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Writer: Audun Tufte Veisene

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(Writer's signatures)

Faculty supervisor: Mesfin Belayneh

External supervisor: Ola M. Vestavik

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I Abstract

Well control is always of great importance during well operations. The main purpose of well control is to keep downhole pressures in the operating window between pore and fracture pressure. In the case of a well control situation where either the formation is fractured causing loss of circulation or the pressure in the well drops below pore pressure causing a kick, measures have to be taken in order to get the situation under control. When drilling horizontal and extended reach wells the same basic principles of well control apply, but also other aspects have to be considered.

In this thesis the basics of well control has been discussed, along with considerations by use in Extended Reach Drilling, both conventionally and for the Reelwell Drilling Method, which is a new drilling method developed by REELWELL™.

The first part of the thesis contains literature review of well-established well control procedures and an overview of the Reelwell Drilling Method. Due to RDM being a new drilling method, well control issues haven't been studied to the same extent as for conventional, and less literature exists on the matter.

The second part consists of simulation studies performed for 2 extended reach case wells. Landmark Wellplan was used for the conventional simulations, while DrillSIM-5 was used for the RDM simulations. The focus of the simulations has been on circulating kicks of different volumes out of the well. The effect of different mud densities and kick intensities was also included for the Wellplan simulations.

II ACKNOWLEDGEMENTS

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III TABLE OF CONTENTS

1. Introduction

REELWELL™ Company has developed a new Extended Reach Drilling (ERD) solution with the aim of drilling beyond 20km horizontal reach. The ERD solution is still in the development phase, however, most of the equipment and engineering related to the system has been tested in full scale drilling trials and with numerical software. Recently field scale feasibility tests have been performed in Canada and the result shows positive. As part of the project, evaluation of well control is an important issue. Therefore, this thesis work deals with the well control phenomenon in REEWELL and conventional ERD.

Two example wells are used for the simulations presented here:

- Well 1 - a shallow extended reach well having a vertical depth (TVD) of 264,5m and a total measured depth (MD) of 1500 m.
- Well 2 - an ultra-extended reach well with a TVD of 2337m and a total MD of 15800m.

The following presents the background, problem formulation and technology. Subsequently the simulation results are presented and discussed.

1.1 Background

Reelwell was founded in 2004, and started the development of the Reelwell Drilling Method (RDM) [15]. Reelwell intends to expand the existing boundaries of drilling processes, with the ultimate aim of recovering more hydrocarbons in a safe, eco-friendly and cost efficient manner. Figure 1.1 shows the comparison of conventional and the RDM drilling envelope.

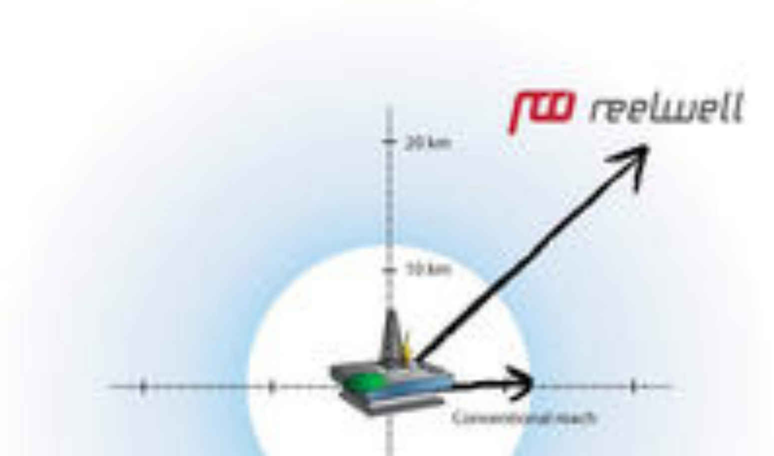

Figure 1.1: Drilling envelope for conventional vs Reelwell

The outer big circle in Figure 1.2 represents the Reelwell reach and the inner small circles are the conventional reaches. Reelwell shows a longer offset and reducing the number of rigs required.

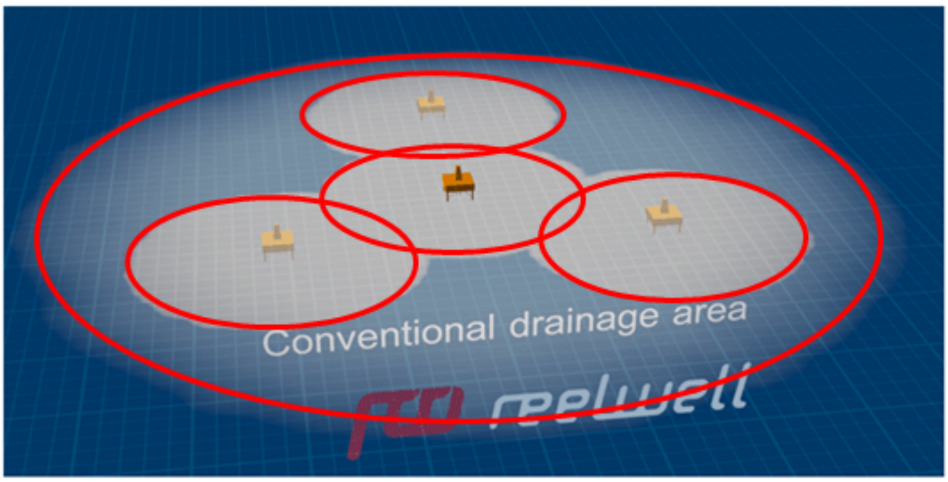

Figure 1.2: Comparisons of conventional and Reelwell drainage area [18]

1.2 Extended Reach Drilling

ERD is commonly defined as drilling of a well with departure-to-depth ratio above 2:1. Going back to 1975 this was the limit of what was possible. Today, the departure-to-depth record is over 10:1. This shows it has been a great development in extended reach drilling. However, during the last years, the advance has slowed down. This means that extended reach drilling might have reached its limits using conventional methods and equipment. [3]

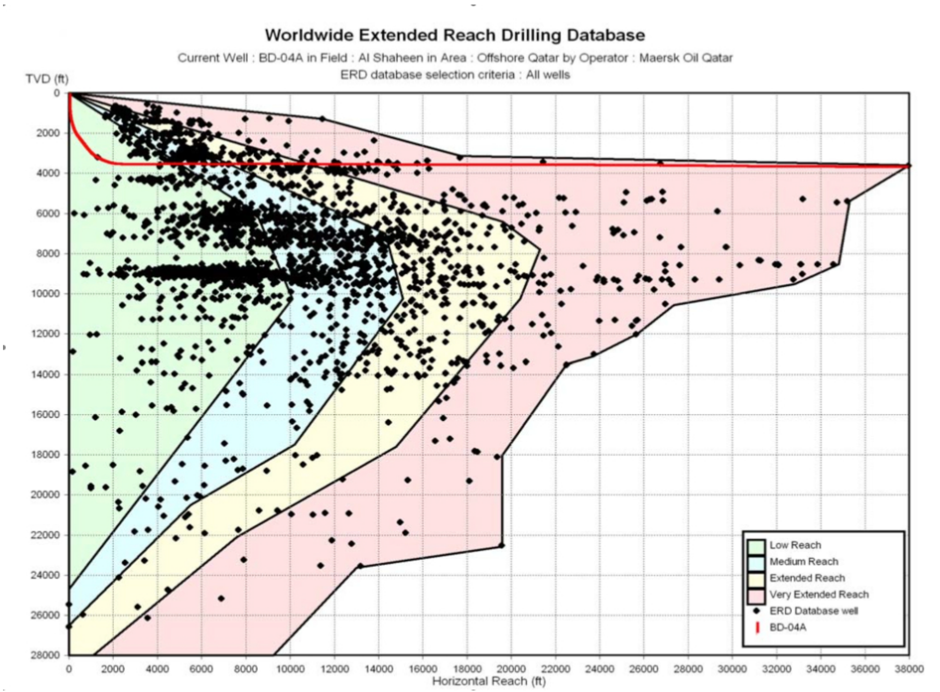

Figure 1.3: Extended reach envelope [16]

Rank	Horizontal displacement, ft	Measure d depth, ft	TVD, ft	Operator	Well	Location
1	37956	40320*	3482**	Maersk	BD-04A	Qatar
2	33182	34967	5266	BP	M-11	UK, Wytch Farm
3	26446	30308	9554	Philips	Xijiang 24-3	South China Sea
4	26361	28593	5285	BP	M-05	UK, Wytch Farm
5	25764	30600	NA	Norsk Hydro	30/6 C-26	North Sea
6	25108	27241	NA	BP	M-09	UK, Wytch Farm
7	23917	28743	9147	Statoil	33/9 C-2	North Sea
8	22369	24442	NA	BP	M-03	UK, Wytch Farm
9	22180	24680	5243	BP	M-02	UK, Wytch Farm
10	21490	26509	NA	Norsk Hydro	30/6 B-34	North Sea

Table 1.1: Top ten extended reach wells in the world *MDRT **TVDRT [17]

The most recent world record is Sakhalin-1, with MD of 12345 m (40,502 ft.) and a horizontal displacement of 11475 m (37,648 ft.), drilled at the Odoptu field in 2011. [12]

1.3 Problem formulation

Well control during ERD is the main issue to be analyzed. In conventional wells, there are established well control procedures. The Reelwell Drilling Method is a new technology, and has adapted well control procedures. The issues to be addressed are:

- Difference between well control kill procedures used for RDM as compared to conventional extended reach wells.
- Pressure development at casing shoe and choke when using different values for mud weight, influx rate and influx volume.
- Kick tolerance for extended reach wells
- Kill circulation time when using RDM compared to conventional.

1.4 Objectives

The objectives of the thesis are,

a) Review the well control issues and the kill methods
b) Perform well control simulations for conventional ERD, using Wellplan industry standard software.
c) Perform well control simulations using DrillSIM 5 drilling and well control simulator developed for the RDM and using hand calculations based on well-established theories.
d) Analyze kick tolerance and choke pressure from simulations.
e) Compare the analysis of the conventional drilling vs the RDM

2. Reelwell technology

2.1 Reelwell vs conventional

The main difference between the RDM and conventional is the dual drill string, which consists of a conventional drill string with an inner string. The RDM uses the inner annulus of the dual drill string to pump the fluid down, and the inner string to transport the drilling fluid and cuttings back to surface. This leaves the mud in the well annulus static, giving a smaller active mud volume than for conventional drilling. Figure 2.1 shows the flow arrangement of the RDM compared to conventional.

