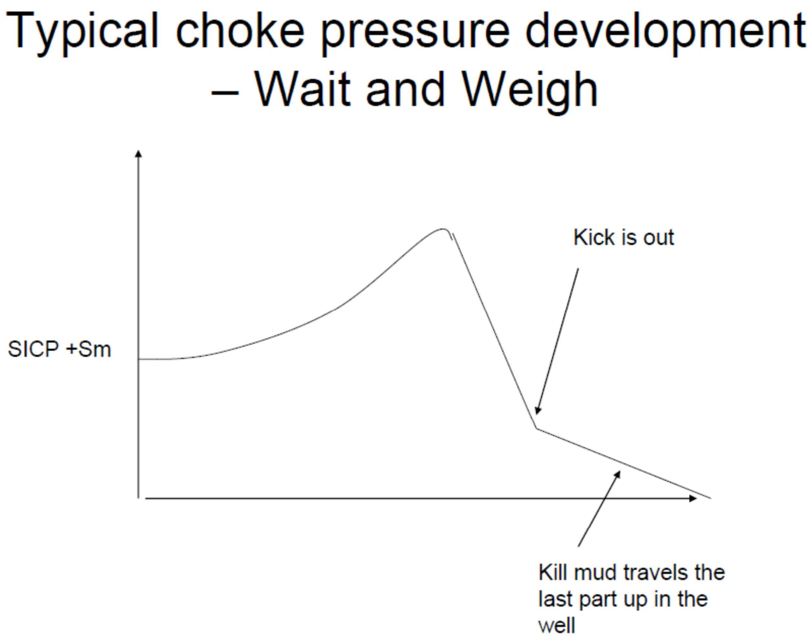


Figure 4.12 – Shows choke pressure development in a W&W operation

To sum up the W&W method, it has its positive and negative sides and Table 4.2 below is retrieved from [10] where these are listed.

Table 4.2 Advantages and Disadvantages with the use of Wait and Weight Method [10]

Advantages	Disadvantages
• If all goes according to plan, this operations can be done in one circulation • It will be exposed to larger pressures over a shorter period compared to Driller`s method	• Before starting up, the well needs a lot of circulations • Prior to circulation the well may be held shut-in for a long time, this is because the mud needs to be weighted up to the kill mud weight at the surface • Harder to keep a constant bottom hole pressure, therefore it is important to monitor the pumping schedule to keep the pressure above formation pressure or equal • If the calculated mud weight is too low they may not be able to increase it during the one circulation, but needs to perform a second circulation run

4.4 Bullheading

Operators sometimes have to look at different alternatives to solve critical well control problems. When conventional method of circulating down the drill string and up the annulus no longer is an option, an alternative is to use a technique called bullheading. This method is performed with the use of pumps in a closed in well, the influx fluids are then pushed- and forced back down into the weakest point of the exposed open hole interval. In this way well control is regained. Bullheading method may also be the safest option if personnel do not hold the right knowledge to calculate the pressures and volumes required to perform a conventional kill circulation process [19]. It is also the only option if the H_2S content is too high to be handled on surface, another if the kick is too large with respect to separator capacities or there is a potential risk of breaking the casing shoe.

When a bullheading operation is performed it is important that the pump pressure is noted throughout the process, here the LOT/FIT diagram can be used. In this way it is easier to control the situation, and if the process starts to develop in an unwanted way actions can be initiated immediately [10].

Bullheading is done by adding some pressure, in this way the wellbore pressure gets overbalanced compared to the reservoir pressure and the formation fluids are pushed back into the formation. The pressure acting on the bottom during a bullheading operation is [20]:

$$\mathbf{P_{BH} = P_{res} + P_{over}} \qquad \textbf{(4.25)[20]}$$

Where:

P_{BH} = Bottom hole pressure
P_{res} = Reservoir pressure
P_{over} = Overpressure

The P_{over} is dependent to the reservoir properties (permeability and porosity) and the influx concentration. The higher the properties in the reservoir are (high permeability and porosity) the lower the overbalance pressure needs to be in order to force the influx back into the formation.

What determines whether the bullheading operation is a success or not depends on the casing shoe integrity, the goal is to preserve it during the whole process. Given all gas is below the casing shoe, then the pressure that acts on the casing shoe can be given in a formula that is retrieved from [20]:

The column of mud and influx fluid will give a total hydrostatic contribution in the well:

$$\mathbf{HS_{C\&K} + HS_{CSG} + HS_{OH} = \rho_m g(h_{well} - h_{influx}) + \rho_{influx} g h_{influx}} \qquad \textbf{(4.26) [20]}$$

Where:

HS_{CSG} = Hydrostatic pressure in casing
$HS_{C\&K}$ = Hydrostatic pressure in the choke line and kill line

This gives the bullheading injection pressure during the operation:

$$\mathbf{P_{inj} = SICP + P_{OVER} + CLFPL + FPL_{CSG} + FPL_{OH}} \quad \mathbf{(4.27)}$$

To determine the casing shoe pressure a LOT (Leak off Test) test is performed, here the weakest part of the formation below the casing shoe is identified by increasing the surface pressure until it starts to break down. This gives the MASP (Maximum Allowable Surface Pressure).

LOT determines the fracturing pressure in the wellbore and the shoe, and it is performed by increasing the well bore pressure, the MASP (maximum allowable surface pressure) is equal to and represents the difference between the fracture pressure and the hydrostatic pressure.

$$\mathbf{P_{FRAC} = MASP + HS_{C\&K} + HS_{CSG}} \quad \mathbf{(4.28)}$$

During a bullheading operation the pressure on the casing shoe is given by:

$$\mathbf{P_{CSS} = P_{inj} + HS_{C\&K} + HS_{CSG} - FPL_{CSG} - CLFPL} \quad \mathbf{(4.29)}$$

Assuming that the casing shoe pressure (P_{CSS}) equals the fracture pressure (P_{FRAC}) the Maximum Allowable Injection Pressure (MAIP) is given from eq. (4.30). Then by using P_{inj} = MAIP and combining equation (4.28) and (4.29) we get:

$$\mathbf{MAIP = MASP + CLFPL + FPL_{CSG}} \quad \mathbf{(4.30)}$$

Having an influx below the casing shoe is the assumption which this relation is derived from.

In order to have a successful bullheading operation an assumption is given from the equation below (eq. 4.31). The MACSPI (Maximum Allowable Casing Shoe Pressure Initially) must be higher than the pressure applied from the surface in order to maintain the casing shoe integrity. After taking a kick the SICP will reach a certain level, and in order to push the influx fluid back into the formation a high pump pressure must be applied from the surface. The pressure build-up after a kick is the SICP, and to overcome the SICP and push the fluid back down the annulus the pump pressure needs to be added a P_{over} (over pressure). The casing shoe will in addition to the P_{over} also experience an extra pressure from the FPL_{OH} (Frictional Pressure Loss in the open hole) during the process, and it is important that the total applied pressure during this operation do not exceed the MACPSI, in this way the casing shoe integrity is maintained. The equation then becomes:

$$\mathbf{MACSPI > SICP + P_{over} + FPL_{OH}} \qquad \textbf{(4.31)}$$

Where:

MACSPI = Maximum Allowable Casing Shoe Pressure Increase
MAIP = Maximum Allowable Injection Pressure
MASP = Maximum Allowable Surface Pressure
CLFPL = Choke line frictional pressure loss
SICP = Shut in Casing Pressure
P_{over} = Overbalance pressure
FPL_{OH} = Frictional Pressure Loss in the open hole
FPL_{CSG} = Frictional Pressure Loss in the casing

Another aspect to the bullheading method has to do with the pumping speed and flow rates that are needed in order to have a successful squeeze operation of formation fluid. The flow rate (Q) needs to be higher than the gas rising velocity. For a vertical well the gas rising velocity is given by the following equation [20]:

$$\mathbf{V_{gas} = V_{slip} + C_1 * V_{mix}} \qquad \textbf{(4.32)[20]}$$

For a bubble flow it can be assumed that C_1=1,0. If one makes this assumption the minimum average pumping velocity must not go below the slip velocity upwards. When bullheading the gas must not be allowed to migrate upwards, and this must be one of the main focus areas when the operation is performed. This can be summed up in a formula and it must be true in order to prevent upwards gas migration during bullheading [20]:

$$\frac{\mathbf{Q_{pump}}}{\mathbf{A_{annulus}}} = \mathbf{V_{mean}} > \mathbf{V_{slip}} \qquad \textbf{(4.33)}$$

When bullheading mud pumps are often used, the reason is that they are capable of handling large pressures (15,000 psi). But, the pumps limitations lie in pump rate, and they are not able to pump more than 420 gallon/min, which is 1590 l/min or 10 bbl/min. But these rates are rarely used. Based on industry experience pumping rates lies between 0,25 bbl/min and up to 2,0 bbl/min during an operation. In many ways a bullheading operation is like a leak of test (LOT), the pressure must be raised slowly until it is seen that the influx goes back in the formation. It is important not to use a high circulation rate as this increase the risk of pump failure, this happens when mud starts to go into the formation and a large and rapid pressure increase is induced. There is also a risk of fracturing. It is preferred to have the same mud weight and not adding a mud with different density, this will just make it harder to keep track of the pressure signals from the well.

There are many useful situations where bullheading method may be the best choice. Here are some advantages and disadvantages with the use of this method [6]:

Table 4.3: Advantages and disadvantages with the use of the Bullhead method [6]

Advantages	Disadvantages
• The H_2S readings is above the operator limit • Due to obstacles in the drill pipe it is not possible to get kill mud down to the bottom • The kick will lead to too high surface pressures • When weak zones below the kick prevent the use of conventional methods due to potential large mud losses • To save time if the available resources are not adequate to handle the situation	• No obvious sign for the operators/crew when to use this technique or not • The fluid flow will follow in the direction of least resistance, and it is not given that it will follow a desired pathway • A potential risk of creating blowout either at surface or underground

4.5 Volumetric

The Volumetric method is based on the assumption that the influx is gas that migrates upwards in the well. It cannot be used if the influx fluid is either salt water or oil. Compared to Driller`s method and W&W method the Volumetric method is used in situations where there are no possibility to circulate out the kick conventionally [10].

The reasons for using this method instead of another kill method are based on different variables in the well. Some of them are listed below [10]:

- If the drill string is on its way in the well or out of it, if this is the case an attempt to run it to the bottom with the drill string should be made
- If there are no drill string in the well
- If the drill bit or the drill string has been plugged with some kind of debris or lost circulation material (LCM), to open the plugged area explosives can be an alternative
- Hole collapse can be a reason – this prevents circulation

- It there has been a power failure and mud pumps along with emergency pumps are down
- If there is a long way between drill string and bottom of the well
- Not able to circulate due to drill string has been cut and dropped into the well

In this method the choke is opened and closed in steps to bleed of the inflow gas. It is performed by staying within the designated pore and fracture pressures together with a safety margin. As gas moves up and pressure in the well increases, the choke is opened to bleed off and reduce the well pressure and it is then closed when the pressure drops to a certain level. This procedure is maintained until the gas is completely out of the well.

In the Volumetric method the gas is allowed to expand as it moves upwards in the well while the bottom hole pressure is held more or less constant. In theory, the Volumetric method states that a hydrostatic pressure can be represented with a given volume of mud by expressing the pressure in bars/litre, this is done by dividing the pressure gradient of mud (bars/meter) with annulus capacity (litre/meter) instantaneously over the top of the kick [10].

It is important to monitor how far the gas has migrated upwards in the well, because the annulus capacity may change as the gas moves towards the surface. The annulus pressure is calculated based on where the gas kick is at any given time so it is important to keep track of where it is, in this way the annulus pressure is controlled. The mud volume must be measured accurately in order to have bottom hole pressure control, both for the bleed off phase and the pump in phase [10].

