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Abstract

Well control is needed during drilling operations to maintain a stable and safe well. Moving towards deeper wells with higher pressures and temperatures makes the operational working window smaller and more complicated than for conventional wells. In this work some of the challenges when dealing with a HPHT well environment are identified.

During conventional well operations it is desirable to keep the well pressures above the pore pressure and below the fracture pressure in the formation. This is to avoid inflow of formation fluids into the wellbore or the flow of drilling mud into the formation. The pore pressure prognosis is therefore very important in the casing and drilling mud design.

The well control aspects are described focusing on kick causes, kick detection and the well kill procedures.

The simulation set up was based on a constructed HPHT well case. The simulations and analysis in this work is focused on pressure and volume development in the well during a kick circulation, focusing on the differences when circulating out a kick in OBM, where the gas will dissolve in the mud, and a WBM, where gas migration will occur. A comparison between a kick circulated out in an OBM and in a WBM shows that in general the well pressures and gas volumes in the well will be higher when the kick is taken in a WBM

Simulations were also done looking at the pressure effect experienced when performing connections and swabbing operations. Here it was shown that the pressure drop experienced during connections can lead to an underbalanced situation where we get an inflow of formation fluids. It is also seen that the pressure drop during connections increases in smaller hole section and it is also seen that the swabbing effect during tripping out of the well can be reduced by pumping out of the hole. The pressure drop over the bit is also dependent on the pump rate used, an increase in pump rate gives a smaller pressure drop when the pipe is pulled at a high speed. The swabbing effect also gets worse in smaller hole sections.

Acknowledgement

In this thesis, the Drillbench software (Presmod and Kick) has been used on a constructed example case to demonstrate some transient well dynamics related to pressure/well control in HPHT conditions.

I will like to thank the SPTGroup (www.sptgroup.com) for giving me the chance to use these simulators in my thesis work. They have been very useful tools to demonstrate some important issues to be aware of when within pressure control and well control training. A further presentation of the SPT group and the softwares used are given later in the thesis.

I would also like to thank Bjørn Thore Leidland and Sajjad Sajdi for the help I got in the beginning of my thesis and for providing me with the Drillbench software.

Finally I would like to express my sincere gratitude to my supervisors Kjell Kåre Fjelde and Mesfin Belaynhe for their helpful guidance and involvement during my work on this thesis.

Contents

Nomenclature

OBM – Oil Based Mud
WBM – Water Based Mud
BHA – Bottom Hole Assembly
LOT – Leak off Test
FIT – Formation Integrity Test
BOP – Blow Out Preventer
MW – Mud Weight
KMW – Kill Mud Weight
LPM – Liters Per Minute
BHP – Bottom Hole Pressure
BHT – Bottom Hole Temperature
ROP – Rate Of Penetration
TVD – True Vertical Depth
MD – Measured Depth
TD – Target Depth
SG – Specific Gravity
DP – Drill Pipe
DC – Drill Collar
ID – Inner Diameter
OD – Outer diameter
ECD – Equivalent Circulating Density
HPHT – High Pressure High Temperature

1 Introduction

1.1Well Control and its importance

Well control is of major importance when planning, designing and constructing a well. An uncontrolled well can lead to unwanted situation and in worst case scenario it can lead to a blow out. We are dealing with an unstable well if we have fluid flowing from the formation into the well or if the well fluids are flowing into the formation.

During conventional drilling the well pressure is kept above the formation pressure. If the pressure in the well is below the pore pressure, underbalanced conditions, there is a risk of potential kick. If the well pressure is above the fracture pressure, there is a potential risk for losses of the drilling mud into the formation. The goal is therefore to stay above the pore pressure and below the fracture pressure when drilling the well. The pore pressure and fracture pressure prognosis is very important in determining the casing setting depth, for maintaining a stable well.

Casing design base on mud density is shown in Fig. 1. Designing the well sections according to the pore pressure prognosis of the well is a common procedure [11]. Minimum mud density is based on controlling the pore pressure, the mud weight is here the pore pressure gradient in the well plus an added safety margin. At the same time the maximum mud density is based on controlling the fracture pressure, here the mud weight is the fracture pressure plus a safety margin. “The method is straightforward, casing seats are selected so that the minimum mud density does not exceed the maximum allowable density. In the planning phase, reasonably accurate pore gradient and fracture gradient predictions are essential. One or two contingency strings should be planned if this knowledge is lacking” [2].

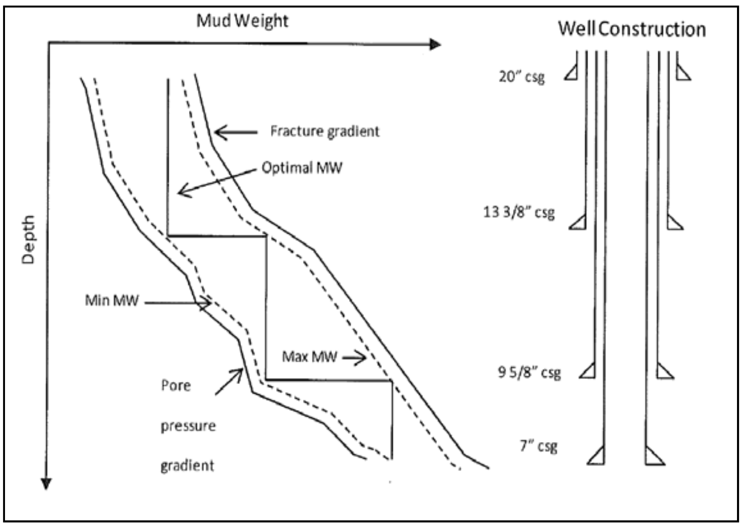


Figure 1: Mud density and casing design based on pore pressure prognosis.[26]

HPHT wells means that we are dealing with high pressure and high temperature formations in the well. Under these conditions normal well design becomes more advanced [23]. Here we have smaller operating margins since then we are dealing with a smaller window between pore and fracture pressure. There are also the effects from the high temperature both when it comes to equipment tolerance and also the temperature can influence the well stability.

1.2 Pressure and kick simulations

To investigate the pressure development in the well during a kick situation, it is possible to use a simulator. In this thesis the Drillbench Kick and Presmod softwares have been used to simulate a constructed HPHT well case.

1.3 Study objective

The objective of this thesis is to look at well control in a HPHT well. Building a constructed HPHT well scenario for simulation purposes. Analyzing the pressure development in HPHT wells during different operations and analyzing different kick situations and investigate how OBM and WBM affect the pressure and volume development during a kick situation.

1.4 Structure of the thesis

This thesis starts with chapter 1, where the basic pore and fracture pressure prognosis and its importance in the well construction process are described. In chapter 2, some basic physics is described. In chapter 3 there is presented a general theory about well control focusing on kick causes, kick detection, well control procedures and special aspects in a HPHT well. Chapter 4 gives an introduction to the Drillbench software used for simulations and a discussion of some special challenges in a HPHT well environment. Then in chapter 5 a HPHT well scenario is built for simulation purposes. In chapter 6 the results from the simulations are presented and discussed and finally a conclusion is given in chapter 7.

2 Basic physics

2.1 Well pressure

The hydrostatic pressure in the well is given by:

$$P_W = \rho \times 0.0981 \times h_{TVD} \tag{2.1}$$

P_W = hydrostatic pressure in the well
ρ = density of the fluid in the well
h = the TVD of the well

During conventional drilling we want to keep the well pressure, P_W, above the formation pressure, P_P, and below the fracture pressure, P_F, at all times. This is referred to as overbalanced drilling.

$$P_F > P_W > P_P \tag{2.2}$$

When we have underbalanced conditions, the pressures in the well are lower than the formation pressure, resulting in a productive formation, where formation fluids can enter the well. The flow rate is dependent on permeability and the pressure difference between the formation and the well [2, 3]. When performing underbalanced drilling there need to be installed mud/gas separators to handle the return of formation fluids mixed with the drilling mud.

Managed pressure drilling is drilling with a pressure very close to the formation pressure. Equipment is installed to keep the well pressure close to the formation pressure at all times. There is also extra equipment available to handle kicks during the operation [24].

2.2 Boyles law

The ideal gas law is given by [2] :

$$P \times V = n \times R \times T \tag{2.3}$$

Where n is the number of moles and R the universal gas constant. In the case of a gas influx contained within a wellbore, n is constant and it follows that:

$$\frac{P_1 V_1}{T_1} = \frac{P_2 V_2}{T_2} \tag{2.4}$$

Boyles law states that at constant temperature, the volume of a quantity of gas is inversely proportional to its pressure. It is expressed as [2]:

$$P \times V = constant = P_1 \times V_1 = P_2 \times V_2 \qquad (2.3)$$

Where P and V are the pressure and volume of the gas at conditions 1 and 2.

This means that if a gas bubble can rise and expand freely in a fluid column, it will double in volume for each half in pressure. This is illustrated in Fig. 2, where the gas bubble is expanding upwards in an open well. Here it is shown that when a gas kick moves up in an open well the gas volume will expand and the well pressures get lower.

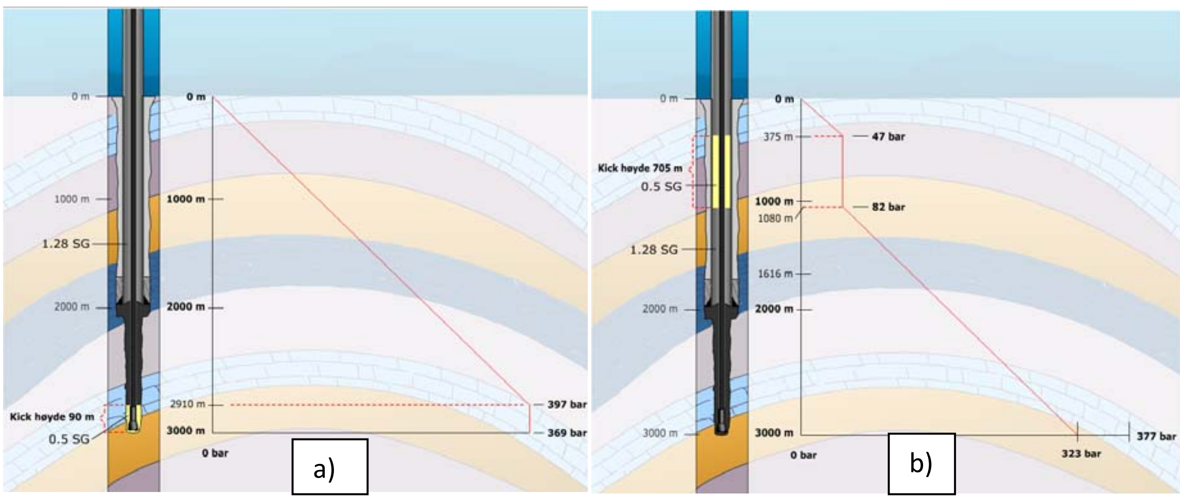


Figure 2: a) The gas bubble at bottom of the well. b) The gas bubble has migrated up in the open well. [3]

If the well is closed in, and this gas bubble rises upwards in the well, it will inflict a BHP twice the size as before the well was closed. One can say that the gas brings the BHP up to surface as it migrates upwards in a closed in well. This is shown in Fig. 3, where the gas bubble is moving up in the closed in well. Here the gas kick will move up in the well, but the gas bubble will not increase in volume, it will transport the pressure from bottom off the well up to the surface. Boyles law tells us that in a closed well, the gas bubble pressure at bottom will be the same as the gas bubble pressure at surface. This means that in the situation where a gas kick can move up in a closed in well there will be very high well pressures, which can lead to well problems [3].

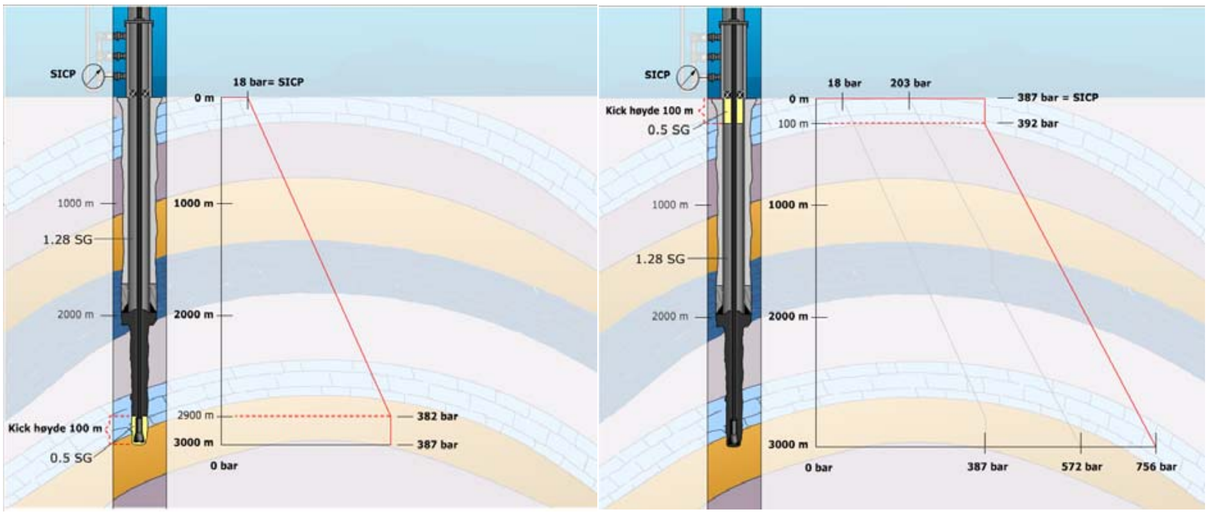


Figure 3: a) The gas bubble at bottom of the well. b) The gas bubble has traveled to the surface in the closed in well. [3]

2.3 Gas migration and migration speed

A gas influx will tend to migrate upwards in a well, this is due to the low density of the gas compared to the drilling fluid. When a gas influx is migrating through drilling fluids it is often simplified as a continuous slug, a single bubble gas influx. However, to give realistic results it cannot just be described by a single slip velocity. “At large concentrations (>10%) the gas will rise fast at around 0.5 m/s in a typical drilling geometry. The rapidly moving gas cloud will leave a trail of bubbles suspended in the well by the yield stress of the mud. These small gas bubbles will be stopped. Mis-interpretation of surface pressure during shut-in will indicate that gas migration is slow” [4].

2.4 Gas solubility

An assumption often made is that an influx does not react with the drilling fluid and that the PVT properties of the influx of formation fluids at wellbore conditions correspond to the surface conditions. This is not true if we are dealing with gas influxes where a significant amount of gas is dissolved in the drilling fluid. Hydrocarbon gas will to some extent dissolve in any drilling fluid, but the solubility effect can generally be ignored in a WBM. In an OBM the gas solubility is more important because here a gas kick can be completely dissolved in the drilling mud [5, 23].

3 Basic review of well control

Well control is defined by the NORSOK D-010 standard, “it is the collective expression for all measures that can be applied to prevent the uncontrolled release of wellbore effluents to the external environment or uncontrolled underground flow” [6]. Pressure control is of major importance when it comes to safety. It is therefore important to understand the different mechanisms that can lead to an uncontrolled well.

Primary well control concerns mainly the control of pressure during drilling using drilling/completion-fluids and other weight materials to avoid kick situations to occur. For some operations the primary well control may also be performed using well control equipment, such as MPD. Secondary well control will for all types of well operations be performed using well control equipment. That is, measures and procedures that applies when you have lost or are losing the primary well control. Tertiary well control is to control the well pressures by drilling relief wells [7].

Figure 4: The Deepwater Horizon blow out in the Gulf of Mexico.[8]

An illustration of the well control equipment is shown in Fig. 5. Here the most important equipment during drilling is shown:

- The drilling fluid goes down the well inside the drill pipe and up the well in the annulus to the pit tank at surface, where the pit volume is measured.
- The BOP seals of the well in case of an inflow situation.
- The choke is used to control the well pressure, while the chokeline allows well fluids to be transported out the well when the BOP is closed.
- A separator is used to separate the gas from the mud.

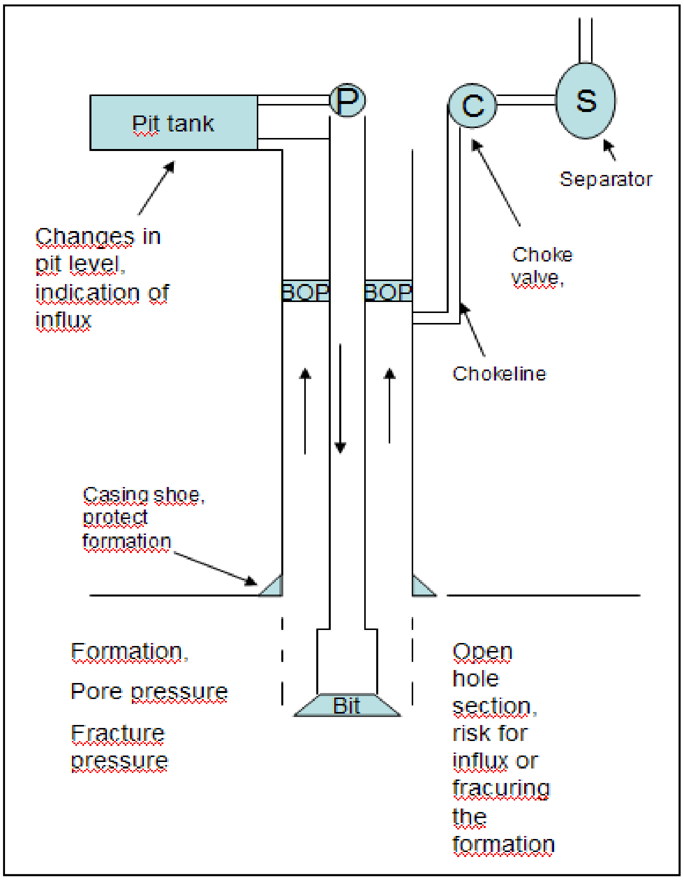


Figure 5: Well control equipment.[9]

Leak off test is performed to prevent lost circulation. This procedure is done by closing the well and then pressure up the open hole section in the well below the last set casing. It Is done before drilling into the next well section or next interval. The test indicates the strength of the wellbore at the last set casing shoe [10].

Formation integrity test is performed at the casing shoe to determine if the wellbore will be able to handle the maximum mud weight anticipated while drilling the section. The test is done by pressurizing the casing seat according to the expected mud density, if the formation holds, drilling is resumed [10].

3.1 Kick and Kick detection

3.1.1 What is kick?

A kick is an unwanted situation where you have an uncontrolled inflow of formation fluid into the wellbore. A kick can occur when we have a hydrostatic pressure in the well that is lower than the pore pressure in the formation surrounding the well. When this occur the higher formation pressure has a tendency to force formation fluids into the wellbore. The inflow of formation fluid can be gas, oil or salt water [2,3].

For a kick to occur we need;

- Wellbore pressure < pore pressure
- A reasonable level of permeability
- Presence of formation fluids

3.1.2 Reasons for kick

Kicks normally occur when the formation pressure is greater than the mud hydrostatic pressure. This causes fluids to flow from the formation and into the wellbore. There are multiple reasons why the formation pressure exceeds the mud pressure in the well, the most important reasons are [2, 10];

- Insufficient mud weight
- Swabbing effects
- Improper fill up
- Lost circulation
- Gas cut mud

3.1.2.1 Insufficient mud weight

When performing various well operations it is important to ensure that the well fluids used have a higher hydrostatic pressure than the formation pressure. If the mud weight used in the well is too low, lower than the formation pressure, there is a possibility for getting inflow of formation fluids into the well inducing a so called kick. In some cases there can be some uncertainty in the pore pressure prognosis and during drilling there is a risk for experiencing unexpected high pore pressures which can result in a kick situation. The temperature effect in HPHT wells can make us believe that the mud weight at bottom of the well is the same as we observe at surface, while the effective mud weight in the well might be lower.

3.1.2.2 Swabbing effects

The swabbing effect is the temporary pressure reduction we get in the well when pulling the drill pipe out of the well. This pressure reduction can result in inflow of formation fluids to the wellbore. If we circulate while pulling the pipe we can reduce or eliminate the swab effect, in HPHT wells this procedure is common and called “pumping out of hole”. The pulling speed is also of importance, it is important not to pull out too fast. During well planning it is common to perform swab/surge calculations in advance to determine the safe operational limits [3, 24]. An example on the swabbing effect can be if we have a 1.83 sg mud in the well, the expected pore gradient is 1.8 sg. The swabbing effect when pulling the pipe is 0.04 sg. This means that now the well pressure is 1.79 sg, which is below the pore pressure, this can lead to inflow of formation fluids into the well.

3.1.2.3 Improper fill up
During tripping, when the pipe is pulled out of the well, the fluid level in the well is reduced due to the volume of pulled pipe. This can result in a reduction of the hydrostatic pressure in the well which can lead to a kick. It is therefore of importance to pay attention when pulling pipe out of the well and refilling the well with mud.

Example: When pulling the 5” DP out of a 2000 m deep well, how much will the mud level in the 19” riser sink? How large volume do we need to refill? A 5” DP = 4.05 l/m.

2000 m x 4.05 l/m = 8100 l = 8.1 m^3 is the volume we need to refill when pulling the pipe out.

19 x 0.0254 = 0.4826 m ID

Area of the riser is given by: $(\pi\ d^2/4) = (\pi \times 0.4826^2\ /4) = 2.4649\ m^2$

The mud level in the riser will fall: $8.1\ m^3\ /2.4649\ m^2$ =3,29 m

3.1.2.4 Lost circulation
When tripping into the well we can get a surge effect, which can result in an increase of the well pressure. This can lead to fracturing of the formation and loss of well fluid into the fractured formation. The loss of well fluids will lead to a drop in the annulus fluid level and we get a reduction of hydrostatic pressure in the well which can result in a kick situation.

3.1.2.5 Gas cut mud
When drilling formation gas we get a reduction of the effective mud weight in the well. The reduced mud weight leads to a reduced bottom hole pressure, which can result in inflow of formation fluids into the wellbore.

3.1.3 Kick detection
When we have any signals indicating an unbalanced well we should always perform a flow check. Then the pumps are stopped and the mud flow is observed. If the well is flowing when the pumps are off it is a clear indication that the well is not in balance. Then the well must immediately be closed. It is important to detect the kick as early as possible to limit the

volume of inflow into the well by closing the BOP. The most important warning signs of a kick situation are discussed below.

3.1.3.1 Drilling break

A sudden increase of the ROP can be a warning sign that the overbalance is being reduced. This can be a warning sign for a potential kick situation. The ROP will vary in different formations, this is due to different formation types and formation strengths, there is a lower resistance in soft formations like sandstone. We can also experience an increase in ROP when drilling through a transition zone above a permeable reservoir.

3.1.3.2 Increase in pit volume

An increase in the pit volume during drilling is a signal of a kick. We then very clearly see that we have an inflow of formation fluid into the wellbore, resulting in increased pit gain. Normally flow rates are measured using flowmeters. Flowmeters give a direct measure of the flow out of the well, so if the pump rate is 2500 lpm but the gain is 2700 lpm, then there might be a kick situation in the well.

3.1.3.3 The well is flowing when mud pumps are stopped

During different operations in the well the mud pumps will be shut off. A flowing well when the pumps are shut off can be an indication of a kick. It is important to understand that a flowing well with pumps off not necessarily means that we have a kick, the well can also be flowing due to temperature effects or density difference between inside and outside of the drill string. During connections we can experience a net increase in the well temperature. This temperature effect can lead to fluid volume expansion, resulting in increased return volume at surface.

3.1.3.4 Improper hole fill up during tripping

During tripping and pulling operations a trip sheet is used recording the volume of displaced mud during tripping and the volume of pumped mud during pulling. This sheet should be calculated and prepared before well entry, and any large deviation from the calculated volumes can indicate that we have an inflow of formation fluids or a loss of well fluids to the formation.

3.1.3.5 Increase in return flow of mud

When we have an increase in the return flow rate while pumping at a constant rate, it can be a sign of a kick situation. Inflow of formation fluid into the wellbore can result in an increased rate in the upward flow in the annulus. When formation fluid starts to flow up in the well the formation fluid will mix with the mud giving an increase in the return flow rate.

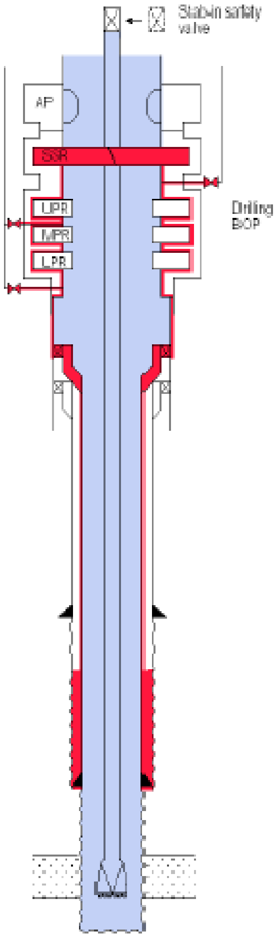
3.2 Barriers

It is crucial for a safe well operation that there is a pressure balance in the well at all times. ie that the well pressure should always be higher or the same as the pore pressure. A barrier consists of one or more barrier elements to prevent an uncontrolled blowout from the well. Norwegian authorities claim says that at any time there shall be two independent barriers tested in the well. If one of the barriers fails, all effort is to be concentrated on restoring this barrier.

The BOP is the surface well control equipment, the main purpose of the BOP is to close in the well when needed. The BOP during drilling operations is according to NORSOK D-010 classified as a secondary barrier element [6]. There are different types of BOP`s; annular BOP and ram BOP. The annular BOP is typically used on top of the BOP stack, which has the flexibility to seal around a variable pipe size.

Fig. 6 shows the well barriers during drilling. Here we see a drilling BOP, the function of the drilling BOP is to provide capabilities to close in and seal the well bore with or without tools/equipment through the BOP [6].

5.8.1 Drilling, coring and tripping with shearable drill string



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

Note

None

Figure 6: Illustration of the well barriers during drilling.[6]

3.3 Well control procedures

If the detection signals indicate that we have an uncontrolled well, and we have a kick, then we need to handle fast. We need to stop the inflow of formation fluids from the bottom of the well to quickly restore the pressure balance. The first step is to stop drill pipe rotation and mud pumps and shut-in the well at the top of annulus. The safety valve on top of the well, the BOP, will shut the annulus between the well and the drill string.

There are two different procedures for shutting in the well, we have hard shut-in and soft shut-in. In hard shut-in the annular preventer is closed immediately after the pumps are shut down. In soft shut-in procedures, the choke is opened before the preventers are closed, and once the preventers are closed, then the choke is closed. The type of shut-in procedure chosen depends mostly on type of rig and the drilling operation occurring [10].

After the well is closed, the inflow at the bottom will start to slow down due to the pressure build up when more formation fluids and gas migrates upwards in the well. We will also register this pressure build up at the top of the well where we have pressure gauges both in the annulus and on the drill string. The stabilized pressure on the top of the drill string is called SIDPP (Shut in drill pipe pressure) and on top of the annulus is called SICP (shut in casing pressure), shown in Fig. 7. After the pressures at top have stabilized, the well is in balance again, but this is a temporary situation. We need to get the well in full balance with a heavier mud column before the valves can be opened and drilling resumed [7]. This is done using one of the well kill methods described below; drillers method, wait and weigh method, volumetric method or bullheading.

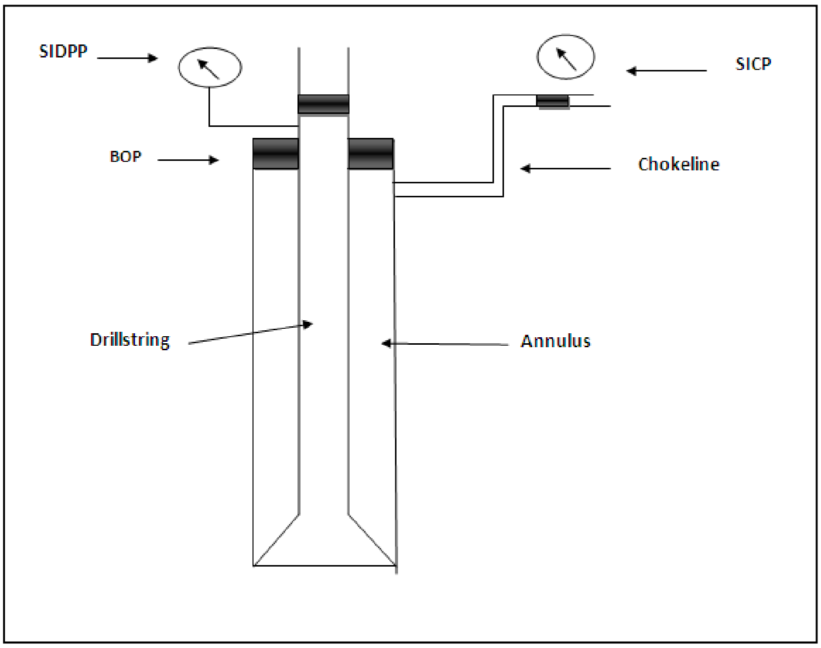


Figure 7: Well system with closed valves.

The formation fluid entering the well before it is shut in often contains large volumes of gas. When the well is shut in, the gas over time can change the well pressure, resulting in major consequences. The influx of gas will behave very different when the well is shut in regarding which type of mud is used in the well. If the gas influx is taken in OBM, then the influx will dissolve in the mud and stay at bottom as long as the well is closed in. If the gas influx is taken in WBM it is not possible to stop the gas from migrating upwards, then we must allow the gas to expand upwards in the well and thereby gain lower pressure. If the pressure exceeds what the formation can handle then we have the possibility for fracturing. The pressure load in the well and especially at the casing shoe where there is a larger possibility for fracturing or leakage is very dependent on the height of the inflow in the well and also the density [7]. The density of the mixing between mud and formation influx will vary if we have gas, oil or water in the well. The height of the inflow is dependent on the volume and the capacity of the well. In a well with a low capacity (small annulus), even small volumes can give relatively large heights, while wells with a larger annulus will be able to handle larger inflow volumes without effecting the height significantly, this is shown in Fig. 8. The pressure load is therefore affected by the inflow volume, and we want to avoid large inflow volumes.

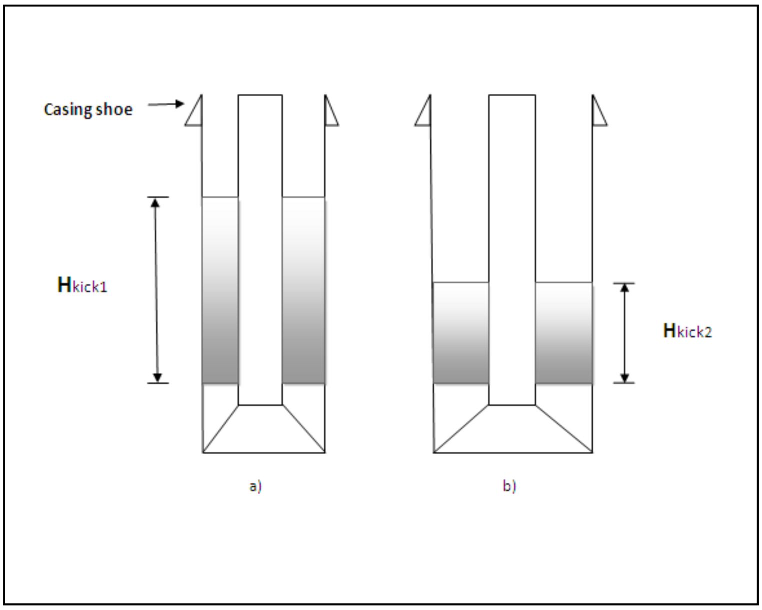


Figure 8: Kick height comparison between a) small annulus and b) large annulus.