Using the inner sting for cuttings transport have shown to cause less grinding of the cuttings and significantly reducing the time needed to transport the cuttings to surface [5]. RDM also uses managed pressure drilling. By adjusting the annulus pressure at surface the BHP can be easily controlled, and because of the mud in the annulus being static, a different mud can be used for drilling.

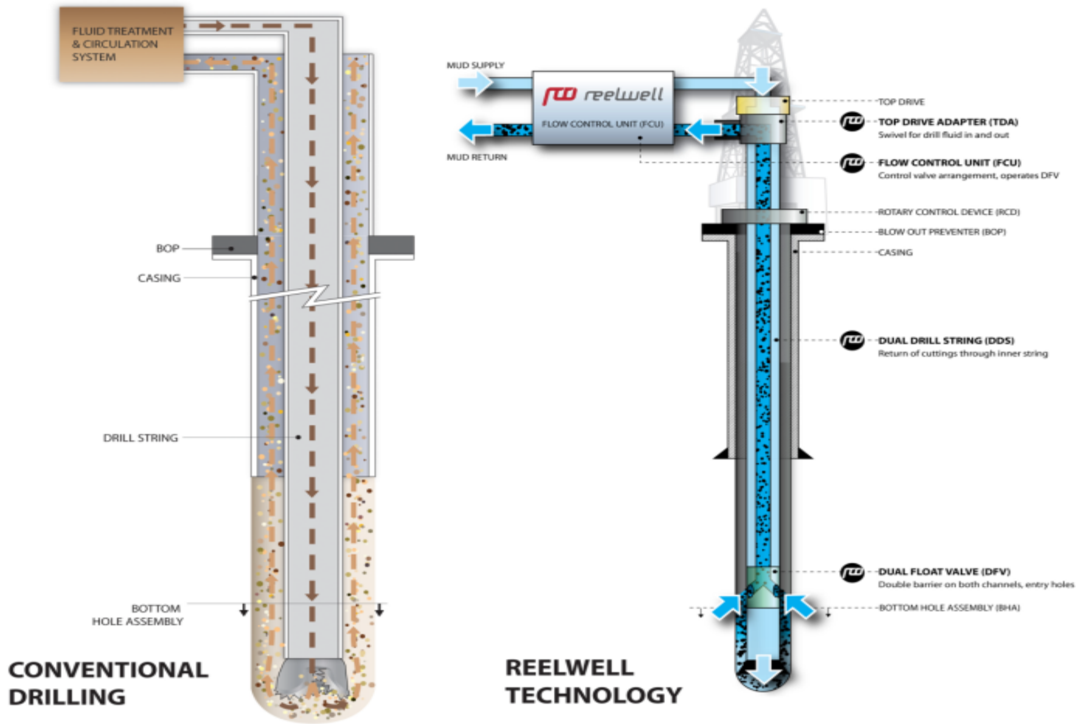

Figure 2.1: Flow arrangement Conventional and RDM

Another difference is the ability to close the drill string using the DFV, which can be used to bleed off the drill pipe pressures during pipe connections.

2.2 Reelwell equipment

Compared to conventional drilling the RDM requires a different fluid flow arrangement (Figure 2.2) and equipment based around the concentric drill string.

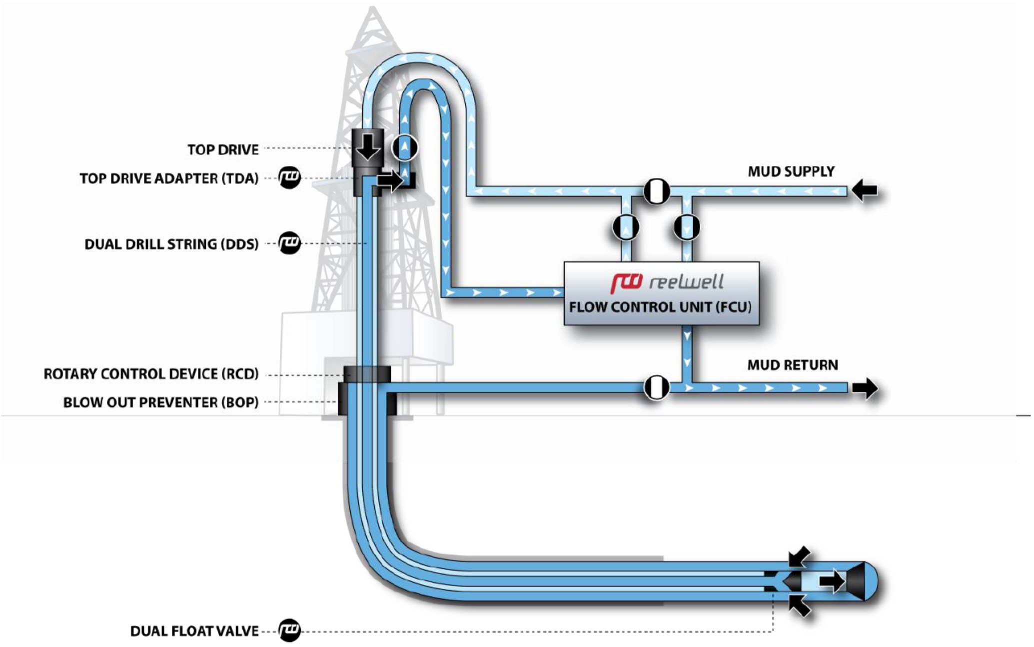

Figure 2.2: Flow arrangement RDM

Dual Drill String (DDS)

The dual drill string (Figure 2.3) is the main difference between the Reelwell Drilling Method and Conventional drilling. The drilling fluid is pumped down the annulus of the DDS, and directed from the DDS trough a conventional BHA. The return flow, including cuttings is transported back through the inner string. The mud enters the inner string just above the BHA, through the flow x-over (FXO) and inner pipe valve (IPV), leaving the rest of the well annulus with a static mud clean of cuttings.

Figure 2.3: Dual Drill String [5]

Top Drive Adapter (TDA)

The TDA (Figure 2.4) is a special swivel to adapt and allow the DDS for rotation with the top drive. The TDA is connected to the Reelwell Flow Control Unit trough an additional mounted standpipe and mud hose.

Figure 2.4: Top Drive Adapter [5]

Flow Control Unit (FCU)

The FCU (Figure 2.5) is a control valve arrangement equipped with pressure and flow sensors for pressure and flow control of the system. The control unit connects to all of the flow paths of the system.

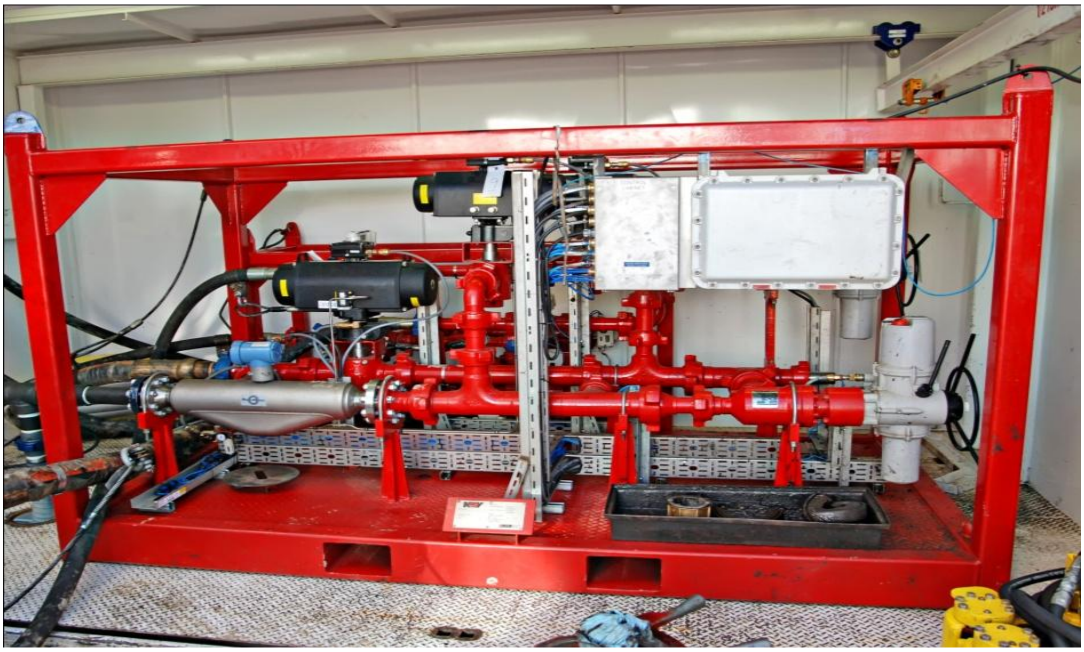

Figure 2.5: Flow Control Unit [5]

Dual Float Valve (DFV)

The DFV (Figure 2.6) terminates the DDS into a conventional BHA. Includes a flow x-over from the annulus into the return channel of the DDS and include valves to isolate the drill sting during connections.