It is necessary to do some volume calculations that are related to the pressure increase in advance of using this method. Fracture pressure is the guide line, and the pressure calculations need to be based on this and one must not exceed it to avoid any losses. Calculating the entire volume and then divide on the entire well length is the easiest way to do it with this method [18].

In this formula the density of the mud is used together with the average well volume. From this pressure a safety factor (SF) needs to be established in order to prevent more influx of formation fluid. By adding a SF, the bottom hole pressure will go up, it is therefore also important to keep it below the fracture pressure and above the formation pressure. If the fracture pressure is exceeded before it passes the casing shoe, it is an imminent danger that the formation will fracture. In worst case the result can lead to a underground blow out [18].

5 Calculation examples

In the section to come calculation examples will be carried out. These are shown to increase the understanding of the different kill methods. The different examples that will be more elaborated in this section are:

1. Driller`s method in vertical well from platform
2. W&W method in vertical well from platform
3. Subsea inclined well and changes to procedures in W&W

5.1 Driller`s method in vertical well from platform

As there is a platform well there is no choke line friction to be taken in consideration in the calculations, this is due to short choke lines because BOP is placed on platform deck. A safety margin (SM) of 10 bar is used in this calculation.

<u>Beneath the following calculation will be carried out:</u>

1. Establish the pore pressure
2. Finding kill mud density with safety margin
3. Calculate ICP and FCP
4. Finding the strokes and volumes required in order to circulate out the kick by using a table:
    a. Drill string
    b. Annulus
5. The amount of kill fluid required in the DP and annulus
6. The time it takes to perform the different circulations

These steps are carried out by using the equations from section 4.2 and the data given in section 3.

Vertical well with BOP on platform deck

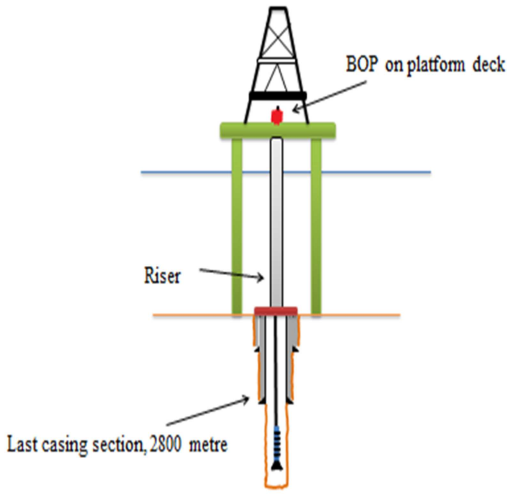


Figure 5.1 – A vertical well with BOP placed on platform deck

<u>Known data:</u>

1. Depth = 4300 meters
2. Last casing shoe = 2800 meters
3. $\rho_{old\ mud}$ = 1,52 sg
4. SIDPP (P_D) = 40 bar
5. SICP (P_a) = 48 bar
6. SM = 10 bar
7. Kill pump delivers 17,5 litre per stroke
8. The operation shall be carried out with:
    a. 34 strokes per minute (spm)
    b. A kill rate of 595 l/min
9. Drill pipe is 4020 meters with inner capacity 9,15 l/m
10. Drill collar (DC) is 280 meters with inner capacity 4,0 l/m
11. Annular capacity:
    a. DP/Csg 24,2 l/m
    b. DP/OH 23,6 l/m
    c. DC/OH 15,2 l/m
12. SR1 = 18 bar

With the information above it is possible to calculate the volumes, ICP, FCP, strokes and time it takes to complete the kill operation. This will be shown in the steps carried out below.

Step 1: Establish the pore pressure

At shut in conditions, the pore pressure and the BHP are equal. We can find BHP using SIDPP and the hydrostatic gradient in the pipe. This is done by using the SIDPP as we know the density of the fluid in the DP and can calculate the pore pressure by using eq. (4.1):

$$\mathrm{BHP} = \mathrm{SIDPP} + \rho_{\mathrm{mud}} g h_{\mathrm{TVD}}$$

$$\mathrm{BHP} = 40\ \mathrm{bar} + (1{,}52\ \mathrm{sg} \times 0{,}0981 \times 4300\ \mathrm{meter})$$

$$\mathrm{BHP} = \underline{\mathbf{681,2\ bar}}$$

→The pore pressure in specific gravity:

$$\mathrm{BHP} = \frac{681{,}2\ \mathrm{bar}}{0{,}0981 \times 4300\mathrm{m}} = 1{,}615\ \mathrm{sg}$$

$$\mathrm{BHP} = \underline{\mathbf{1,62\ sg}}$$

This will be the same as the pore pressure at shut in conditions.

Step 2: Finding kill mud density with safety margin from eq. (4.2)

$$\rho_{\mathrm{kill\ mud}} = \rho_{\mathrm{old\ mud}} + \frac{\mathrm{SIDPP} + \mathrm{SM}}{0{,}0981 \times \mathrm{TVD_{well}}}$$

$$\rho_{\mathrm{kill\ mud}} = 1{,}52\ \mathrm{sg} + \frac{40\ \mathrm{bar} + 10\ \mathrm{bar}}{0{,}0981 \times 4300\ \mathrm{m}}$$

$$\rho_{\mathrm{kill\ mud}} = 1{,}6385\ \mathrm{sg}$$

$$\rho_{\mathrm{kill\ mud}} = \underline{\mathbf{1,64\ sg}}$$

Step 3: Calculate ICP and FCP

ICP from eq. (4.10):

$$\mathrm{ICP} = \mathrm{SIDPP} + \mathrm{SM} + \mathrm{SR_1}$$

$$\mathrm{ICP} = 40\ \mathrm{bar} + 10\ \mathrm{bar} + 18\ \mathrm{bar}$$

$$\mathrm{ICP} = \underline{\mathbf{68\ bar}}$$

FCP from eq. (4.4):

$$\mathrm{FCP} = \mathrm{SR_1} \times \frac{\rho_{\mathrm{kill\ mud}}}{\rho_{\mathrm{old\ mud}}}$$

$$\mathrm{FCP} = 18\ \mathrm{bar} \times \frac{1{,}64\ \mathrm{sg}}{1{,}52\ \mathrm{sg}} = 19{,}42\ \mathrm{bar}$$

$$\mathrm{FCP} = \underline{\mathbf{19,4\ bar}}$$

The kill pressure gradient is then calculated. This is used to find the pressure reduction as kill mud travels down in the drill pipe and through different constrains along the way. As this is a vertical well the only constrain or change that is expected to come is when the mud goes from the drill pipe and enters the drill collars.

$$\Delta \mathrm{P_{gradient}} = \frac{\mathrm{ICP} - \mathrm{FCP}}{\mathrm{TVD}}$$

$$\Delta \mathrm{P_{gradient}} = \frac{(68 - 19{,}4)\mathrm{bar}}{4300\ \mathrm{m}}$$

$$\Delta \mathrm{P_{gradient}} = \underline{\mathbf{0,01130\ bar/m}}$$

Step 4: Find the strokes and volumes that is required in order to circulate out the kick by using a table:

In order to find the amount of strokes required to circulate out the different sections in the well. The best way may be with the use of a table. This will make the calculations more transparent and easier to see.

Table 5.1 - Table beneath shows a kill table for Driller`s method (the number will be rounded to nearest whole stroke and bar with one digit)

Section	Depth (TVD)	No of pump strokes	Drill pipe pressure [bar]
	0	0	ICP = 68 bar
DP	4020 m	(4020m x 9,15 l/m) / (17,5 l/strokes = **2102 strokes**	68 bar – (0.01130 bar/m x 4020m) = **22,6 bar**
DC	280 m	(280m x 4,0 l/m) / (17,5 l/strokes = **64 strokes**	68 bar – (0.01130 bar/m x 4300m) = **19,4 bar**
DP/Csg	2800 m	(2800m x 24,2 l/m) / (17,5 l/strokes = **3872 strokes**	FCP = **19,4 bar**
DC/OH	280 m	(280m x 15,2 l/m) / (17,5 l/strokes **= 244 strokes**	FCP = **19,4 bar**
DP/OH	1220	**(**1220m x 23,6 l/m**)** / (17,5 l/strokes) = **1646 strokes**	FCP = **19,4 bar**
Total		**= 7928 strokes**	

The total amount of strokes for one whole circulation process is found by adding the total amount of strokes down the drill string and up the annulus.

When killing a well the amount of fluid that is required is wisely to calculate to make sure that sufficient kill fluid is available. Beneath is calculated how much each section holds in terms of litres and how the amount of strokes is calculated.

<u>Volume and strokes in the DP:</u>

a) Volume

$$V_{DP} = \text{capacity } \times h_{DP}$$

$$V_{DP} = 9{,}15\ {}^{l}/_{m} \times (4300 - 280)m$$

$$V_{DP} = 36783\ l$$

b) Strokes required circulating the DP

$$\text{Strokes} = V_{DP} \times \text{kill pump delivery}$$

$$\text{Strokes} = \frac{36783\ l}{17{,}5\ {}^{l}/_{\text{strokes}}}$$

$$\text{Strokes} = \underline{\mathbf{2102\ strokes}}$$

<u>Volume and strokes in the DC:</u>

a) Volume in DC:

$$V_{DC} = \text{capacity } \times h_{DC}$$

$$V_{DC} = 4{,}0\ {}^{l}/_{m} \times 280m =$$

$$V_{DC} = \underline{\mathbf{1120\ litre}}$$

b) Strokes required circulating the DC:

$$\text{Strokes} = \mathrm{V_{DP}} \times \text{kill pump delivery}$$

$$\text{Strokes} = \frac{1120\ \mathrm{l}}{17{,}5\ {}^{\mathrm{l}}\!/_{\mathrm{strokes}}}$$

$$\text{Strokes} = \underline{\mathbf{64\ strokes}}$$

<u>Volume in the open annulus and DC/OH:</u>

$$\mathrm{V_{DC/OH}} = \text{capacity} \times \mathrm{h_{DC}}$$

$$\mathrm{V_{DC/OH}} = 15{,}2\ {}^{\mathrm{l}}\!/_{\mathrm{m}} \times 280\ \mathrm{m}$$

$$\mathrm{V_{DC/OH}} = \underline{\mathbf{4256\ litre}}$$

<u>Volume in the open annulus and DP/OH:</u>

$$\mathrm{V_{DP/OH}} = \text{capacity} \times \mathrm{h_{DP}}$$

$$\mathrm{V_{DP/OH}} = 23{,}6\ {}^{\mathrm{l}}\!/_{\mathrm{m}} \times 1220\ \mathrm{m}$$

$$\mathrm{V_{DC/OH}} = \underline{\mathbf{28792\ litre}}$$

The amount of strokes that is required circulating the different annular sections are found in the same way as for DP and DC above, they are also listed up in Table 5.1.

Here there are many calculations and it can be a bit confusing, to sum up the volumes and strokes related to the different sections they are listed up in the table below.

Table 5.2 - Sums up the volume and the strokes needed for each section

Sections	Depth [m]	Capacities [l/m]	Volumes [l]	Strokes
DP	4020	9,15	36783	2102
DC	280	4,0	1120	64
DP/Csg	2800	24,2	67760	3872
DP/OH	1220	23,6	28792	1646
DC/OH	280	15,2	4256	244
Total			**138711**	**7928**

Step 5: The amount of kill fluid required in the DP and annulus

As can be shown from Table 5.2 the total amount of kill mud just to fill the annular volumes is 100808 litres and the whole well 138711 litres. According to [2] there should at all times be 1,5 times the well volumes of kill fluid available in case of emergency.