The influx will not stop until the wellbore pressure at the point of influx is equal to the formation pressure:

$$BHP = P_p$$

$$SIDPP + P_{HDP} = SICP + P_{HA} + P_{HKICK} \tag{3.1}$$

P_p = formation pressure
P_{HDP} = Hydrostatic pressure of mud in the drill pipe
P_{HA} = Hydrostatic pressure of mud in the annulus
P_{HKICK} = Hydrostatic pressure of kick in the annulus

When the well is closed due to an inflow of formation fluids, and we are waiting for the pressure buildup to stabilize, we can still get a formation fracture at the weakest point in the well, normally just below the last set casing shoe. Here the mud will start to leak into the formation, before the pressures at bottom are high enough to stop the inflow. We then get an underground blow out [2]. To get out of this problem we need to increase the pressures at bottom and also reduce the pressures at the fracture. When the pressure in the well exceeds the formation strength the well can fracture all the way up to surface. We then get a blow out, which usually must be repaired by drilling a relief well [7].

To be able to kill the well safely we rely on good knowledge about the volumes in the well, both inside the drill pipe and in the annulus. After the well is closed in a kick situation, we have lost our primary barrier. We now need to restore this barrier by replacing the mud in the well with a heavier mud. When the well is closed in and stabilized, the pressures at top of the well in combination with the mud column at the bottom, keep the balance at the bottom. To restore full control and resume drilling we need to remove the formation fluid in the well and change the mud [3]. To kill the well means to restore full hydrostatic balance. To circulate the influx up and out of the well we need to have the drill string at bottom of the well and circulate the fluid down it and return up through the annulus. This can be done with the different methods described below.

Data that needs to be calculated when performing a kill procedure are [3]:

The kill mud density is calculated from the SIDPP:

$$\rho_{killmud} = \rho_{oldmud} + \frac{SIDPP+Sm}{0.0981 \times TVD} \qquad (3.2)$$

$\rho_{killmud}$ = Kill mud density
ρ_{oldmud} = Old mud density
Sm = Safety margin

The pump pressure to start the kill procedure:

$$ICP = SIDPP + Sr + Sm \qquad (3.3)$$

ICP = Initial circulation pressure
Sr = Well friction measured when circulating the well with kill rate (found in advance)
Sm = Safety margin, (required overbalance)

Pump pressure needed when the kill mud is down at the bit:

$$FCP = Sr \times \frac{\rho_{killmud}}{\rho_{oldmud}} \qquad (3.4)$$

FCP = Final circulation pressure

3.3.1 Drillers method

The principle behind this method is to keep the BHP constant when circulating the kick out through the chokeline. The BHP is kept constant by proper choke adjustments. Since there is a direct correspondence between the pressure at bottom and the pressure in the pump we want to keep the pump pressure constant during circulation.

$$P_{BH} = P_{HYD} + P_F + P_C \qquad (3.5)$$

P_{BH} = Bottom hole pressure
P_{HYD} = Hydrostatic pressure
P_F = Frictional pressure
P_C = Choke pressure

As the gas is rising in the well we want to keep both the BHP and the pressure at top of the drill string constant. The kick is circulated slowly upwards in the annulus towards the chokeline. The mud pump is driven with constant speed and circulates the inflow upwards in the well, shown in Fig. 9. At the same time we have to regulate the choke valve at top of the annulus and keep a constant pressure at top of the drill string, shown in Fig. 10. The kick is circulated out through the chokeline and is then sent through a mud/gas separator where the gas is flared. It is important to keep the bottom hole pressure constant during the operation, to balance the formation pressure. Now the well is filled with a light mud, and to restore the pressure balance in the well, we need to circulate in a heavier mud. The new heavier mud is then calculated. Then we start to circulate in the heavier mud by keeping the BHP constant. When the mud column enters up the annulus it is heavy enough to balance the formation pressure, and no extra pressure at top is needed. Eventually the heavy mud fills the entire well and now the well is killed [3, 7].

Review

- Easy to implement, it doesn`t demand any special calculations. Two manometer keeping control of the different pressures.
- Circulation can start at once when the pressures at the top have stabilized.
- The method demands a longer circulation time, because we first have to circulate out the influx, before introducing the new heavy mud.

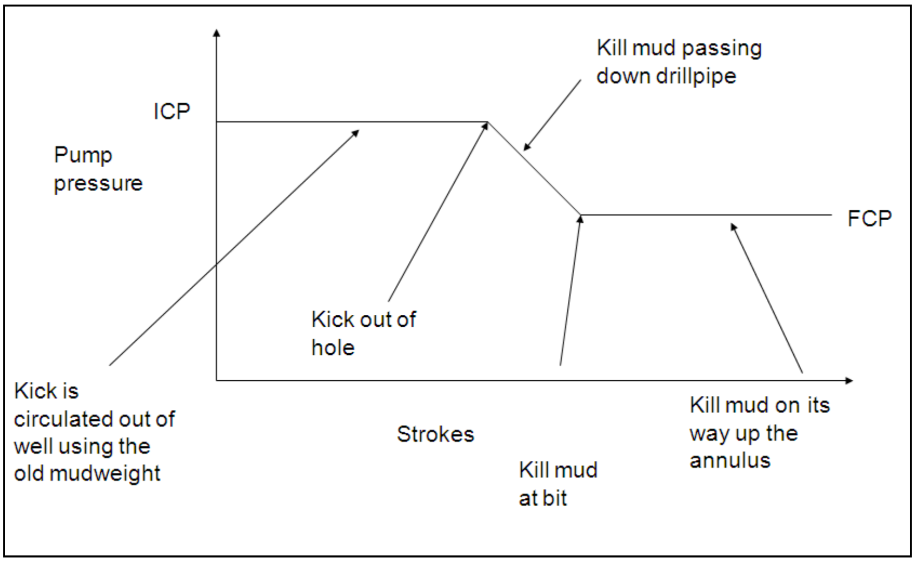


Figure 9: Kill sheet during drillers method.[9]

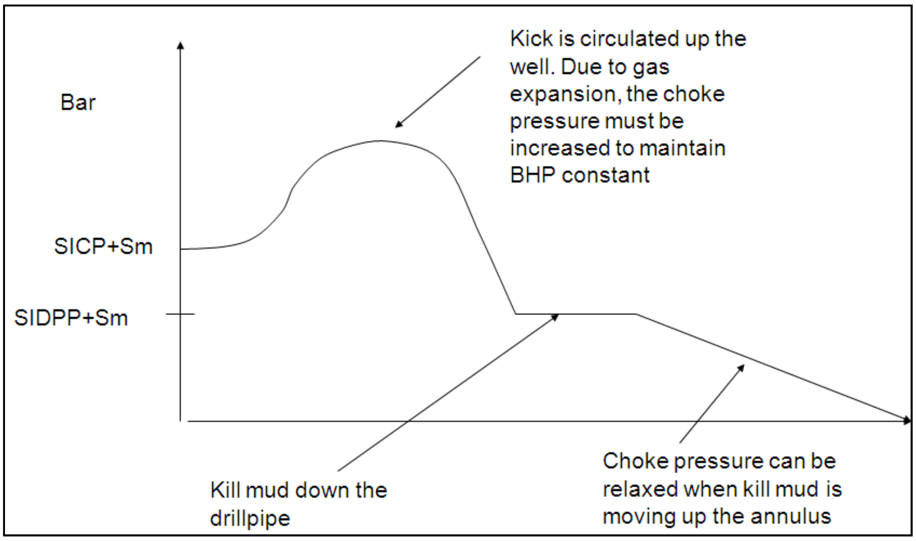


Figure 10: Choke pressure development using drillers method.[9]

3.3.2 Wait & Weight

The wait and weight procedure involves circulating out the influx at the same time as the heavier mud is introduced. We still have to keep the BHP constant during the kill procedure. When changing the mud at the same time as circulating the influx out we don`t have a constant mud column in the well to start with. In the drill string the heavier mud will go down and gradually change the mud column, while in the annulus we still have an influx going upwards which changes the composition of the mud column. Since we don`t have a constant mud column when using the wait and weight method we need to calculate the pressure changes in the drill string. We need to calculate in advance how the pump pressure need to be decreased while filling the pipe with kill mud and at the same time maintaining a constant BHP all the time. The choke is properly adjusted such that this pump pressure schedule is followed. This ensures that our BHP is kept constant [3, 7]. In Figs. 11 and 12 a typical pump and choke pressure development is shown during the kill circulation.

When the heavier mud is starting to return up the annulus, the pressure at top of the drill string will be kept constant. From this point the method is no different from the Drillers method. To “wait” entails that we have to wait with the killing of the well until the mud density and the circulation graph with the pressures is calculated/predicted. To “weight” entails that we need to weigh up the heavy mud before starting to inject it.

Review

- We have to wait with circulating the well until the calculations are done and the pump pressure schedule kill sheet is ready. The required kill mud density must be calculated and the new heavy mud must be mixed.
- This is a faster method when killing the well. Circulating in the heavy mud at once.

- The method is more complicated to perform, first calculations, and then we have to follow a predetermined path for pressure control and pumping of the heavy mud.
- This method has limitations when we are dealing with horizontal wells, difficult to predict the pressure circulation graph.

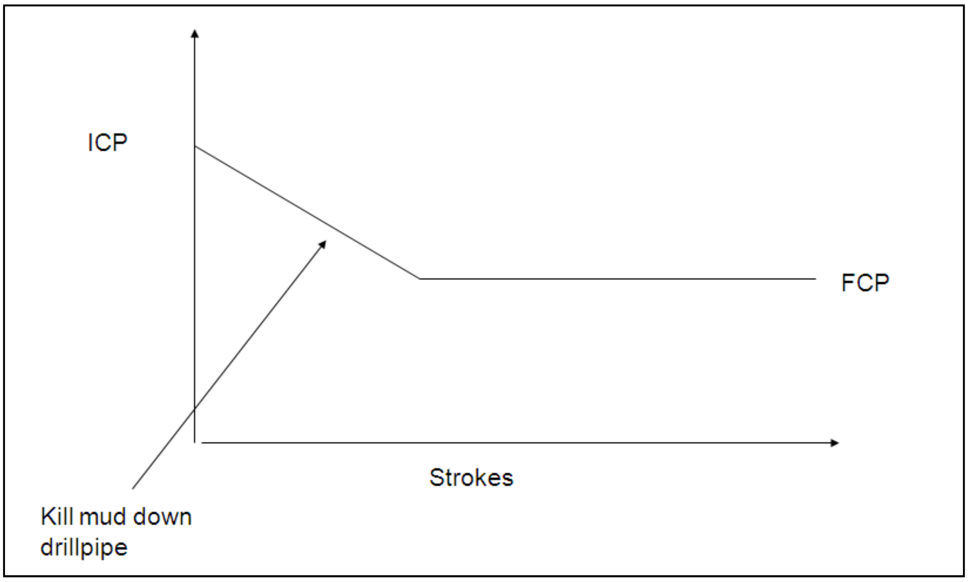


Figure 11: Kill sheet during wait and weight.[9]

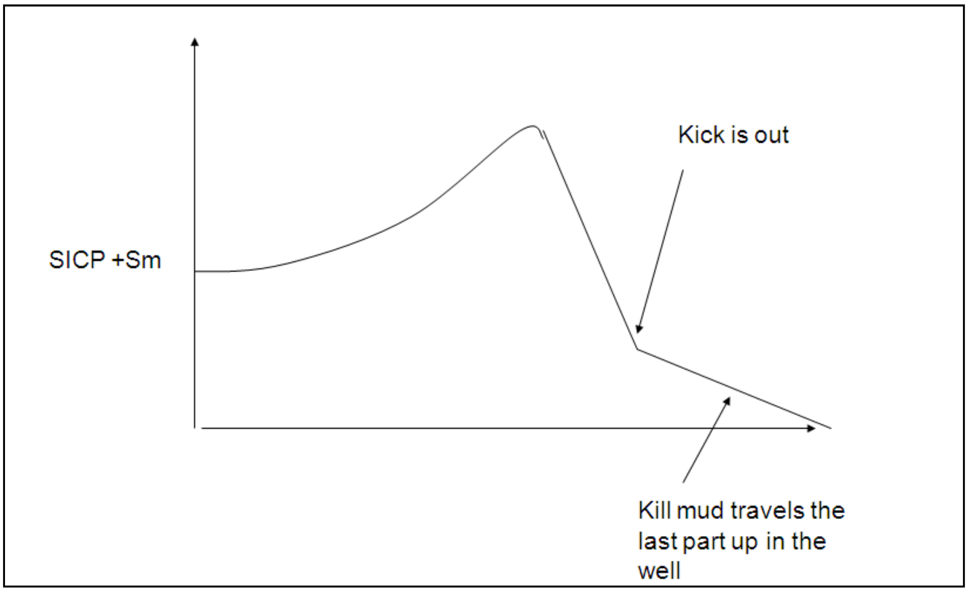


Figure 12: Choke pressure development using wait and weight.[9]

3.3.3 Bullheading

The purpose of bullheading is to pump the kick back into the reservoir, using reverse circulation. There is a risk for increasing the BHP when using this method, which can lead to formation fracturing. This method is also used if there are problems with underground blow outs, in HPHT wells. [3]

3.3.4 Volumetric method

Using the volumetric method implies that the kick is not circulated to surface, but it migrates up in the well. This method is used if there is no possibility to circulate the well through the drill string. This method can therefore only be used in free gas kicks that naturally will migrate up in the well.

Using the volumetric method we are letting the gas kick expand as it migrates up in the well, while keeping the BHP constant. The BHP is kept constant by bleeding of or pumping mud into the well as the gas expands up in the well. [3]

3.4 Kick tolerance

Kick tolerance is a sensitivity study of maximum kick volume that can be tolerated in the well and safely circulated out without fracturing the weakest formation in the well. The weakest formation is normally just below the last set casing shoe. The kick tolerance can also be defined as the maximum allowable pore pressure at next target depth or the maximum allowable mud weight in the well without breaking the last set casing shoe. It is important to estimate if the well pressure at the casing shoe will exceed the fracture pressure and thereby cause lost circulation/and an underground blow out. Kick tolerance is affected by a number of variables such as; kick size, casing shoe pressure, formation pressure, mud weight, density of influx and circulating temperature [2]. Typical kick tolerance values are shown in table 1. If a well cannot handle kick sizes defined by the volumes specified, the last casing shoe has to be set deeper.

Table 1: Typical values of kick tolerances [21].

Hole size (inch)	Kick volume (bbl)
6 and smaller	10-25
8.5	25-50
12.25	50-100
17.5	100-150
26	250

From the equation below (3.1) we see that the maximum casing shoe pressure also depends on the density of the fluid mixture in the well, the smaller ρ_{mix} we have, the larger will the maximum casing shoe pressure be.

$$P_{CS} = P_{BH} - \rho_{mix}\, g\, h_{TVD} \quad (3.6)$$

P_{cs} = casing shoe pressure
P_{BOT} = bottom hole pressure
ρ_{mix} = density of the mixed fluid
h_{TVD} = height of the well

The casing should be set as deep as possible in the well due to economical reasons, so the optimal selection of casing setting depths is important. The casing setting depth is normally determined from the pore pressure and fracture pressure prognosis. It is important that the hydrostatic pressure of the mud always is higher than the formation pressure, but lower than the fracture pressure. In the casing seat selection it is not always enough to only look at the pore pressure prognosis. The weakest point in the well will be below the last set casing shoe, and the open hole section might not be able to withstand the forces experienced during a kick and lead to fracturing. Therefore it can be crucial to include kick tolerance calculations in the casing seat design [2, 22]. In the paper "*HPHT Well Control; An Integrated Approach*" [1] kick tolerance data where updated and the casing design was based on using a more advanced dynamic kick simulator. An example of kick tolerance curves are given in Fig. 13.

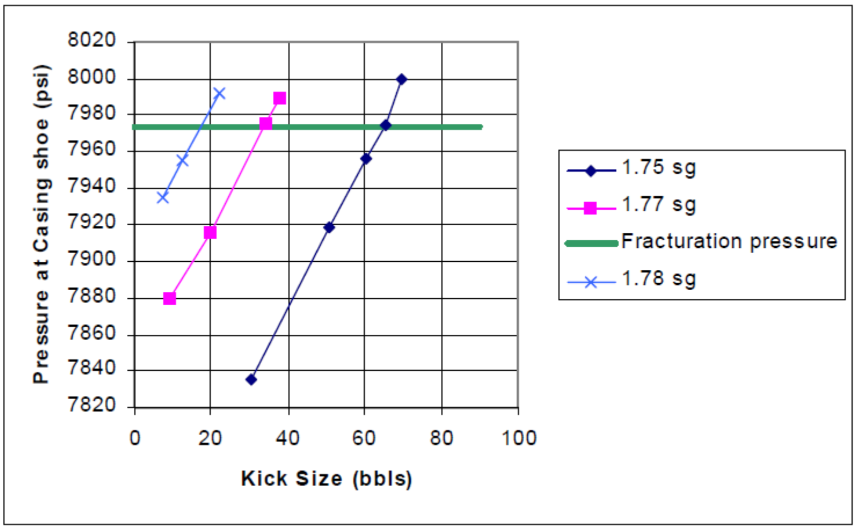


Figure 13: Casing shoe pressure for different kick sizes [1].

3.5 HPHT wells and special challenges

A high pressure and high temperature well is defined in the NORSOK_010 rev 3 as "a well where the expected shut-in well pressure is higher than 690 bars and the static BHT is above 150 degrees Celsius" [6].

3.5.1 Challenges in HPHT wells

We have different challenges when dealing with a HPHT well; one is due to the small margin between pore pressure and fracture pressure which requires that the BHP is controlled carefully. Also temperature, pressure and ballooning effects can be challenging in a HPHT environment.

3.5.1.1 Temperature effect

We have temperature effects in high temperature wells. Due to the temperature effects the drilling fluid density will change along the well depth. High temperatures will decrease the density of mud, so if the well is dominated by high temperature the down hole effective mud weight will be lower than what you observe at surface. In some cases it is easy to mix the temperature effect with a kick incident due to the increase in mud volume at surface. This can be dangerous during drilling operations because we then have an effective mud weight down in the well that is lower than what we observe at surface, this means that the risk of an underbalance situation is higher [1]. If we get underbalance during drilling then formation fluids can start to flow into the wellbore. To avoid kicks it can be necessary to adjust the effective surface mud weight so that we get the correct effective mud weight down hole. The temperature of the drilling mud can change rapidly depending on the operation, when we have static conditions in the well the mud temperature approaches the geothermal temperature in the well. When we start to circulate the well, cold mud from the drill string will enter the annulus while hot mud will be flowing up the upper part of the annulus. This causes the mud density and rheology to change rapidly at different positions in the well, causing variations in the ECDs and changes in surface mud volumes [11].

3.5.1.2 Pressure effects

In HPHT wells we get more variation in the hydrostatic pressures than we get when drilling standard wells. This is due to the mud density changes caused by temperature and pressure. High pressures increases the density of mud, so if the well is dominated by high pressures the down hole effective mud weight will be higher than what we observe at surface. We also experience pressure effects due to changes in the rheology, first we get frictional pressure changes due to rheology variations caused by temperature effects and also rheology changes can induce transitions in flow regimes causing higher frictional pressure losses [1].

3.5.1.3 Ballooning

Normally HPHT wells are deeper than conventional wells, we can therefore see a ballooning effect. Ballooning effects can occur during drilling operations, where the return mud volume varies, giving either a too low or a too high return rate. These false kicks can make the driller shut down the well when it is completely unnecessary. It is therefore important to separate the ballooning effect from situations where we have mud loss to the formation or a kick. We can experience the ballooning effect when we look at the well under both static and dynamic conditions [11].

The ballooning of shales is one of the effects. When the pumps in the well are turned on, we have a pressure loss in the annulus and the drilling hydrostatic pressure which cause an over pressure on the shale formation in the well. When the pumps then are turned off we get a pressure decrease on the shale, which can lead to a small decrease in diameter of the well leading to an increased mud volume out of the well. This can be interpreted as a kick, leading to well shut-down. The ballooning effect also occur in conventional wells but is much more common in HPHT wells, this is because they often have grater depths [19, 22].

3.5.1.4 Undetected kicks

For HPHT wells there is a risk for taking small undetected kicks in oil based mud, because the influx of gas dissolves totally and hides in the mud. In this case we will not see any change in pit volume when the influx is moving towards the surface until free gas starts to boil out. Then we will have a sharp increase in the pit volume and we need to shut in the well as soon as possible. It is important that the kick doesn't reach the riser, which lead to a very critical situation, because then we no longer have the ability to lead the kick away from the open platform. When the free gas starts to boil out of the solution we get a decrease in the BHP, this decrease can lead to a new kick situation in the well [2].

3.5.2 Physical behavior in HPHT wells

Different components in the drilling mud will change according to the pressure and temperature in the well. The most common components in a drilling mud are water, base oil and weight materials. We normally distinguish between water based mud (WBM), which normally comprises of water and different salts, and oil based mud (OBM). These different types of drilling fluids will react differently to pressure and temperature.

The drilling mud density is both dependent on pressure and temperature. The density of mud will vary in the well with varying temperature, and the active mud volume might change during drilling when turning the pumps on and off. This can occur due to mud expansion/contraction because of temperature or pressure variations in the well [1].

The drilling mud rheology is affected by temperature and pressure, especially in wells with small margin between fracture pressure and pore pressure like HPHT well, it is therefore a need for appropriate evaluations of the pressure and temperature distribution in the well [1,18].

In the mixture between mud and hydrocarbons we see a big difference between when the hydrocarbons are mixing with water based mud or if they are mixing with oil based mud. The solubility of hydrocarbons in OBM is much larger than in WBM, they will therefore behave significantly different when we have influx into the well. An influx of volatile oil in WBM will release free gas when it is pumped upwards in the well due to pressure reduction, and this free gas will expand according to the ideal gas law. A influx of free gas in WBM will not dissolve in the mud. When we have an influx of volatile oil in OBM it will mix totally with the base oil and we will get a new base oil with different properties, and if we have a influx of free gas in OBM it will be infinite soluble in the base oil [25]. The flow of free gas is generally taking place in the bubble or slug flow regime. This transition zone will be determined by the non-Newtonian properties of the mixture between the mud and the influx [1]. When the gas is in the slug flow regime there will be a much higher gas slip velocity than during dispersed bubble flow regime.

When we have low circulation in the well and the drill string is rotated slowly or not at all, then we can get sagging of weight material out of the drilling fluid in the long run. This occurs in highly inclined sections of the well, and can be pronounced in wells with long, horizontal sections. Loss of weight material from the mud may cause serious problems for the pressure control when the lighter mud reaches sections with small inclinations, where a stronger carrying capacity of cuttings is needed [1].

In overbalanced conditions, the well pressure is above the formation pressure and we have no inflow of formation fluids. But if a HPHT well is drilled in overbalance through a gas formation and is then left without circulation for a time period, then gas from the formation can start to diffuse through the spurt zone and filter cake, and accumulate in the drilling fluid. If we are drilling with OBM substantial amounts of gas can diffuse into the mud despite overbalanced conditions. This can lead to potential well control problems when the well is circulated again [12].

Hydrates can form when we have water and light hydrocarbons present. Hydrate formation can take place in the well, normally we see hydrates form when we have low temperature and low pressures, or if there is temperatures above 25°C and large pressure changes. The risk of hydrate formation taking place also increases with increasing water depths. The hydrates can cause severe problems in the well with respect to well control as they deposit in the well and the well equipment. Hydrates can plug the choke and kill-line which prevent their use in a well circulation they can plug formation at or below the BOP, they can also plug around the drill string preventing drill string movement, and they can plug the BOP preventing it from closing fully [13]. It is therefore very important to evaluate the potential for hydrate formation and how to handle them. It is common procedure to pump glycol in wells to prevent hydrate formation.

It is also important to understand that during drilling operations we have various drilling parameters which create a very transient down hole situation.

4 Well control training & simulators

The need for appropriate training becomes more important as we move towards more narrow margins, deeper wells, higher temperatures and pressures. It becomes more crucial to be able to foresee possible unwanted events that can occur and how to avoid them from happening [22]. In drilling operations the main goal is to prevent kick incidents. By using a drilling simulator in the planning stage of the well it can help eliminate unwanted well situations, to analyze different well control situations and for evaluating procedures. Advanced well control software is therefore important in the planning, operational and evaluation stages.

If we are using simulators for training, it is important that they represent the real well conditions as realistic as possible. Hence, accurate input data is required if a specific well prospect is to be drilled and trained for.

In HPHT well training it is important to put focus on the following:

- There is an increasing amount of well control incidents, training can help us better understand how to avoid unwanted situations.
- Training can help in the understanding of how to operate in narrow margins, deep wells, horizontal wells…..
- Training can help identify well control risks.
- See if current procedures need to be updated.
- Help improve crew training, train the personnel to make the right decisions in the different situations.

4.1 Drillbench

Drillbench is a commercial software package which can be obtained from the SPT Group which owns the software. It is a simulation package that can be used for planning and follow up of drilling operations. In this thesis we have been very fortunate to been using this software package to simulate different well control scenarios. The Drillbench software has several modules and amongst other there exist both steady state and transient modules that can be used for analyzing the pressure conditions in wells both during normal operations and during well control incidents. In this chapter Presmod and Kick modules will be described together with a presentation of the SPT Group taken directly from [14].

Figure 14: SPT Group.[14]

“Today SPT Group develops and markets OLGA, OLGA Online (edpm), Drillbench (Flow Simulations) and MEPO (Reservoir Optimisation), software products that support solutions maximizing production and reservoir performance. OLGA Online (edpm) is a proven dynamic online real-time production support system, assisting in the understanding of multiphase flow that enables sustained cost effective operations.

SPT Group currently employs more than 200 professionals world-wide, with a good mix of experience, expertise and education for maintaining the anticipated growth of the company. In addition to a full complement of engineers, our employees range from paleontologists to programmers to highly skilled sales and marketing personnel.

Headquartered in Oslo, Norway, SPT Group has offices and subsidiaries in Bergen, Cairo, Calgary, Dubai, Hamburg, Houston, Kuala Lumpur, London, Mexico City, Milan, Moscow, Rio de Janeiro, Perth and Stavanger. To support these corporate offices, SPT Group also has an extensive network of agents and representatives worldwide.”

Figure 15: Drillbench.[14]

“DRILLBENCH®

DYNAMIC WELL CONTROL

Realistic multiphase well control simulator providing the best planning and operational support through consideration of:

- Personnel safety
- Rig downtime
- Kick tolerance
- Maximum pressure loads
- Free gas breakout depth
- Water based gas migration
- Oil based gas dissolution
- Mud gas separator capacity
- Horizontal kicks
- Well kill operations”[17]

4.1.1 Presmod module

“Presmod adds a new dimension to drilling hydraulics by including dynamic temperature calculations in the hydraulic model. Presmod offers the user an easier and more exact evaluation of how the operational conditions and critical fluid properties influence pressure (ECD) and temperature conditions in the well.

Key features;

- Hydraulic design
- Operational forecasting
- Interpretation of downhole pressure and temperature readings (PWD)
- Development of operational guidelines
- Development of operational guide-lines in critical wells
- Calculation of equivalent static and circulation density (ESD & ECD)
- Calculation of temperature profiles for different operational conditions
- Calculations of thermal expansion effects
- Calculation of fluid properties vs. depth

Challenge

Lack of hydraulic power to reach the target in an ERD well, fracturing the formation with large mud losses and frequent kick incidents are only a few examples of very costly problems that can be reduced through proper planning with the correct tool.

Drillbench Presmod is a hydraulic software program used worldwide by drilling engineers to help in their decision-making processes. Presmod allows the engineer to design and plan operations within the simulator and thus prepare for reality. The parameters used in normal operations (i.e., circulation, rotation, drilling) can all be altered to reproduce real operational situations. Critical parameters can be visualised at several locations in the well through the flexible graphics.

The combination of accurate modelling, the graphical presentation and the ability to simulate are of special importance whenever the design margins decreases. It is well known that in advanced wells like HPHT wells, deep water wells, extended reach wells, wells in depleted reservoirs or in areas with gas or water injection, the margins between pore pressure and fracture pressure may be small. In the future, the drilling targets will probably be even more difficult. Drilling advanced and complicated wells requires an extra planning effort. Presmod can be used to simplify this planning process and it allows the drilling engineer to make better decisions.

Solution

Drillbench Presmod adds a new dimension to drilling hydraulics by including dynamic temperature calculations in the hydraulic model. This software program is a result of extensive R&D performed at Rogaland Research within flow modelling of non-Newtonian fluids. Presmod offers the user an easier and more exact evaluation of how the operational conditions and critical fluid properties influence pressure (ECD) and temperature conditions in the well. By using Presmod in the planning stage of the well, the drilling engineer will be able to monitor the processes that occur, thus allowing the user to supervise that the well conditions will meet the design requirements throughout the operations.”[16]

4.1.2 Kick module

“**Kick** is a unique software program for well control engineering, training and decision making support. The software is based on the results of R&D activities of multi-phase flow modelling, laboratory and full-scale experiments and extensive verification. The simulator uses advanced mathematical models in order to simulate the real process in the well. It can handle various wells, including many special and complex conditions. Kick is the result of extensive R&D activities within well control, performed at Petec and Rogaland Research during the last decades.

Key features;

- Evaluation of well control procedures
- Kick tolerance studies
- Evaluation of casing setting depths
- Casing design
- Design of surface equipment
- Evaluation of kick detection systems
- Post analysis of kick incidents
- Training of key personnel prior to difficult drilling operations

Making mistakes in a kick situation can be dangerous and result in huge costs additions to your total well project. Should things go terrible wrong, it might result in an uncontrolled blow-out situation. Even if a normal kick incident rarely leads to a full blow-out situation, it is expensive to handle the kick due to the costly rig time which is lost. A primary goal for drilling engineers is therefore to avoid any kick situation in well planning and design. Proper well design by using an accurate kick simulator is fairly critical when trying to reduce the frequency of kick incidence and to find the optimal method for handling a kick.

Furthermore, as the drilling targets are getting harder to reach, it may be necessary to evaluate safety margins in the well design. Trying to maintain an adequate safety level will require careful planning involving advanced software. Kick is a superior engineering tool used world-wide by drilling engineers for achieving best well control.”[15]

4.2 Discussion of special training aspects in an HPHT well environment

In the following, we will try to highlight some special things that one has to be especially aware of when addressing an HPHT well. An HPHT well is much more critical with respect to well control both with respect to frequency of kick and consequences. There are aspects that are more critical/special for a HPHT well and it is important to reflect this in training programs and simulator tools used. Drillbench has the capacity to evaluate HPHT wells and one of the wells it has been used for is shown in [1].

4.2.1 Kick behavior in OBM and WBM

The mud is normally either water based or oil based. The main tasks for the mud are to transport cuttings and cool down the system. The mud type chosen will have a huge impact on the well control scenario, and it is therefore important to choose the right mud in the different sections for the well [18, 22].