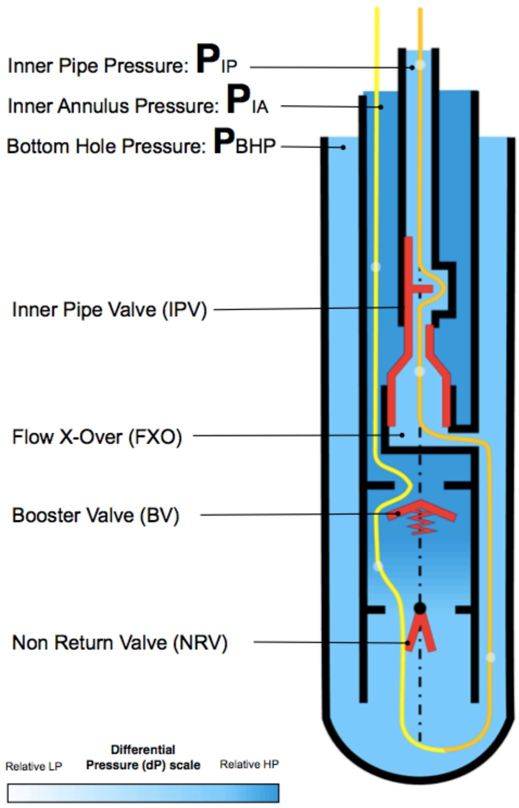

Figure 2.6: Down hole valve system

Heavy Over Light

The Reelwell Multi Gradient System (RMGS) allows for the use of a heavy static mud in the well annulus and a lighter active drilling fluid. The main purpose of Heavy Over Light (HOL) solution is to reduce the torque by causing a buoyancy effect on the drill string, allowing longer horizontal reach. Figure 2.7 shows the HOL configuration, with the red fluid in the annulus representing the heavy static fluid. The blue fluid inside the DDS represents the light drilling fluid. The well annulus is connected to the FCU allowing kill mud to be pumped down the annulus. For a more detailed description of HOL see ref. [10]

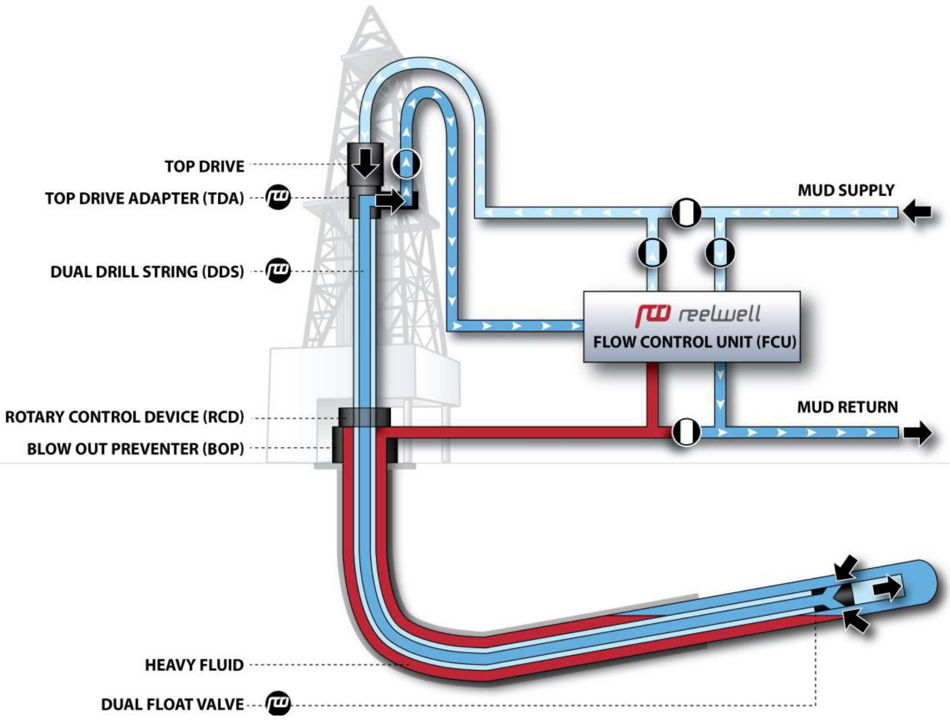

Figure 2.7: HOL fluid configuration [10]

3. Basics of well control

Well control is one of the most important issues during the planning and drilling of a well. The main purpose of well control is to prevent unwanted inflow of fluid into the wellbore, which can lead to kicks and in worst-case blowouts (Figure 3.1). Especially during ERD a well-designed plan for well control is very important, as the margins becomes smaller the further you drill.

In this section, the basics of well control will be discussed and methods and procedures for well control in conventional drilling will be compared to the Reelwell Drilling Method. This part of the comparison will be based on literature review, and in later sections simulations for both methods will be performed.

Figure 3.1: Blow out

3.1 What is a Kick?

A kick is a well control problem that occurs when you get unwanted influx of formation fluid into the wellbore due to a BHP lower than the formation pressure. A too low mud density is considered the main reason for a kick, this is called an underbalanced kick, and occurs because the mud column itself in not enough to balance the formation pressure. An induced kick happens due to dynamic effects such as surge and swab, this can happen even when the well is overbalanced. When a kick is detected, the well has to be shut in as soon as possible. If a kick is not detected in time, it can cause a blowout. There are two kinds of blowouts, surface and underground. A surface blowout is when an uncontrolled flow of formation fluids reaches the surface facilities, with potentially catastrophic consequences for rig personnel, environment and equipment. An underground blowout can happen even if the personnel close the BOP in time. When a high-pressure zone is penetrated, the pressure in the well builds up until a weaker formation is fractured, and an uncontrolled flow of formation fluids from the high-pressure zone into the new formation occurs. Even if an underground blowout might not be as dangerous for surface equipment and personnel, it can be even more expensive than a surface blowout, since the drilling of a secondary relief well might be the only solution.

After the kick has been detected and the well shut in, the pressure in the well has to stabilize before the kick can be circulated out. There are different methods of circulating out the kick and killing the well; the 2 most common are Drillers Method and Wait & Weigh. For both methods, the goals is to circulate out the influx by keeping the BHP constant and pump down a new, heavier mud, which is able to balance the formation pressure on its own.

3.2 Reasons for kick

A kick occurs when the formation pressure exceeds the hydrostatic pressure in the well. However, other factors like porosity and permeability are also of importance. For example, for a slightly underbalanced wellbore a kick is less likely to occur if the permeability and porosity is low. The differential pressure between the wellbore and formation has to be higher than the pressure needed to push the fluid out of the formation.

Reasons for kick can be [1]:

- *Insufficient mud weight*
- *Improper hole fill-ups during tripping*
- *Swabbing*
- *Gas cut mud*
- *Lost circulation*

Mud weight

Insufficient mud weight is one of the predominant reasons for kick.

The mud column in the well is the primary well barrier and if the mud weight is too low it will not be able to balance the formation pressure, thus risking a kick. Especially when drilling into a permeable formation with a high pore pressure.

When drilling into a formation with an abnormal formation pressure, the mud weight of the mud already in the wellbore is usually not enough. When drilling the pressure fall from pumping the mud will apply an additional pressure to the borehole so a lighter mud is possible. However, in most conventional operations mud heavy enough to balance the formation pressure on its own is used.

Failure to keep hole full

Improper hole fill-ups during trips is another predominant cause of kicks.

When tripping the drill string out of the hole the volume originally occupied by the drill string will have to be filled with mud. If the volume isn't replaced by mud while tripping, the mud column height in the annulus will decrease, causing the hydrostatic pressure in the well to decrease. Because of this it's very important to pay attention when tripping, and if needed the trip tank is used to refill the well.

Swabbing

Swabbing means to pull the drill string out of the borehole. This will cause a piston like effect causing the effective hydrostatic pressure below the drill collar to fall, risking influx. Pulling speed, mud properties, hole configuration and "balled" equipment are variables that affect swab pressures.

Cut mud

Cut mud means gas contaminated mud and can sometimes cause a kick, although it's not a common cause. Gas cut mud occurs when drilling in formations containing hydrocarbons. Small amounts of gas from the drilled formation will be brought to surface along with the cuttings and will expand potentially causing a kick. However in most cases this is a very small amount, usually not enough to cause a kick.

Lost circulation

In the case of lost circulation, the mud level in the annulus will sink, causing the hydrostatic pressure to decrease, potentially causing a kick.

3.2 Kick detection

Warning signs and indicators of a kick can be observed at surface. The warning signs are identified as primary or secondary relative to their importance.
Warning signs include [1]:

- *-Flow rate increase*
- *-Pit volume increase*
- *-Flow when pumps are off*
- *-Pump pressure decrease and pump stroke increase*
- *-Improper hole fill-up on trips*
- *-Change in string weight*
- *-Drilling break*
- *-Cut mud weight*

Flow rate increase (Primary indicator)
An increase in flow rate with constant pump rate is a primary indicator. Increased flow can be interpreted to mean an influx from the formation is aiding the pumps in moving fluid up the annulus.

Pit volume increase (Primary indicator)
If the pit volume increases while pumping at a constant rate this is an indicator of influx, displacing the mud in the wellbore causing the pit volume to increase.

Flow with pumps off (Primary indicator)
If the well continues to flow when the pumps are turned off could mean a kick in progress. An exception can be if the mud in the drill string is considerably heavier than the mud in the annulus due to a slug.

Improper hole fill-up (Primary indicator)
When the drill sting is tripped out of the hole, the mud level should decrease by a volume equivalent of the volume of the removed drill pipe. If a mud volume less than expected is required to bring the mud level back to surface, a kick might be in progress.

Pump pressure decrease and stroke increase (Secondary indicator)

A change in pump pressure may indicate a kick. If an influx occurs there's a chance the mud might flocculate temporarily increasing the pump pressure. As the influx continues to displace heavier mud the pressure might start to decrease. As the fluid in the annulus becomes less dense, the mud in the pipe will fall and the pump rate might increase.

This is considered a secondary indicator as other drilling problems might cause the same signs. A "washout" in the open hole annulus or a pipe twist-off can cause the same signs, however, one should check for a kick if these signs occur.

String weight change (Secondary indicator)

Changes to the weight of the drill string might be an indicator that an influx of formation fluid has decreased the density of the mud in the wellbore decreasing the effect of buoyancy. An increased observed weight at surface would indicate an influx of light fluid.

Drilling break (Secondary indicator)

A drilling break is an abrupt increase in penetration rate. When the drilling rate suddenly increases, it means the bit has entered a new formation, which is assumed to have a potential to kick. For example, drilling from a shale formation to a sandstone formation might cause an increased penetration rate. However, an increased rate doesn't necessarily have to mean a kick is in progress, just that the new formation have the potential to kick. Recommended practice in the case of a drilling break is to continue to drill a few feet into the new formation, then stop and check for flowing formation fluids.