With the information found in Table 5.1 a kill sheet can be made. The first straight line is in the sheet the ICP (initial circulation pressure), and it is a full bottoms up circulation to get the kick out of the well with the use of the old mud. As kill mud moves down the DP, the pump pressure will decrease linearly. When kill mud is introduced the straight line starts to dip and gets a slight change, when it goes from DP to DC due to change in inner diameter and capacity. When the line once more becomes horizontal the kill mud reaches the annulus, and the FCP (final circulation pressure) is reached and carried out until the whole well is filled up with kill mud.

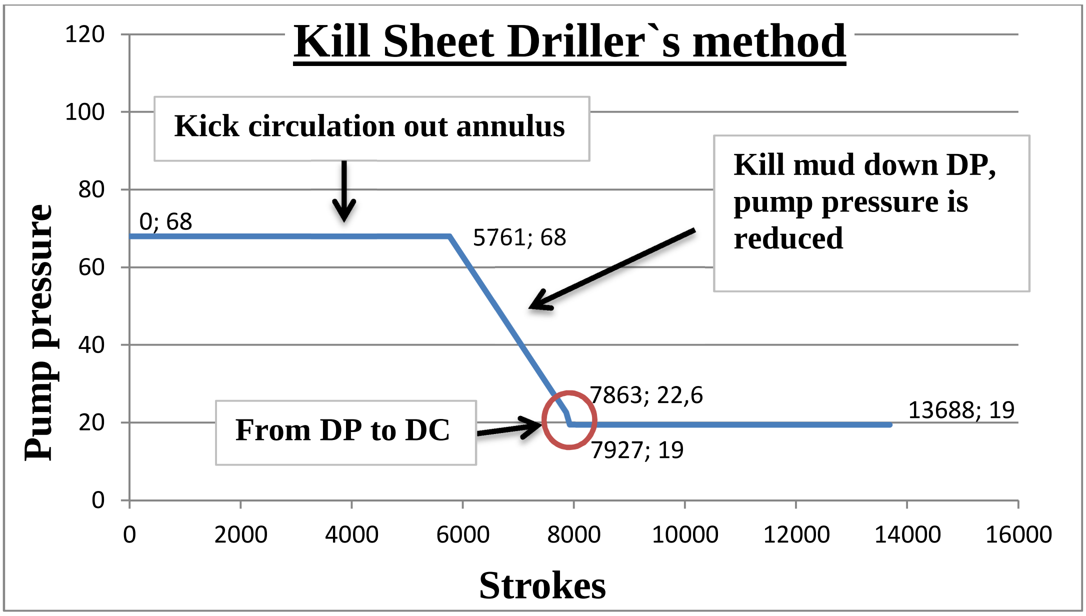


Figure 5.2 – Showing a Kill Sheet on a vertical well using Driller`s method

One should note that for Driller`s method, the BHP is controlled during kill mud displacement in DP, by just keeping the choke pressure equal to SIDPP + SM. In a real operation this would not be necessary to calculate.

Step 6: The time it takes to perform the different circulations

The kill operation is carried out with 34 strokes per minute.

As a calculation example the DP is used:

DP:

$$\text{Time} = \frac{\text{Number of strokes}}{\text{strokes/min}}$$

$$\text{Time}_{\text{DP}} = \frac{2102 \text{ strokes}}{34 \ \text{ strokes/min}}$$

$$\text{Time}_{\text{DP}} = \underline{\mathbf{61,8\ min}}$$

Table 5.3 – Shows volumes, strokes and the time it takes to circulate out the different sections

Sections	Depth [m]	Capacities [l/m]	Volumes [l]	Strokes	Time [min]
DP	4020	9,15	36783	2102	61,8
DC	280	4,0	1120	64	1,9
DP/Csg	2800	24,2	67760	3872	113,9
DP/OH	1220	23,6	28792	1646	48,4
DC/OH	280	15,2	4256	244	7,2
Total			138711	7928	233,2

The kick is circulated out of the annulus before the kill mud is introduced in the Driller`s method, this means that the time it takes before kill mud is introduced is 169,5 minute (which is the time it takes to circulate out the annulus). Then the DP is displaced with kill mud which takes 63,7 minutes, then another 169,5 minutes to fill the annulus in order to fill the well entirely with kill mud. All together this gives a total theoretical time of 402,7 minutes. However, safety is first priority and the total circulation time may exceed the theoretical time if the process demands it.

5.2 W&W method in vertical well from platform

This example is with the same platform as in section 2 with the well head on the platform deck, the only difference is that instead of using Driller`s method now the W&W method is used.

The calculations in this section are the same as for the Driller`s method in section 2, this has been done to avoid confusion related to where the numbers comes from and how they are calculated. In this way the reader do not have to go back in order to understand the calculations. In addition the tables are also included. The only thing that is different is the kill sheet and some of the text.

As written in the W&W section 5.2, instead of circulating out the kick before introducing kill mud into the well, like Driller`s method do, the W&W introduce kill mud and circulate out the kick simultaneously. The data and information used for the Driller`s method example above (section 2) will also be used in this example.

A safety margin (SM) of 10 bar is used in this calculation.

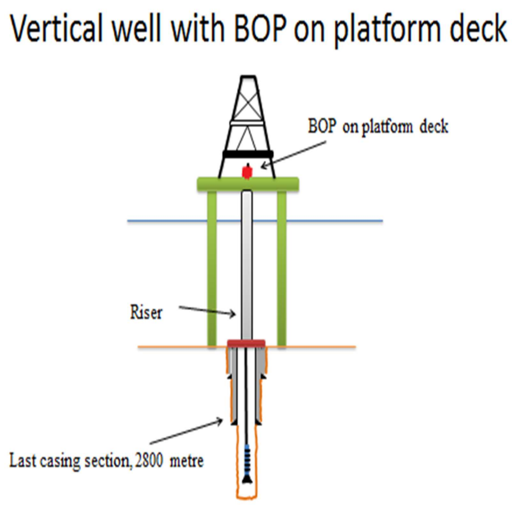


Figure 5.3 – Vertical well with BOP on platform deck

Known data:

1. Depth = 4300 meters
2. Last casing shoe = 2800 meters
3. $\rho_{old\ mud}$ = 1,52 sg
4. SIDPP (P_D) = 40 bar
5. SICP (P_a) = 48 bar
6. SM = 10 bar
7. Kill pump delivers 17,5 litre per stroke
8. The operation shall be carried out with:
    a. 34 strokes per minute (spm)
    b. A kill rate of 595 l/min
9. Drill pipe is 4020 meters with inner capacity 9,15 l/m
10. Drill collar (DC) is 280 meters with inner capacity 4,0 l/m
11. Annular capacity:
    a. DP/Csg 24,2 l/m
    b. DP/OH 23,6 l/m
    c. DC/OH 15,2 l/m
12. SR1 = 18 bar

Beneath the following calculation will be carried out here as we did in section 2:

1. Establish the pore pressure
2. Finding kill mud density with safety margin
3. Calculate ICP and FCP
4. Find the strokes and volumes required in order to circulate out the kick by using a table:

   a. Drill string
   b. Annulus
5. The amount of kill fluid required in the DP and annulus
6. The time it takes to perform the different circulations

These steps are carried out by using the equations from section 4.2 and the data given in section 3.2.

<u>Step 1: Establish the pore pressure</u>

At shut in conditions, the pore pressure and the BHP are equal. We can find BHP using SIDPP and the hydrostatic gradient in the pipe. This is done by using the SIDPP as we know the density of the fluid in the DP and can calculate the BHP by using eq. (4.1):

$$\mathrm{BHP} = \mathrm{SIDPP} + \rho_{\mathrm{mud}} g h_{\mathrm{TVD}}$$

$$\mathrm{BHP} = 40\ \mathrm{bar} + (1{,}52\ \mathrm{sg} \times 0{,}0981 \times 4300\ \mathrm{meter})$$

$$\mathrm{BHP} = \underline{\mathbf{681,2\ bar}}$$

→The bottom hole pressure in specific gravity:

$$\mathrm{BHP} = \frac{681{,}2\ \mathrm{bar}}{0{,}0981 + 4300\mathrm{m}} = 1{,}615\ \mathrm{sg}$$

$$\mathrm{BHP} = \underline{\mathbf{1,62\ sg}}$$

This will be the same as the pore pressure at shut in conditions.

Step 2: Finding kill mud density with safety margin from eq. (4.2):

$$\rho_{\text{kill mud}} = \rho_{\text{old mud}} + \frac{\text{SIDPP} + \text{SM}}{0{,}0981 \times \text{TVD}_{\text{well}}}$$

$$\rho_{\text{kill mud}} = 1{,}52\ \text{sg} + \frac{40\ \text{bar} + 10\ \text{bar}}{0{,}0981 + 4300\ \text{m}}$$

$$\rho_{\text{kill mud}} = 1{,}6385\ \text{sg}$$

$$\rho_{\text{kill mud}} = \underline{1{,}64\ \text{sg}}$$

Step 3: Calculate ICP and FCP

ICP from eq. (4.10):

$$\text{ICP} = \text{SIDPP} + \text{SM} + SR_1$$

$$\text{ICP} = 40\ \text{bar} + 10\ \text{bar} + 18\ \text{bar}$$

$$\text{ICP} = \underline{\mathbf{68\ bar}}$$

FCP from eq. (4.4):

$$\text{FCP} = \text{SR}_1 \times \frac{\rho_{\text{kill mud}}}{\rho_{\text{old mud}}}$$

$$\text{FCP} = 18\ \text{bar} \times \frac{1{,}64\ \text{s.g}}{1{,}52\ \text{s.g}} = 19{,}42\ \text{bar}$$

$$\text{FCP} = \underline{\mathbf{19,4\ bar}}$$

The kill pressure gradient is then calculated. This is used to find the pressure reduction pr. meter as kill mud travels down in the drill pipe and through different constrains along the way. As this is a vertical well the only constrain or change that is expected to come is when the mud goes from the drill pipe and enters the drill collars.

$$\Delta P_{gradient} = \frac{ICP - FCP}{TVD}$$

$$\Delta P_{gradient} = \frac{(68 - 19{,}4)bar}{4300\ m}$$

$$\Delta P_{gradient} = \underline{\mathbf{0,01130\ bar/m}}$$

Step 4: Find the strokes and volumes that is required in order to circulate out the kick by using a table:

In order to find the amount of strokes required to circulate out the different sections in the well. The best way may be with the use of a table. This will make the calculations more transparent and easier to see.

Table 5.4 - Table beneath shows a kill table for W&W method (the number will be rounded to nearest whole stroke and bar with one digit)

Section	Depth (TVD)	Number of pump strokes	Drill pipe pressure
	0	0	ICP = 68 bar
DP	4020 m	(4020m x 9,15 l/m) / (17,5 l/strokes = **2102 strokes**	68 bar – (0.01130 bar/m x 4020m) = **22,6 bar**
DC	280 m	(280m x 4,0 l/m) / (17,5 l/strokes = **64 strokes**	68 bar – (0.01130 bar/m x 4300m) = **19,4 bar**
DP/Csg	2800 m	(2800m x 24,2 l/m) / (17,5 l/strokes = **3872 strokes**	FCP = **19,4 bar**
DC/OH	280 m	(280m x 15,2 l/m) / (17,5 l/strokes **= 244 strokes**	FCP = **19,4 bar**
DP/OH	1220	(1220m x 23,6 l/m) / (17,5 l/strokes) = **1646 strokes**	FCP = **19,4 bar**
Total		**= 7928 strokes**	

The total amount of strokes for one whole circulation process is found by adding the total amount of strokes down the drill string and up the annulus, which gives 7928 strokes in total.