WBM [9]:

- The kick is easily detected.
- The gas kick will start to migrate upwards even if the well is shut in.
- Maximum casing shoe pressure and choke pressures will be larger during well kill operations compared to OBM.
- In WBM the gas kick is expected at surface earlier than in OBM.
- The well pressures will build up all the time the well is shut in, they will build up until the kick is just below the BOP.

OBM [9]:

- For high pressures the kick will fully dissolve in the OBM.
- The kick can be undetected in the well.
- The kick will boil rapidly in the upper parts of the well.
- Requires fast action, there will be a large expansion in the well as the free gas starts to boil out from the mud, the well therefore needs to be shut in as quickly as possible.
- There will be lower maximum casing shoe pressure and choke pressure in a well with OBM.
- The kick will not migrate upwards when the kick is dissolved in the mud, with no circulation.
- The gas kick is expected at surface later than with WBM since there is no free gas migration when the kick is dissolved.

4.2.2 ECD

The equivalent circulating density is a very important parameter in avoiding kicks and losses, particularly in wells that have a narrow window between the fracture gradient and pore-pressure gradient. It is an increase in the BHP that occurs only when the mud is circulated, this is due to friction in the annulus as the mud is pumped. The ECD is important in a HPHT well because of the narrow window between pore pressure and fracture pressure. The ECD is a function of the mud weight, the rheological properties , frictional pressure drop in the annulus and solids loading. The mud weight we observe at surface might not be the effective mud weight down in the well, the ECD takes into account the pressure drop in the annulus [2].

4.2.3 Temperature effects

In a HPHT well we are submitted to high temperatures and high pressures which can affect the conditions in the well. The hydraulic simulation takes into account that mud density will change depending on the temperature and pressure conditions in the well. Temperature effects during connections can cause flow return at surface and is easily mixed with an inflow situation. It can therefore be very important to perform fingerprinting, to avoid being fooled by the temperature effect. By using fingerprinting, [23], we mean that when the well is getting an increase in the return mud during connections, we can record how much increase we get each time we perform a connection. That way we can more easily control and monitor the well situation, because we know how much increase in mud level to expect during different well operations.

When the well is circulated there is either a net cooling in the well or a net heating in the well. If there is a net cooling in the well the well is pressure dominated, then the mud weight will increase down in the well. If the well is temperature dominated there will be a net heating in the well, then the mud weight will decrease down in the well. When the well is temperature dominated there is a higher risk for taking a kick down in the well, because the mud weight in the bottom of the well might be lower than what is observed at surface. When this occurs there is a risk for underbalanced conditions, which can lead to a kick [11].

4.2.4 Effect of cuttings

The muds carrying capacity is important to be able to carry out the cuttings from the well. When dissolved gas is mixed with the mud the mud weight will decrease and the carrying capacity and weight material of the mud is affected.

4.2.5 Effect of gas solubility

We are dealing with different types of mud, from WBM that has no gas solubility to OBM that can solve large amounts of gas. This means that it is crucial to be able to detect any volume changes in the well as early as possible. The effect of gas solubility can lead to undetected kicks. Since large amount of gas can dissolve in OBM, the gas might not be detected before it starts to boil out from the mud. Normally when we experience undetected kicks, they are relatively small, less than $0.5m^3$. It is therefore important to have a detailed pore pressure prognosis to avoid situations where the well is in underbalance, and can take a kick [2].

4.2.6 Surge and swab effect

The effect of the up and down movements of the string can influence the conditions in the well. When the string is tripping into the hole the mud will be pushed forwards into a wave motion, this is called surge pressure. When pulling the pipe out of the well, swabbing, there can form a “under pressure” in the well that can lead to an inflow of formation fluids into the well. The pressure that arises is dependent on the free area between the pipe and the annulus, it is also dependent on the viscosity of the mud, the velocity of the pipe movement and the length of the pipe [3]. In HPHT wells where there are small margins, it is common procedure to pump out of hole to reduce the swab pressure. Fig. 16 shows how important it is to maintain circulation during swabbing operations to avoid underbalanced conditions.

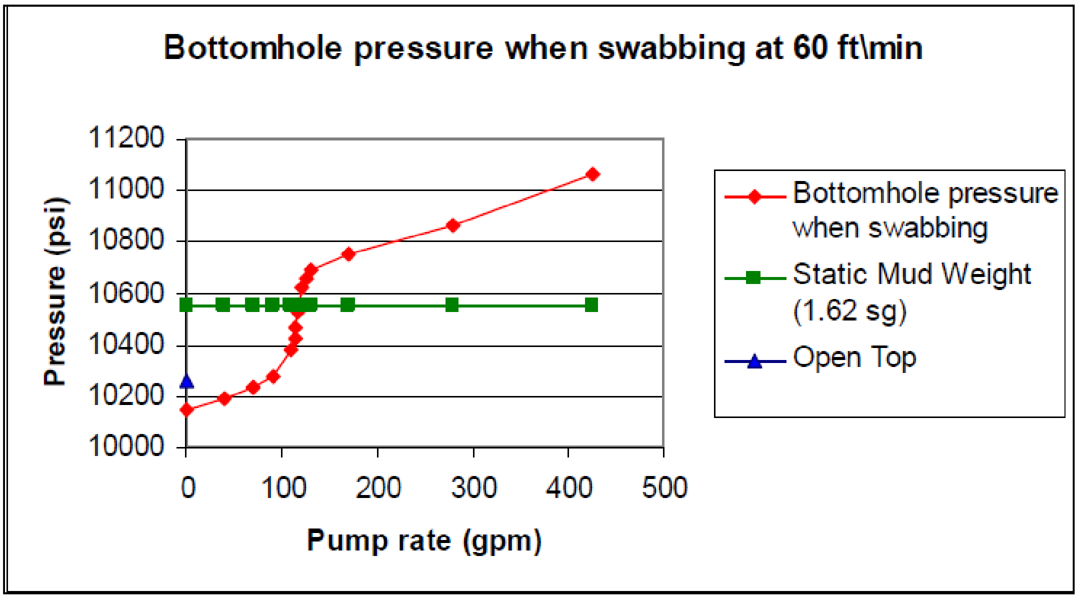


Figure 16: BHP when swabbing.[1]

5 Building a scenario in Drillbench for training purposes

5.1 Case description

In this case we are looking at a HPHT well. It is an exploration well drilled to investigate if there is an oil reservoir in the limestone/dolomite formation at approximately 4400 m TVD seen in the pore pressure prognosis Fig. 16. There is an expected reservoir temperature of 170 °C and the expected reservoir pressure is:

$P_p = 1.8 \times 4400 \times 0.0981 = 777$ bar

The well is planned as a vertical well drilled from surface down to the reservoir located at approximately 4400 m TVD. The well is extended from sea bottom to surface using a 21" OD riser, sea level is set to 250 m TVD. In general the casing and liners in the well are set to ensure well integrity and protect the formation against large pressures during the operation. The casing is set and cemented before the well is introduced to a new heavier mud. The heavier mud is introduced to balance the pore and fracture pressures in the well, this is to maintain a stable well before drilling further down. The casing seat design is normally decided from the pore gradient prognosis.

The first well section, the 30" conductor is set at 350 m TVD, 100 meters below sea bottom. The next section is the 20" casing section and that extends from sea bottom down to 1400 m TVD, this section is set in shale and it is set right before the pore pressure increases. Then the next casing section, 13 3/8" casing, is set at 2900 m TVD, where the pore pressure is around 1.5 sg. The reason why we want to set the casing as deep as 2900 m, is because there is a suspected unstable shale formation at 2700 m. The 12 ¼ " hole is then planned drilled down to 4200 m TVD, where the 9 5/8" casing is planned set. The 9 5/8" casing setting depth is determined from the pore pressure prognosis, we want to set the casing just above the reservoir section.

We assume that we take a kick in the 12 ¼ " section prior to reaching the next casing seat depth at 4200 m TVD. Here we are assuming that we have a permeable formation with porosity, resulting in inflow of formation fluids into the wellbore. When we are drilling this section the mud used will be both an OBM and also a WBM.

When performing the different simulations, we want to see the different effects the drill fluid will have in different kick scenarios. As described earlier OBM and WBM will react very different when there is an influx of gas in the well. For OBM the gas kick will completely dissolve in the mud and if the well is closed the kick will stay at bottom until the well is circulated again. Undetected kicks can be taken without a severe increase in pit gain and they will not be detected before free gas starts to boil out of the solution in the upper parts of the well. For WBM the gas kick will be able to migrate up in the well even at closed in conditions. A normal kick circulation is also performed, where we look at the different pressure and volume development in both OBM and WBM. In the 12 ¼ " open hole section we also look at;

- Mud temperature during static and dynamic conditions
- Pressure drop during connections and flow rate changes
- Swabbing effect
- Different kick scenarios

The 8 ½ " section is then drilled down to top of the reservoir We will also simulate a situation in the 8 ½ " well section. Here we will look at the swabbing effect and how the well pressure will change with varying flow rate.

The pore pressure prognosis in the well is found from the diagram below (Fig. 17):

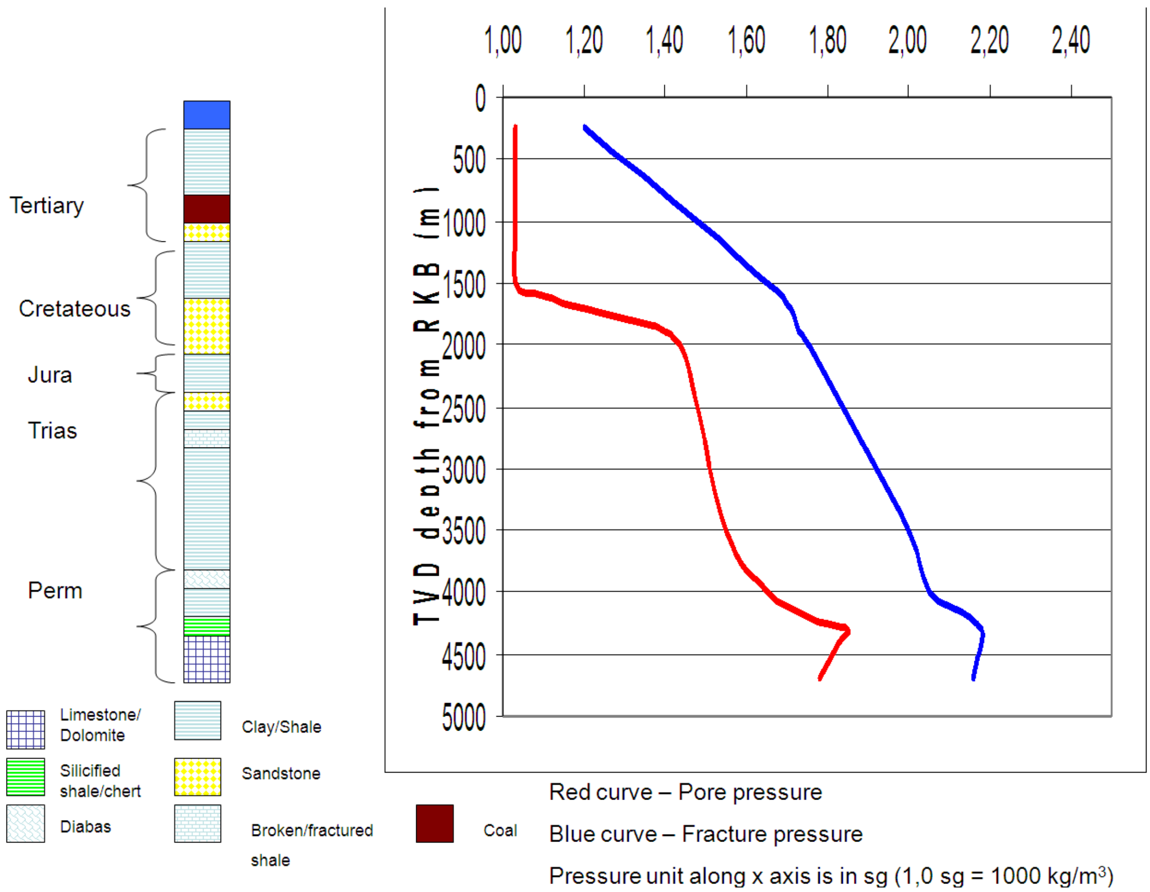


Figure 17: Expected pore and fracture pressure in the well.

5.2 Well Input

The input data describes the parameters used in defining the simulation case. Here the input data for the 12 ¼ " hole section is described in detail, and then the additional data used when simulating the 8 ½ " hole is mentioned at the end of this section

5.2.1 Input in the 12 ¼ " section

5.2.1.1 Formation

The surface temperature specifies the starting point for calculating the geothermal temperature shown in Fig. 18.

The lithology is the different formations we see in a vertical well. In this case we assume that we only have seawater and one formation with a geothermal gradient down in the well.

Lithology									
Name	Top	Bottom	Geothermal gradient	Specific heat	Specific heat gradient	Thermal conductivity	Thermal conductivity gradient	Density	Density gradient
	[m]	[m]	[C/m]	[J/kg*K]	[J/kg*K2]	[W/m*K]	[W/m2*K2]	[kg/m3]	[kg/m3*K]
Sea water	25,00	250,00	-0,01	4180,00	NAN	0,58	0,00	1000,00	NAN
Formation 1	250,00	6000,00	0,04	1000,00	NAN	2,00	NAN	2500,00	NAN

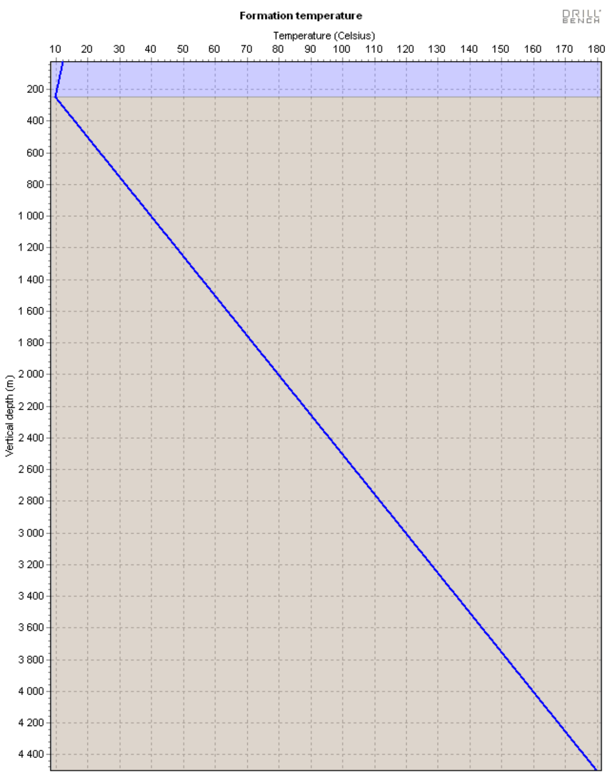


Figure 18: Geothermal temperature in the formation.

5.2.1.2 Survey

The survey input shows the well trajectory. In this case we have a vertical well with no inclination.

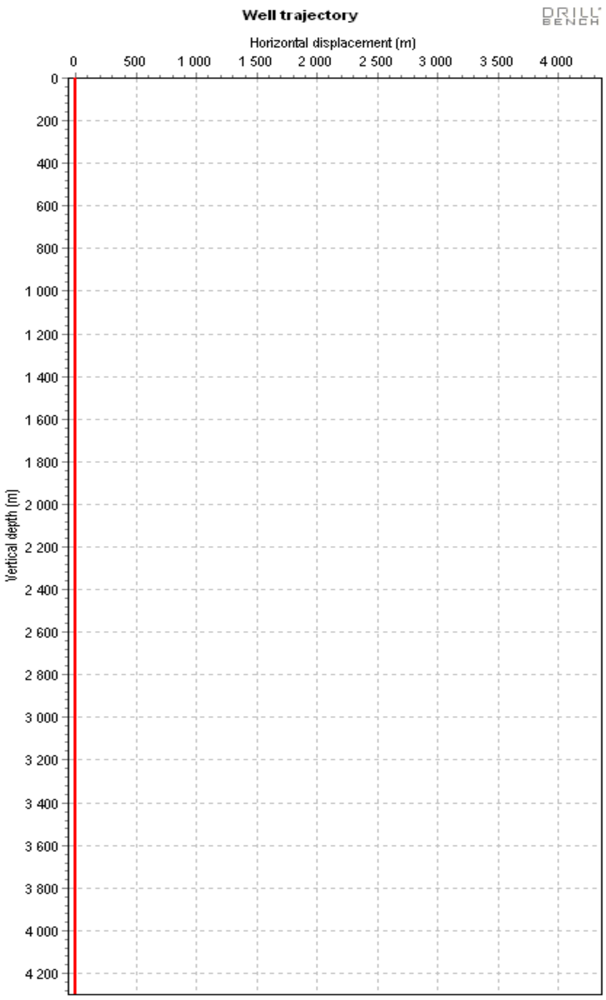


Figure 19: Trajectory of the vertical well.

5.2.1.3 Pore and fracture pressure

The pore pressures and fracture pressures for this case is found from the pore pressure prognosis of the well in Fig. 17. Here they are specified for various depths and plotted in the simulator.

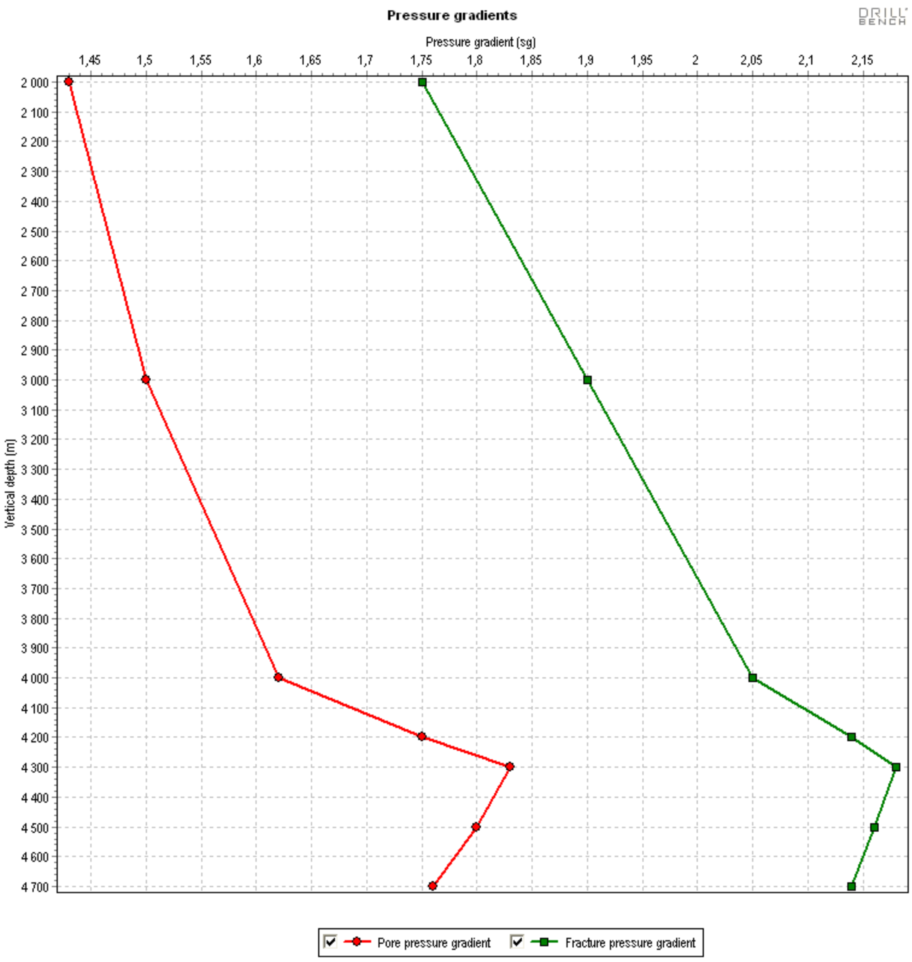


Figure 20: Pore gradient and fracture gradient.

5.2.1.4 Wellbore geometry

The wellbore geometry is the specification of the actual hole. The riser elongates the well from the bottom of the sea up to surface.

Riser			
Name	Length	Inner diameter	Outer diameter
	[m]	[in]	[in]
21" Riser	250,00	19,000	21,000

The casing program chosen is described in more detail in the case description.

Casing program							
Name	**Hanger depth**	**Setting depth**	**Inner diameter**	**Outer diameter**	**Hole diameter**	**Top of cement**	**Material above cement**
	[m]	**[m]**	**[in]**	**[in]**	**[in]**	**[m]**	
30" X-52 309.7 lbs/ft	250,00	350,00	28,000	30,000	36,000	250,00	Sea water
20" P110 94 lbs/ft	250,00	1400,00	19,122	20,000	26,000	250,00	WBM example#2 1.5sg
13 3/8" P110 80.70 lbs/ft	250,00	2900,00	12,217	13,374	17,500	2700,00	WBM example#2 1.5sg

The length of the open hole section is from the last set casing shoe to the bottom of the drilled well.

Open hole section	
Length	**Diameter**
[m]	**[in]**
1300,00	12,250

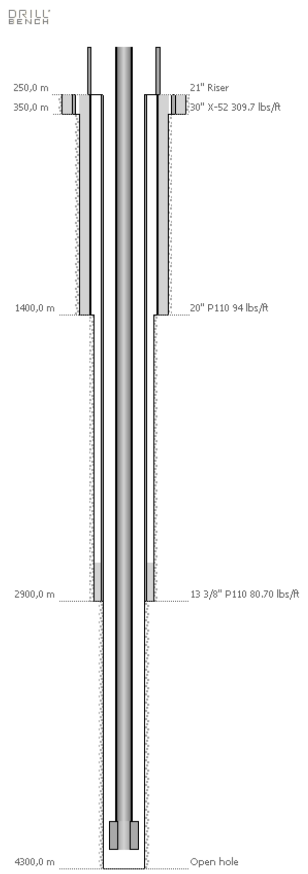


Figure 21: Well schematics.

5.2.1.5 Drill string and bit

The drill string is composed of a drill collar and a drill pipe, values and section lengths are given in the table below.

Component section						
Component	Type	Section length	Inner diameter	Outer diameter	Joint inner diameter	Joint outer diameter
		[m]	[in]	[in]	[in]	[in]
DC 8 1/2"	DrillCollar	150,00	3,750	8,500	3,750	8,500
dp 5" S135 19.50 lb/ft	Drillpipe	4050,00	4,276	5,000	2,750	6,625

The bit used to drill the 12 ¼ " section of the well is a Tricone bit, data is given below.

Bit: Bit 12 1/4 TriCone		
Name:		Bit 12 1/4 TriCone
Outer diameter	[in]	12,252
Flow area	[in^2]	0,95

Bit nozzles
Diameter
[in]
0,563
0,563
0,563
0,500

5.2.1.6 Drilling fluid, PVT model and rheology

The drilling mud used in this case is one OBM and one WBM, the data is given below.

Table 2: The oil based mud data.

Fluid: My mud		
Name:		My mud
Base oil density	[kg/m^3]	820,00
Water density	[kg/m^3]	1000,00
Solids density	[kg/m^3]	4200,00
Density	[kg/m^3]	1830,00
Reference temperature	[Celsius]	15,56
Oil water ratio:		80/20
Rheology type:		Non-Newtonian; Fann tables
Pvt model:		Compositional

Table 3: The water based mud data.

Fluid: Mynew mud		
Name:		Mynew mud
Base oil density	[kg/m^3]	820,00
Water density	[kg/m^3]	1000,00
Solids density	[kg/m^3]	4200,00
Density	[kg/m^3]	1830,00
Reference temperature	[Celsius]	15,56
Oil water ratio:		0/100
Rheology type:		Non-Newtonian; Fann tables
Pvt model:		Compositional

In the PVT model separate density models are applied for each phase; oil, water and solid material. And fluid density is calculated by combining the phase densities.

The simulator computes the frictional pressure losses through the well, to do this a rheology model is needed. A rheology model describes how the yield stress and the shear rate in the fluid is connected. The simplest model is the Newtonian model which describes a linear relationship between shear stress and shear rate. In most drilling fluids the apparent viscosity measured depends on shear rate. Non Newtonian fluids that are dependent on the shear rate are pseudoplastic if the apparent viscosity decreases with increasing shear rates and dilatants if the apparent viscosity is increasing with increasing shear rate. Drilling fluids and slurries are generally pseudoplastic. The simulator can use three different rheology models; Bingham plastic, Power law and Robertson Stiff. [20]

Any mixing ratio of reservoir fluid and drilling mud can occur after influx in a well, the objective of the PVT compositional model is to predict the physical properties of the mixed fluid.

The PVT model chosen for the OBM example is density correlations model:

Fluid models	
Oil density model:	Glasso
Rheology model:	Robertson-Stiff
Water density model:	Dodson-Standing

Temperature (Celsius)	Pressure (bar)	600 RPM (Pa)	300 RPM (Pa)	200 RPM (Pa)	100 RPM (Pa)	60 RPM (Pa)	30 RPM (Pa)	6 RPM (Pa)	3 RPM (Pa)
28,80	0,0	69	39	29	17	12	8		
28,80	100,0	69	39	29	17	12	8		
28,80	600,0	69	39	29	17	12	8		
28,80	1200,0	69	39	29	17	12	8		
50,00	0,0	47	23	17	10	8	6		
50,00	100,0	50	25	18	12	8	6		
50,00	600,0	54	28	20	13	10	7		
50,00	1200,0	61	34	24	15	12	8		
100,00	0,0	24	13	11	7	7	6		
100,00	100,0	28	16	12	9	7	6		
100,00	600,0	36	19	15	10	8	7		
100,00	1200,0	42	22	18	13	11	9		
200,00	0,0	19	16	16	16	14	14		
200,00	100,0	26	17	17	15	14	14		
200,00	600,0	33	20	18	14	14	13		
200,00	1200,0	43	28	25	20	18	18		

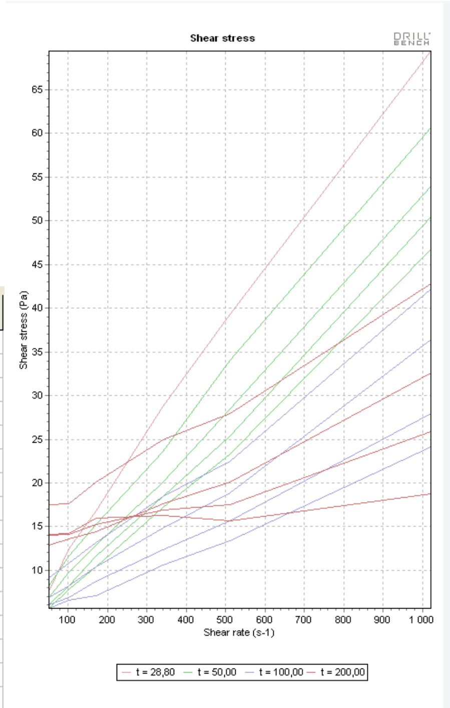


Figure 22: Fann readings and shear stress.

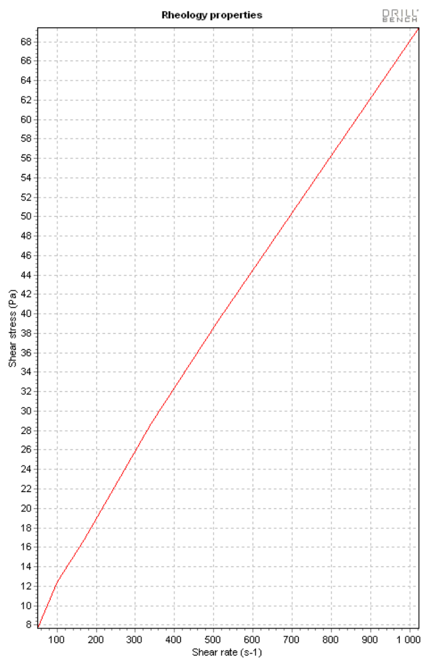
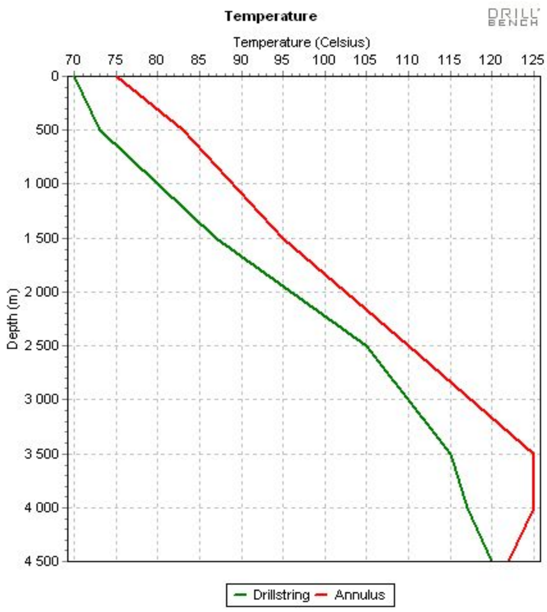


Figure 23: Rheology properties for the1.83 sg OBM.

5.2.1.7 Temperature

There are two types of temperature models that can be used in the simulations, dynamic and measured. In the dynamic temperature model, heat transfer and temperature will be computed dynamically. The measured temperature in the well is found using the geothermal temperature. By performing simulations in Presmod, the expected well temperature is found using the geothermal temperature as a starting point. The simulation result is shown in figure 4. The temperature is found by circulating the well until the mud in the well reaches a steady state. Constant temperature difference is chosen between the inlet and outlet of the mud.



Annulus temperature		Drillstring temperature	
Depth [m]	Temperature [Celsius]	Depth [m]	Temperature [Celsius]
0,00	75,00	0,00	70,00
500,00	83,00	500,00	73,00
1500,00	95,00	1500,00	87,00
2500,00	110,00	2500,00	105,00
3500,00	125,00	3500,00	115,00
4000,00	125,00	4000,00	117,00
4500,00	122,00	4500,00	120,00

Figure 24: Simulation of well temperature during circulation performed in Presmod.

5.2.1.8 Reservoir properties

We assume that the pore pressure at 4200 meters is equal to the mud weight to be able to take in a kick:

Pp = 4200 x 1.83 x 0.0981 = 754

The reservoir data is given below.

Lithology					
Name	Top [m]	Bottom [m]	Pressure [bar]	Temperature [Celsius]	Flow model
Formation1	4190,00	4200,00	754,0	170,00	Reservoir model

Reservoir fluid	
Pvt model:	Compositional

Influx type: Methane

5.2.1.9 Surface equipment

The surface equipment is important during the kill circulation. The main data is listed below.

Chokeline		
Length	[m]	250,00
Number of kill and chokelines		1

Pump		
Liquid rate change	[m^3/s^2]	0,00
Volumetric output	[m^3/stroke]	0,01
Response delay	[min]	0,20

BOP		
Closure time	[min]	0,30
Response delay	[min]	0,45

5.2.2 Input in the 8 ½ "section

In the 8 ½ "section we have some additional input data, these are given below.

5.2.2.1 Wellbore geometry

In the casing program, a 9 5/8" casing is set at 4200 m TVD. And the open hole 8 ½ "section is only 200 meters.