Cut mud weight (Secondary indicator)

Reduced mud weight observed at the flow line can occasionally cause a kick to occur. The reduction in mud weight due to expanded gas from the cuttings is usually very small, and if the well did not kick in the time needed to drill the formation containing gas and transport it to the surface, there's just a small possibility it will kick. Generally, gas cuttings only indicates that the formation drilled contains gas, and doesn't necessarily mean the mud weight have to be increased.

3.3 Well control methods in conventional drilling

Shut-in procedures

If one or more kick indicators occur, steps should be taken to shut in the well. Even when there's doubt about if there's a kick or not, the well should be shut in and the pressures checked. A small flow should be treated the same as a full flowing well as it potentially could lead to a big blowout.

There have been concerns about pipe-sticking and underground blowouts as a result of shutting the well in, but when there's a possibility of a kick the primary concern should be to safely kill the well and the secondary concern to avoid pipe sticking. As for underground blowout there's a bigger chance of this occurring if the well is able to flow for a while after the initial kick detection compared to shutting in the well immediately after detecting the kick.

Initial shut-in

Two different methods are used for initial shut-in, "hard" and "soft". There have been discussions about which one should be used. Hard shut-in means to close the annular preventers immediately after the pumps are stopped. In soft shut in the choke is opened prior to closing the annular preventers, and shut after the annulus is closed.

The main difference between the two methods is the pressure change in the annulus after shut-in. The main argument for choosing the soft shut-in is that by using the hard shut-in, a "water hammer" effect will occur causing a spike in casing pressure. It also provides an alternate mean of well control in the case of excessive casing pressure (low choke pressure method). However, the water hammer effect has no proven substance [8], and the low choke pressure method is an unreliable method. The main argument against the soft shut-in is that a continuous influx is allowed for the duration it takes to execute the procedures.

Obtaining and interpreting shut-in pressures [1]

Shut-in pressures are the stabilized surface pressures in the pipe and casing when the well is closed. These pressures are called shut-in drill pipe pressure (SIDPP) and shut-in casing pressure (SICP). Both pressures are important, but mainly the drill pipe pressure is used in killing the well.

When a kick is detected and the well shut in, the pressure at surface will build up due to influx of formation fluid into the wellbore and the difference between the hydrostatic mud pressure and the formation pressure. The surface pressure will build until it is high enough to balance the formation pressure. When the pressures have stabilized the surface pressure plus the hydrostatic pressure from the column of mud and influx fluid should be equal to the formation pressure. At this point the influx should stop.

$$\text{SIDPP} + \text{Drill pipe mud hydrostatic pressure} = \text{Bottom hole formation pressure} \quad (1)$$

$$\text{SICP} + \text{Annular mud hydrostatic pressure} + \text{Annular influx hydrostatic pressure} = \text{Bottom hole formation pressure} \quad (2)$$

Shut-in pressure is equal to bottom-hole formation pressure minus the hydrostatic pressure of the mud column. As the annulus will contain formation fluid, which has a lower density than the mud, the SICP will always be higher than the SIDPP.

Trapped pressure [1]

"Trapped pressure" is any pressure in the pipe or casing more than needed to balance off the formation pressure. Reasons for trapped pressure can be that the well was closed before the pumps were shut off, or gas migrating up the annulus causing it to expand. Using recorded pressures including trapped pressure will cause errors in the kill calculations. As the trapped pressure isn't needed to balance the formation pressure, it can be bled off without causing any additional influx. It should be bled from the casing, as this is where the choke is located and to avoid contamination of the mud in the drill pipe. Since the SIDPP is a direct bottom-hole pressure indicator, it should be used as a guide when bleeding the trapped pressure. If bleeding is continued after the trapped pressure is bled, more influx will be allowed into the wellbore. Therefore, the pressure should be bled small amounts at a time, then closing the choke before observing the pressure in the drill pipe. The trapped pressure is bled of when the SIDPP stops to decrease. This will be the true SIDPP, and should be used for further calculations.

Observed SIDPP = True SIDPP + Trapped pressure (3)

True SIDPP = Formation pressure – Hydrostatic mud pressure (4)

Observed SIDPP = Formation pressure – Hydrostatic mud pressure + Trapped pressure (5)

As the Formation pressure and the hydrostatic mud pressure in the drill pipe is constant, the observed SIDPP will stop decreasing when the trapped pressure is 0, and observed SIDPP is equal to “true SIDPP”.

Kill weight mud calculation

After a kick is detected and the well shut in it is necessary to calculate the mud weight needed to balance the formation pressure. “Kill weight mud” is defined as the exact weight needed to balance the well. Since the SIDPP is defined as a bottom hole pressure gauge, it can be used to calculate the K.W.M.

Kill mud formula:

$$KWM = SIDPP * \frac{19.23}{depth} + OWM \tag{6}$$

KWM = Kill Weight Mud, ppg

19.23= Reciprocal of 0.052, ppg/psi/ft

Depth= TVD, ft

OWM= Original weight mud in drill pipe, ppg

Since the casing pressure is not used in the formula, a high SICP does not necessarily mean a high KWM is needed. The same is true for pit gain [1].

Well control procedures

Several methods of circulating out a kick have been developed over the years. Prior to the early 1960s, keeping the pit level constant, also known as the barrel in - barrel out method, did the circulation of the influx. When the influx was mostly liquid, the method was successful, but if the influx was gas, the result could be disastrous. In the late 1950s and early 1960s, some began to realize that the barrel in - barrel out method wasn't reliable. If the influx was gas, it had to be allowed to expand as it came to the surface. [2]

The most common kill procedures are the driller's method and wait & weigh. Others are the concurrent method, volumetric method, bull heading etc. Mainly driller's method and wait & weigh will be discussed here.

3.3.1 Driller's Method

Driller's method is most commonly used well control procedure. It is also called the "two circulation method", since the influx is circulated out before kill mud is added. It requires less complicated calculations than wait & weigh and is considered easier to use.

The first circulation is started as soon as the well is shut in and the SICP and SIDPP have stabilized. The purpose of the first circulation is to circulate the influx out of the well, using the original mud weight. The bottom hole pressure is held constant for the entire procedure, preferably slightly higher than the formation pressure, to avoid further influx into the wellbore. When starting the pumps, casing pressure is held constant until kill rate is reached. Then the drill pipe pressure is held constant to keep the bottom hole pressure equal to or slightly higher than formation pressure. The drill pipe pressure is held constant until the influx is circulated out. If the influx is gas, it will expand as it is brought up the wellbore, causing an increase in pit volume and casing pressure. When the entire influx is circulated out, the well is shut in, and casing and drill pipe pressures recorded. ((1) in Figure 3.2))

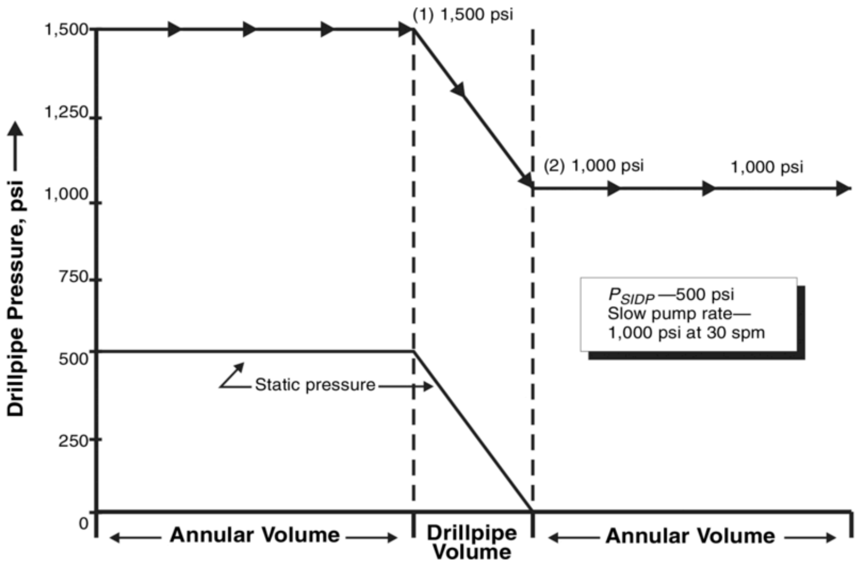

Figure 3.2: Drill pipe pressure during Drillers Method [19]

These should now be equal. If not, there might still be influx left in the well, or trapped pressure. Before startup of the second circulation, the kill mud weight must be calculated and prepared, kill mud weight is calculated using equation 6.

The second circulation is then performed to kill the well. Kill mud is pumped down the drill string to displace the original mud. First the pumps are brought to kill rate by keeping the casing pressure constant. The casing pressure is held constant until the kill mud reaches the bit ((2) in Figure 3.2), to keep bottom hole pressure constant. When the kill mud reaches the bits and starts to go up the annulus the drill pipe pressure needs to be kept constant until the mud reaches the surface. When the kill mud reaches the surface the pumps are shut down and the drill pipe and casing pressures recorded. These should both be zero if the kill operation was successful. If not means there's still influx left in the well.

3.3.2 Wait & Weigh

The wait & weigh method, also called engineers method or "one circulation method" [1]. The main difference compared to driller's method is that wait & weigh is done in only one circulation. As for driller's method the well is shut in when the kick is detected, and the casing and drill pipe pressures are allowed to stabilize. The SICP and SIDPP is then recorded and SIDPP is used to calculate kill mud weight. Since the operation is done in only one circulation, the kill mud needs to be prepared before the circulation can start. A drill pipe schedule also has to be figured out. Since the drill pipe is full of the original mud and the influx is still in the annulus when kill mud circulation is started, both hydrostatic pressures will change until the kill mud reaches the bit. Because of this it's not enough to keep one of the pressures constant wile pumping.