When killing a well the amount of strokes is calculated form the volume that each section holds, this volume is divided with the mud pumps capacities (l/strokes). Beneath it is showed how volumes for each well section is calculated, the answers gives the amount each section holds in litres.

The amount of strokes that is required circulating the different annular sections are found in the same way as for DP and DC above, they are also listed up in Table 5.1.

Due to many calculations which can be confusing, a sum up of the volumes and strokes related to the different sections are listed up in the table below.

Table 5.5 - Sums up the volumes and the strokes needed for each section

Sections	Depth [m]	Capacities [l/m]	Volumes [l]	Strokes
DP	4020	9,15	36783	2102
DC	280	4,0	1120	64
DP/Csg	2800	24,2	67760	3872
DP/OH	1220	23,6	28792	1646
DC/OH	280	15,2	4256	244
Total			**138711**	**7928**

Step 5: The amount of kill fluid required in the DP and annulus

As can be shown from Figure 5.2 the total amount of kill mud just to fill the annular volumes is 138711 litres. According to [2] there should at all times be 1.5 times the well volumes of kill fluid available in case of emergency.

With the information found in Figure 5.1 kill sheet can be made. This method starts out with the ICP (initial circulation pressure) and moves down with an inclined line as can be seen in the sheet. The reason for this inclined line is that kill mud moves down the DP form the start and pump pressure is reduced due to the heavier mud. It can also be seen when kill mud goes from DP to DC (in the red circle) it gets a slight dip in the line, this is because the DP and DC does not have the same capacities and diameter. When the line once more becomes horizontal the kill mud reaches the bit and moves into the annulus. This is when the FCP (final circulation pressure) is reached until the whole well is filled up with kill mud.

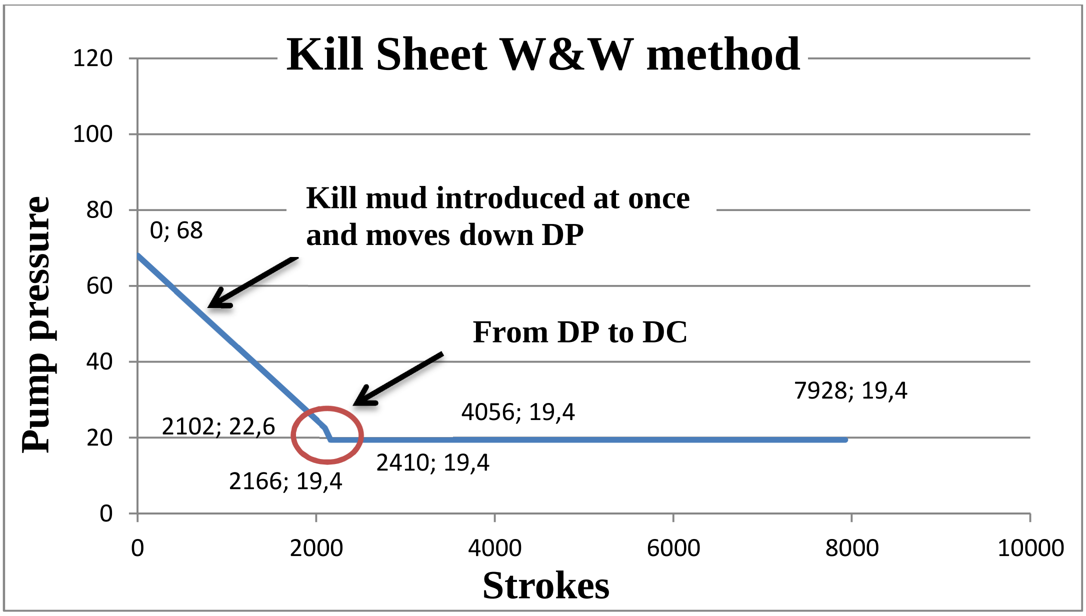


Figure 5.4 – Showing a kill sheet using W&W method

Step 6: The time it takes to perform the differ circulations

The kill operation is carried out with 34 strokes per minute.

As a calculation example the DP is used:

DP:

$$\text{Time} = \frac{\text{Number of strokes}}{\text{strokes/min}}$$

$$\text{Time}_{\text{DP}} = \frac{2102 \text{ strokes}}{34 \ \text{strokes/min}}$$

$$\text{Time}_{\text{DP}} = \underline{\mathbf{61,8\ min}}$$

Table 5.6 – Shows volumes, strokes and the time it takes to circulate out the different sections

Sections	Depth [m]	Capacities [l/m]	Volumes [l]	Strokes	Time [min]
DP	4020	9,15	36783	2102	61,8
DC	280	4,0	1120	64	1,9
DP/Csg	2800	24,2	67760	3872	113,9
DP/OH	1220	23,6	28792	1646	48,4
DC/OH	280	15,2	4256	244	7,2
Total			**138711**	**7928**	**233,2**

For the W&W the kill mud is introduced at once, this means a total theoretical circulation time of 233,2 minutes compare to the Driller`s method with a theoretical time of 402,7 minutes.

5.3 Subsea inclined well and changes to procedures in W&W

In the sections above Drillers method and W&W method has been illustrated for a vertical well where the BOP was on the platform deck. This in practise means that the riser margin can be excluded from the calculations.

In this example the choke- and kill- line are attached to the riser and have a length corresponding to the water depth of 500 meter. In this case we have to account for choke line friction pressure losses.

<u>From section 3.1 a short recap of the data used for this example:</u>

1. Well profile
    a. Water depth – 500 meters
    b. Vertical down to 1800 meters
    c. 55° from 1800 m TVD to 3500 m (MD), 2775 m (TVD)
    d. 42° from 3500 m (MD) to 4580 m (MD), 3578 m (TVD)
2. Drill pipe geometry
    a. 5 ” DP down to 4380 m MD/3429 m TVD with capacity 9,15 l/m
    b. 200 meter of 6 ½” Drill Collar with capacity 4,01 l/m.
3. Mud density 1,73 sg

4. Air gap to platform is 30 meters
5. Pump capacity 17,2 l/stroke
6. SR_1 – 35 bar
7. SR_2 – 49 bar
8. SIDPP – 43 bar
9. SICP – 57 bar
10. A safety margin (SM) of 10 bar is used in the calculation
11. Last casing at 2800 m TVD

The figure below shows the well profile that is to be used in this example.

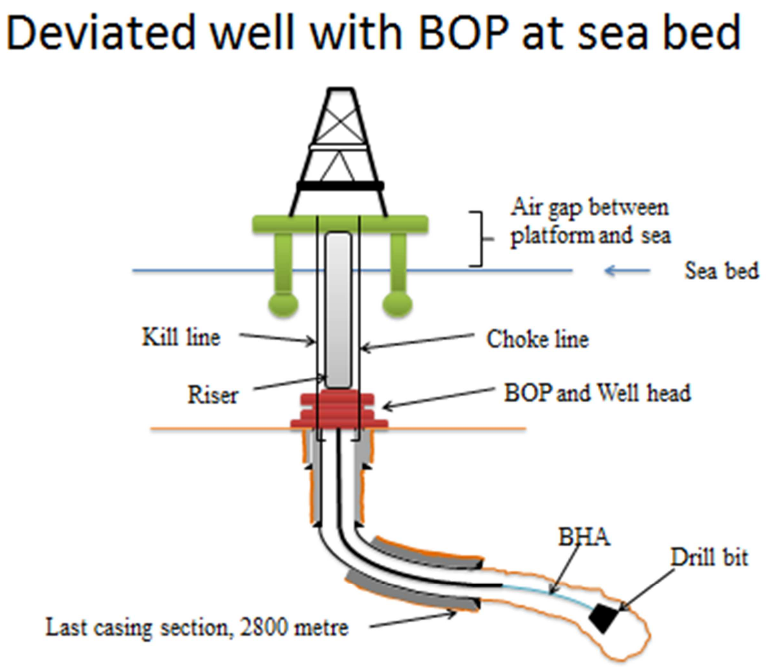


Figure 5.5 – Shows subsurface inclined well profile

The complete information related to this example is given in section 3.1.

For a subsea inclined well the BOP is placed on the seabed, this means that the choke and kill lines are long and the friction pressure in the tubes needs to be taken into considerations in the calculations due to their length. Another aspect in a subsea well compared to a platform well is the riser margins. Should the platform for some reason abandon the well, it has to disconnect the riser from the well head and leave the area. This means that the mud left in the well should, together with the hydrostatic column from the sea water, have a sufficient weight to balance the formation pressure.

Beneath the following calculations will be carried out:

1. Determine the pore pressure
2. Determine the kill mud density
    - Without riser margin
    - With riser margin
3. Frictional pressure in the long choke- and kill line
4. Calculation of ICP and FCP
5. Initial choke line pressure
6. Required volumes in each section, strokes and time to circulate with use of a table
7. Kill sheet

These are the steps that will be carried out and there will be an explanation where it is appropriate to elaborate on some details.

Step 1: Determine the bottom hole pressure with the use of equation (4.1):

$$\mathrm{BHP} = \mathrm{SIDPP} + \rho_{\mathrm{mud}} g h_{\mathrm{TVD}}$$

$$\mathrm{BHP} = 43\ \mathrm{bar} + (1{,}73 \times 0{,}0981 \times 4120)$$

This gives the bottom hole pressure or the formation pore pressure:

BHP =**742,2 bar**

BHP written in specific gravity:

BHP =**1,84 sg**

The formation pressure is 742,2 bar, and it is this pressure the mud has to balance in order to maintain well integrity.

<u>Step 2: Determine the kill mud density with SM:</u>

First a calculation where the riser margin is not included in the calculations, this gives an ordinary approach as done in the examples in section 5.1 and 5.2.

- <u>Determine the kill mud density using old mud and SIDPP without riser margin from eq.(4.2)</u>

$$\mathrm{SIDPP} + \mathrm{SM} = \rho_{\text{kill mud}} g h_{\text{kill mud}} - \rho_{\text{old mud}} h_{\text{old mud}}$$

$$\rho_{\text{kill mud}} = \rho_{\text{old mud}} + \frac{\mathrm{SIDPP} + \mathrm{SM}}{g \times h_{\mathrm{TVD}}}$$

$$\rho_{\text{kill mud}} = 1{,}73\ \mathrm{sg} + \frac{43\ \mathrm{bar} + 10\ \mathrm{bar}}{0{,}0981 \times 4120\ \mathrm{m}}$$

$$\boldsymbol{\rho_{\text{kill mud}}} = \underline{\mathbf{1{,}86\ sg}}$$

- <u>Without riser margin and with SM using pore pressure from eq.(4.15):</u>

$$\rho_{\text{pore}} g h_{\mathrm{TVD}} + \mathrm{SM} = \rho_{\text{mud}} g h_{\mathrm{DP}}$$

$$\rho_{\text{mud}} = \rho_{\text{pore}} + \frac{\mathrm{SM}}{g h_{\mathrm{DP}}}$$

$$\rho_{\text{mud}} = 1{,}84\ \mathrm{sg} + \frac{10\ \mathrm{bar}}{0{,}0981 * 4120\ \mathrm{m}}$$

The new mud specific density without riser margin and with SM is:

$$\boldsymbol{\rho_{\text{mud}}} = \underline{\mathbf{1{,}86\ sg}}$$

Then a possibility may occur that forces to leave the sight and disconnect the riser. In the following calculation the safety margin is included and also the riser margin. In this way the well is able to maintain its integrity if it is temporarily abandon.