Casing program							
Name	Hanger depth	Setting depth	Inner diameter	Outer diameter	Hole diameter	Top of cement	Material above cement
	[m]	[m]	[in]	[in]	[in]	[m]	
30" X-52 309.7 lbs/ft	250,00	350,00	28,000	30,000	36,000	250,00	Sea water
20" P110 94 lbs/ft	250,00	1400,00	19,122	20,000	26,000	250,00	WBM example#2 1.5sg
13 3/8" P110 80.70 lbs/ft	250,00	2900,00	12,217	13,374	17,500	2700,00	WBM example#2 1.5sg
9 5/8" P110 43.5 lbs/ft	250,00	4200,00	8,756	9,626	12,250	4000,00	OBM example#1 1.86 sg

Open hole section	
Length	Diameter
[m]	[in]
200,00	12,250

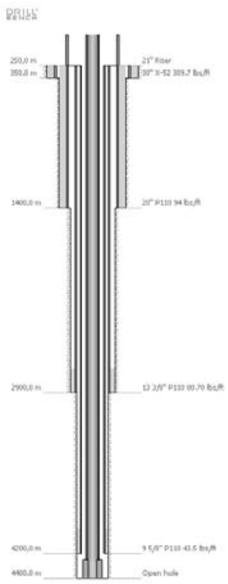


Figure 25: Well schematics for the 8 ½ "section.

5.2.2.2 Drill string and bit

This section has a smaller diameter so the drill collar and bit size is smaller here than in the 12 ¼" section.

Component section						
Component	**Type**	**Section length**	**Inner diameter**	**Outer diameter**	**Joint inner diameter**	**Joint outer diameter**
		[m]	**[in]**	**[in]**	**[in]**	**[in]**
DC 7 1/2"	DrillCollar	150,00	3,500	7,500	3,500	7,500
dp 5" S135 19.50 lb/ft	Drillpipe	4250,00	4,276	5,000	2,750	6,625

Bit: Bit 8 1/2 pdc		
Name:		Bit 8 1/2 pdc
Outer diameter	[in]	8,500
Flow area	[in^2]	0,70

5.2.2.3 Drilling fluid

The drilling fluid used in the 8 ½" section is a 2.0 sg OBM.

Fluid: My mud		
Name:		My mud
Base oil density	[kg/m^3]	820,00
Water density	[kg/m^3]	1000,00
Solids density	[kg/m^3]	4200,00
Density	[kg/m^3]	2000,00
Reference temperature	[Celsius]	15,56
Oil water ratio:		80/20
Rheology type:		Non-Newtonian; Fann tables

6 Simulation results

This chapter will address the results found from the simulations done both in Presmod and Kick. In the pressure and temperature simulations done in Presmod, the drilling fluid used is OBM for both the 12 ¼ “section and the 8 ½” section. While the different Kick simulations in the 12 ¼ “section is done using both OBM and WBM.

Simulations done in Presmod are;

- The temperature profile of the mud during static and dynamic conditions.
- The friction pressure loss during connections, both in the 12 ¼ “section and the 8 ½ “section.
- The effect of swabbing with and without pump connected, both in the 12 ¼ “section and the 8 ½ “section.

Simulations done in Kick;

- Undetected kick in OBM.
- Closed in well with OBM.
- Kick circulation in OBM.
- Closed in well with WBM.
- Kick circulation in WBM

A comparison of a kick circulation in both OBM and WBM is shown. Here we clearly see the differences in pressure and volume as the kick is circulated out the chokeline.

6.1 Presmod simulation

6.1.1 Mud gradient and temperature

The temperature profile in the well will reach a steady state when the well is circulated. As seen from Fig.26, at steady state conditions there will be a positive heat transfer from the formation in the lower parts of the well, while in the upper parts there will be a negative heat transfer to the formation. However, due to convection (fluid transport) the temperature profile of the mud will be different than the geothermal gradient. It will be warmer in the upper parts and colder in the lower parts.

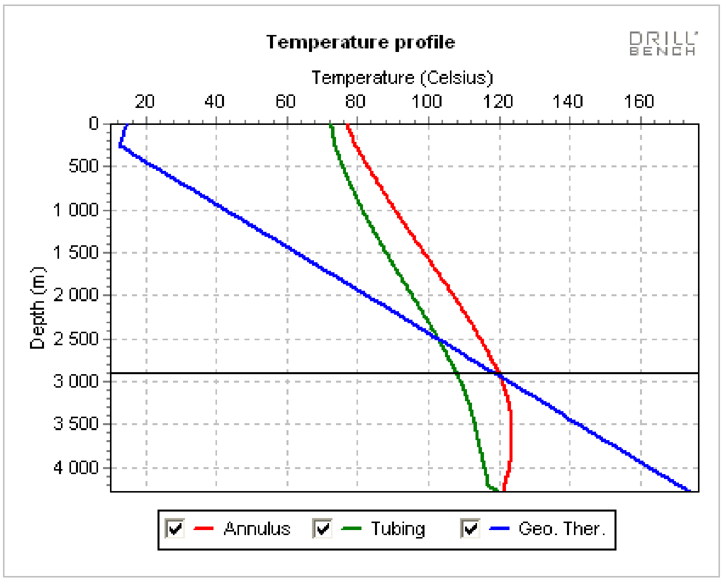


Figure 26: Temperature of mud when the well is circulated.

When the fluids in the well are held static the mud temperature in the well will approach the geothermal temperature gradient in the well. This is shown in Fig.27. Under static conditions there is no new mud going into the system, therefore the mud in the well will be affected by the geothermal conditions in the well. In the upper sections in the well the mud will cool down, while in the lower sections the mud will get warmed up, getting close to the temperature given by the geothermal gradient.

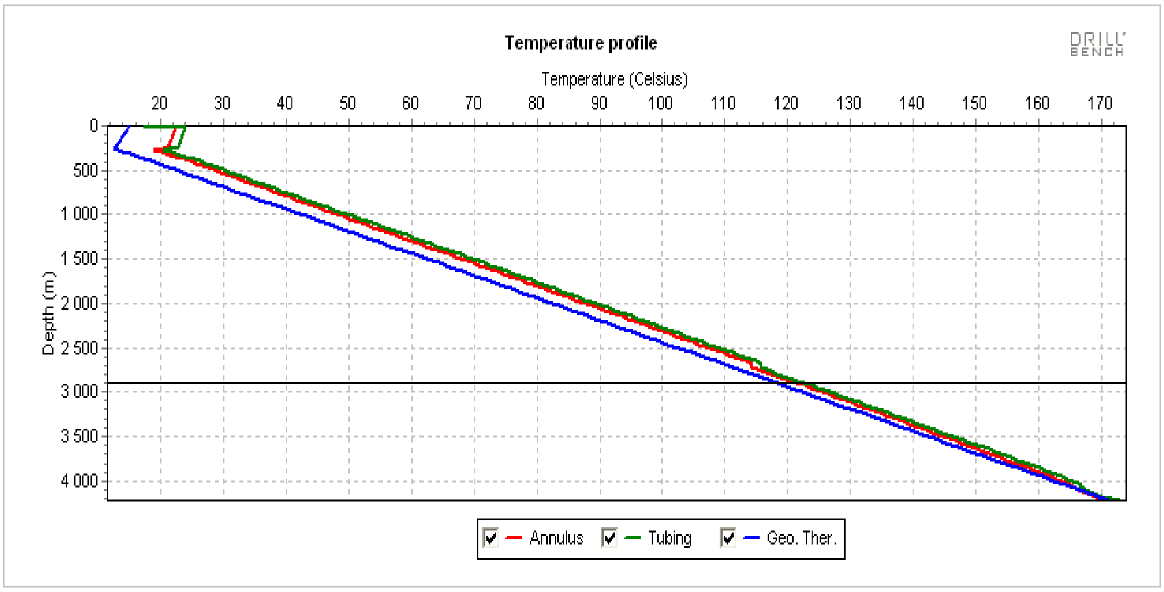


Figure 27: Temperature of mud when the well is not circulated.

6.1.2 Friction and ECD

In the well we will have a friction force acting when the well fluid is circulated, but when the well fluids are static we will not have the dynamic friction force present. As the fluid moves through the well there will be friction between the fluid and the surrounding casing and pipe wall and within the fluid itself, this creates a pressure drop. The friction effect can be found using the Presmod simulator. From the simulated ECD we can find the frictional pressures for various flow rates. The ECD simulation is done for both the 12 ¼ " section and for the 8 ½ " section in the well with the 1.83 sg OBM.

6.1.2.1 Friction and ECD in the 12 ¼ " section

In Fig. 28 we can see the mud flow rate distribution during the simulation. First we circulate the well until steady state with a rate of 3000 lpm, then the well stops circulating for 10 minutes, before we start to circulate with 500 lpm, 2000 lpm and 3000 lpm.

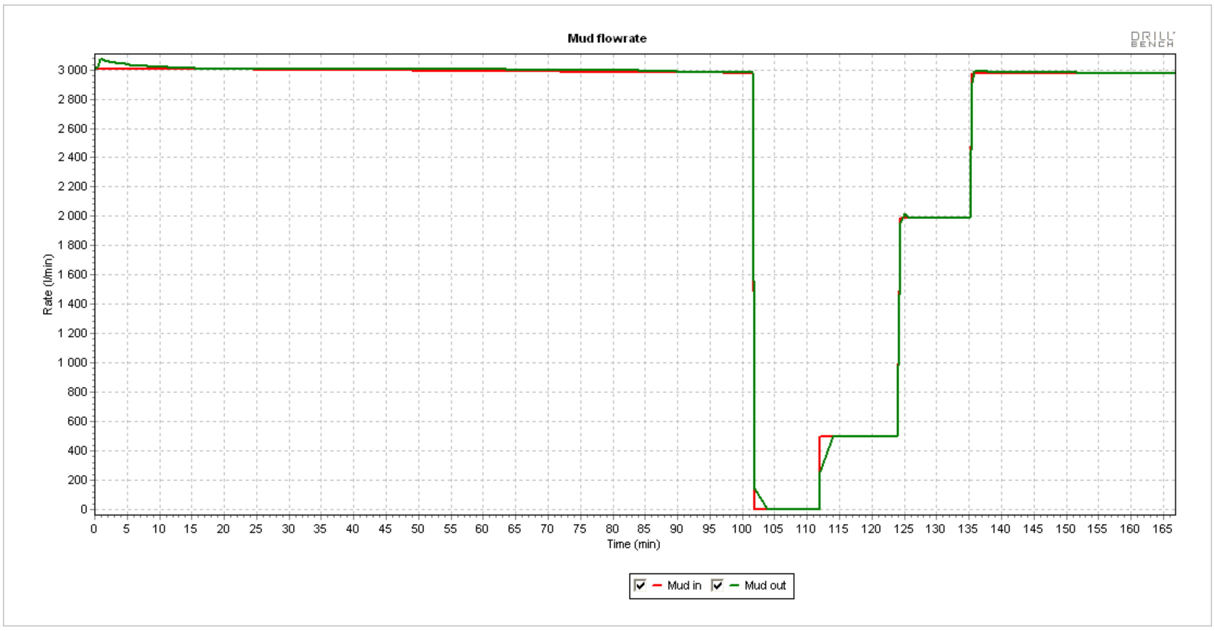


Figure 28: Mud flow rate for the 12 ¼ ” section.

From Fig. 29 the ECD at bit depth is simulated using the 1.83 sg OBM. When the well is circulated with a rate of 3000 lpm the ECD at bit depth is stable at 1830 kg/m^3.

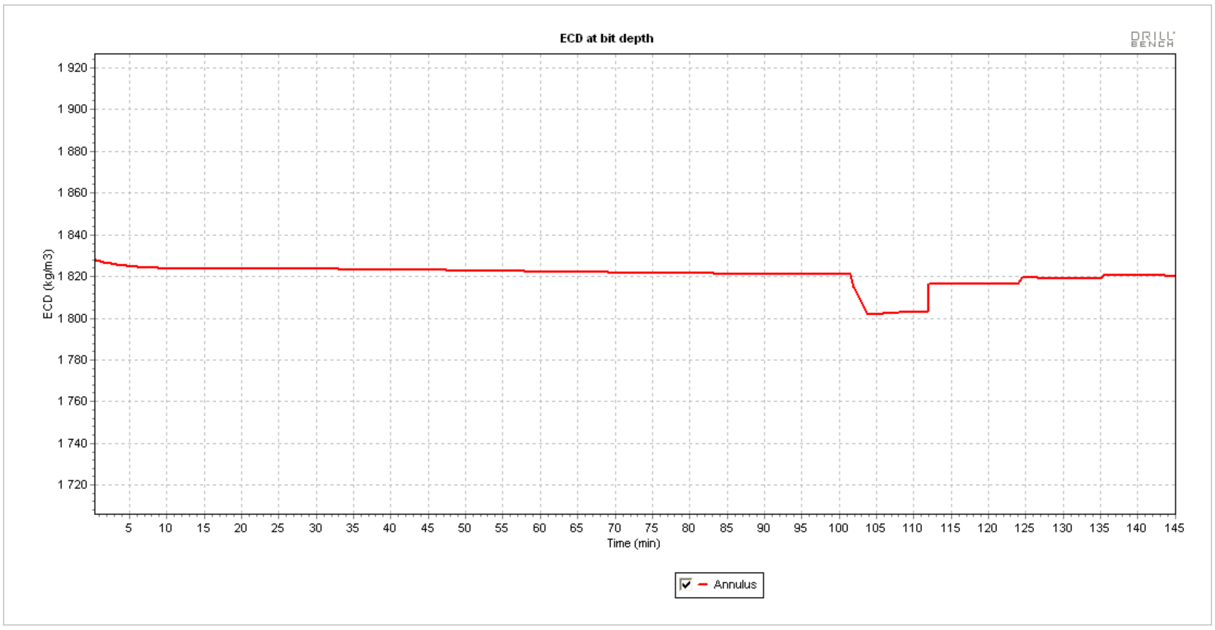


Figure 29: ECD for a 1.83 sg OBM in the 12 ¼ ” section.

In Table 4 the result from the simulation is shown, also the friction pressure is shown when changing flow rate. Here it is shown that the frictional pressure drop during connections is 6.7 bars.

Table 4: ECD and friction pressure drop when changing flow rate in the 12 ¼ " section.

Flow rate (lpm)	ECD (kg/m^3)	$\Delta P_{FRICTION}$ (sg)	$\Delta P_{FRICTION}$ (bar)
3000	1821		
0	1805	0.016	6.7
500	1815	0.010	4
2000	1819	0.004	1.6
3000	1821	0.002	0.8

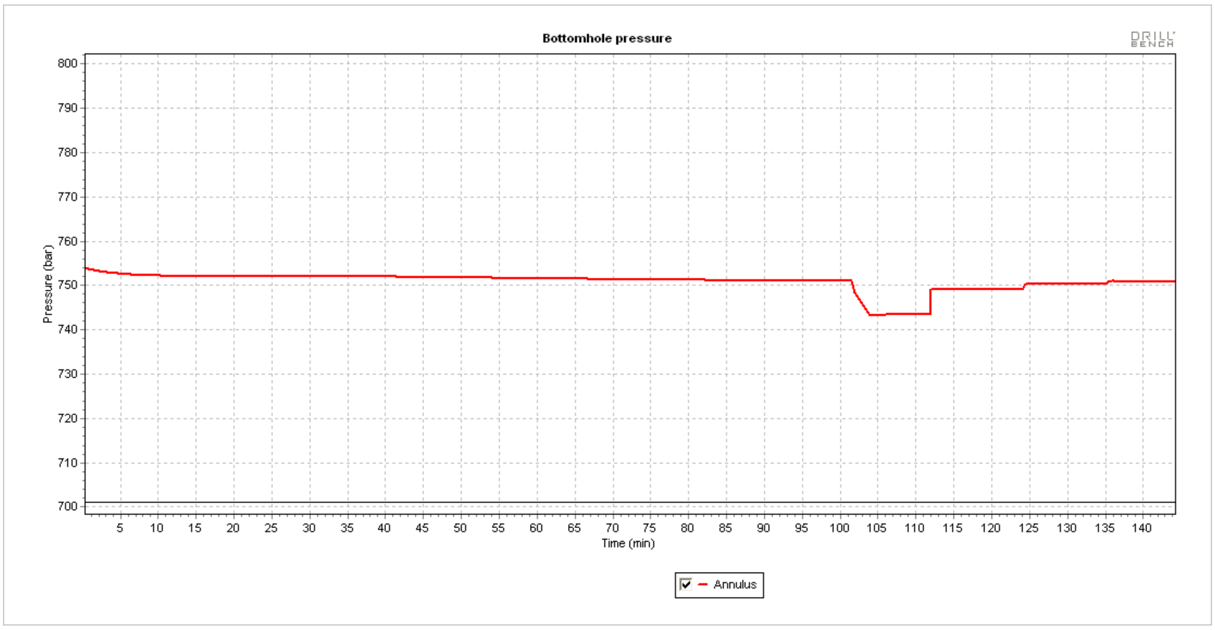


Figure 30: BHP in the 12 ¼" section.

In Fig. 30 the pressure drop during the simulation is shown. When the circulation starts the BHP stabilizes at 751 bar, when the pump is turned off the pressure falls down to 744 bar during the 10 minutes with no circulation, i.e when pumping with 3000 lpm, there is around 7 bars frictional pressure loss during connections.

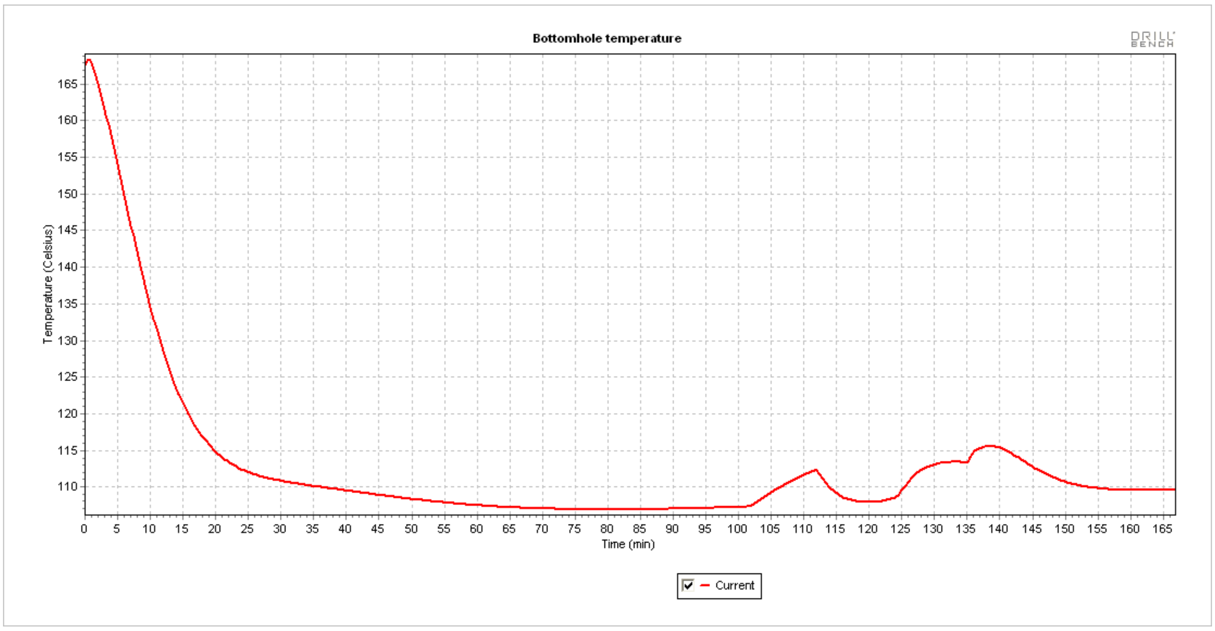


Figure 31: BHT in the 12 ¼ " section.

Initially the mud was assumed to have a temperature equal to the geothermal profile. When the well is circulated the BHT will stabilize at a constant temperature shown in Fig. 31. During a connection when the well is not circulated the BHT will start to increase, and it will then start to decrease again when the mud in the well starts circulating again. The reason for this is that the surrounding formation starts to heat up the well in the lower parts when the pumps are off.

During the simulation there is an increase in the pit gain when the well is circulated in Fig. 32. This just express that when the well starts with a mud temperature equal to the geothermal profile and is being circulated for a while, there will be a net heating of the mud in the system. It also tells us that if the well is closed for a long time, a reverse effect will be seen.

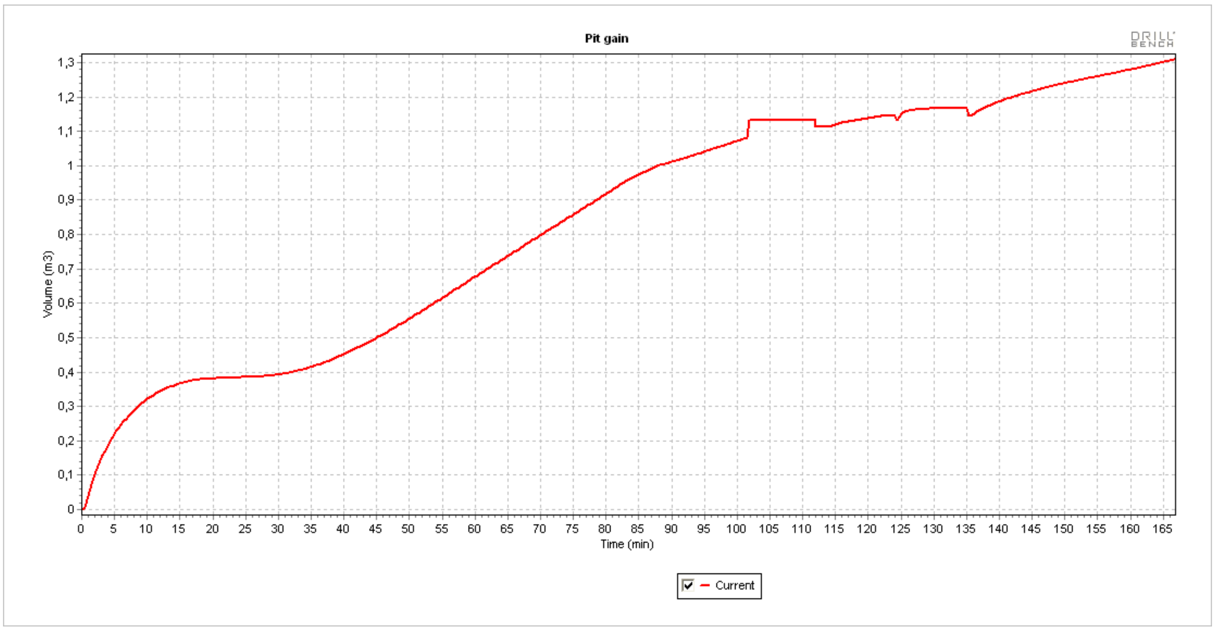


Figure 32: Pit gain in the well during simulation.

6.1.2.2 Friction and ECD in the 8 ½ " section

The same procedure as above is performed during simulation of the 8 ½ " section. Except here the start flow rate is set to 1500 lpm, which is a normal circulation rate in this section. The change in mud flow rate is shown in Fig. 33.

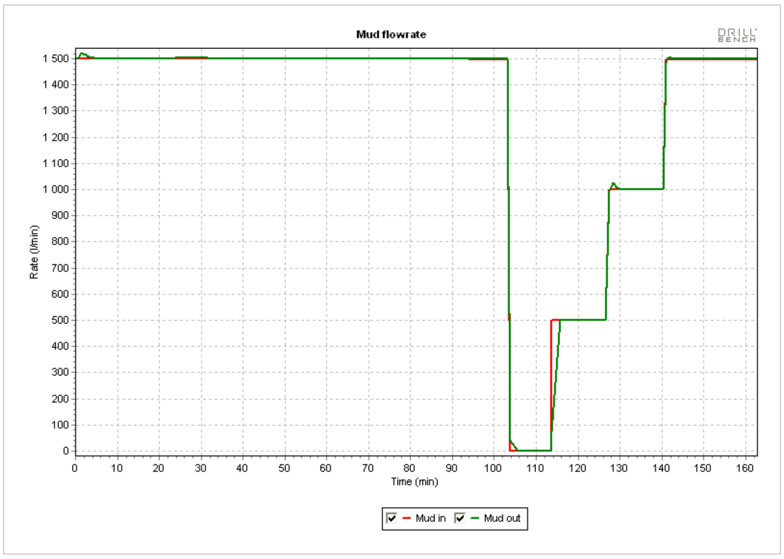


Figure 33: Mud flow rate for the 8 ½ " section.

In Fig. 34 the ECD for the 8 ½ " section is shown. Here there is observed a larger drop in the ECD when the circulation is stopped than for the 12 ¼ " section in Fig. 29.

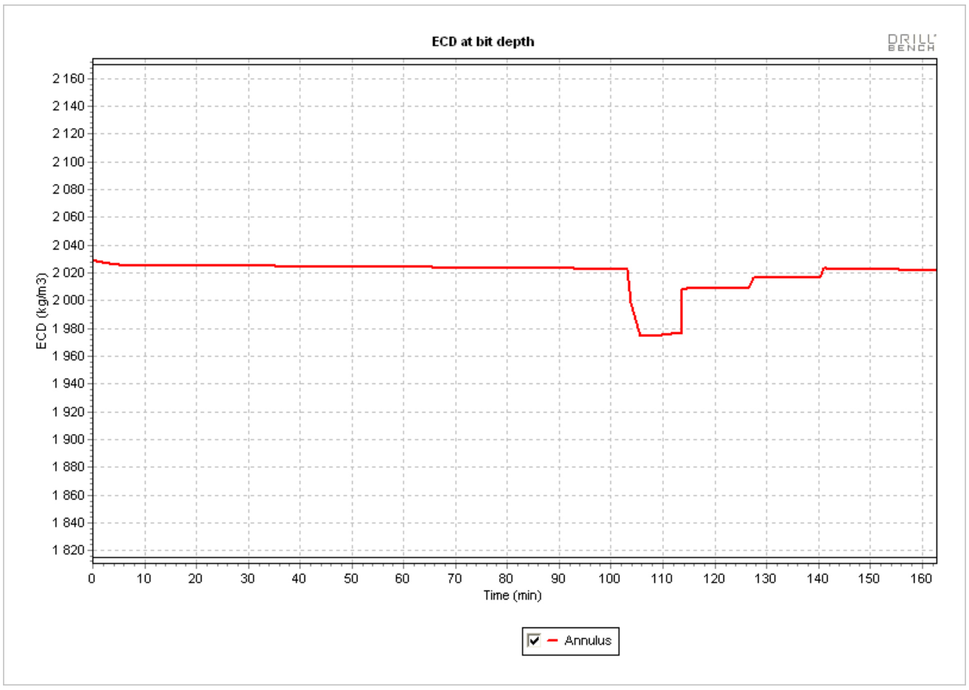


Figure 34: ECD at bit depth for the 2.0 sg OBM.

From Fig. 34 the ECD at bit depth is simulated using the 2.0 sg OBM. When the well is circulated with a rate of 1500 lpm the ECD at bit depth is stable at 2023 kg/m^3. From Table 5 the results from the simulation are shown, also the friction pressure is shown when changing flow rate. Here it is shown that the frictional pressure drop experienced under connections is 20 bars.

Table 5: ECD and friction pressure drop when changing flow rate in the 8 ½ " section.

Flow rate (lpm)	ECD (kg/m^3)	$\Delta P_{FRICTION}$ (sg)	$\Delta P_{FRICTION}$ (bar)
1500	2023		
0	1977	0.046	20
500	2010	0.033	14.2
1000	2018	0.008	3.5
1500	2023	0.005	2.2

The drop in ECD is larger in the 8 ½ "section, showing that the ECD can have a huge impact on the well when it is not circulated. It is important to simulate the ECD closely during connections to know how much the ECD will be affected by the change in flow rate in the different well sections, since we get a large drop in ECD which can lead to a well problem.

When the circulation starts the BHP stabilizes at 873 bar, when the pump is turned off there is a pressure drop down to 854 bar during the 10 minutes with no circulation. That is a pressure decrease of 20 bars. The pressure decrease is shown in Fig. 35.

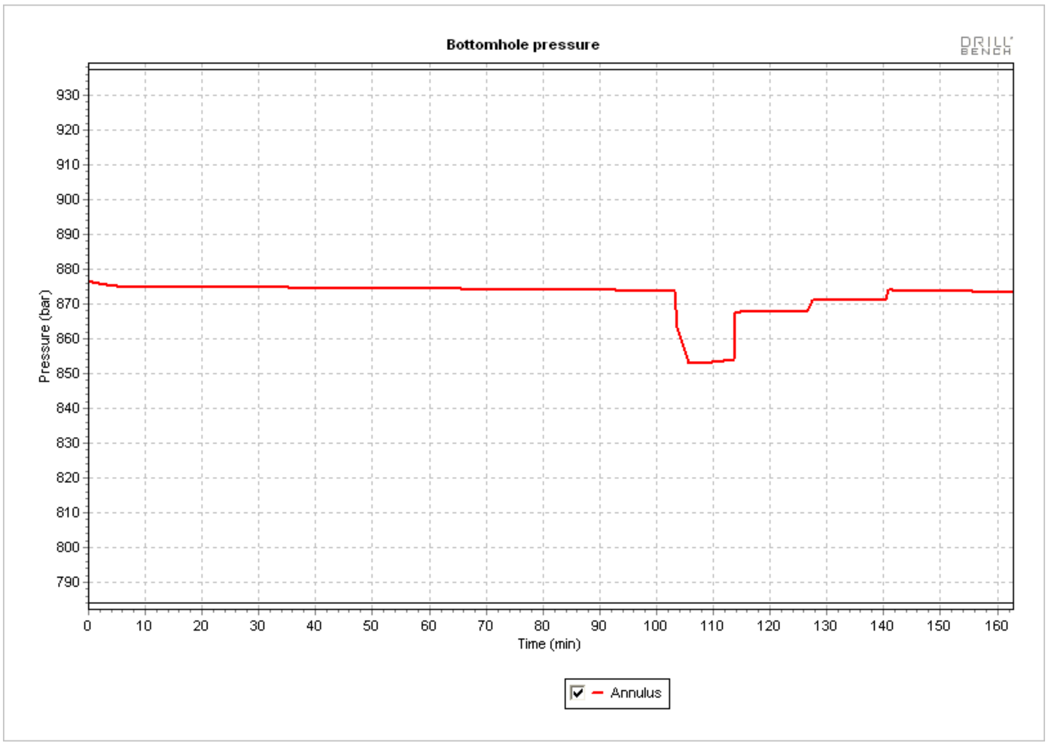


Figure 35: BHP in the 8 ½ ” section.