At the beginning of the circulation, the drill pipe pressure will be SIDPP plus pumping pressure ((3) in Figure 3.3). This should be decreased linearly until the kill mud reaches the bit. At this point, the drill pipe pressure should be equal to pumping pressure ((4) in Figure 3.3) since the hydrostatic column of kill mud should balance the formation pressure. Since the drill pipe now is completely filled with kill mud, the drill pipe pressure should be kept constant for the rest of the circulation. When the influx is circulated out and the well is filled with kill mud the pumps are shut down and surface pressures recorded. As for the driller's method both drill pipe and casing pressure should be zero. If not there's still influx left in the well.

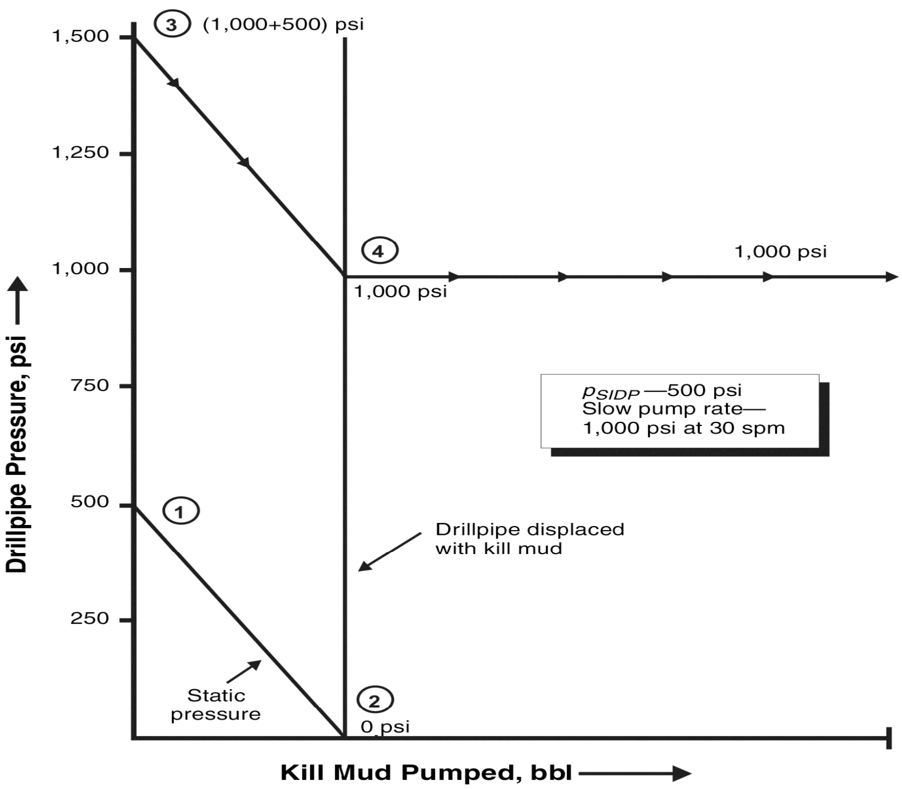

Figure 3.3: Drill pipe pressure during Wait & Weigh [19]

3.4 Well control considerations for RDM

Most conventional well control methods can be applied when using RDM [5], however, there are a few differences. In this section different well control procedures will be discussed and how they will work during ERD using the RDM.

Causes of kick and detection

The different reasons for a kick happening will also apply when using the RDM. Managed Pressure Drilling will help keeping a stable BHP, decreasing the chance of well control problems. In the case of lost circulation, a sliding Piston can be used to limit the loss, by isolating the annulus fluid above it.

Most kick detection methods will also be the same when using RDM. Due to less active fluid volume, a pit gain of under 100l (under 2/3 bbl) can be recorded, [4] resulting in quicker reaction times and smaller kick size.

Smaller active drilling mud and return through small diameter IP will cause higher surf pressure for same kick size (longer gas column). Due to the kick is circulated out the inner pipe the casing shoe pressure will not be affected, assuming the influx doesn't migrate up the well annulus.

Shut-in and kill procedures

Detailed comparison of shut-in and HOL kill procedure and driller's method in appendix E.

3.4.1 Heavy Over Light return up inner pipe kick circulation method

The HOL return up inner pipe is a kill method developed for the Reelwell Drilling Method. It is performed in 3 separate circulations, shown in Figure 3.4. The kick is circulated out through the inner pipe and the kill mud is pumped down the well annulus. Heavy Over Light means using a heavy mud in the well annulus and a lighter mud as the active drilling fluid. [9]

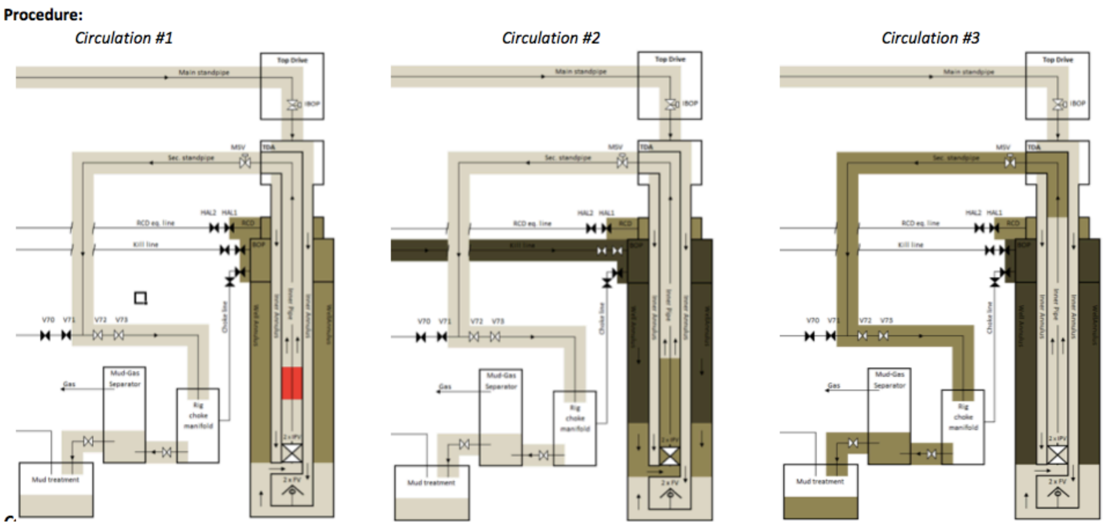

Figure 3.4: HOL return up inner pipe circulation steps [9]

Calculate kill mud weight

Pump down inner annulus at very slow circulation rate and record inner annulus pressure. Record casing pressure and pressure to open Inner Pipe Valve (IPV). Apply safety margin to heavy mud in annulus.

Start mixing new heavy mud for circulation 2 and simultaneously go to circulation 1. Ensure that a pit plan has been prepared and that means of volume control is in place as mud with three different densities are involved.

Circulation 1

- Circulate light mud down Inner Annulus
- Take returns up Inner Pipe through the rig choke
- Use rig choke to keep well annulus pressure stable
- Circulate until influx is out and the gas reading is down

Circulation 2

- Circulate light mud down Inner Annulus at a very slow constant rate to monitor BHP
- Pump kill mud down the well annulus. The rate can be increased until max pump pressure is reached.
- Take returns up Inner Pipe through the rig choke
- Adjust rig choke to keep Inner Annulus pressure stable
- Stop pumping when kill mud at FXO

Circulation 3

- Circulate light mud down Inner Annulus to displace kill mud from Inner Pipe
- Take returns up Inner Pipe through rig choke
- Adjust rig choke to keep well annulus pressure stable
- Continue until kill mud is displaced out of Inner Pipe

If influx is expected taken at the bit, it is sufficient to pump kill mud down to the casing shoe. If influx is taken behind the FXO, circulation 2 can contain influx. [9]

3.5 Well control considerations in Extended Reach Drilling

Although there are a lot of factors limiting the possible reach of a drilling operation, well control is very important, especially when it comes to safety. Losing control of a well can in the worst-case scenario lead to a blowout. Compared to vertical wells, most of the basic well control procedures will be the same for horizontal/extended reach wells, such as kick reasons, detection methods, shut-in and kill procedures. However, there are also differences, which will be discussed in this section. Even though ERD doesn't necessarily have to mean that the well has a completely horizontal section, the situations described assume a well with a horizontal section.

ECD for long horizontal sections

One of the limiting factors of conventional ERD is the ECD in the horizontal section. For very long horizontal open hole sections the ECD will cause a high BHP, risking formation fracture and lost circulation. Reducing circulation rate and mud weight can reduce the BHP, but this on the other hand can cause a kick at the casing shoe, where the ECD will be much lower compared to TD (Figure 3.5). When using RDM this problem will be eliminated due to no flow going through the well annulus, giving a static gradient. [13]

Figure 3.5: RDM vs Conventional dynamic gradient

Faults

During horizontal drilling, the formation pressure will usually stay the same as long as the TVD is constant. However, drilling through faults can cause abrupt changes in formation pressure, both higher and lower than the normal formation pressure. For example, drilling trough two or more originally unconnected faults, where one or more has an abnormally high pressure, can lead to an underground blowout. On the other hand, lost circulation can occur by drilling into a low-pressured fault. [1]

Influx volumes

Most extended reach wells is designed to expose more of the producing formation to the wellbore than vertical wells [1]. Because of this the influx rate into the wellbore might be significantly higher than for vertical wells, when the conditions of pressure differential and time of underbalance otherwise are the same. Higher influx rate mean a greater total influx volume by the time the well is shut in, potentially causing high pressures that can burst the casing or result in an underground blow out.

Kick tolerance

Equation 7 is used to calculate the kick tolerance of a vertical well, where L_{Vkc} is vertical length of the kick. Compared to a vertical well, the vertical length of a kick in an extended reach well is close to zero, assuming the entire influx volume is located in the horizontal section of the well. Setting L_{Vkc} to zero in eq. 7 will cause the kick tolerance to be higher in a horizontal well compared to a vertical well [11].