- With riser margin from eq. (4.16):

$$\rho_{mud} g(h_{TVD} - h_{water} - h_{air\ gap}) + \rho_{water} g h_{water} = \rho_{pore} g h_{TVD} + SM$$

$$\rho_{mud} = \frac{\rho_{pore} g h_{TVD} - \rho_{water} g h_{water} + SM}{g(h_{TVD} - h_{water} - h_{air\ gap})}$$

$$\rho_{mud} = \frac{(1{,}84\ sg * 0{,}0981 * 4120m) - (1{,}03 * 0{,}0981 * 500\ m) + 10\ bar}{0{,}0981 * (4120\ m - 500\ m - 30\ m)}$$

The new mud if the riser margin is included together with the SM will then be:

$$\rho_{mud} = 1{,}997\ sg$$

$$\rho_{mud} \approx \underline{\mathbf{2{,}00\ sg}}$$

Step 3: Frictional pressure in the long choke line

Because this is a subsea well, the BOP is placed on the seabed. This means that the choke and kill line goes outside of the riser and up to surface. With a water depth of 500 meter the pressure drop due to friction in the lines are rather high. This means that the ICP is slightly different compared to short choke- and kill lines. This step will go more in detail on how this is calculated.

First the frictional pressure loss from the circulation test through riser- and choke line. To find the frictional pressure loss equation (2.2) is used:

$$\Delta P_{friction,cl} = SR_2 - SR_1$$

$$P_{friction,cl} = 49\ bar - 35\ bar$$

The pressure difference corresponds to the frictional pressure loss in the choke line, this is:

$$\Delta P_{friction,cl} = \underline{\mathbf{14\ bar}}$$

Step 4: Calculation of ICP and FCP

Before circulation starts after taking a kick the ICP and FCP needs to be determined. The bottom hole pressure is based on these values during the killing process. If either or both of these values are wrong the killing process will end unsuccessful.

This will give ICP from eq. (4.10):

$$\mathrm{ICP} = \mathrm{SIDPP} + \mathrm{SM} + \mathrm{SR}_1$$

$$\mathrm{ICP} = 43\ \mathrm{bar} + 35\ \mathrm{bar} + 10\ \mathrm{bar}$$

$$\mathrm{ICP} = \underline{\mathbf{88\ bar}}$$

The FCP from equation (4.4) is:

$$\mathrm{FCP} = \mathrm{SR}_1 \times \frac{\rho_{\mathrm{kill\ mud}}}{\rho_{\mathrm{old\ mud}}}$$

$$\mathrm{FCP} = 35\ \mathrm{bar} \times \frac{1{,}86\ \mathrm{sg}}{1{,}73\ \mathrm{sg}}$$

$$\mathrm{FCP} = \underline{\mathbf{37{,}6\ bar}}$$

The pressure gradient is then determined, this to calculate the kill sheet according to obstacles that might wary the pressure profile in the well.

The pressure gradient:

$$\Delta \mathrm{P}_{\mathrm{gradient}} = \frac{\mathrm{ICP} - \mathrm{FCP}}{\mathrm{TVD}}$$

$$\Delta \mathrm{P}_{\mathrm{gradient}} = \frac{88\ \mathrm{bar} - 37{,}6\ \mathrm{bar}}{3578\ \mathrm{m}}$$

$$\Delta \mathrm{P}_{\mathrm{gradient}} = \underline{\mathbf{0{,}01409\ bar/m}}$$

Step 5: Initial choke line pressure

To avoid fracturing the formation due to the extensive choke line friction is to open the choke more than in the case of a platform with short choke lines. In this way the choke line friction is in some sense taken out of the equation and "annihilated".

The initial choke pressure will be determined from equation (4.11):

$$\text{Initial choke line} = \text{SICP} + \text{SM} - \Delta P_{\text{friction,cl}}$$

$$\text{Initial choke line} = 57\ \text{bar} + 10\ \text{bar} - 14\ \text{bar}$$

The initial choke pressure with long choke- and kill lines then becomes:

$$\text{Initial choke line} = \underline{\mathbf{53\ bar}}$$

To ensure that the correct initial choke pressure is correct, we monitor the kill line pressure. Here there is only stagnant liquid and it gives a measure of the BHP

In this case the initial kill line pressure will be from (eq. 4.12):

$$\text{Initial kill line} = \text{SICP} + \text{SM}$$

$$\text{Initial kill line} = 57\ \text{bar} + 10\ \text{bar}$$

$$\text{Initial kill line} = \underline{\mathbf{67\ bar}}$$

Step 6: Required volumes in each section, strokes and time to circulate with use of a table.

Here are the different sections listed up with their length both in measured depth (MD) and in true vertical depth (TVD).

Table 5.7 – Shows a table consisting of relevant information regarding the kill operation

Section	Depth (TVD) [m]	Depth (MD) [m]	Capacities [l/m]	Volume [l]	Number of pump strokes (pr. section)	Number of pump strokes (total)	Drill pipe pressure [bar]	Time [min]
					0	0	88,0	0
DP	1800	1800	9,15	16470	958	958	62,7	27,4
DP, 55	2775	3500	9,15	15555	904	1862	49,0	25,8
DP, 42	3429	4380	9,15	8052	468	2330	39,7	13,4
DC	3578	4580	4,01	802	47	2377	37,7	1,3
DC/OH		200	15,2	3040	177	2553	37,7	5,0
DP/OH		1580	23,6	37288	2168	4721	37,7	61,9
DP/Csg		2800	24,2	67760	3940	8300	37,7	112,6
Choke						8661	39,7	0,0
Total				**148967**	**8661**			**247**

In the table above there is a line which say choke, this line represents when choke line friction becomes a part of the circulation pressure. When kill mud and choke line friction is balanced at some point before kill mud reaches the choke line, the friction in the choke lines must be balanced by the pumps.

Step 7: Kill sheet

From Table 5.7 it is possible to draw a kill sheet which shows the pressure profile the choke should be regulated against.

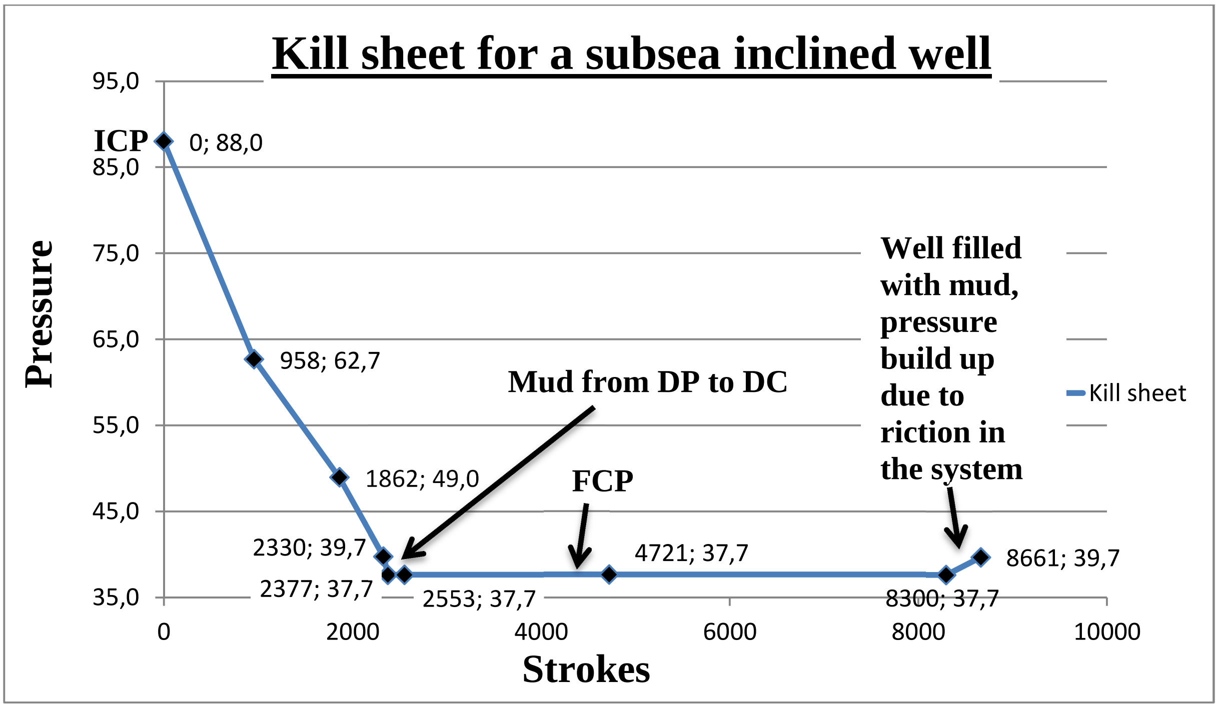


Figure 5.6 – Shows the kill sheet for the subsea inclined well

From Figure 5.3 it is possible to see that it is the W&W method that is used, this because the line declines at once, meaning that kill fluid is introduced as the kick is circulated out. There are several black dots along the pressure line, these represents the different sections in the well, but the first are related to the inclination. When the line levels out to a straight line the kill mud has entered the annulus and FCP. This pressure is kept constant until the kill mud pressure and choke line pressure is balanced, and to further fill the well the friction in the choke line must be overcome, this is the reason for the pressure build up in the end of the FCP line. The pressure build up at the end is not calculated, but is there just to show the effect after the balance point between kill mud and choke line friction. At this point the choke will be fully open and it is no longer possible to annihilate the choke line friction.

6 Discussion and conclusion

In this section a variety of questions will be discussed based on the theoretical content in this thesis. This section is divided into:

1. The difference between Driller`s and W&W method
2. Procedural changes when there is a inclined well
3. OBM vs. WBM
4. Kick tolerances
5. When it is suitable to use Bullheading?

6.1 The difference between Driller`s and W&W method

In principle Driller`s method (DM) and W&W method are the same, the way the kick is circulated out of the well are performed in the same way, the choke is used to control and maintain a constant bottom hole pressure and the goal is to re-establish the primary well barrier. However, there are one major difference between the two, that is when kill mud is introduced to the circulation process. For DM a whole annulus circulation is performed before kill mud goes into the circulation flow. With W&W method weighted kill mud is added simultaneously as the kill circulation process starts. This will, compared to DM, reduce the process time, but not necessary be a better solution. Due to this difference the kill sheet will not start in the same way, which can be seen from Figure 5.2 and Figure 5.4. The pressure drop will with the W&W method come at once compared to DM where this drop will come after one annulus circulation.

Time vice the W&W method is performed more effectively compared to DM. However, this method creates more challenges, it is more difficult to maintain a constant bottom hole pressure during the kill process, this is why it is more crucial to follow the kill sheet in detail with the use of this method.

Why is it harder to control the bottom hole pressure with the W&W method? One reason is more calculations which are time consuming. And to carry out the operation the kill sheet needs to be ready in advance of circulation start. Also, there are no constant fluid columns to base the bottom hole pressure on with this method, instead there is a mix of fluids both in the annulus and in the drill pipe during the kill circulation. Old mud is mixed with new kill mud in the drill pipe, and gas mixes with mud in the annulus. This creates changing pressure readings in both sections during the process, making it more challenging to regulate the choke to follow a certain pressure development when the heavier mud is pumped in the drill string and kill circulation starts. With DM there is always one compartment with one type of fluid. When the kick circulation starts, the entire drill pipe will contain only one type of mud, this makes it easier to regulate the choke pressure. Also for the DM, when kill mud enters the drill pipe it changes the pressure profile as it moves down, the annulus will during this process remain completely filled with one type of mud (old mud) and not be affected by this changing pressure development in the drill pipe. By holding top choke pressure equal to **SIDPP + SM** one knows that the well is in overbalance. From this it can be shown that with W&W method it is more challenging to regulate the bottom hole pressure compare to the DM, on the other hand it is more effective and saves time which reduces costs.