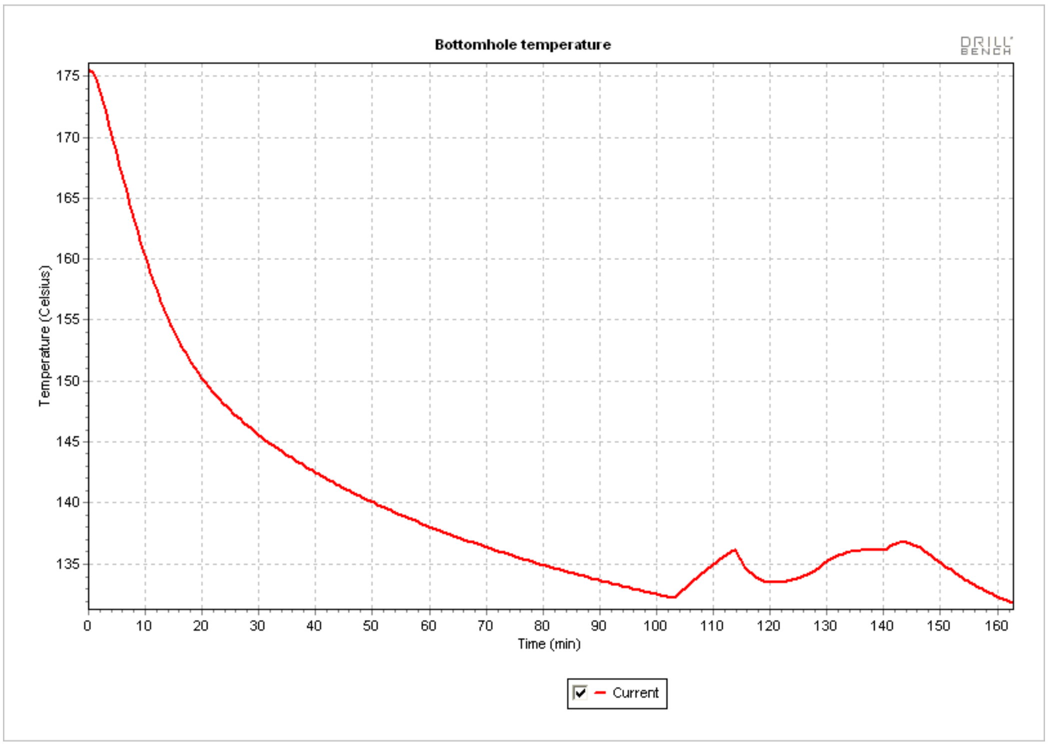


Figure 36: BHT in the 8 ½ ” section.

During the simulation there is a small increase in the pit gain when the well is circulated. During the 10 min connection there is no increase in pit gain, from Fig. 37. As for the 12 ¼ "section we see the increase in pit gain because when we start to circulate the well we will get a net heating of the mud. There is also a clear increase in pit gain as the connection starts, this is due to the 20 bars drop in BHP seen in Fig. 35, and the pressure drop leads to fluid expansion as the pump is turned off.

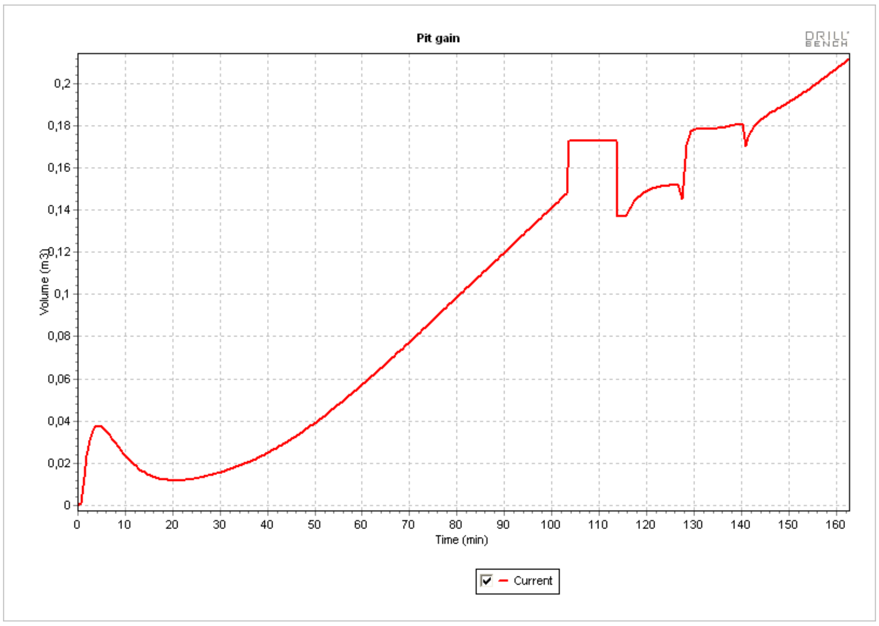


Figure 37: Pit gain during simulation.

6.1.3 Temperature effect

In Fig. 38 the temperature of the mud in the well is shown. From the mud density plot, Fig. 39, it is shown how the mud density is affected down in the well. The mud density observed at surface is not same as the one observed down in the well. This plot shows that the well is subjected to temperature effects and that temperature is dominating with respect to fluid densities in the well. The mud density going up in the annulus is actually 1.79 sg down in the well and 1.8 sg at surface. This shows how important it is to ensure that the mud weight is large enough, the mud weight should always be a few pressure points above the pore pressure to account for both temperature and potential swab effects. This makes it more complicated to design the mud gradient in HPHT wells where there usually is very small margins in the well.

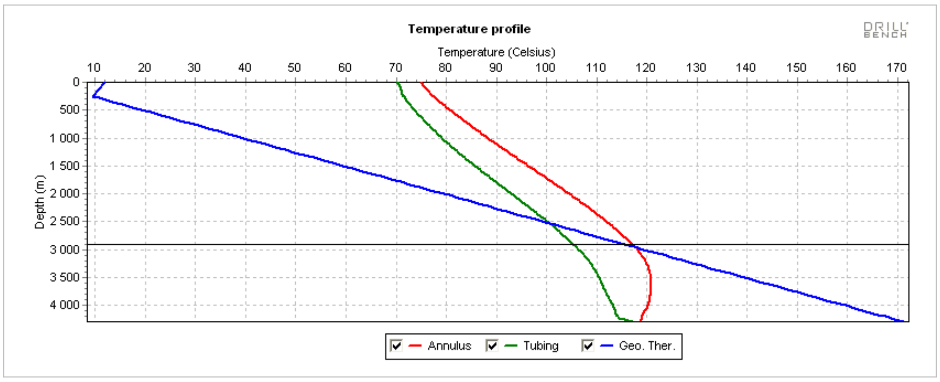


Figure 38: Temperature profile in the well.

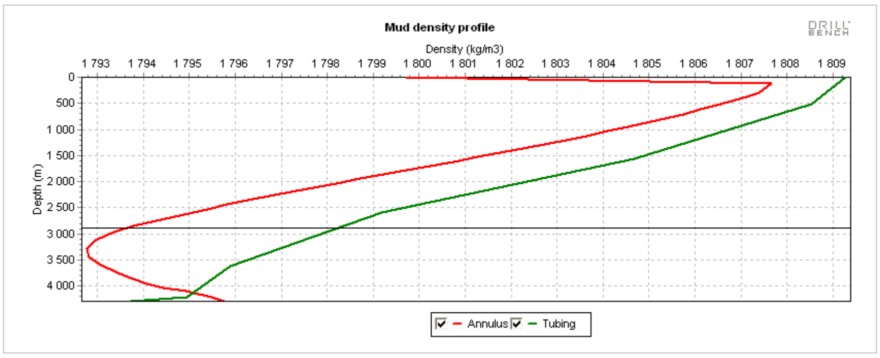


Figure 39: Mud density in the well.

6.1.4 Swabbing

When swabbing there are two options, either to use open top, meaning no circulation during swabbing or using pump connected, meaning that the pump is circulating mud into the well. Swabbing fast means that the stand is pulled out of the hole at a speed around 1 minute per stand, while swabbing slow is to pull the stand out at around 5 minutes per stand. The swabbing simulation is done for both the 12 ¼ “section and 8 ½ “section, this is to show the difference in ECD when swabbing in the two sections. The swabbing effect gets worse in smaller sections.

6.1.4.1 Swabbing in the 12 ¼ “ section

Swabbing the well with no circulation is shown in Fig. 40 and 41 below, the red curve is for swabbing slow at 5 minutes per stand, while the green curve is for swabbing fast at 1,4 minutes per stand. Here there is almost no difference in swabbing out of the hole fast or slow. The ECD during swabbing falls from 1800 kg/m^3 to approximately 1780 kg/m^3.

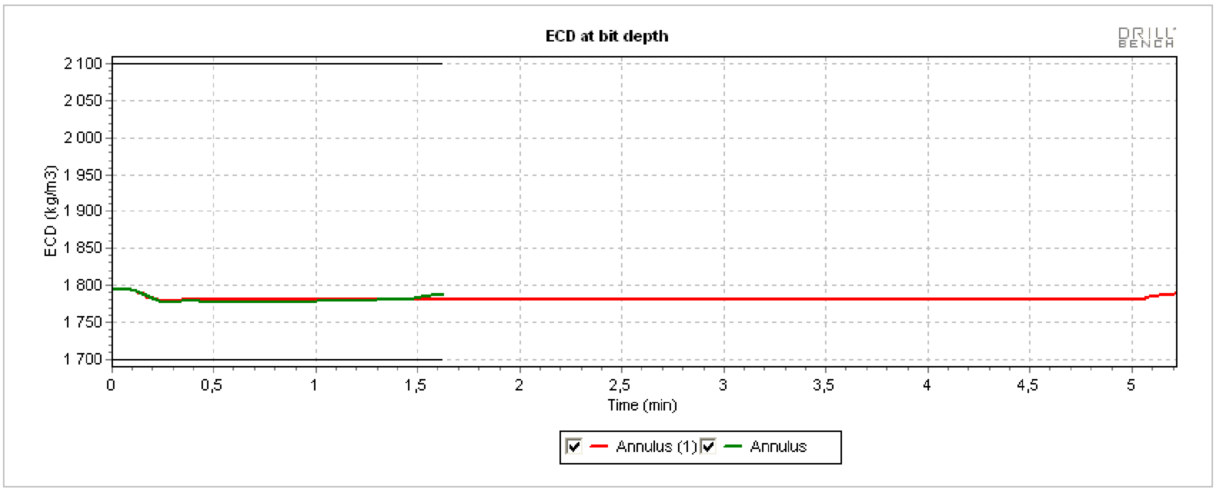


Figure 40: ECD when swabbing in the 12 ¼ " section, no circulation. Red curve is for pulling slow, green curve is for pulling fast.

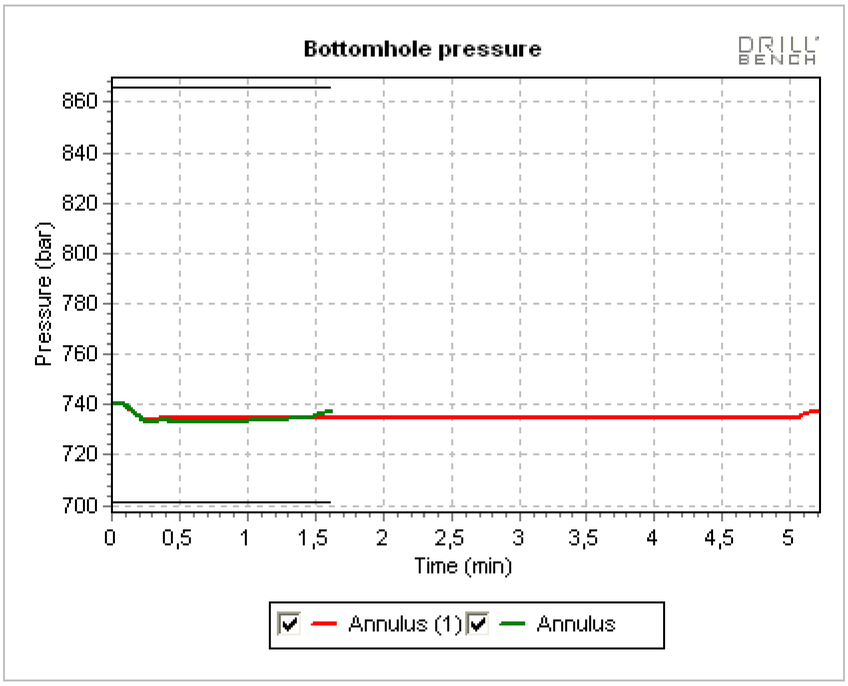


Figure 41: BHP when swabbing in the 12 ¼ " section, no circulation. Red curve is for pulling slow, green curve is for pulling fast.

Swabbing with pump connected, with a circulation rate of 500 lpm is shown in Fig. 42. When the pump is connected during swabbing, the pressure is higher than without circulation. This means that the well pressure is less affected when we circulate, which means that it is smart to connect the pump during swabbing to avoid a decrease in pressure, then we can avoid inducing a kick. When we look at the red curve, swabbing with a low rate of 5 minutes per stand we see that the well pressure is almost not affected, indicating that we almost have no friction when pumping out of the hole. When pulling the stand at a high speed, 1,4 minutes per stand, the effect on the ECD becomes more prominent, here we see that we get friction when pulling the stand.. This indicates that when swabbing it is important to not swab too fast, because it can lead to a large decrease in well pressure and the well can take in a kick. In Fig. 43 the same effect as for the ECD is shown for the BHP, here there is a pressure decrease when swabbing fast.

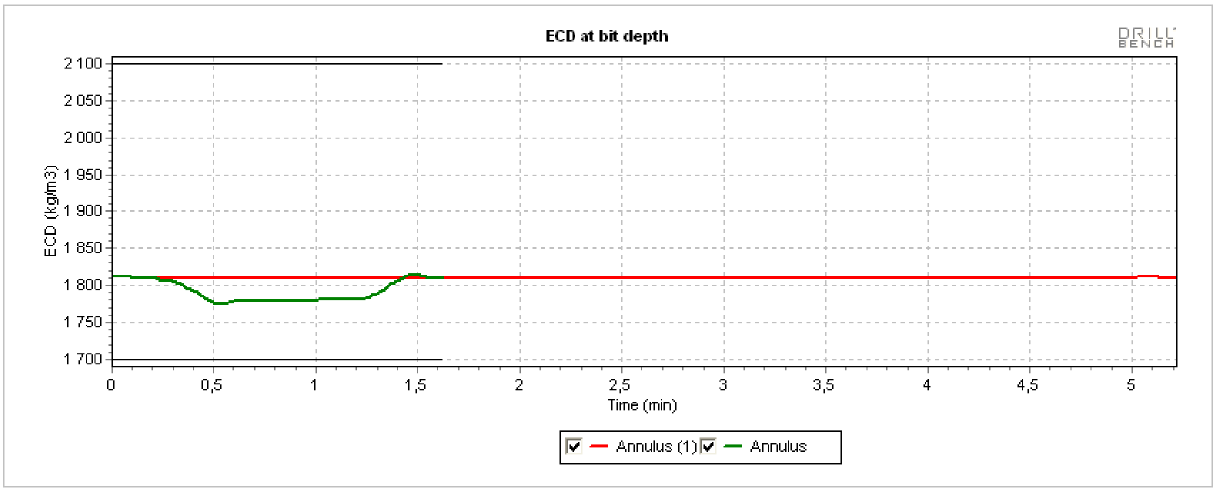


Figure 42: ECD when swabbing in the 12 ¼ " section, circulation rate 500 lpm. Red curve is for pulling slow, green curve is for pulling fast.

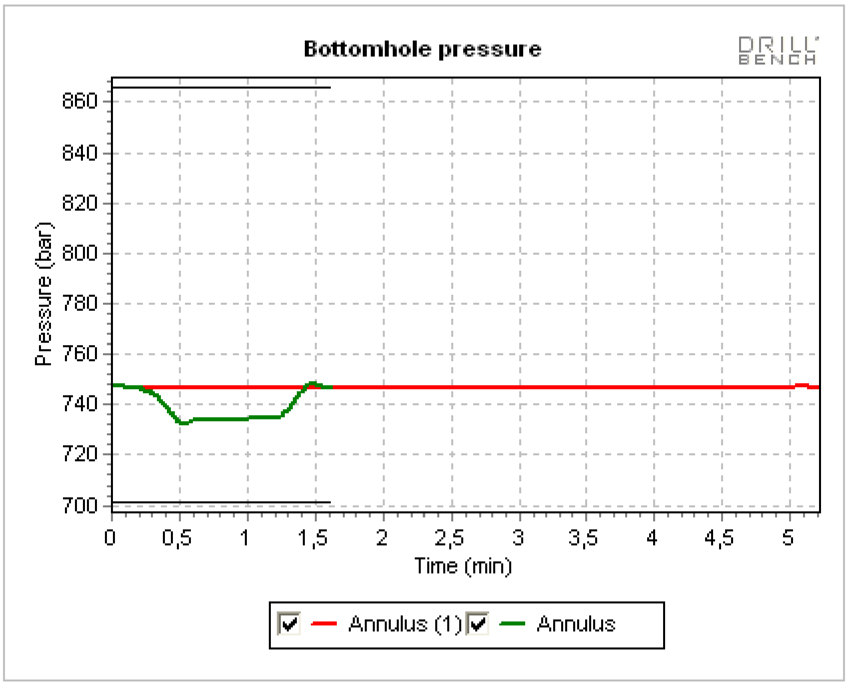


Figure 43: BHP when swabbing in the 12 ¼ " section, circulation rate 500 lpm. Red curve is for pulling slow, green curve is for pulling fast.

Swabbing with pump connected, with a circulation rate of 1500 lpm is shown in Fig. 44. Looking at the green curve when the pump is circulating with a high circulation rate the ECD is less affected when swabbing fast. This indicates that an increase in the pump rate during swabbing can avoid the decrease in well pressure that can lead to kick. This also demonstrates that one has to use simulations to find the optimal rate.

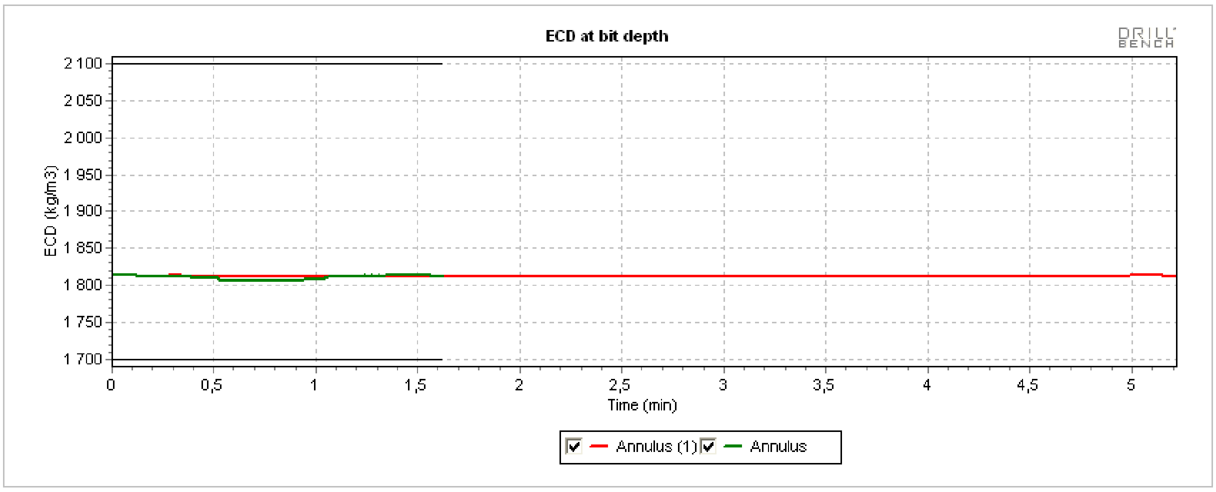


Figure 44: ECD when swabbing in the 12 ¼ " section, circulation rate 1500 lpm. Red curve is for pulling slow, green curve is for pulling fast.

6.1.4.2 Swabbing the 8 ½ " section

When swabbing in the 8 ½ " section with open top, no circulation, the well pressure is more affected than for the 12 ¼ " section. The ECD at bit depth with no circulation in Fig. 45 drops down from 1960 kg/m^3 to 1915 kg/m^3. Here we see a larger effect when swabbing fast, the green curve. The BHP in Fig. 46 shows the same trend as the ECD.

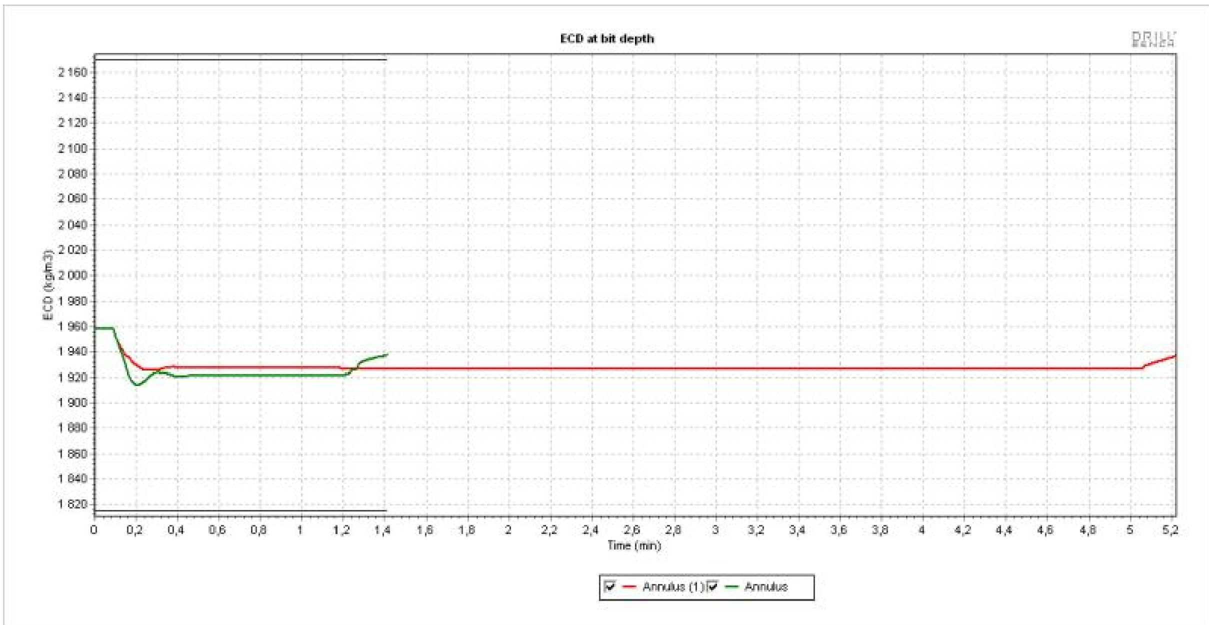


Figure 45: ECD when swabbing in the the 8 ½" section, no circulation. Red curve is for pulling slow, green curve is for pulling fast.

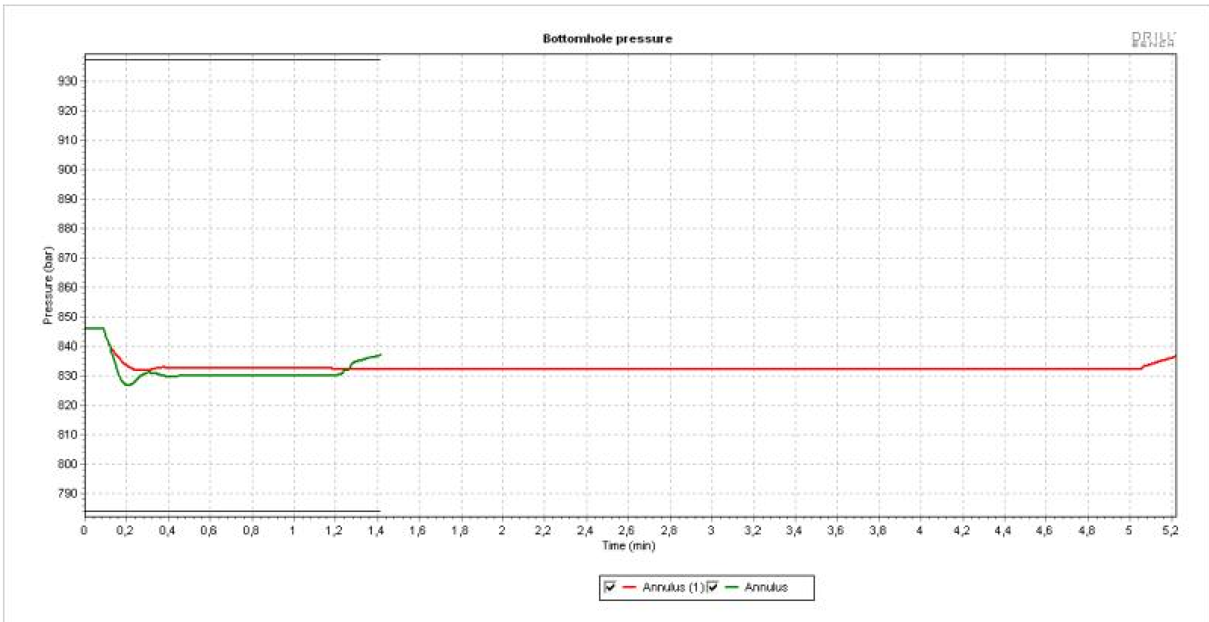


Figure 46: BHP when swabbing in the 8 ½ " section, no circulation. Red curve is for pulling slow, green curve is for pulling fast.

Swabbing with pump connected, with a circulation rate of 500 lpm is shown in Fig. 47. Looking at the green curve for swabbing fast the ECD falls from 2000 kg/m^3 to 1925 kg/m^3. Here we again see the effect of swabbing fast. We get a higher BHP drop and a higher drop in ECD. This shows that in smaller hole sections, one has to be careful with the tripping speed.

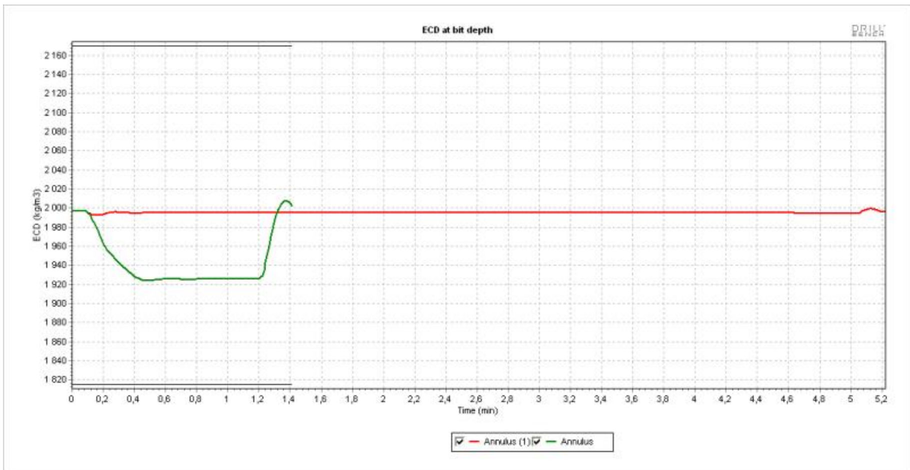


Figure 47: ECD when swabbing in the 8 ½ "section, circulation rate 500 lpm. Red curve is for pulling slow, green curve is for pulling fast.

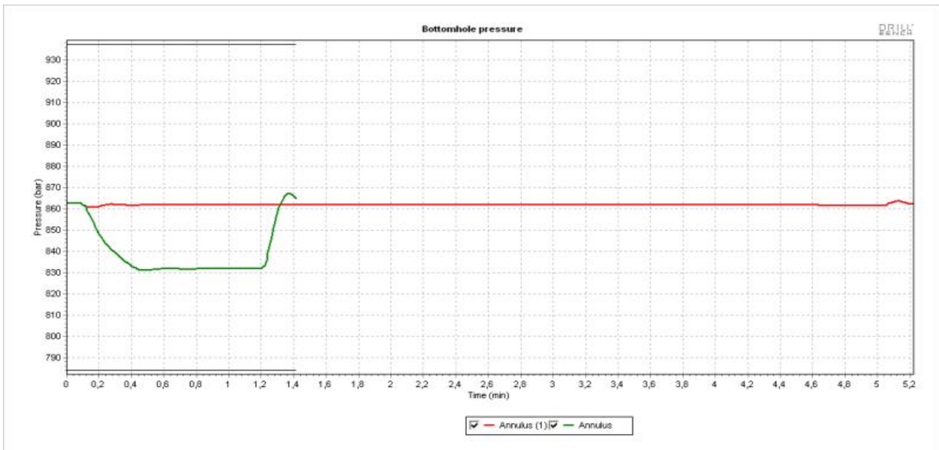


Figure 48: BHP when swabbing in the 8 ½ " section, circulation rate 500 lpm. Red curve is for pulling slow, green curve is for pulling fast.

Swabbing with pump connected, with a circulation rate of 1500 lpm is shown in Fig. 49. Looking at the green curve when the pump is circulating with a high circulation rate, the ECD is less affected when swabbing fast. This is the same effect that we can see in the 12 ¼ "section. It indicates that an increase in the pump rate during swabbing can eliminate the decrease in ECD and avoid the risk for taking a kick. This is very important in the 8 ½ “section where the swab effects are larger.

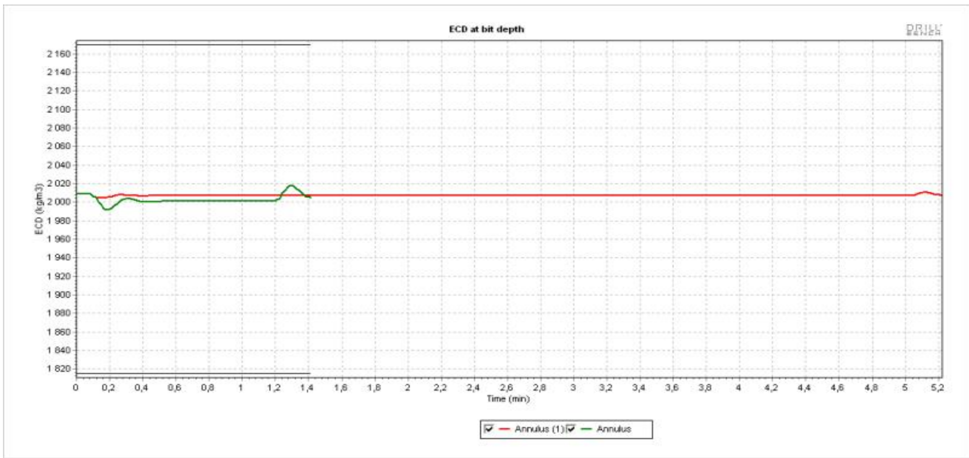


Figure 49: ECD when swabbing 8 ½ “ section, circulation rate 1500 l/min.

In HPHT wells it is common procedure to circulate the well while pulling out of the hole to eliminate the effect of swab pressures. Simulations can be used to find the optimal rate since this will depend on the rheological behavior of the mud which may vary depending on mud chosen.

6.2 Kick simulation

The kick simulations performed in this section are done both with OBM and WBM. Looking especially at how the pressure development in the well is affected using different types of mud in a kick situation. Simulation is done for an undetected kick in OBM, a closed in well with OBM and with WBM, a standard kick circulation for OBM and for WBM. In the different simulations we look at how the well pressures will be affected and how the different kick scenarios will develop in the well and also comparing the differences in a kick circulation in OBM and WBM.

6.2.1 Undetected kick in OBM

When the well is subjected to HPHT conditions we can get undetected kicks in oil based mud. This means that a small amount of gas influx will completely dissolve in the mud and not be registered by the drilling personnel, this can e.g. happen when we are pulling pipe too fast on reciprocating casing. In this case we will not see any change in pit volume when the influx is moving towards the surface before the free gas starts to boil out. Then we will have a sharp increase in the pit volume and need to shut in the well as soon as possible. When this happens, the hydrostatic pressure will start to reduce and there can be a risk for taking a new kick. It is very important to find out when this happens to check if there is time to close the BOP before the kick enters the riser. If the kick starts to migrate inside the riser, the only option left is the diverter, to force the kick away from the rig.