This implies that horizontal wells have a greater tolerance to contain a kick without fracturing the weakest formation than vertical wells. When using RDM the influx is taken up the inner pipe, leaving the mud in the annulus static and thus the shoe pressure unaffected by the kick circulation.

$$K = \frac{D_S}{D_{Vt}}\left(\rho_{frac} - \rho_L\right) - \left[\frac{L_{Vkc}}{D_{Vt}}\left(\rho_L - \rho_{kc}\right)\right] \tag{7}$$

K= Kick tolerance lbm/gal

D_s= Casing shoe depth ft

D_{Vt}= TVD ft

ρ_{frac}= fracture equivalent density lbm/gal

ρ_L= Liquid density lbm/gal

ρ_L= Kick density lbm/gal

Shut-in procedures

The procedure for shut-in is the same for horizontal wells as for vertical wells. However, it has been shown that "hard shut-in" should be used in most situations, since the "water hammer effect" has been proven to be insignificant [8]. Since the influx rate is likely to be higher in extended reach wells, hard shut-in is preferred, as soft shut-in is more time consuming, causing a larger volume of influx to be allowed into the wellbore.

SICP and SIDPP in a horizontal well

Assuming the kick happens due to drilling into a high-pressure formation in the horizontal section of the well, and the well is shut in time to contain the influx in the horizontal section, the recorded SICP and SIDPP will be equal. Figure 3.6 shows an example of shut-in pressures as a function of kick volume for a horizontal well [14]. Because of this, a small amount of gas left in the horizontal section after a kill operation will not affect SICP as in a vertical well. Therefore it is no way to tell if there is left influx from the shut-in pressures. If there is the remaining gas will expand when it is circulated up the vertical section when drilling continues, possibly causing a second kick.

Because of this, kicks should be circulated out with the bit at the bottom of the hole in horizontal wells, to avoid influx being left behind below the bit.

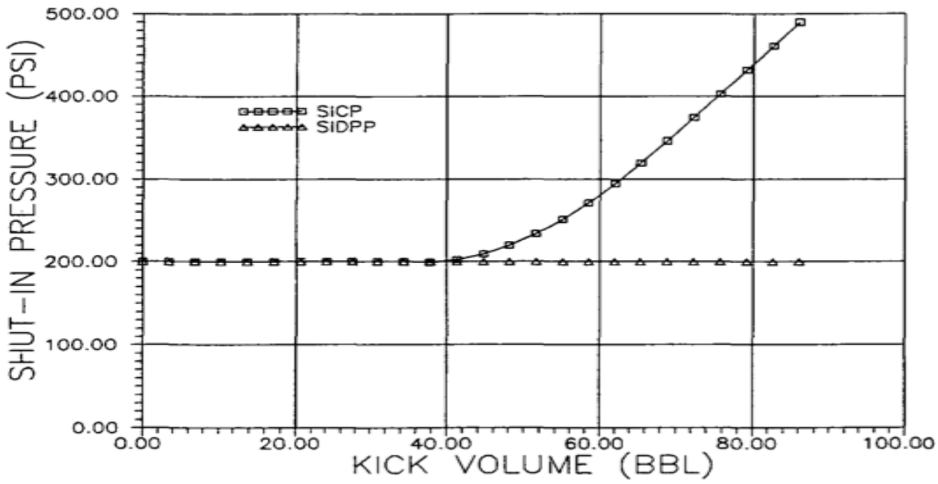

FIG. 12 - SICP AND SIDPP AS FUNCTIONS OF XICX SIZE

Figure 3.6: SICP and SIDPP as a function of kick volume in horizontal well [14]

Swabbing

Because the formation pressure usually doesn't change over the horizontal section in extended reach wells, tripping out of the well will be more critical than in vertical wells, as the pressure drop from swabbing will be a function of the measured length of the pipe [11]. Also, for a swabbing induced kick, the shut-in pressures will remain zero if the influx stays in the horizontal section.

Gas migration rates

For horizontal wells, the gas migration rates will be zero, even when using WBM. Of course, this is only the case when the gas is located in the horizontal section and the well is shut in.

Drill pipe pressure schedule

Displacement of the mud in the drill string with heavier kill mud is usually aided with the use of a pressure schedule, to control the BHP at all times. It shows the surface drill pipe pressure needed to balance the formation pressure. The drill pipe pressure needed will decrease as the kill mud is pumped down. For vertical wells this decrease is linear, from the point the kill mud enters the pipe until it reaches the bit. For horizontal wells the pressure schedule will be different. The difference between vertical and horizontal is shown in Figure 3.7. Overbalance will occur if a vertical pressure schedule is used, causing a risk of lost circulation [1].

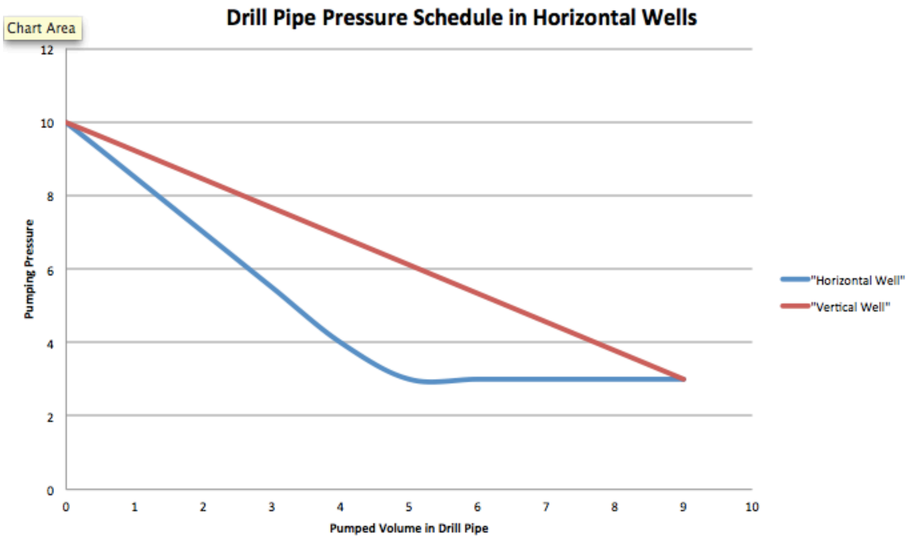

Figure 3.7: Illustration of drill pipe pressure schedule for vertical and horizontal wells

3.6 Which circulation method to choose for horizontal wells

Influx circulation

Highly deviated and horizontal wells might require more than one circulation to get rid of all the influx, because of gas pockets in the top side of the inclined section. If the horizontal section has an inclination of more than 90 degrees, the influx will accumulate at the end of the section, making it even more difficult to circulate it out.

Hole problems

A horizontal section means higher chance of cuttings to settle and accumulate. Better to start circulating right away.

Casing shoe pressure

One of the advantages of Wait & Weigh is that is can might cause a lower pressure at the casing shoe. However in horizontal wells, this problem will be of less significance, as the casing shoe usually is located at nearly the same depth as the TVD of the well.

Mud mixing time and circulation time

For long horizontal wells, a large volume of kill mud is required, and depending on the mixing capabilities of the rig, this can be time consuming. This is especially the case for older rigs. By using Driller's Method, circulation can be started as soon as the shut-in pressures are recorded. However, one extra circulation is required when using DM, increasing the total circulation time. The total time needed for each of the methods therefore depends on both mixing time and circulation time. [6]

Formation ballooning

Formation ballooning can occur in certain rock formations, and can easily be misinterpreted as kick. Driller's Method allows reassessing the situation after circulating with original MW. [6]

Considering these factors, Driller's Method should be the best choice for extended reach drilling. This is also supported by other sources [6, 7]. For the simulations performed, mainly Driller's Method will be the used.

4. Well control simulation

Two different wells were used for the well control simulations, one shallow extended reach well with a total MD of 1500 m, and one ultra-extended reach well with MD 15800 m. Both were drilled from an onshore location. For the conventional simulations Landmark Wellplan was used. Only well control problems were considered, using the simulators kick tolerance mode. The simulations were done assuming a kick while drilling at TD, into an over pressured formation.

For the RDM simulations DrillSIM 5 was used. This is a simulator developed to use the RDM well geometry. The same casing and hole sizes as for the conventional were used, but different drill pipe sizes, as the dual drill string was used. Also when using DrillSIM the kick was assumed to occur at TD during drilling.

4.1 Simulation arrangement

4.1.1 Well 1 - Shallow extended reach well geometry

The well was constructed as a vertical, bend and horizontal extended reach well. The KOP was set at 27m, followed by a build section of 473m. The casing was set at the end of the build section, at 500m MD. The final inclination was 93^0. The operational window between fracture and pore pressure was 8,84ppg and 15,51ppg respectively. The open hole well diameter was 8,5". Well, casing and drill pipe data is found in tables 4.1-4.3. Figure 4.1 shows the section view of well 1. The pore and fracture pressure gradients was assumed to be the same for the entire open hole section.

KOP	27 m	88,58 ft
Casing Shoe MD (End of build section)	500 m	1640,42 ft
Casing Shoe TVD	316,8 m	1039,5 ft
Well depth MD	1500 m	4921,3 ft
Well depth TVD	264,5 m	867,8 ft
Open hole diameter	8,5 in	
Pore Pressure	10,4 kPa/m	8,84 ppg
Fracture Pressure	19,42 kPa/m	15,51 ppg

Table 4.1: Shallow ERD well data

Casing Data	Length ft	OD (in)	ID (in)	Capacity (bbl/ft)	Weight (lbs/ft)	Grade
	1640,4	9,625	9,001	0,0787	32,3	H-40

Table 4.2: Shallow ERD casing data (Same configuration for Conventional and RDM)

Drill pipe data	Conventional	Reelwell Drilling Method
Length (ft)	4920,3	4920,3
OD (in)	5	6,625
ID (in)	4,276	5,901
IP OD (in)	-	3,5
IP ID (in)	-	3