There is, however, one upside with the W&W compare to DM, this is related to the early introduction of kill mud. If kill mud enters the annulus before the gas bubble reaches the wells weakest point, which is the casing shoe, it will have a positive effect by reducing the gas bubble pressure. If this is possible depends on the depth of the casing shoe and the volumes within the well. An example of this will be discussed below in section 6.5, Kick tolerances.

Which type of well control method gives the best result depends on a various considerations. To mention a few:

1. What pressures do the kick give on surface
2. What competence do the workers have
3. Available equipment and resources
4. What type of mud is used
5. Time it takes to perform all preparations and operational phases for the kill operation
6. Casing shoe pressure limits
7. The formation properties and pressure limitations
8. Etc.

Several other considerations must be evaluated before a method can be chosen. The following general industry opinion is retrieved from [6]:

1. As a general rule, in most cases the W&W method should be used
2. If the casing shoe has a good quality then the Driller`s method should be the chosen method. The shoe will in DM be exposed to large pressures for a longer time period compare to W&W. Also if it takes a long time to weight up kill mud the DM should be used

6.2 Procedural changes when there is a inclined well

The kill procedures will depend on what type of well we are dealing with (subsea vs. platform). In this thesis it will be discussed the difference related to the exercises done in section 5, between a fixed platform with a vertical well and a rig with an inclined subsea well.

One of the differences is where the BOP is placed. On a fixed installation it is placed on the platform deck, and on a rig it is placed on the seabed. The rig needs a riser to connect to the BOP, which can be seen as an umbilical between rig and well. In seldom occasions, due to bad and harsh weather, a rig needs to disconnect the riser from the BOP and abandon the well area before they are finished drilling. This is done to maintain the overall safety to personnel, equipment on board the vessel and the environment. When the riser is disconnected the mud column in the riser will be replaced with a water column from the seawater. The seawater should together with the mud column left below the removed riser be sufficient to balance the formation pressure. This is the reason why a riser margin is added to the calculated mud weight. The weight is added to the mud and it is done to compensate for the weight lost when mud in the riser is replaced with a lighter water column from seawater. The riser margin must, however, not be so high that it fracture the well, but be sufficient to balance the formation pressure if abandonment is necessary. But, if the calculated riser margin is to low there is a risk that the well will have a kick below the wellhead. In this case the wellhead pressure will increase with the bottom hole pressure minus the hydrostatic mud column. When the rig returns to continue its work and drilling operation, the first thing it does is to drops anchors and then reattaches to the well. If the mud weight in the closed in well is too low the result can lead a closed in blowout. If no one suspects that the calculations are wrong and the mud weight in the well is too low to balance out the formation pressure, they will come across a pressurised well, and the consequence will be a surface blowout that reaches the platform deck with catastrophic consequences.

It is therefore very important that the calculations are done correctly. In this way the water column together with the closed in well`s mud column are able to balance the formation pressures preventing a closed in blowout from happening.

This is why kill calculations on a rig are done with riser margin. On a platform this is not an issue due to very short choke lines and no riser, they are therefore not included in the calculations.

The length of the choke and kill lines are also a factor that needs to be addressed in a subsea well case. On a fixed platform the kill and choke lines will be very short compared to a subsea well where they go from the rig and down to the BOP (height of platform + water depth). The main difference in this case compared to a case where the BOP is placed on deck with short choke lines, are the frictional pressure development and pressure losses when kill circulation goes through the small diameter choke lines. The formula for ICP (Initial Circulating Pressure) pump pressure is the same, but the inlet choke pressure will differ, from eq. (4.10):

$$\mathbf{ICP = SIDPP + SM + SR_1}$$

However, for a rig, one has to take into account choke line friction. Hence, the initial choke line pressure must be reduced correspondingly. The formula will be from eq. (4.11):

$$\mathbf{Initial\ choke\ line\ pressure = SICP + SM - \Delta P_{friction,ch}}$$

Regulating the choke initially is done by using the kill line pressure as the initial reference. The kill line pressure from equation (4.12):

$$\mathbf{Initial\ kill\ line\ pressure = SICP + SM}$$

In an inclined well profile the path will deviate from vertical, the result when circulating the kill mud using W&W is a non-linear pump pressure profile, which can be observed from the kill sheet in Figure 5.6. The different pressure slope variations when kill mud moves down the drill pipe is due to the change in inclination, but also due to the reduced gravity effect when inclination increases. This will give a pressure curve for each section related to the particular inclination for that section in the well, and the pressure line will change when inclination in the well profile changes. It is therefore important to keep track of the progress and where in the operation the process is at any given point, the reason for this focus is that the choke needs to be regulated at certain time steps to obtain a constant bottom hole pressure.

It is a known fact that most of the well profiles in today's oil industry are more complex than seen in this thesis. So are we able to take into account and calculate all these new and complex variables in these modern wells by hand? Or do we need advanced simulators? The answer is no. It is a known fact that if the complexity gets too big the probability of making a calculation error grows significantly, based on this and the high focus on safety the only possibility to make a usable kill sheet is with the use of advanced simulators. They are able to take into account all variables related to the complexity of the well profile together with mud and formation properties, simulators takes over when hand calculations gets too complicated, time-consuming and advanced.

6.3 OBM vs. WBM

If a kick is taken in WBM, an increase of pit level can be observed from surface shortly after influx, this is because the inflow fluid displaces large volumes of drilling fluid as the kick propagates. If using OBM instead of WBM it will yield a higher risk of a blowout compare to taking a kick in WBM. Why? The reason is that the inflow gas is dissolved into the OBM, which will increase the detection time before an action to the well control situation can be initiated. In HPHT wells the solubility of gas in OBM is almost infinite, which means that large amount of gas can be dissolve in OBM without detecting it. If the dissolved gas reaches the flash point above the BOP before it is closed a catastrophe is the end result and will be disastrous. The use of OBM is a major concern in the industry due to this lack of visibility when taking a kick [21]. What if there are long risers with the BOP placed on seabed? And it turns out that the flash point is above the BOP in the riser? When tripping there is a risk of taking a kick, to mitigate this risk and reduce it circulation is maintained during tripping. Circulation adds friction which will increase the bottom hole pressure preventing formation fluid from flowing into the wellbore. However, if personnel suspects a kick another procedure is followed, it involves closing the annular preventer in the BOP and performing one bottom`s up circulation through the choke line. A "bottoms up" circulation is to replace the entire well volume below the BOP once, in this way a potential kick is circulated out safely. The reason for using this procedure is to minimize the risk and consequence, if a kick is hidden in the OBM it will be circulated out in a safe way preventing any unwanted incidents. Also if the rig have been abandon or away from the well for some time, a bottom`s up circulation through the coke line may be performed to avoid any surprises.

What happens if the procedures are not followed and circulation starts up normally after tripping back in? There is potential risk that a hidden kick moves past the BOP before personnel are able to detect it. If this happens the dissolved gas in the OBM will reach its flash point in the riser, here there are no more obstacles points or barriers in place to prevent the kick from reaching the surface and a blowout will be the outcome. Small kicks to surface happens from time to time, what they do is to opening a hatch in the top riser, then the kick is lead away from the rig with the opening facing in the wind direction.

If a kick is suspected in OBM and mud pumps are turned off, the dissolved gas will remain in place until circulation is initiated. The dissolved gas will when circulating move as a passive tracer, suspended in the OBM towards the surface, until it reaches the flash point, also called the bubble point. This point is where gas goes out of suspension and back into free gas, and in some sense "explode" out of suspension, lifting the entire mud column and create a major pit gain. This may lead to a very difficult well control situation. Small kicks to surface are, as mentioned earlier, directed through a hatch and directed away from the platform in the wind direction. The result if a large kick reaches the surface are much more serious, a known example of such a disaster is BP`s Macondo well incident in the Gulf of Mexico in 2010, where the rig Deepwater Horizon sank, taking 11 lives, and causing one of the largest oil spills in history. If interest, the whole report of this incident is available online [15]. This is why procedures are so important and in place, to reduce the risk of getting a blowout and protect personnel, material and the environment. This is also the reason, as mentioned earlier, why it is of great importance in HPHT wells if suspecting a kick. Then the BOP shall be closed and the well shall be circulated one "bottoms up" through the choke lines (one bottom`s up means replacing the entire well volume below BOP).

Oil and water based mud have several important functions during the drilling operation. And it is the composition that gives the mud its special quality and physical properties. Some of the main functions are [22]:

1. Prevent formation fluids from entering the wellbore
   - Have a higher hydrostatic pressure of drilling fluids than formation fluid, this is done to balance the formation pressure and wellbore fluids
2. Remove the cuttings from the hole and acts as a transporter towards the surface, where it can be separated from the sludge
   - It is important that the drilling fluids are able to move the cuttings away from underneath the drill bit as soon as possible, to do so the mud needs to have low viscosity. If this removal is not done the cuttings will be grained to smaller pieces, and this will be more challenging to remove.
3. Make a filter cake on the bore wall which is thin, impermeable and solid which prevent mud from entering the formation
   - The particles in the mud will move towards the lower pressure in the formation and get stuck to the wall, these particles will then create a thin layer that prevents drilling fluids from entering the formation
4. It should also act as a coolant on the drill bit. It should also act as a lubricator for the same equipment
   - When drilling, the drill string and drill collar will be pushed towards the bottom and the drill string will be pressing towards the walls. When the string also rotates this contact with the wall will create friction which will create heat. The drill fluids function is to cool this effect and transport the heat to the surface, but it should also lubricate to reduce friction which also will reduce heat development
5. Stabilize the borehole and protect the formation
   - If not the formation reacts with the drill fluid the hole will be stable after drilling. Should, however, the formation react with the drill mud, then the walls will be unstable and it increase the risk of a cave in or hole collapse. Most common instabilities are when water reacts with clay or shale and creates an induced stress in them when they swell due to the reaction. If a WBM is used it needs to be saturated with salt if not to react with clay and

shale minerals, this fluids is also called "inhibitive" mud. OBM are also a "inhibitive" fluid

6. Provide uplift to the drill string and casing
   - When drilling long sections huge tension is placed on top pipe and top side equipment due to the large amount of drill pipes and drill collars hanging down in the well. The fluid column will create natural buoyancy which will reduce tension but still having enough weight to create pressure force on bit
7. Corrosion control
   - Drilling fluids must be non-corrosive to drill string, casing and other drilling equipment. To obtain this is to use a mud with pH > 9,5. OBM gives specially good protection towards corrosion whilst WBM needs additives to get this quality

6.4 HPHT

The HPHT case is another aspect when discussing different killing methods. A HPHT well is defined as a well with shut in wellhead pressure above 690 bars and temperatures exceeding 150^0 C. The reason that this is worse compared to a conventional well is the reduced drilling window, which means low pressure difference between pore pressures and fracture pressures. HPHT wells sets high requirements to drilling mud and completion fluids, it is important to make sure that they are able to cope with the harsh conditions down in the well. The depths were these HPHT reservoirs are located are the main reason for the high temperatures and pressures, a rock has a temperature gradient about 3^0 C/100 meters, which means that the depths are substantial.

Drilling long well sections requires a lot of planning and preparations in advance, this to make sure that every aspect in the process is included. It also puts high requirements on the equipment in use and material selection, having reliable tools and equipment is crucial for a safe operation and a long well duration. All well related equipment should be able to cope with the harsh conditions, high temperatures and high pressures without malfunctioning.