A 1.0 m^3 kick is taken in the lower part of the 12 ¼ " section. Circulation rate is 2000 lpm. There will be no major increase in pit gain before the influx starts to boil out of the mud, as shown in Fig. 50.

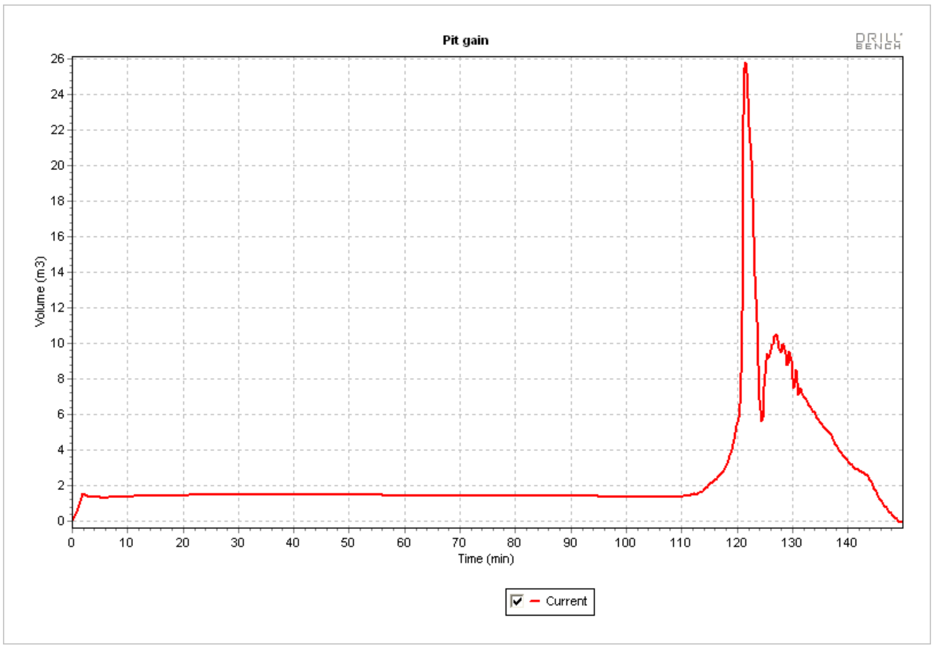


Figure 50: Shows the pit gain when running the 13 3/8 "casing.

It is shown in the plot that the free gas starts to boil out after approximately 110 minutes. We then see a large expansion in the pit gain. The position where free gas starts to boil out is crucial for maintaining a safe well. The procedure is then to shut in the well as soon as possible and circulate it through the choke. The kick is hopefully below the riser and when it is detected. If the kick has entered the riser it will be more difficult and sometimes impossible to maintain well control. One should also note that when the kick is in free gas form it will migrate on its own, even when there is no circulation. From Fig. 51 the position at which the free gas starts to boil out is at a 400 meters depth which is just below the BOP placed at the sea bottom, 250 meters depth. The rig personnel then have to react fast and close in the well.

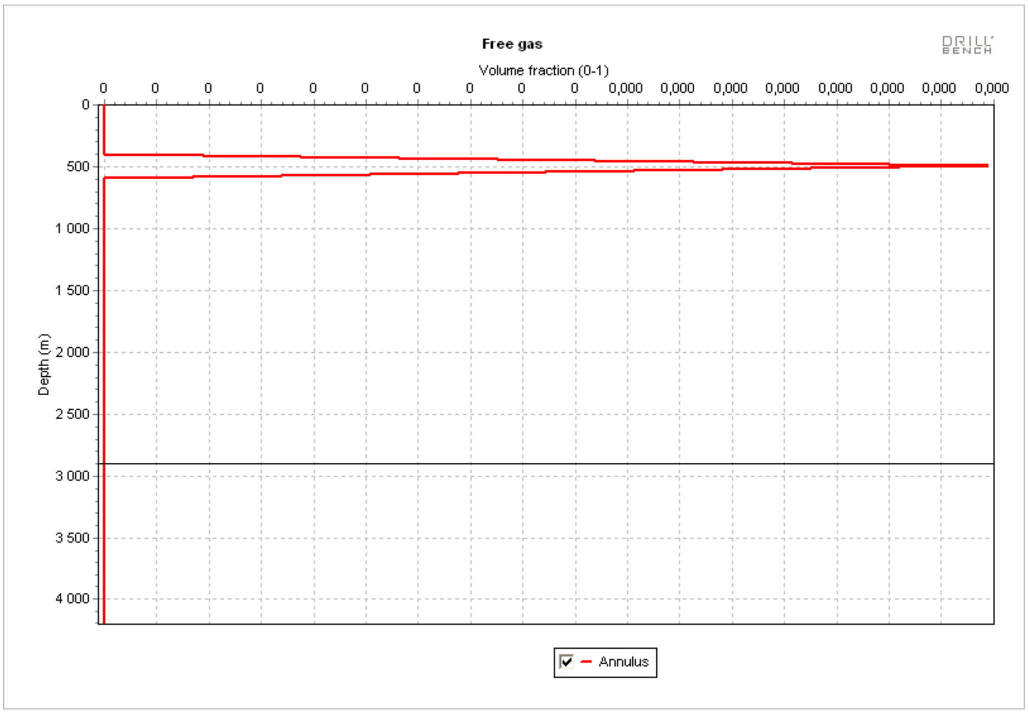


Figure 51: The position in the well where free gas starts to boil out of the mud.

From Fig. 52 we see the BHP development when the kick migrates upwards in the well. First there is a small decrease in pressure as the kick enters the well, but then the pressure is kept stable until the free gas starts to boil out and we see a major decrease in pressure. This pressure decrease can in some cases lead to a new kick situation.

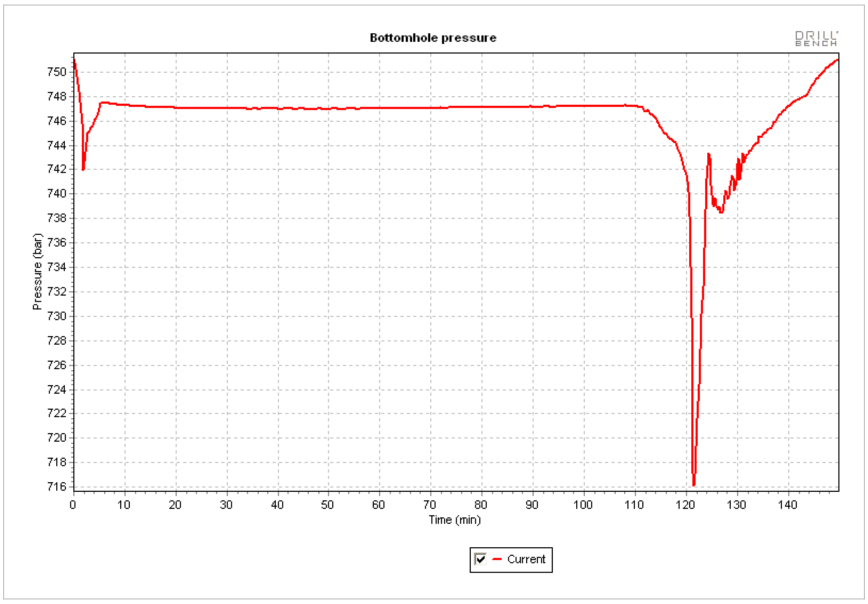


Figure 52: BHP development during undetected kick.

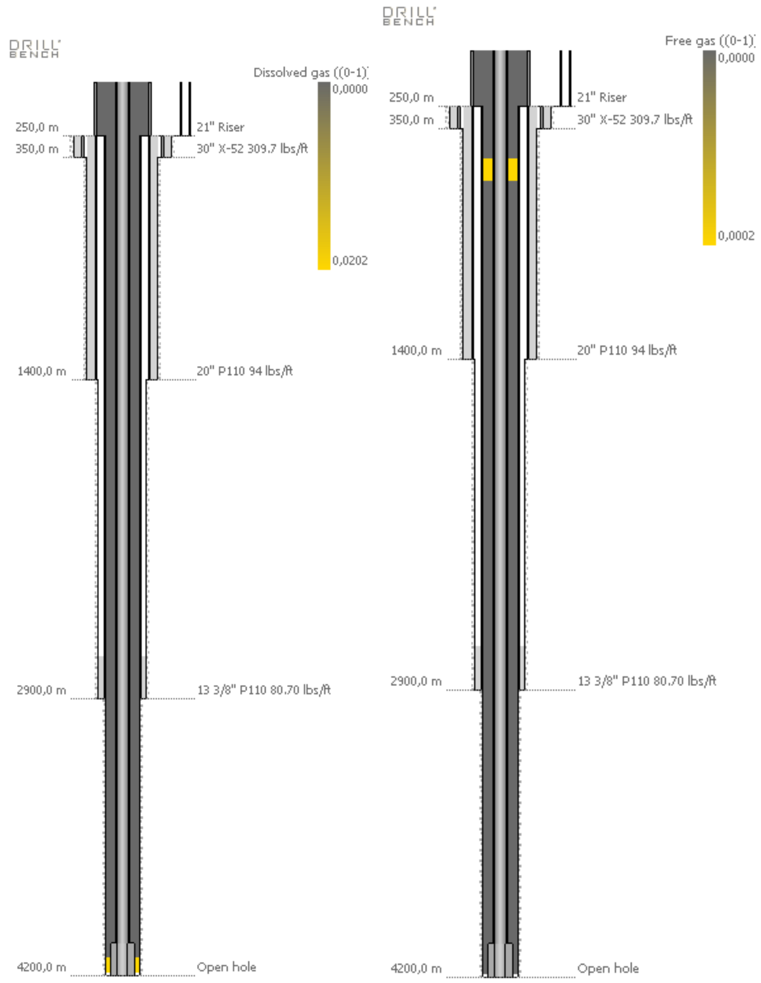


Figure 53; The left figure shows the position where the influx enters the well. The right figure shows the well schematics and at which depth the free gas starts to boil out from the solution.

6.2.2 Closed in well with OBM

The well has taken a kick, the first procedure is then to close the BOP and stop circulation. At this point when the well is closed in the kick will remain at bottom of the well until circulation is resumed.

The well is taking in a kick, pit alarm level is set to $2m^3$. There is no increase in pit level after the well is shut in, Fig 54. This is because with HPHT well conditions the gas kick will dissolve completely in the OBM.

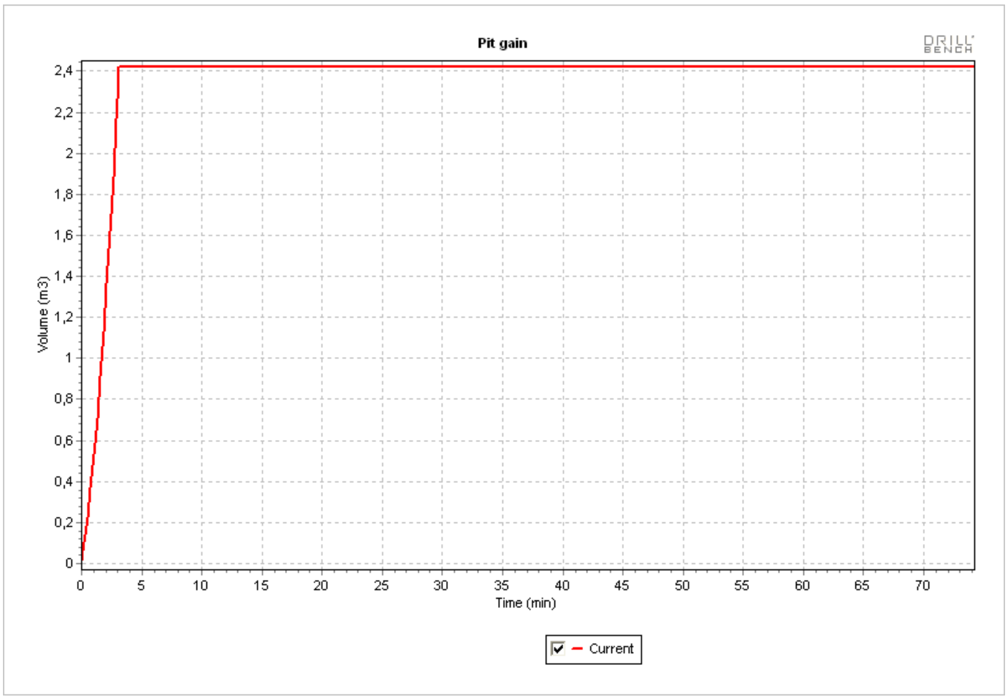


Figure 54: Pit gain in OBM. Pit alarm level is set to $2m^3$.

After 3 minutes the well is closed and circulation is stopped, since the kick is fully dissolved in the mud, it will not be moving upwards in the well. Hence, the casing shoe pressure will be stable and constant after the well has been closed in, Fig. 55.

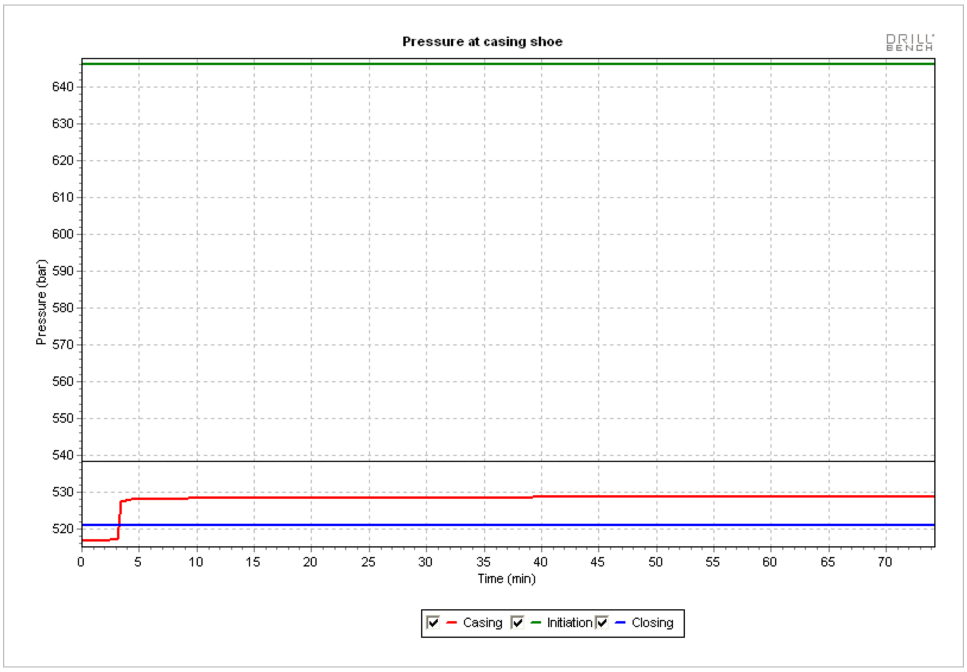


Figure 55: Casing shoe pressure development for kick in closed well with OBM.

Fig. 56 shows the well schematics of the influx, which is positioned at bottom of the well, and it does not migrate upwards as long as the well is not circulated.

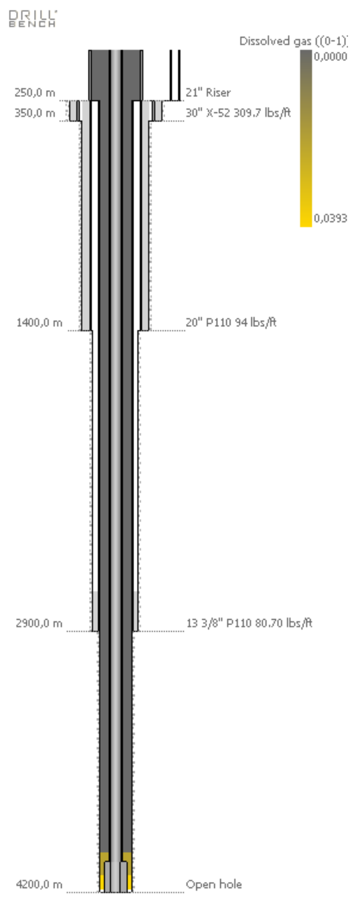


Figure 56: Position of influx in the well.

6.2.3 Standard kick circulation OBM

We are drilling down in the well with an 1.83 sg OBM, the initial rate of penetration is 10 m/hr. While drilling the initial pump rate is set to 2000 lpm. “Constant BHP model” is used to keep the BHP constant during the circulation, this is done by varying the choke pressure. The pit alarm level is set to 2m^3, meaning that when we register this pit gain on surface an alarm will go off telling us to close the BOP and stop circulating.

In this case a kick is detected and we need to shut in the well. Start by turning the pump off and close the BOP. Then we wait until the BHP has stabilized before the choke is opened and the kick is circulated out with a safety margin of 10 bars. The circulation rate used for circulating out the kick is 500 lpm.

From Fig. 57 we see an increase in pit gain when the kick enters the well, then it is kept stable as the kick moves up in the well until the free gas starts to boil out and we see a clear increase in pit volume.

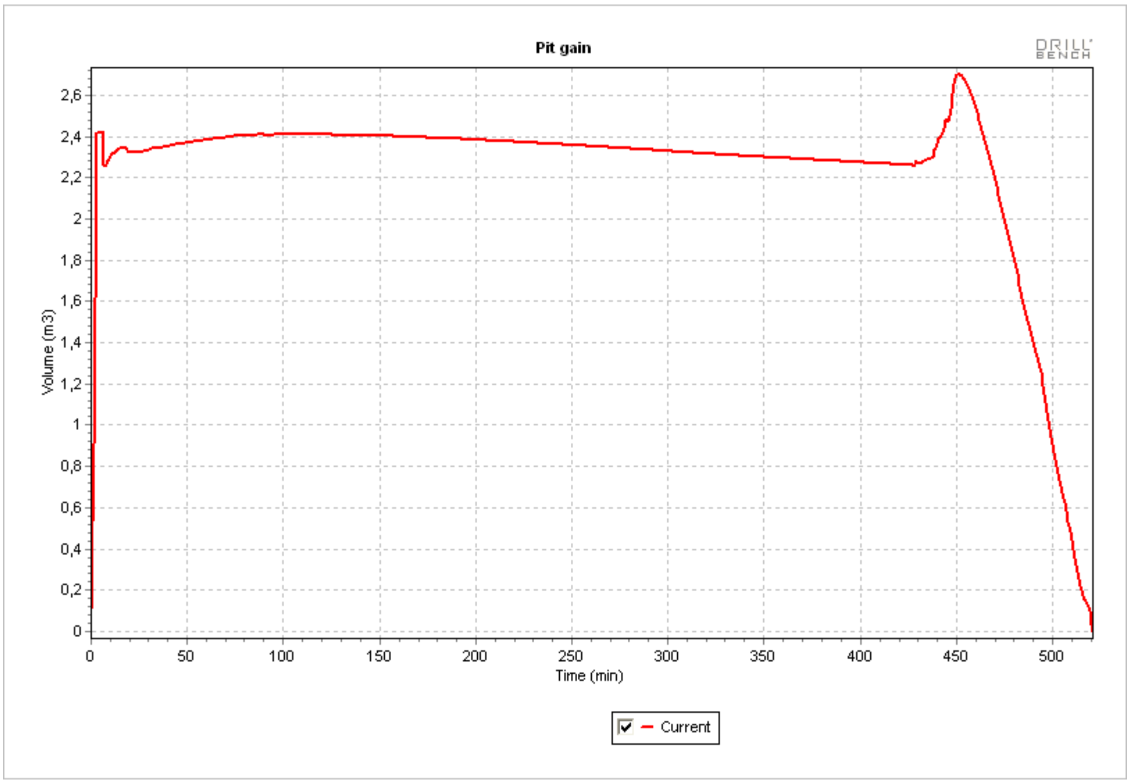


Figure 57; Pit gain during circulation in OBM after kick detection.

We get a decrease in choke pressure (Fig. 58) when we start to circulate out the kick, then it keeps almost constant while the dissolved gas moves up in the well. After approximately 440 minutes there is a large increase in choke pressure, this is the point where free gas starts to expand in the well. This increase in choke pressure is seen because we need a larger pressure across the choke to compensate for the decrease in the hydrostatic column in the well. As the kick starts to leave the well through the chokeline there is a clear decrease in choke pressure, which continues until the kick is out of the well.

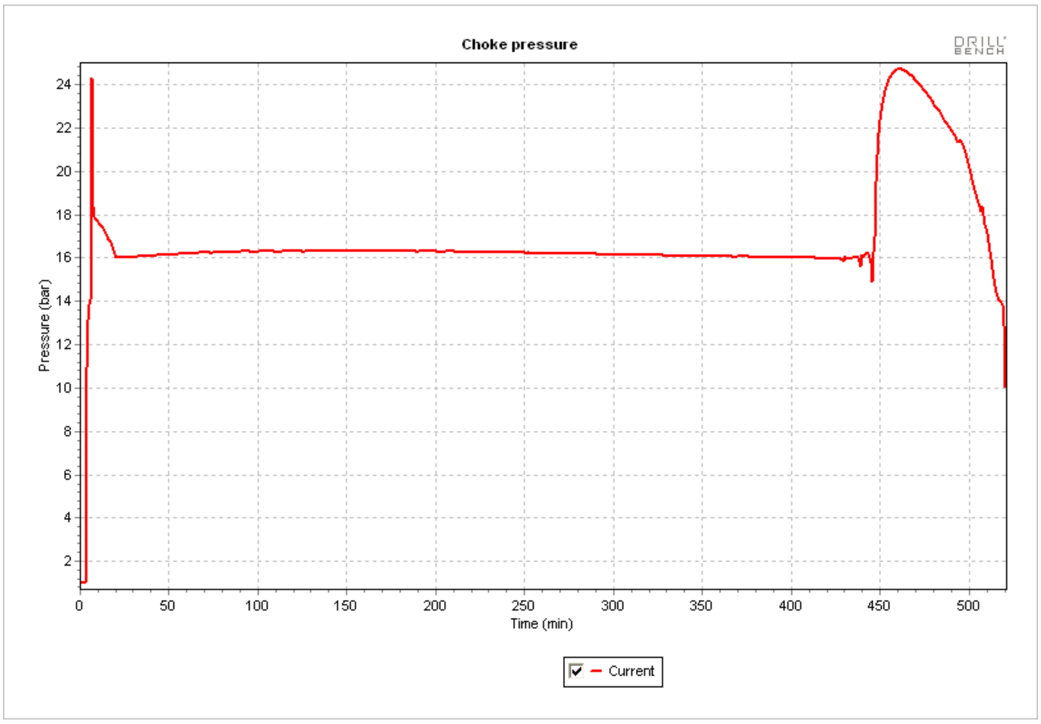


Figure 58: Choke pressure development for a kick in OBM.

The gas flow rate out (Fig. 59) shows the rate of free gas leaving the well. From the figure we see that free gas will be present at the choke and mud/gas separator quite soon after the kick is boiling out of the solution. When the free gas expands close to the surface we get a high gas rate out. Hence, it is important to react quickly and be prepared.

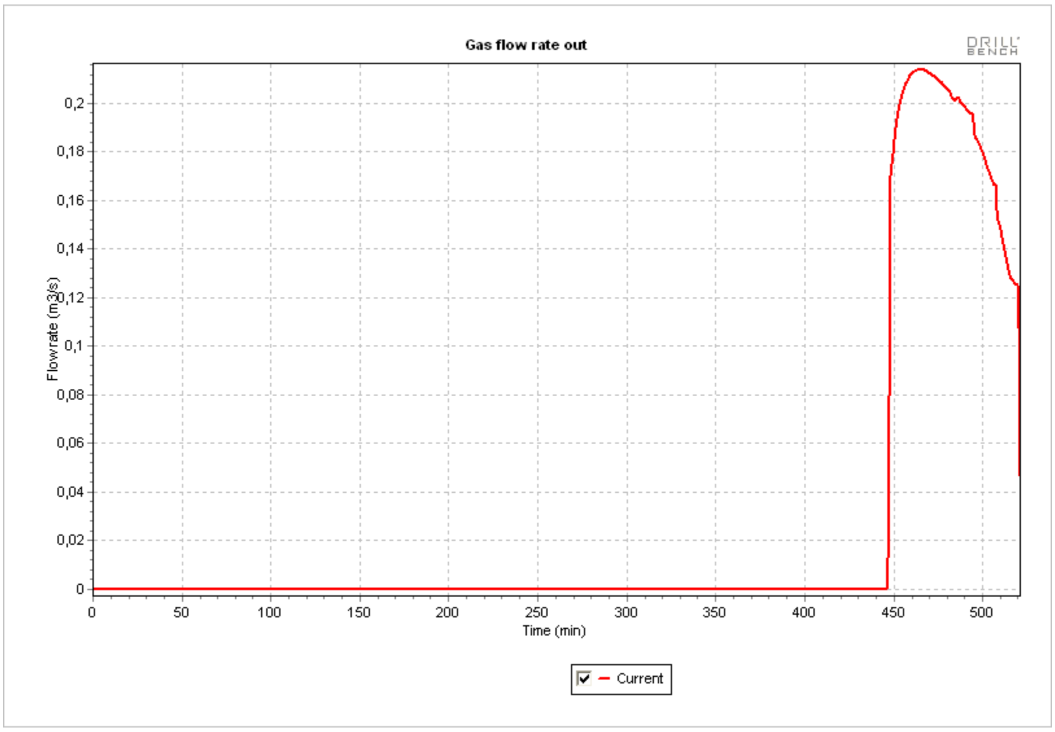


Figure 59: Shows the gas flow rate out of the well with OBM.

The casing shoe pressure in Fig. 60 and 61 increase when we close the BOP and stop the pumps after 3,1 min. After 6,5 minutes the well is stable and the casing shoe pressure is constant at approximately 528 bar.

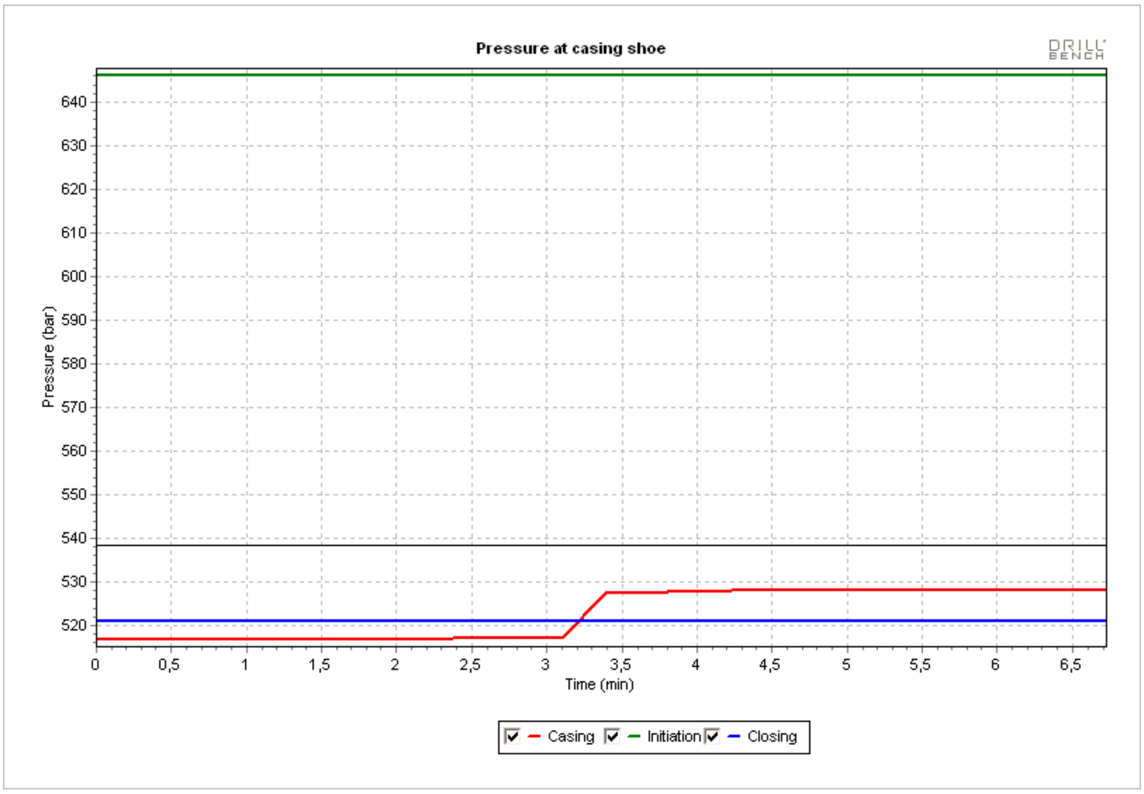


Figure 60: The casing shoe pressure. Kick circulation in OBM.

When the well is circulating the kick up, we need to maintain the constant BHP somewhat higher than the formation pressure. The reason for this is to avoid a new kick. A safety margin of 10 bars is used by adjusting the choke properly. The well is circulated with a kill rate of 500 lpm. One can observe that in this case, the maximum casing shoe pressure will be reached just after the kick is initiated. The reason for this can be that the height of the kick is displaced over a larger height in the beginning due to the drill collars, Fig. 62 a). When the kick moves upward into the wider region between openhole/DC, the height of the kick will be reduced, Fig. 62 b). This can be explained by the formula given below.

$$P_{CS} = P_{BOT} - \rho_m g h_m - \rho_{kick} g h_{kick} \tag{6.1}$$

Both the density for mud and for kick will be fairly constant for a kick in OBM. Therefore it is shown that the maximum casing shoe pressure is very dependent on the height of the kick.

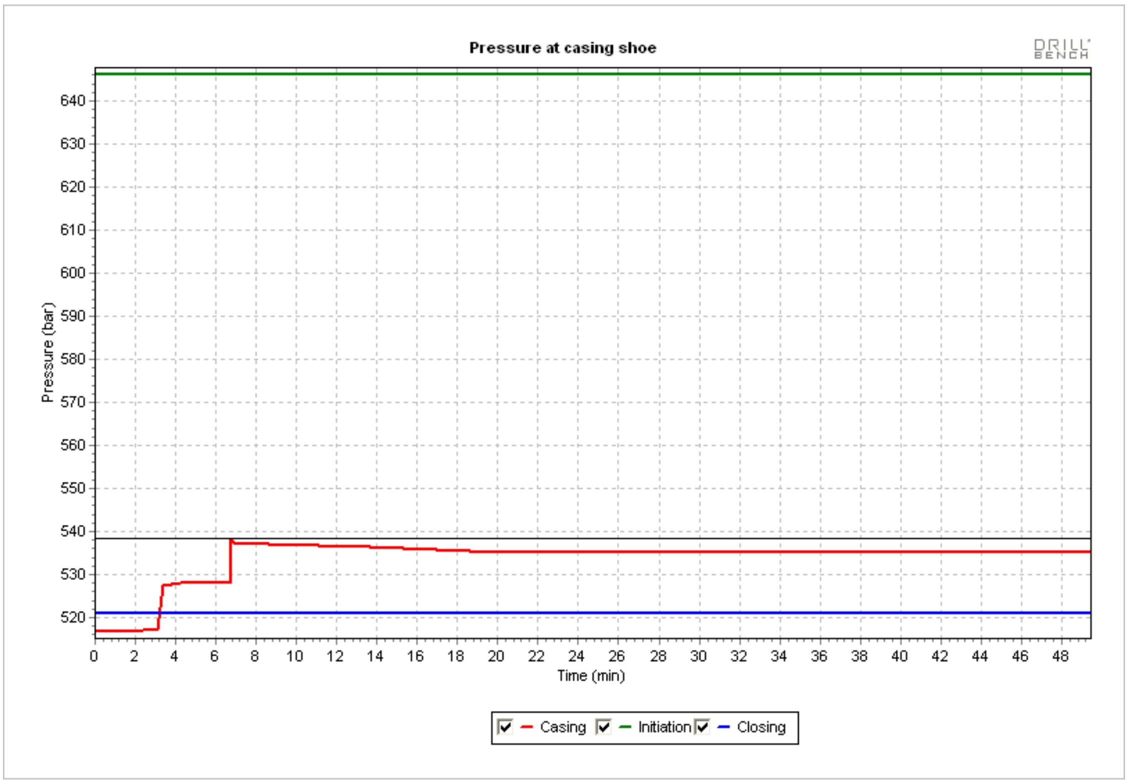


Figure 61:The casing shoe pressure, kick circulation OBM..