Table 4.3: Shallow ERD drill pipe data

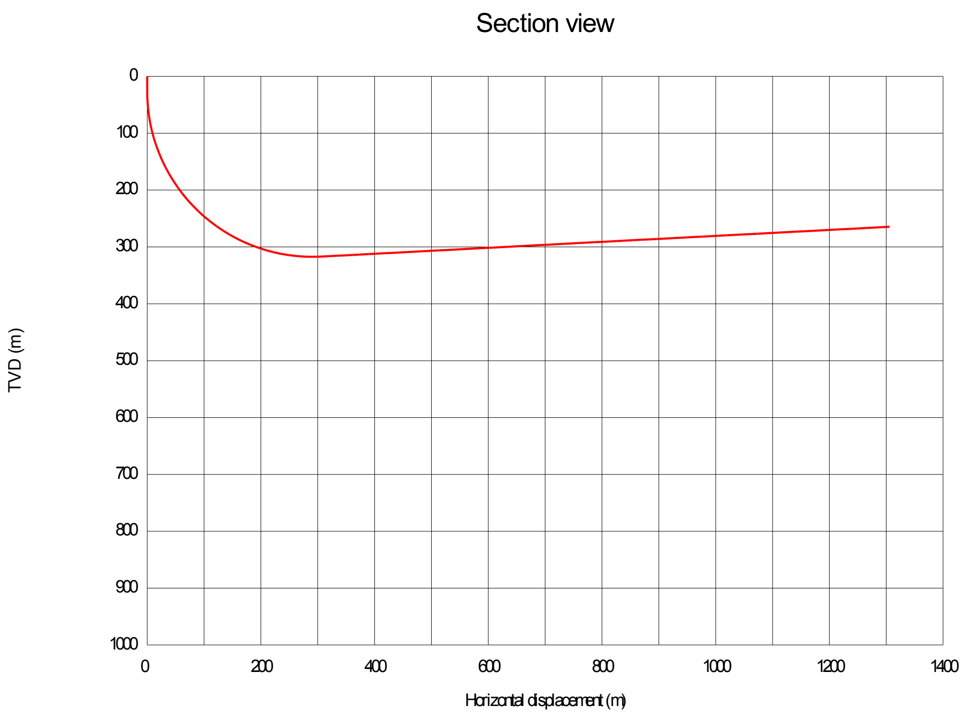

Figure 4.1: Shallow extended reach well section view

4.1.2 Well 2 - Ultra extended reach well geometry

Well 2 was constructed the same way as well 1, with KOP at 1700m. The build section had a buildup rate of 2 degrees per 30 meters reaching the final inclination of 91 degrees at 3065 m MD. The entire horizontal section had a inclination of 91 degrees. The total MD of the well was 15800m. Figure 4.2 shows the section view of the well.

Two sections of the well was used for the simulations; drilling at 5000 m with the shoe at 1000 m (section 1), and drilling at 15800 m with the shoe at 14000 m (section 2). Pore and fracture pressure was 9,33 and 15,4 ppg, respectively, and assumed to be the same for both open hole sections. The same drill pipe diameters were used for the two sections.

KOP	1700 m	5577,43 ft
BUR	2 deg/30m	2,032deg/100ft
Well depth MD	15800 m	51837,27 ft
Well depth TVD	2337 m	7667,5 ft
Pore Pressure	9,33 ppg	1,12 sg
Fracture Pressure	15,4 ppg	1,85 sg

Table 4.4: Ultra ERD well data

Hole size	Casing OD		Shoe depth m	Shoe depth ft
24	20	19,124	1000	3280,84
16	13 3/8	-	5000	16404,20
13 ½	10 ¾	10,192	14000	45931,76
9 7/8	7	-	15800	51837,27

Table 4.5: Ultra ERD casing data

Drill pipe data	Conventional	Reelwell Drilling Method
OD (in)	6,625	6,625
ID (in)	5,965	5,965
IP OD (in)	-	4
IP ID (in)	-	3,54

Table 4.6: Ultra ERD drill pipe data

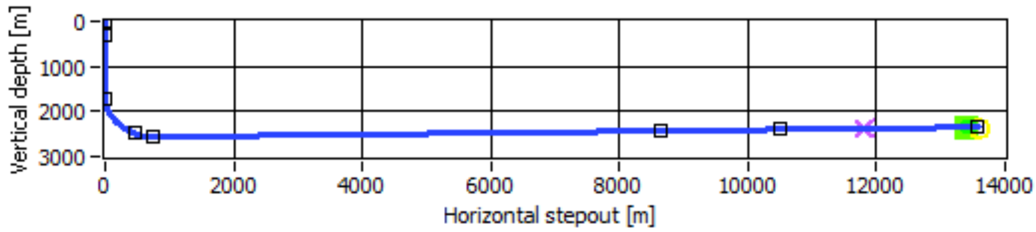

Figure 4.2: Ultra extended reach well section view

Figure 4.3 shows the first section from 1000-5000m was the only one with a significant vertical difference between the casing shoe and bottom hole. The TVD at 5000MD is 2525,5m giving a vertical difference of 1525,5m.

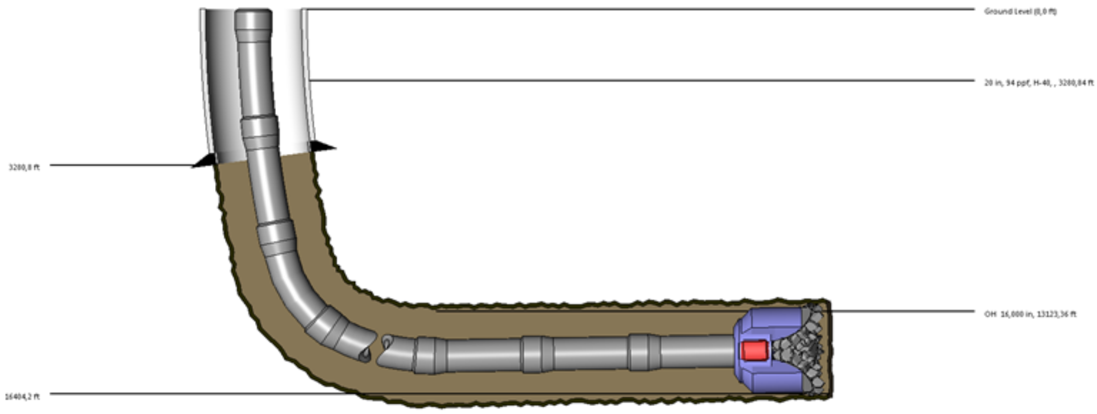

Figure 4.3: Well 2 section 1 schematics

Figure 4.4 shows the second section used for the simulations with a total MD of 15800m, and casing shoe set at 14000m MD. Inclination of the open hole section was 91 degrees.

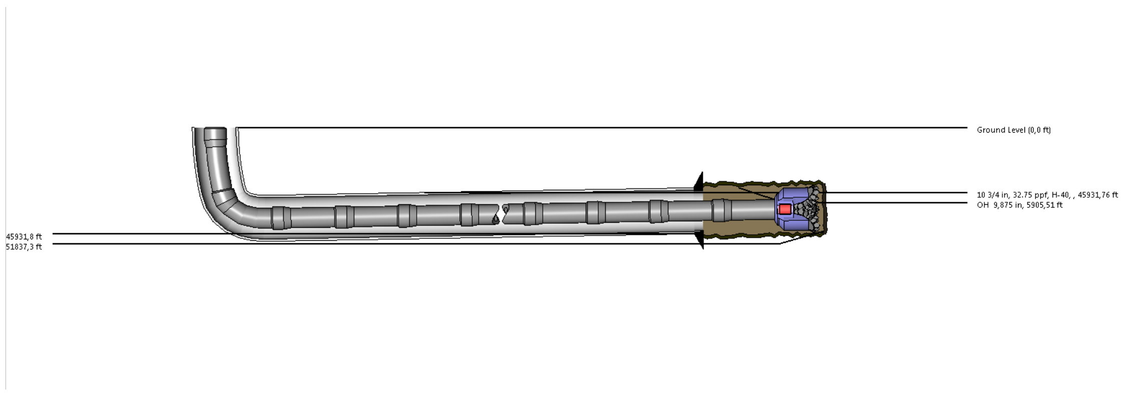

Figure 4.4: Well 2 section 2 schematics

4.2 Drilling fluid properties

4.2.1 Wellplan simulation

For the Wellplan simulations 4 different mud weights was used. These ranged from 9-12ppg for well 1 and from 9,5-12,5ppg for both sections of well 2. The rheology was the same for all simulations. In addition, a 10,12 ppg mud with different properties specially developed for Reelwells HOL configuration was used, to compare the results. The fluid data is given in table 4.7. Oil based mud was used for all simulations, even though this did not seem to give any different results than water based.

	Drilling fluid	**HOL fluid**	
Well 1 MW (ppg)	9/10/11/12	10,12	
Well 2 MW (ppg)	9,5/10,5/11,5/12,5	10,12	
Rheology model	Power law	Herschel-Bulkley	
Rheology data	Fann Data	Fann Data	
Temperature	70°F	70°F	
Fann data drilling fluid:		**Fann data HOL fluid:**	
Speed (rpm)	Dial (°)	Speed (rpm)	Dial (°)
600	73	600	46
300	56	300	26
		200	17
		100	10
		6	3
		3	2

Table 4.7: Wellplan simulation fluid data

4.2.2 DrillSIM simulation

For the DrillSIM simulations only one fluid setting was used for each well. For well 1 and section 2 of well 2 HOL was used, with a heavy static mud in the annulus and a lighter drilling fluid. For section 1 of well 2 the same mud weight was used in the entire well. Except for different densities, the same fluid properties were used for all simulations.

	Well 1	Well 2 –Section 1	Well 2 – Section 2
Active fluid density (ppg)	9	12	10
Static fluid density (ppg)	12	12	13
Active fluid YP (Pa)	5	5	5
Static fluid YP (Pa)	5	5	5
Active fluid PV (cP)	18	18	18
Static fluid PV (cP)	18	18	18

Table 4.8: DrillSIM simulation fluid data

4.3 Simulation results in conventional wells

Landmark Wellplan™ was used for all the simulations of the conventional wells. Only the Well Control module kick tolerance was used. Simulations were performed using several different mud weights assuming kick while drilling into formations of various pressure gradients.

4.3.1 Simulation results Well 1

Because of the entire open hole section being above the casing shoe, and the same fracture gradient apply, a kick at TD shouldn't cause a big risk of fracturing at the shoe. Because of this, 4 different initial mud weights were used, ranging from 9-12 ppg. In addition a 10,12 ppg mud specially developed for Reelwells HOL arrangement was used. However, this didn't give any significant different results, except for the expected difference due to density. Both circulation rate during drilling and kill rate was set to 120 gallons per minute, as the rates didn't seem to affect the results much, and the main objective was to simulate the pressure development for different mud weights, kick intensities and influx volumes.