The special challenges related to drilling a HPHT well compared to a standard well is retrieved from [23]:

1. *" High pressures and temperatures impact mud properties in a dynamic way, and can have effects on well control*
2. *Small margins between pore and fracture pressures will prevail in sections of the well*
3. *The conditions are above the critical point for the gas/oil/condensate influx; which means that the hydrocarbon influx is infinite soluble in the base oil of the mud.*
4. *Hydrocarbon influx will totally mix with the base oil in oil based mud (OBM), and infinite amounts of gas can dissolve in the mud*
5. *Drilling of inclined and horizontal wells will make the consequences of barite sag serious*
6. *Significant quantities of gas can diffuse into a horizontal section of a well if OBM is used even if the well is overbalanced "*

In the section to come the material is retrieved from [23] if not otherwise is stated. In a HPHT well the hole size, temperature and pressures changes with depth. This means that the active mud volume will change in various sections due to these reasons. The mud will expand if the temperature goes up or contract if it goes down, it can be compressed in high pressures or expanded in low pressures. Also changes in wellbore diameter or casing diameter will have an effect on the active mud volume. These changes will appear even if there are no losses or there is no formation influx into the wellbore, but it may change significantly when the mud circulation stops or when it starts back up.

The temperature changes for shallow wells will not be substantial and the effects mentioned above will not be as large, therefore the temperature changes and the effect in the rheology are small. In a well with a large drilling window the gap between pore and fracture pressure is big which means that variations in the dynamic circulation pressure are not that important with respect to kick probability. For shallow wells, an approximation that drilling fluid rheology will be independent of temperature and pressure is a good approximation. In HPHT wells the temperature effect will have a larger impact on the bottom hole pressure compared to shallower wells with lower formation temperatures. The temperature effect will give a larger uncertainty in the ECD and the variation within the pressure. These factors need to be taken into consideration and it comes in addition to the challenges with the small pressure margins within the pore and fracture pressure window in HPHT wells. Also if using OBM and not WBM and vice versa is another factor, and are because of difference in response to temperature and pressures. For this reason it is important to do thorough analysis and evaluation of the different effect that may be encountered during the drilling process. This is important, a difference in the mud column will have an effect on the bottom hole pressure, and if the drilling window is small it may lead to mud losses or influx of formation fluid and the result would be a well control situation.

In HPHT wells large depths are common, it is therefore important to be able to distinguish between temperature effect and a real kick situation. Temperature effects will cause mud expansion during connections and it will be monitored by fingerprinting (fingerprinting in sec. 2.3). High formation temperature down in the well causes the mud to expand. This can be observed on surface as pit gain after mud pumps have been shut off. In addition when circulation is initiated the high annulus temperature down in the well will be cooled down by the mud higher up, and the upper annulus will be heated up by the stationed mud that comes from down in the well. This will force the rheology at any given place to change rapidly as the circulation process is carried out and change the hydrostatic profile. This will cause pressure variations in the well.

When taking a kick, the mixing fluid will be either dry gas (methane) through volatile oil and condensate to heavy oil. The mixing will be between mud and the inflow fluid from the formation. The paper [23] points out the difference in solubility of hydrocarbon gas between oil phase of drilling mud compare to water phase drilling mud. The oil phase drilling mud has several orders of magnitude larger solubility than the water phase drilling mud, it can then be concluded that they will not behave the same when taking a kick. What makes HPHT well conditions so dangerous is related to its infinite solubility in the base oil, and where the gas flashes out of the oil is governed by the mixtures bubble point. The amount of gas that can be dissolved in the oil is what makes these conditions so dangerous, when the gas flashes out of suspension it will be hard to control it, or if they are not able to close the BOP in time it will be impossible and a catastrophe is in progress. The consequence of such an event can be fatal to human, infrastructure and to the surrounding environment. Therefore it is so important with well control training, and make the personnel understand the different well signals and what actions to initiate for a given scenario.

Today, as mentioned earlier, if there are any sign of a kick in a HPHT well the BOP is closed and the well is circulated one bottom up across the choke. This is done as a precaution to avoid any unwanted happenings and just in case there is a kick in progress. During drilling this procedure with BOP closure and circulation process is done many times, it is time consuming but it is much better than the alternative.

Another aspect that was mentioned earlier, to compensate for swab effects which reduces the bottom hole pressure, circulation is continued throughout the whole tripping operation. The circulation creates friction pressure which increase the pressure at the bottom, and in this way the bottom hole pressure is kept constant during the whole operation, it also reduces the chance of getting influx of formation fluids.

6.5 Kick tolerances

Kick tolerances is used when planning the well design. If a well control situation develops into a kick it is required that the design is capable of handling the pressures that develops during a well control incident. Also the amount of inflow gas expected should be evaluated in the design. One also has to consider this in relation to separator design and its capacity.

The well design should also have a weak point in the line of defence, this it is done to minimizing the impact if a well control situation is bigger than anticipated. In a well the casing shoe should be the weakest point. If the casing is the weakest point, the wellhead or the BOP the gas has free pathway up to surface and the consequences of such an event is hard to predict and even harder to control, the only thing that is for sure is that this is a much more undesirable event compare to a fracture at the casing shoe which will develop with lower risk to human life.

The depth to where the last casing section is placed will indicate max pressure the casing shoe can withstand without fracturing. Another factor is the casing burst pressure at this depth, if it is to weak compare the to the formation at this depth it will be decided to raise the casing setting point further up in the well to make sure that the formation at the casing shoe remains the weakest point.

After a kick is taken and the BOP is closed the circulation process can begin. It may be thought that using W&W instead of DM will have a positive effect on the pressure acting on the casing shoe. What needs to be in mind is that a gas kick needs to be circulated out in both cases, and in both cases it needs to go the same way. This means it does not matter if kill mud is pumped at once when the kick is circulated out as in W&W method, or after the kick is circulated out as in DM.

However, there is one upside with the use of W&W instead of DM, if they are able to get kill fluid into the annulus before the kick reaches the casing shoe it will have a positive effect on the pressure acting on the casing shoe. At which depth the casing shoe is placed determines if this is possible or not. If the casing shoe is too deep, then the kick will reach this location before kill mud are able to reach the annulus and reduce the pressure.

All points in the well will be met by the highest pressure when the top kick passes that exact point on its way up towards the surface. In a real kick situation when a gas kick travels up in the annulus it does not behave as a single bubble, it acts as a mix of small and larger bubbles in the mud. The size of the bubble depends on the slip ratio between bubbles and wellbore fluids, but also the flow regime during the kill process. Slip velocity and a "rule of thumb" is not enough to describe how fast gas migrates in drilling mud. However, experiments shows that large gas concentrations migrates fast in a typical well geometry with about 0,5 m/s [24].

The flow regimes are illustrated in Figure 6.1 below. Two phase flow regime means that the flow can either be dispersed bubble flow or slug flow among other. Dispersed bubble flow is induced when the flow velocity increases with increasing wall friction, the friction tries to hold back the moving fluid which creates a flow of disorder, the particles moves in all direction within the moving flow and big bubbles are crush into smaller bubbles. With slug flow all particles moves in the same direction and it is possible for gas bubbles to merge into bigger bubbles.

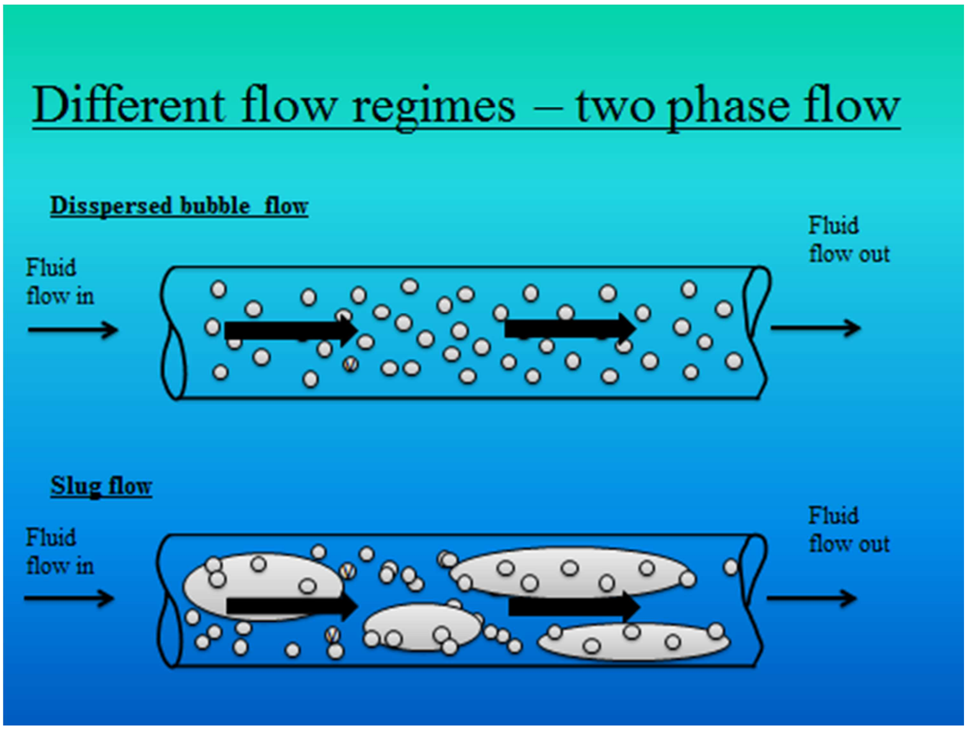


Figure 6.1 – Shows the difference between dispersed bubble flow and slug flow

If the choice lies in weather to use the W&W or DM, one may question what separates them from each other? As mentioned in section 6.1 the W&W has an advantage on the casing shoe pressure compare to the DM, if kill mud are able to enter the annulus before the front of the kick reaches the casing shoe area it will have a positive effect on the maximum pressure on the casing shoe. Another advantage is that the well will be exposed to the high pressure for a shorter period of time with the use of W&W method compared to DM.

Below there is an example where the gas kick travel up the annulus, and if using W&W method how far up will the gas kick travel before the kill mud enters the annulus? From this calculation the maximum depth of the casing shoe can be determined if the W&W method should have a positive effect on the pressure. For this example the vertical well data from section 3.2 will be used. To simplify the calculations two assumptions are made:

- There are no slip
- Gas bubble travels with the same speed as the circulated mud

To illustrate the pressures acting on the casing shoe during a kill circulation a figure is gained from the DrillBench software model [25]. Simulation result presented at the 2002, Drilling Conference in Kristiansand (not available any place except Fjelde`s F-drive).

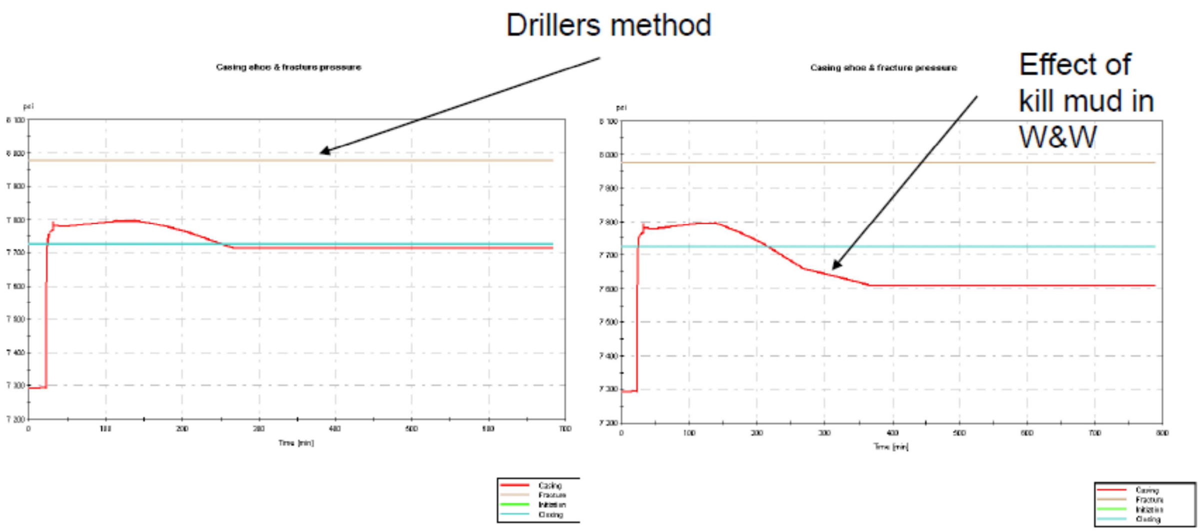


Figure 6.2 – Showing the casing shoe pressure during a kick circulation using Driller`s method and W&W method

In the W&W method it is preferred to get the kill mud to flow into the annulus before the kick passes the casing shoe, if this is obtained the pressure that acts on the casing shoe is reduced due to the heavy kill mud that has entered the annulus. This is however not an issue in the Driller`s method, where the kick is circulated out with the use of old mud.