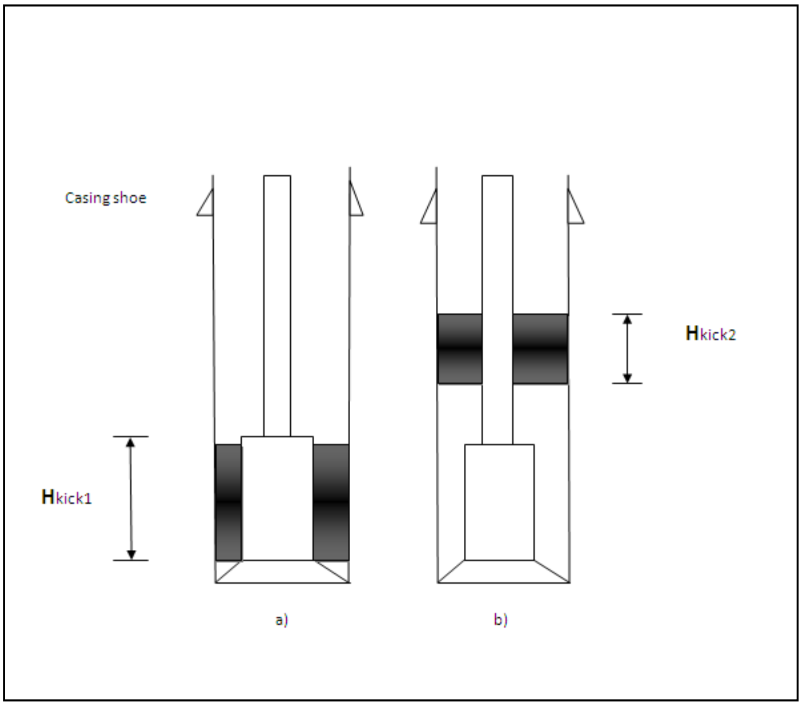


Figure 62: a) Kick is located at DC. b) Kick is located above DC.

After 132 minutes we see that the casing shoe pressure starts to decrease (Fig. 63). This means that the top of the kick is at the casing shoe. Here we clearly see how the casing shoe pressure decreases as the kick is passing the casing shoe, and after 172 minutes the kick has passed the shoe and the casing shoe pressure flattens just below 530 bars. When the kick has passed the casing shoe the casing shoe pressure will keep constant until all of the kick is out of the well. The casing shoe pressure is at a maximum when we start to circulate the kick out of the well.

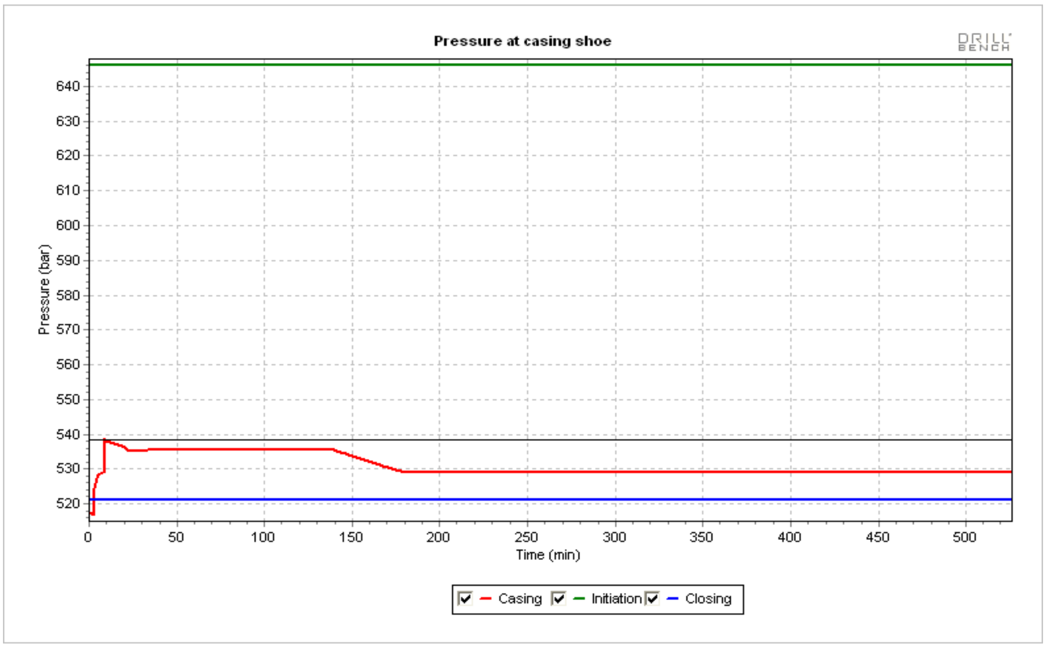


Figure 63: The casing shoe pressure development, in OBM.

Fig. 64 shows how the BHP changes as the kick enters the well, we then get a decrease in pressure due to a reduction in hydrostatic pressure. When the circulation is stopped and the well is closed in there is an increase in pressure due to further inflow of hydrocarbons. Then the pressure is held constant in a short time period before circulation is started. A safety margin is added to the BHP to ensure that the pressure is kept above the formation pressure. During the whole kill circulation the BHP is kept constant.

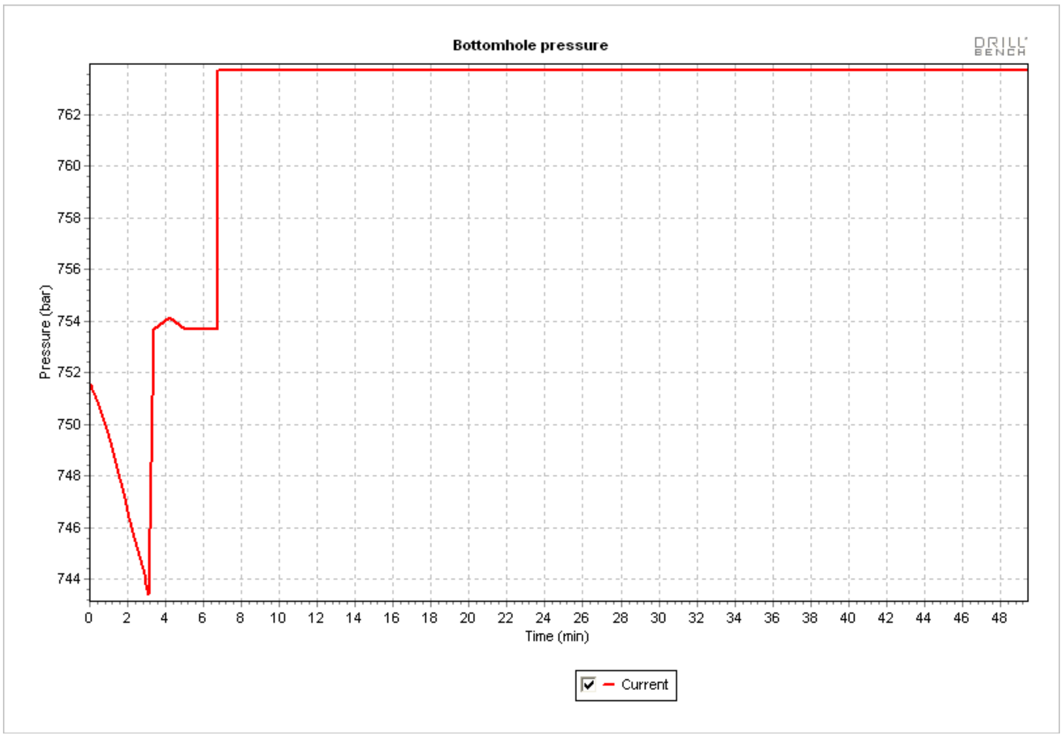


Figure 64: BHP when circulating a kick out in OBM.

6.2.4 Closed in well with WBM

When simulating the well with a kick taken in a 1.83 sg WBM, we are looking at what will happen when the well is closed in and circulation is stopped. A 2m^3 kick is taken into the well and the BOP is then closed and the circulation is stopped. As the well is shut in gas migration will take place and lead to increased well pressures. In closed in conditions the gas will transport the pressure up in the well according to Boyles law given in chapter 2..

In the pit gain plot (Fig. 65) we can see that the kick is taken into the well. Since the well is immediately closed in there will be no increase in pit gain after it is closed.

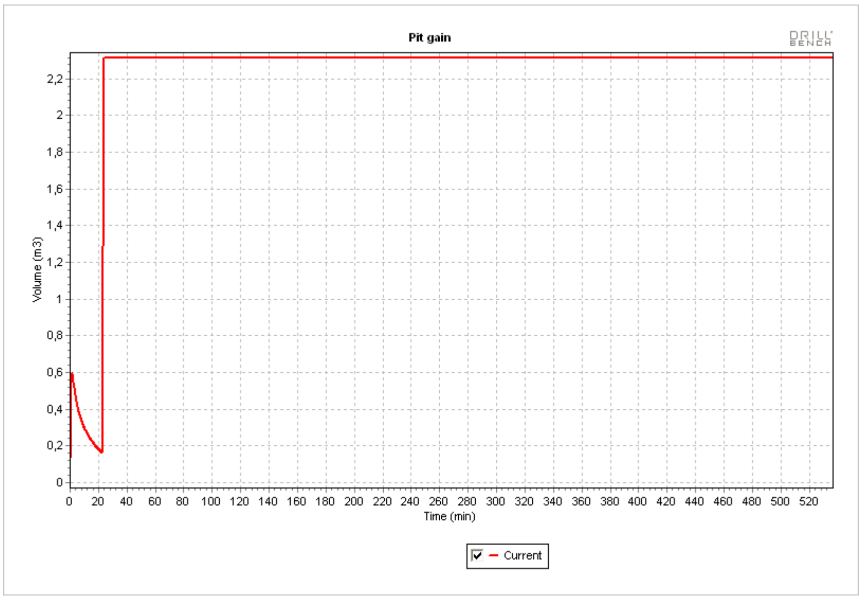


Figure 65: Pit gain closed in well with WBM.

From the casing shoe pressure in Fig. 66 it is shown that the well is closed in after 25 minutes and that there is a pressure build-up even at closed in conditions, this was not the case for OBM. We have a casing shoe brakdown at approximately 80 minutes after the well is closed in. As we see in WBM we have a pressure buildup in the well even at closed in conditions. This pressure build-up is happening due to free gas migration.

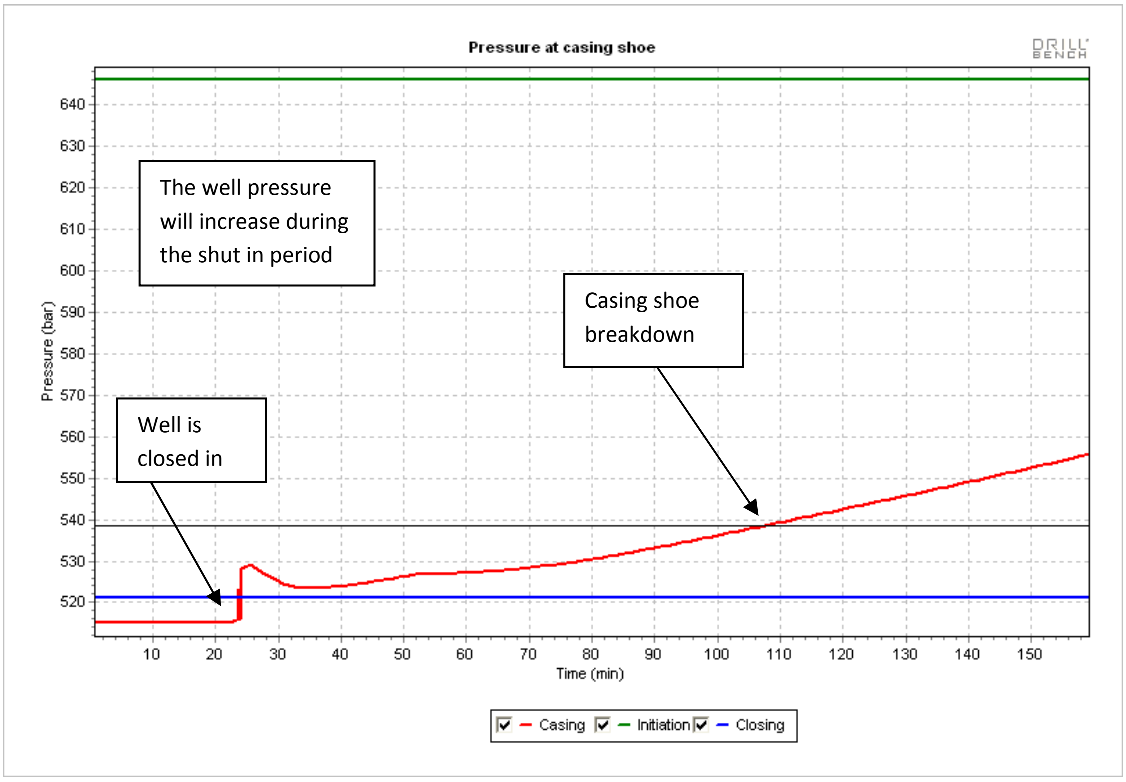


Figure 66:Casing shoe pressure in WBM.

After a certain time the pressure at the casing shoe will stabilize, when this happens all the free gas has gathered at top of the well, (Fig. 67). The equation below can give us the maximum pressure at top of the well.

$$P_{CS} = P_{WH} - (\rho g h)_{gas\ on\ top} - (\rho g h)_{mud\ between\ gas\ and\ casing\ shoe} \tag{6.2}$$

P_{WH} = Well head pressure, the pressure at top of the well.

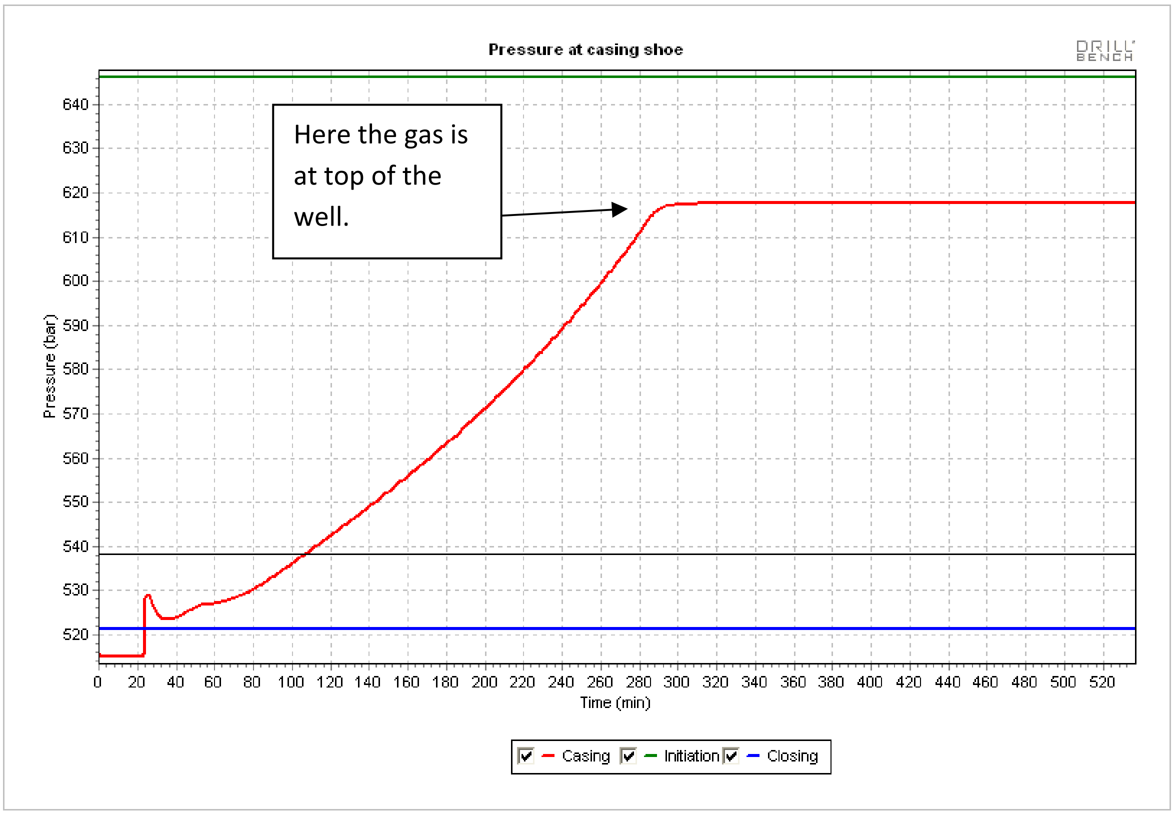


Figure 67: Casing shoe pressure, closed in well with WBM.

The position of the gas front in the well when the casing shoe breaks is shown in Fig. 68. Here we see that when the gas front is at 2200 meters depth the pressure in the well will exceed the maximum pressure that the casing shoe can handle. This happens after approximately 106 minutes, at this point the well is filled with a “gas bubble” extending from 3400 meters all the way up to 2200 meters. From this we can see that we cannot wait too long before well kill procedure is initiated, to prevent fracturing.

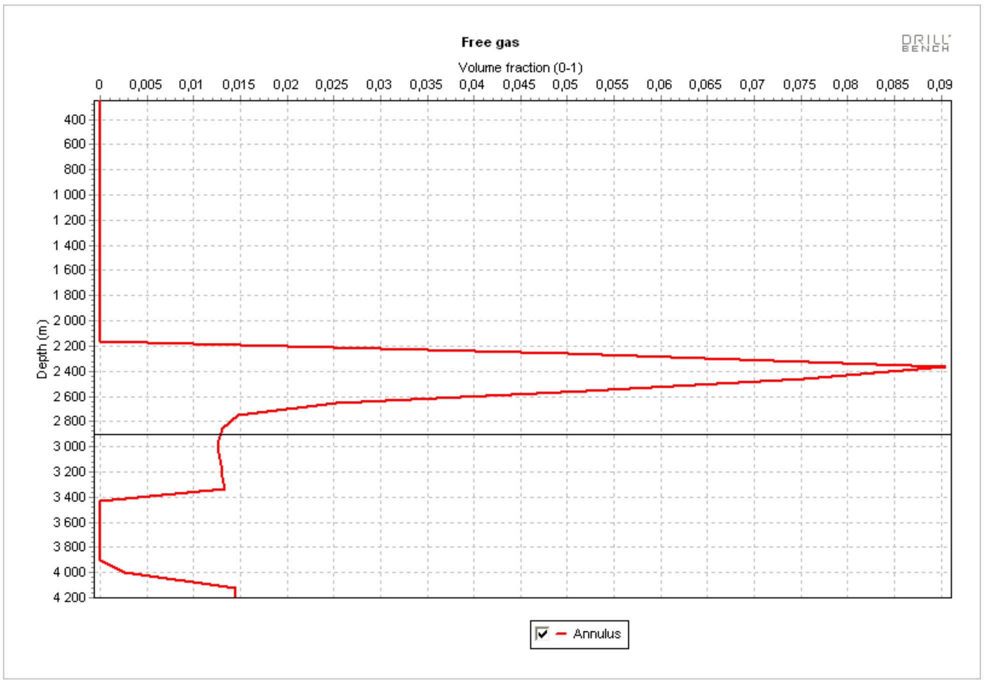


Figure 68: The position in the well where the casing shoe break.

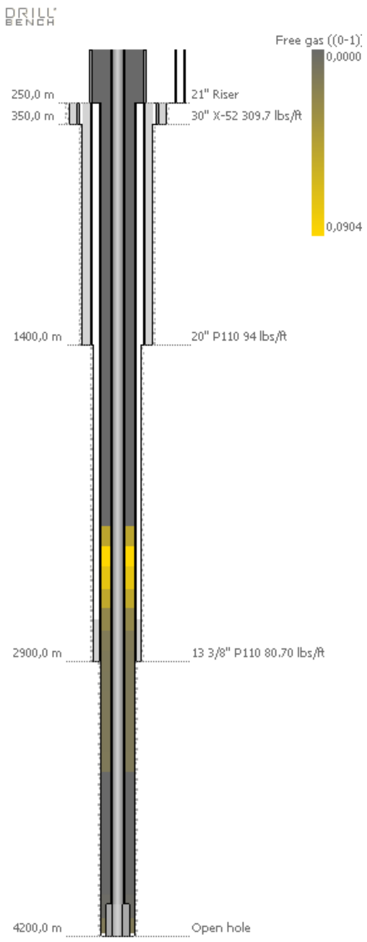


Figure 69: Position of the gas when the casing shoe breaks.

6.2.5 Standard kick circulation WBM

The pit alarm level is set at $2m^3$, the kick is taken into the well and the pumps are immediately shut off and the well is closed. Then we open the choke and start to circulate the kick out of the well. Circulation rate used for circulating the kick out is 500 lpm.

From the pit gain curve, Fig. 70, it is shown that the kick is taken into the well. Then the well is closed in before the kick is circulated out. As we see from the figure we get an increase in pit volume at once we start to circulate the well. This is because the gas at once starts to expand upwards in the well, and at surface we will register an increase in the pit volume.

This can be related to the ideal gas law shown in chapter 2. Where we can assume that if we have a single gas bubble influx in the well with a given volume and pressure, $(PV)_{bottom}$, at closed in conditions it will start to migrate and expand up in the well, then we get a larger volume and lower pressure of the gas bubble as it moves up in the well, $(PV)_{surface}$.

When the gas kick enters the well we have a large pressure and a small volume. As the gas moves up in the well we get a smaller pressure but the volume of gas will expand. At the point where the pit gain starts to decrease the kick is starting to leave the well.

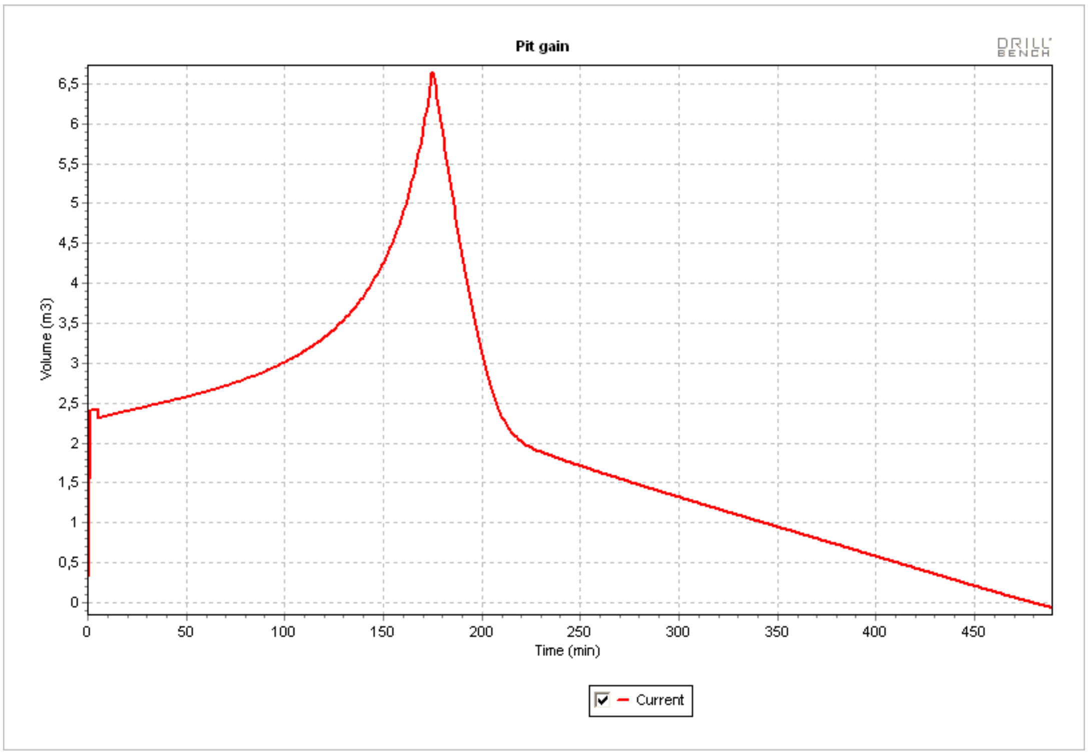


Figure 70: Pit gain in WBM.

The choke pressure, Fig. 71, shows how we get a major increase in choke pressure when we start to circulate the well, this increase in pressure is due to reduced hydrostatic pressure in the well as the gas starts to expand. We need to compensate the lower pressures in the well by increasing the choke pressure to keep a constant bottom hole pressure during the circulation. At the point where the choke pressure starts to decrease the influx is starting to flow out of the well. The point at which the gas starts to flow out of the well is shown in Fig. 72, here we see that the gas starts to flow out at a earlier stage than in OBM.

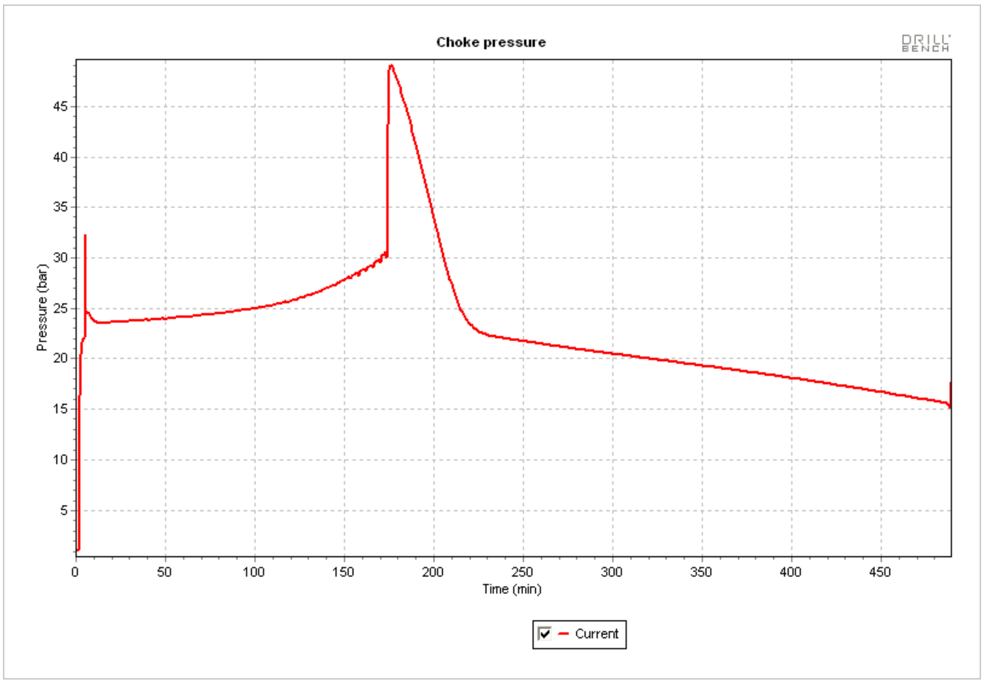


Figure 71: Choke pressure in WBM.

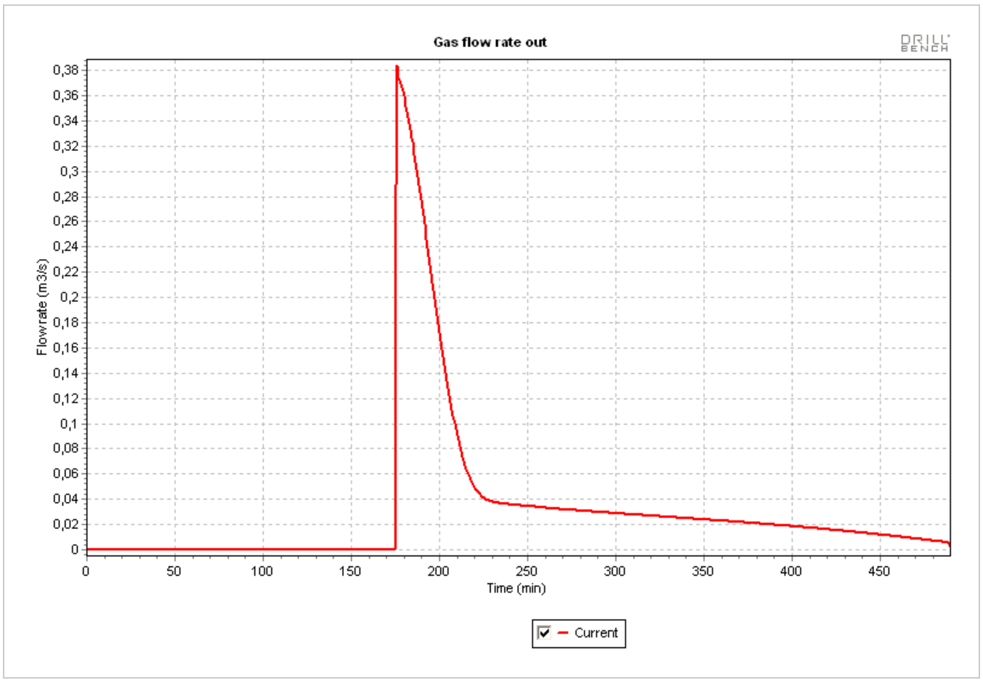


Figure 72: Gas flow rate out for the kick in WBM.

When we start to circulate we see that the casing shoe pressure is higher than the fracture pressure in Figs. 73 and 74, this means that the casing shoe will not be able to withstand the pressures in the well. The front of the influx is at the casing shoe depth after approximately

53 minutes, and it will migrate upwards in the well. The influx will then pass the casing shoe, and we can see that the pressure will start to decrease as the kick is passing. When the kick has past the shoe the pressure will keep constant until the kick is completely circulated out of the well. Maximum casing shoe pressure is approximately 543 bar, this is reached as we start to circulate the kick out of the well.

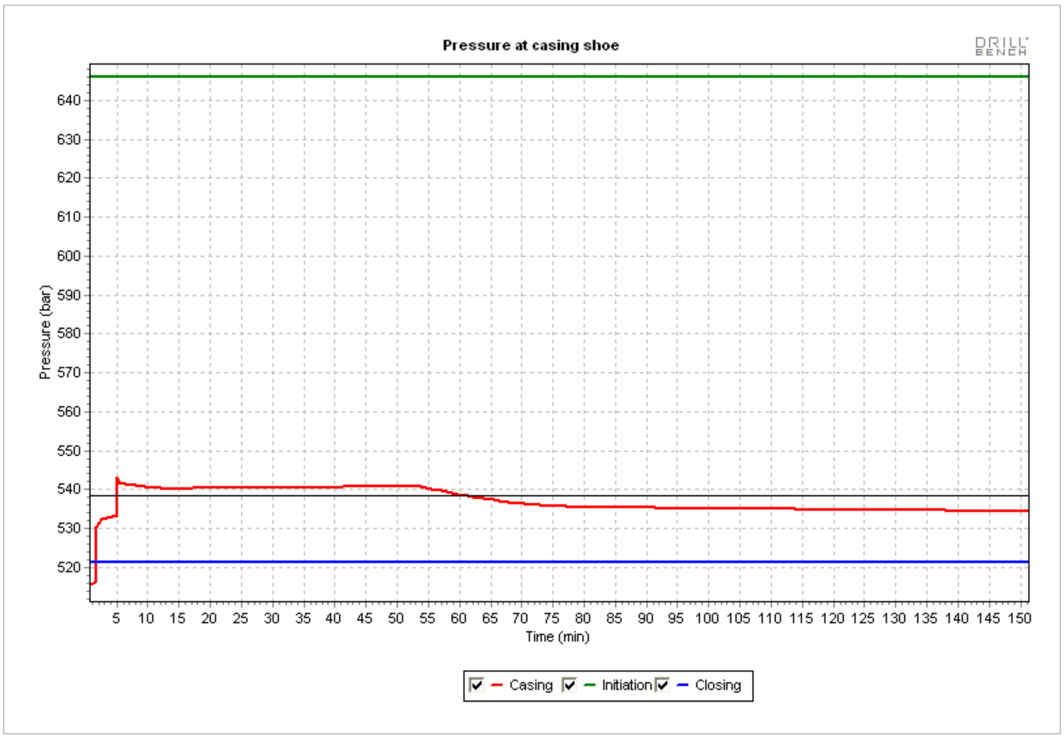


Figure 73: Pressure at casing shoe in WBM.

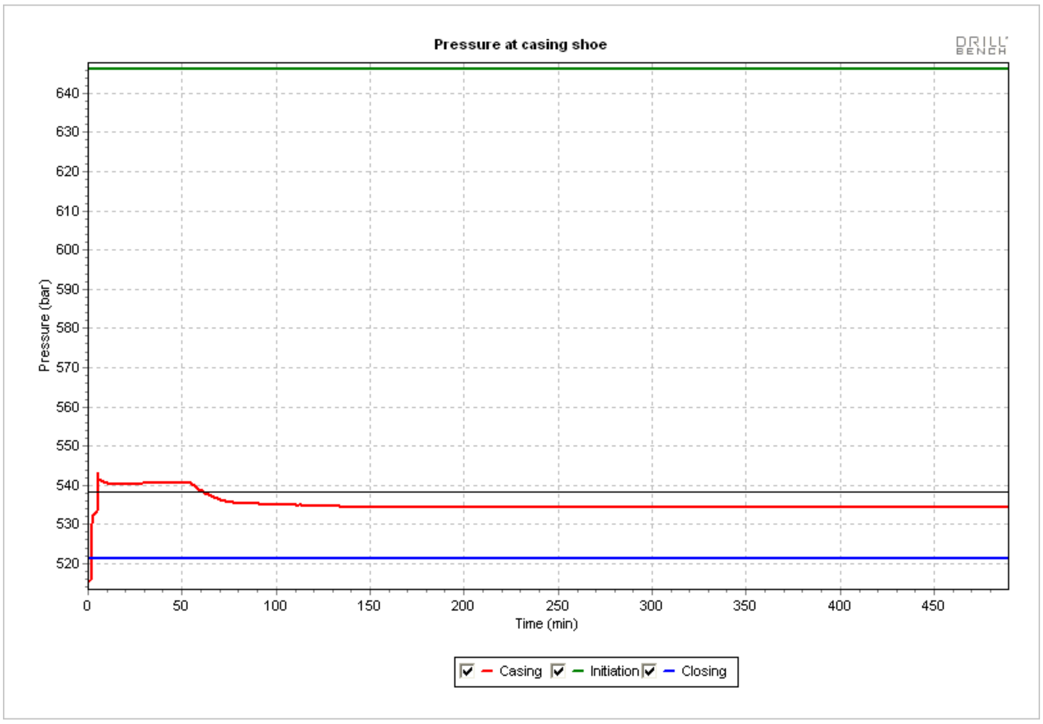


Figure 74: Pressure at casing shoe in WBM, during the whole circulation.

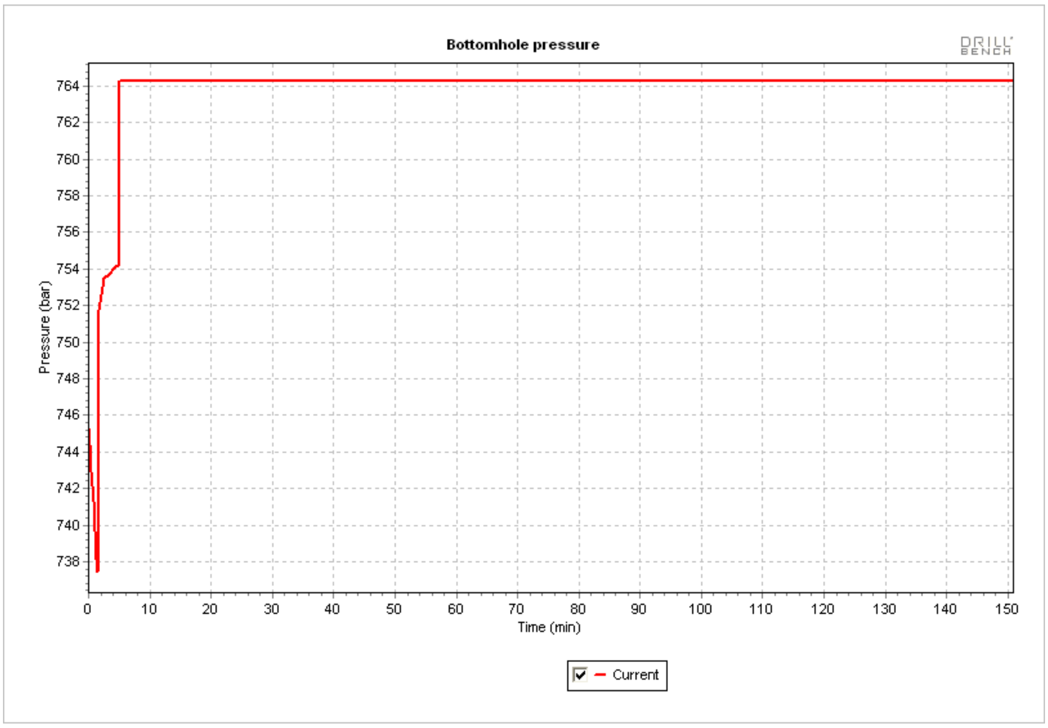


Figure 75: BHP in WBM.

The position of the gas front in Fig. 76 shows how long time it takes before the gas reaches the surface.

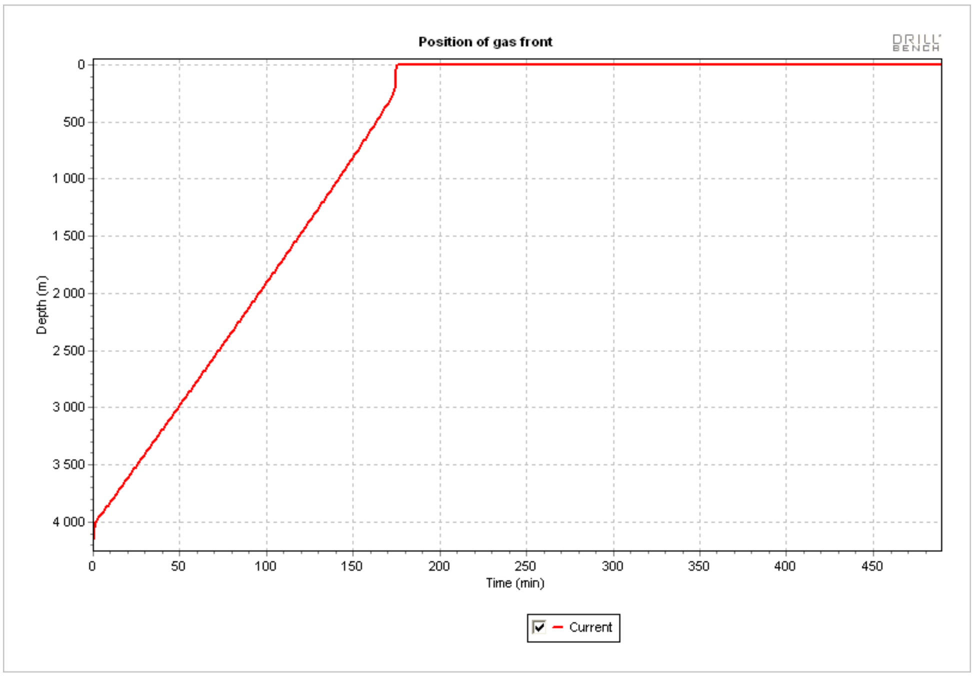


Figure 76: Position of gas front in WBM.

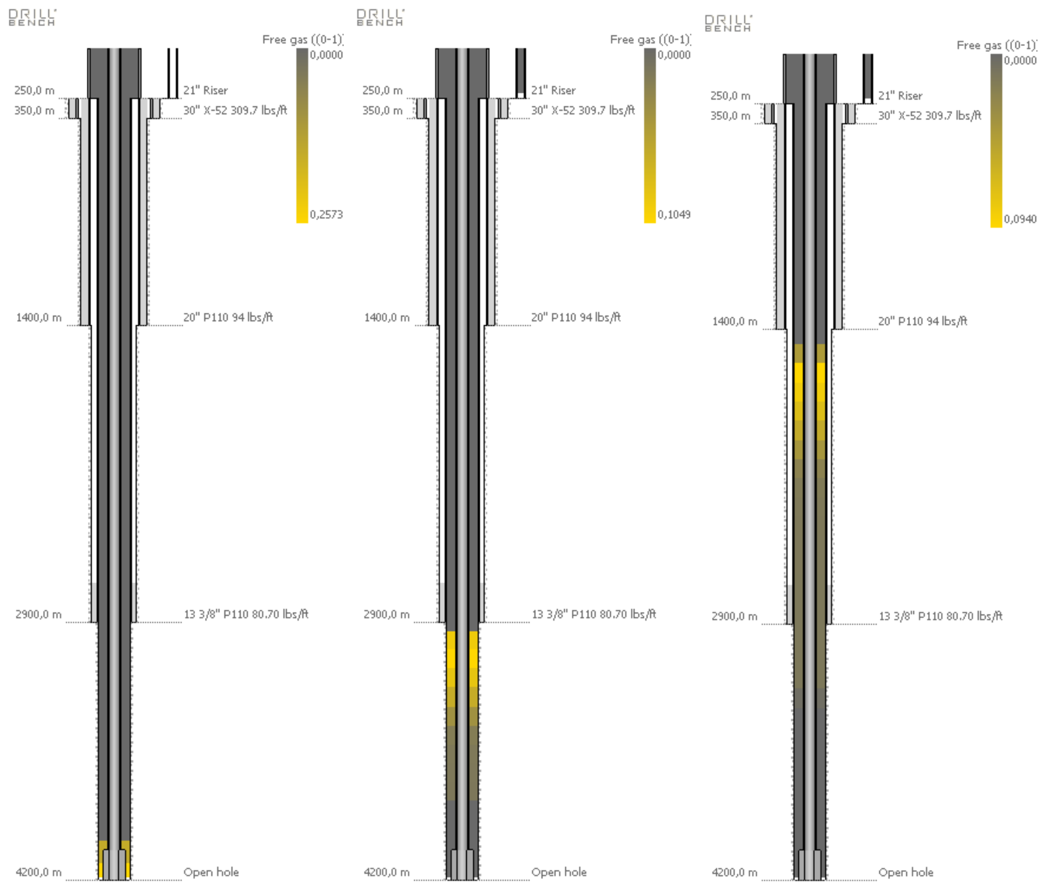


Figure 77: The well schematic to the left shows the well as the kick enters the well. The well schematics in the middle shows the position of the gas when it is just below the casing shoe(53 min). The well schematics the right side shows the position of the gas front as when it has passed the casing shoe, (120 min).

6.3 Comparisons of WBM and OBM

The kick scenario is dependent on the type of mud used in the well. Water based mud and oil based mud will react in different ways when we get an inflow of formation fluids. In some well designs one could prefer the water based type, while in other the oil based would be a better choice. Here I will compare the two different types of mud and then compare the difference in kick behavior. The conditions in the two cases are as equal as possible. In the two situations described here both the OBM and the WBM have a density of 1.83 sg.

The pit alarm level in the well is in both cases set at 4m^3. When the kick has entered the well it is then closed in and circulation is stopped. The BHP is then stabilized as the choke is opened and the pumps are turned on again, circulating the kick out of the well. During the circulation we will look at the casing shoe pressure development in the well, since it is crucial that the casing shoe can withstand the well pressures as the kick moves up in the well.

Fig. 78 shows the pit gain development in the well for both OBM and for WBM. Here we see that for OBM the kick has entered the well and when the well is shut in it keeps constant with a small decrease until there is a small peak at the end of simulation, this is the point where the free gas boils out of the well. For WBM the kick will enter the well and when we start to circulate the kick out the gas will start to expand at once and we get an increase in pit gain at surface much earlier than for OBM. It is also observed that the volume of kick at surface is much higher for WBM than for OBM.

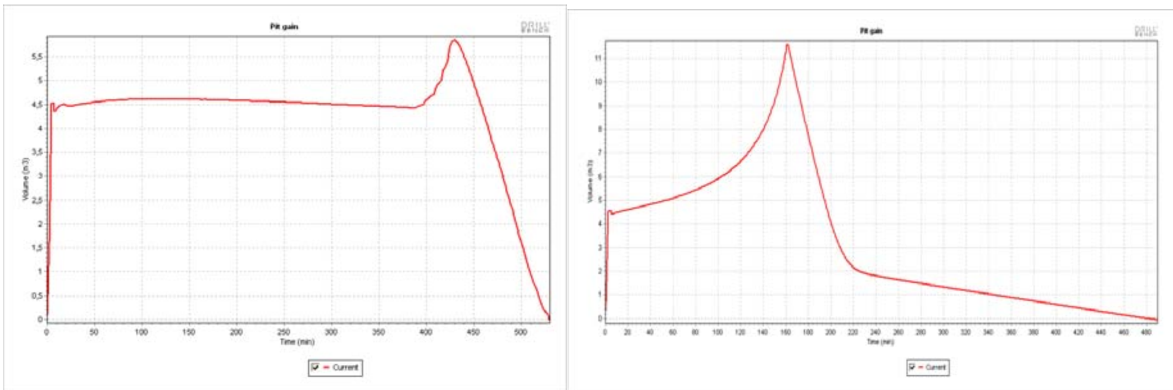


Figure 78: Left is the pit gain in OBM, right is the pit gain in WBM.

For both simulations the method for circulating out the kick is to keep the BHP constant. Below it is shown how the BHP change during the simulation, (Fig. 79). For both the OBM and the WBM simulations the bottom hole pressures are very similar, there is a decrease in pressure when the kick enters the well, then we get a increase as the well is closed in and as circulation starts the pressure is kept constant for the rest of the simulation. From the figure we see that the BHP for both mud types is almost the same.

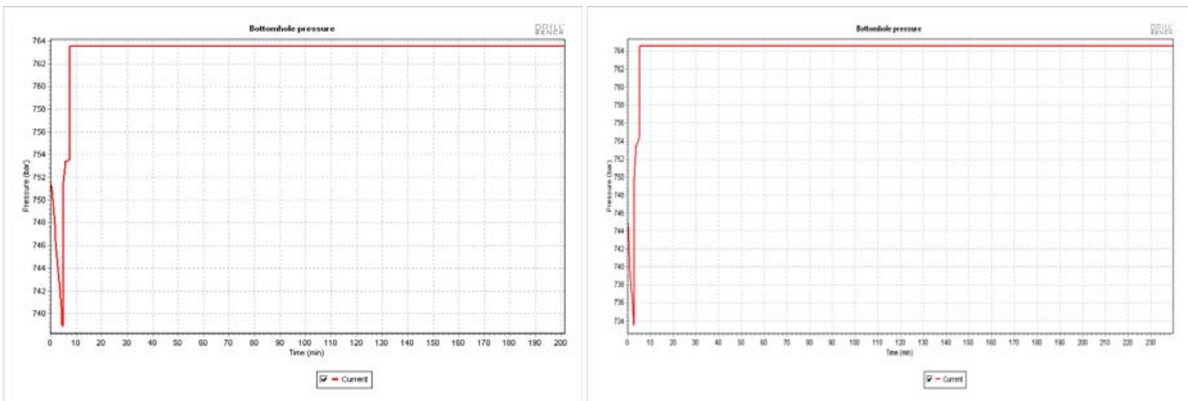


Figure 79: Left is the BHP in OBM, right is the BHP in WBM.

The choke pressure development in Fig. 80 shows that for both OBM and WBM there is a large increase in pressure as the well is closed in. The pressure starts to increase immediately as the gas starts to boil out in the well. For WBM this happens much sooner than for OBM, this is because the gas kick will start to expand immediately as the kick moves up in the well with WBM, while the gas kick will completely dissolve in the OBM and not expand before the free gas starts to boil out from the mud. We also observe that the choke pressures in the well when we use WBM are significantly higher than when we use OBM.

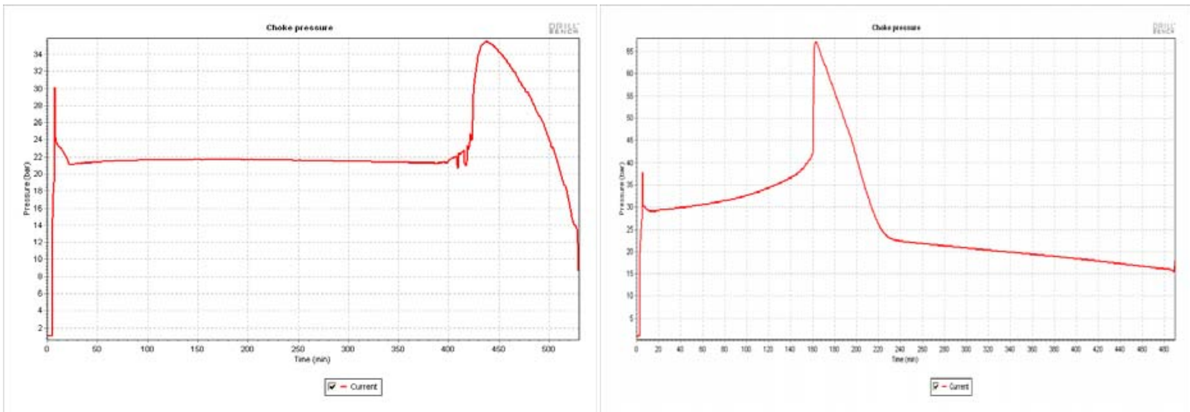


Figure 80: Left is the choke pressure in OBM, right is the choke pressure in WBM.

In the pressure development at the casing shoe (Figs. 81 and 82) there are also larger pressures in the well with WBM. For both the OBM and the WBM the pressure at casing shoe is higher than the fracture pressure and the shoe will break. For both OBM and WBM the maximum casing shoe pressure appears when we start to circulate. The difference in maximum casing shoe pressure in the two cases is due to the larger volume of gas present in WBM. While gas will dissolve in OBM, it will expand in WBM. As the kick passes the shoe we see a clear decrease in casing shoe pressure in both cases, the clear difference is the time the kick passes the shoe. From the casing shoe pressure we see a clear decrease in pressure as the kick starts to move up, passing the casing shoe. For WBM we see this decrease start much earlier, after approximately 45 minutes. While for the kick in OBM we don’t see the decrease in pressure before after 120 minutes. In both cases the pressure is stable after the kick has passed the casing shoe.

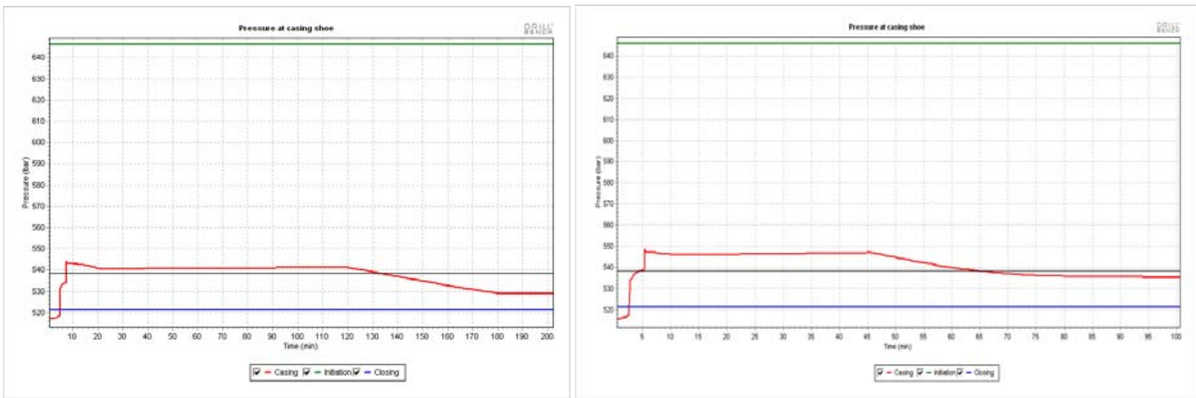


Figure 81: Left is the pressure at casing shoe in OBM, right is the pressure in WBM.

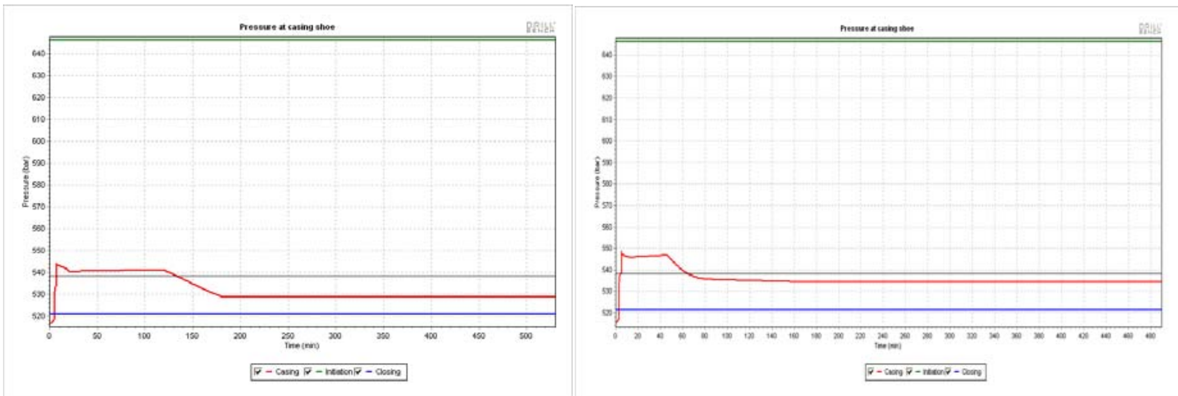


Figure 82: Left is the pressure at casing shoe in OBM, right is the pressure in WBM.

From the gas flow rate out plots (Fig. 83) it is shown at what time the gas starts to leave the well and at which rate. The kick in WBM starts to leave the well much earlier than the kick in OBM. This is because in OBM the kick will be fully dissolved in the mud as the kick moves up in the well until the gas starts to boil out from the solution and we get a high gas flow rate out. The gas flow rate out is higher in WBM than it is in OBM.

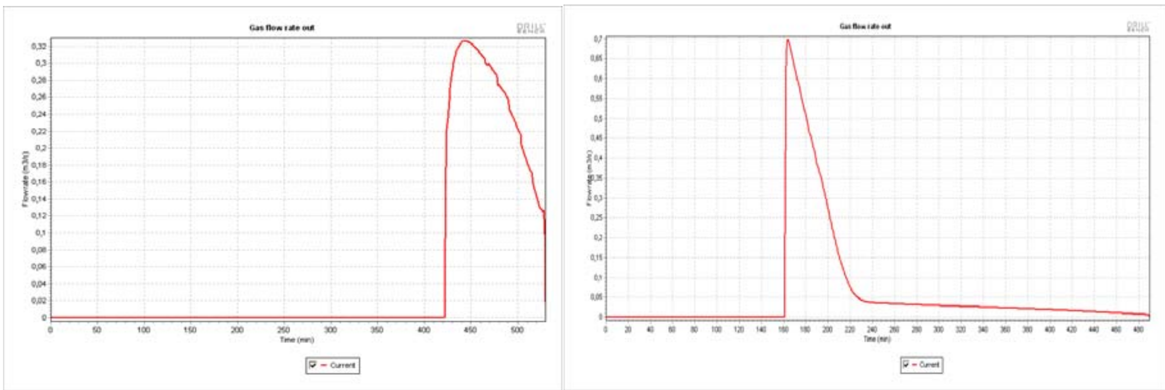


Figure 83: Left is the gas flow rate out in OBM, right is the gas flow rate out in WBM.

In OBM the gas front will reach the surface at a later stage than the gas front in WBM (Fig. 84). This tells us that the kick in WBM moves much faster to the surface and that a kick in WBM is more easily detected than OBM because we observe it at an earlier stage. The reason why the kick in WBM will reach the surface earlier is due to the free gas migration in the well, while the kick in OBM will only travel up the well according to the speed of the pump rate.

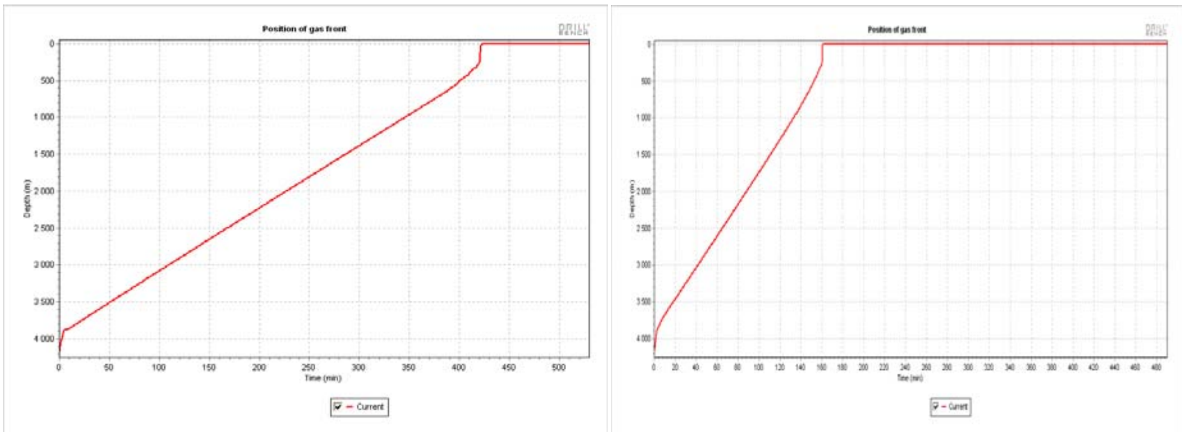


Figure 84: Left is the position of gas front in OBM, right is the position of gas front in WBM.

From the figure below (Fig. 85) it is shown how the kick will affect the pressure at the BOP placed at the sea bottom. Again we observe that the pressures when using WBM are higher than when using OBM.

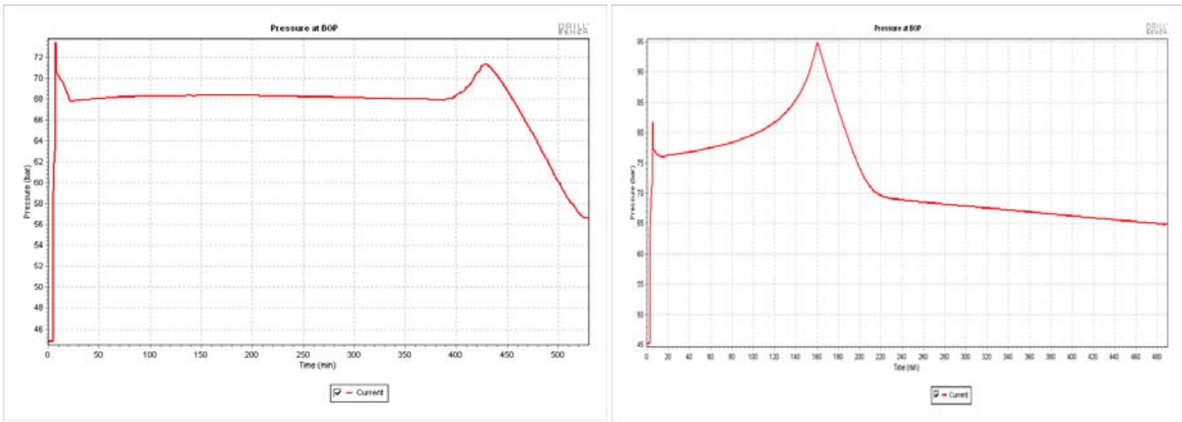


Figure 85: Left is the pressure at BOP in OBM, right is the pressure at BOP in WBM.

7 Conclusions

Well control is of major importance when performing drilling operations. In HPHT wells this becomes even more important, as we are moving towards more narrow margins, deeper wells and higher pressures and temperatures.

In this thesis simulations have been preformed to illustrate the conditions in the well during different well operations, and during different kick situations.

During connections it is seen that there is a significant pressure drop which can influence the pressure in the well. The pressure drop experienced during connections can lead to an underbalanced situation where we get an inflow of formation fluids. It is also seen that the pressure drop during connections increases in smaller hole sections.

It is shown that the swabbing effect during tripping out of the well can be reduced by pumping out of the hole. When the well is circulated during swabbing there is a lower pressure drop over the bit than when the pump is off. The pressure drop over the bit is also dependent on the pump rate used, an increase in pump rate gives a smaller pressure drop when the pipe is pulled at a high speed, this also demonstrates that one can use simulations to find the optimal rate. The swabbing effect also gets worse in smaller hole sections.

Undetected kicks can be a problem in HPHT wells. Here the gas influx can completely dissolve in the OBM without seeing a significant increase In pit gain. As the well is circulated the kick will move upwards in the well and the kick will not be detected before free gas starts to boil out of the solution. The point where the free gas starts to boil is important when it comes to well control.

During closed in conditions a kick will behave differently in OBM and WBM. Since the kick will solve in the OBM it will stay at bottom of the well during closed in conditions until the well is circulated. While in WBM the kick will start to migrate upwards and lead to increased pressures in the well, the kick will transport the BHP up in the well according to Boyles law. This means that one need to react quickly to avoid fracturing of the casing shoe.

A standard kick circulation in OBM and WBM has been performed, looking at the different development in pressures and volumes. From the simulation it is found that there will be a much higher volume increase at surface when a kick in WBM is taken, this is due to the solubility of gas in OBM. The choke pressure development will generally be higher in the WBM, this is due to the gas expansion that takes place as the kick moves up in the well. In WBM the gas front will reach surface much earlier than in the OBM, this is because the kick in OBM only moves up in the well following the pump rate, while the kick in WBM is also affected by the gas slip velocity. The casing shoe pressure is also higher for the kick in WBM, this is because the kick starts to expand immediately the well is circulated, the volume of the kick below the casing shoe is therefore larger than the volume of the kick in OBM, we therefore get a higher casing shoe pressure when using the WBM. The conclusion is therefore that generally will influxes taken in WBM lead to larger pressures and gas volumes at surface during the well kill compared to what is seen in OBM.

List of figures

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