<u>Well data</u>:

This is a vertical well with a TVD deep of 4300 meter. The last casing shoe was placed at 2800 meters. This is a platform well where the BOP is located on the rig.

The drill collar section is 280 meters long.

Drill pipe inner capacity 9,15 l/m
Drill collar (DC) inner capacity 4,0 l/m
Annular capacity

DP/Csg	24,2	l/m
DP/OH	23,6	l/m
DC/OH	15,2	l/m

OH – Open hole
DP – Drill Pipe
Csg – Casing

Need to determine the formula for pressure at the casing shoe:

$$\mathbf{P_{cs} = P_{BOT} - \rho_{mix} g h} \qquad \textbf{(6.1)}$$

ρ_{mix} is the mixture density of mud, gas and potentially kill mud between the bottom and the casing shoe. The heavier the ρ_{mix} gets, the more positive effect it will have on the casing shoe pressure.

First the volumes in the drill pipe and annulus must be determined, in this way the height the gas has travelled can be determined. The well data is retrieved from section 5.2.

Drill pipe plus drill collar volume:

(DP) - 36783 litres
+ (DC) - 1120 "
Total = 37904 litres

Annular volumes:

(DP/Csg): 67760 litres (2800 meter)
+ (DP/OH): 28792 " (1220 meter)
+ (DC/OH): 4256 " (280 meter)
Total = 100808 litres

The total volumes in drill pipe and drill collars are 37904 litres. This is the amount of kill fluid that is required before it enters the annulus. From this volume the height which the gas bubble has travelled can be determined:

Table 6.1 – Shows how the drill string volume is used to determine the gas bubble height

Volume in drill string [l] (step by step)	Section	Capacity [l/m]	Volume annulus [l]	Gas bubble traveling height [m]
37903	DC/OH	15,2	4256	280
33647	DP/OH	23,6	28792	1220
4855	DP/Csg	24,2	67760	200,62
Total				**1700,6**

First the DC/OH volume is subtracted from the total drill string volume. This corresponds to a migration height of 280 m. Then the DP/OH volume is subtracted from the remaining drill pipe volume which will give an additional height of 1220 m. What`s left of the drill pipe volume will then correspond to a height of 200 meter above the shoe. We see that even for this conservative case where we have assumed no slip the kick has been displaced 1700 m up in the well. I.e. when kill mud enters the annulus, the kick front has already passed the shoe.

But the intention is that kill mud should help reduce the casing shoe pressure, which means that the casing setting depth should be placed higher up in order to get kill fluid into the annulus before kick reaches the casing shoe. From the calculations above the gas kick reaches the casing shoe at a depth of 2600 meter. If the kill mud should provide a pressure reduction towards the shoe the casing setting depths needs to be placed further up so kill mud are able to enter the annulus before the kick reaches the casing shoe.

If the kill mud should help, let us consider the case where the last casing is placed at 2400 meter. This enables 200 meter of kill mud to enter the annulus before gas bubble front reaches the casing shoe. A table is worked out to show different pressures on the casing shoe with changing mud weights. The mix density is calculated by taking the gas fraction and mud fraction between casing shoe and bottom hole minus the kill mud height. Then it can be showed that with an increase in kill mud weight the casing shoe pressure will be reduced.

In this table the fraction of gas is 25 % and old mud 75 %, and taken for the 1700 meters between casing shoe and top kill mud. A gas density of 0.019 sg is assumed. The last 200 meters are filled with kill mud, and it is this kill mud density that is increased in the table below to show the effect on the casing shoe pressure.

Table 6.2 – Showing different casing shoe pressures with different kill mud densities

Attempths	Different kill mud density [s.g]	Mix density [s.g]	Casing shoe pressures [bar]
1	1,64	1,203	481
2	1,66	1,205	480
3	1,68	1,208	480
4	1,70	1,210	479
5	1,72	1,212	479
6	1,74	1,215	479
7	1,76	1,217	478
8	1,78	1,219	478
9	1,80	1,222	477
10	1,82	1,224	477
11	1,84	1,227	477
12	1,86	1,229	476
13	1,88	1,231	476
14	1,90	1,234	475
15	1,92	1,236	475
16	1,94	1,238	475
17	1,96	1,241	474
18	1,98	1,243	474
19	2,00	1,245	474

Another and maybe easier way to illustrate the pressure reduction on the casing shoe if the kill mud holds a higher density can be with the use of the graph below. In addition, the table above shows that the increase in mixture density is relatively compared to the increase in kill mud density. The corresponding effect on casing shoe pressure is also shown.

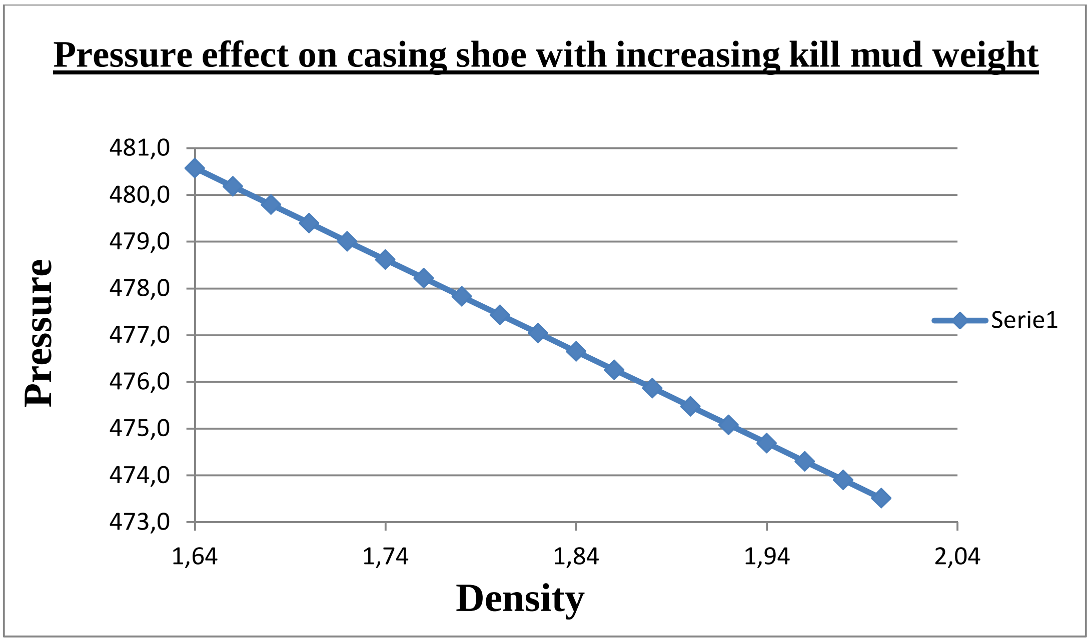


Figure 6.3 – Shows the pressure development on the casing shoe with increasing kill mud weight.

With this in mind, choosing a casing setting depth that allows kill mud to enter the annulus before the kick reaches the casing shoe with the W&W method can give positive result on the casing shoe pressure. If this is not possible, if the formation is too weak to place the casing at a depth so it can benefit the W&W method, then there are no major differences if W&W or DM is the chosen kill method. The only thing that now separates them from each other is operational time. W&W takes less time, but the method needs more preparation and calculations compare to DM in order to be a performed in a safe and effective way. The well is also exposed to large pressures for a shorter period of time when using the W&W method.

6.6 When it is suitable to use Bullheading?

Below it is listed up some points to whether bullheading is suitable, and in which cases. To a large extent the information is retrieved from [19], but it is also valid for this section.

- If a kick turns out to be bigger than expected and the limitation within the facility design shows that it is not capable of handling the large volumes, then bullheading may be a good option
- Loss of return during conventional drilling. If drill mud is lost to the reservoir or in a zone above it, at some point they will run out of mud. The loss zone should be determined so correct weight are measured up and the well is killed

- When swabbing leads to inflow of formation fluids, the drill string can be tripped back to bottom and conventional drilling procedure with the use of Driller`s method can be performed, but bullheading is also an option
- Having personnel with the right expertise are important in any situation. Should the circumstances lead to lack of qualified personnel in the event of a well control situation, that are no able to calculate pressures and volumes within the well, then the best option may be to bullhead the kick back into the formation. In this way there are no risks of calculation errors which can lead to a secondary or third kick situation if a conventional well kill operation is performed
- If there is a well control situation and the forecast says that bad weather is coming and may lead to an abandon situation. Then bullheading should be discussed as the primary well kill method
- If the pressure from the kick leads to fracture of the weakest point in the well, then bullheading should be performed
- If the kick contains a larger H_2S concentration than the operator allows and if the equipment capacities on the facility are not able to handle the large volumes, it should be bullheaded back into the formation
- Should the surface equipment have any pressure limitations and the kick holds very high pressures, bullheading may be the safest and best option to avoid incidents if equipment should fail due to too high pressure exposure
- If the drill string is partially out of the well or completely out, an attempt should be made to try bringing the drill sting back into the well and to the bottom. If this is not possible bullheading should be chosen as the killing method
- The kick volumes are so high that the surface equipment is unable to handle them, and then bullheading should be performed. It should be pointed out that this is not a common happening, the person in charge must have been inattentive or there must have been a defect in the closing mechanism
- If the mud weight is close to the fracture pressure and they are not able to kill the well conventionally

As can be seen from the points above, bullheading is a very useful substitute to the conventional killing methods. There are however, higher risks of damaging the reservoir by contaminating it with mud and wellbore fluids when bullheading is used as a killing method. But with the potential risk of getting a surface blowout if using a conventional method as an alternative this may be a small price to pay. The most important thing is that bullheading is an option to conventional methods. And an alternative when they are not able to manage the well control situation that has developed.

It can be difficult to foresee which type of method that a kick scenario that is to come sometime in the future. It is in all interest that everybody that is dealing with a drilling operation knows what they are doing. At some point they will face a well control situation, and then they need to be capable of handling it and take action to repair it. They must know how to calculate pressures and volumes in the well, this are going to be used when making a kill sheet which is used when the operation is perform, and that it is done according to procedures. The goal is to get everybody educated to raise the overall competence within the work force. But this takes time and costs a lot of money, but it will benefit the end result if the experience is needed and give positive result back to the company. Training is the key and it is very important, that everybody learns the different methods and also the different calculations to each method is vital. In this way people do not forget and are able to take action for any given situation, then human error will be heavily reduced, it will be much safer and a well control situation will be handled more effectively.

The most important thing is to have trained personnel that know what they are doing in any given situation, and that people are able to communicate and know what to do if a well control situation is to evolve. It is a common expectation that everybody working in the field knows the procedures, and knows how to perform a bullheading operation along with the other methods. Ensure that everybody hold this knowledge will secure safety to themselves, their colleagues, the environment and the company in the years to come.

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