Kick tolerance

Kick tolerance is defined as the maximum allowable influx volume that can safely be safely circulated out of the well without fracturing the formation at the casing shoe. Kick intensity is defined as the over pressure of the formation, given in ppg. For example, drilling into a formation with pressure equivatent to 11ppg with a BHP of 10ppg will cause a kick intensity of 1ppg.

The maximum allowable influx volume presented in Figure 4.5 shows very constant pressures for different influx volumes. The reason for this is the small vertical difference between the shoe and TD. Because the casing shoe is located at the deepest point of the open hole section, and the entire section has the same fracture gradient, the formation at the shoe is the least likely to fracture.
This means that values for max allowable influx volume cannot be obtained.

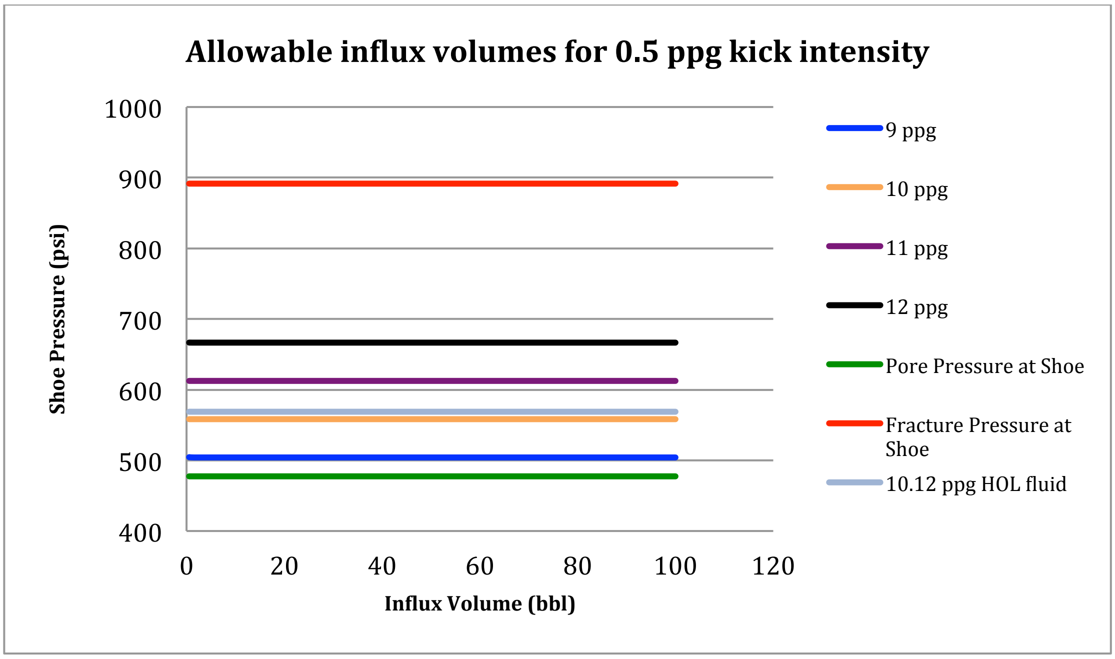

Figure 4.5: Allowable influx volume, well 1 (0,5ppg kick intensity)

By choosing higher kick interval pressures giving greater kick intensities it is shown that the shoe pressure is starting to increase with total influx volume. However, because of the entire open hole section is assumed to have the same fracture gradient, this would cause the formation closer to total measured depth to fracture first. (Figure B.1 in appendix)

Shoe pressures

Figure 4.6 presents shoe pressures during the kill procedure (Drillers method) for a 10 bbl influx. The pressure is increasing as the influx moves along the horizontal section before it decreases to initial pressure as the influx moves up the vertical section. The pressure increases back to the max value when the influx reaches the choke and falls back to starting pressure when the kick is circulated out. None of the curves come close to the fracture pressure but all of them drops below the pore pressure line at least once during the circulations. As all fluid densities used are greater than the pore pressure gradient, this shouldn't happen. The shoe pressure was also expected to stay more stable during the circulation, as the BHP during driller's method is supposed to be constant, and the shoe pressure should follow a similar pressure development, especially after the influx has passed the shoe.

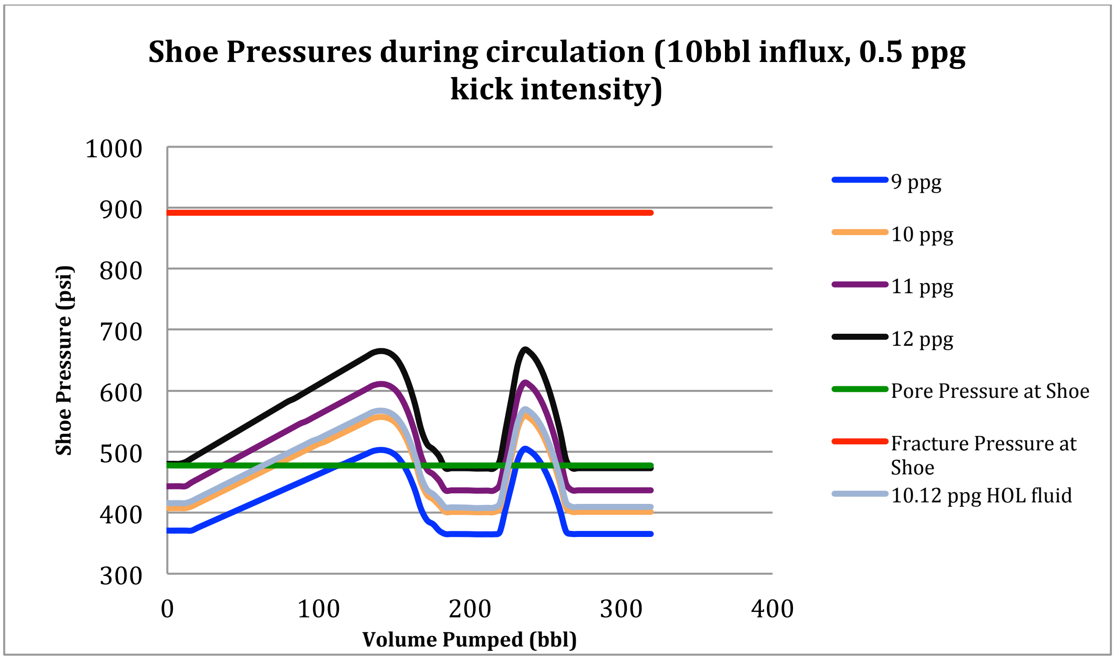

Figure 4.6: Shoe pressure, well 1 (10bbl influx, 0,5ppg kick intensity)

For the same initial mud weight and kick intensity, but different influx volumes, the max and min shoe pressures is showed to be the same during the circulation. The pressure development is different, because of the different influx volumes, causing the kick to reach the shoe and choke at different times. (Figure B.2 in appendix)

Max annulus pressure

Figure 4.7 presents the max annulus pressures for the entire well when considering a 10 bbl influx and 0,5 ppg kick intensity. Only when using the 12 ppg mud the annulus pressure exceeds the fracture pressure, which occurs at a measured depth of approximately 4500 ft and below.

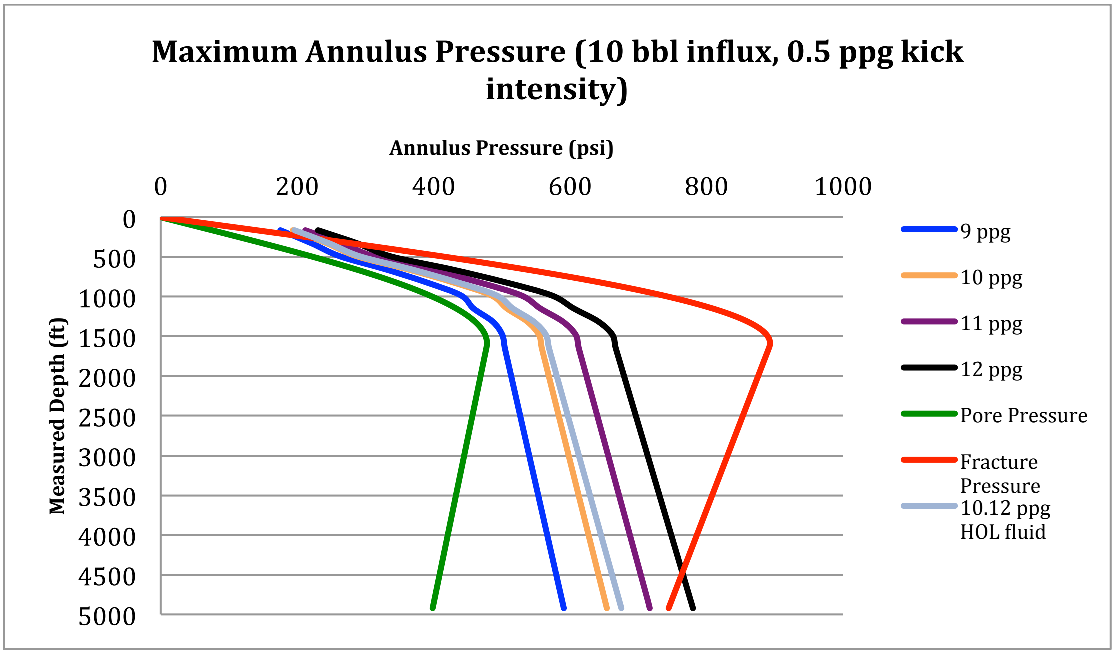

Figure 4.7: Maximum annulus pressure, well 1 (10bbl influx, 0,5ppg kick intensity)

Choke pressure

Figure 4.8 presents the choke pressure for an influx volume of 10bbl and a kick intensity of 0,5 ppg. The max pressures ranges from approx. 145-195 psi. Max choke pressure occurs when the top of the influx reaches the choke.

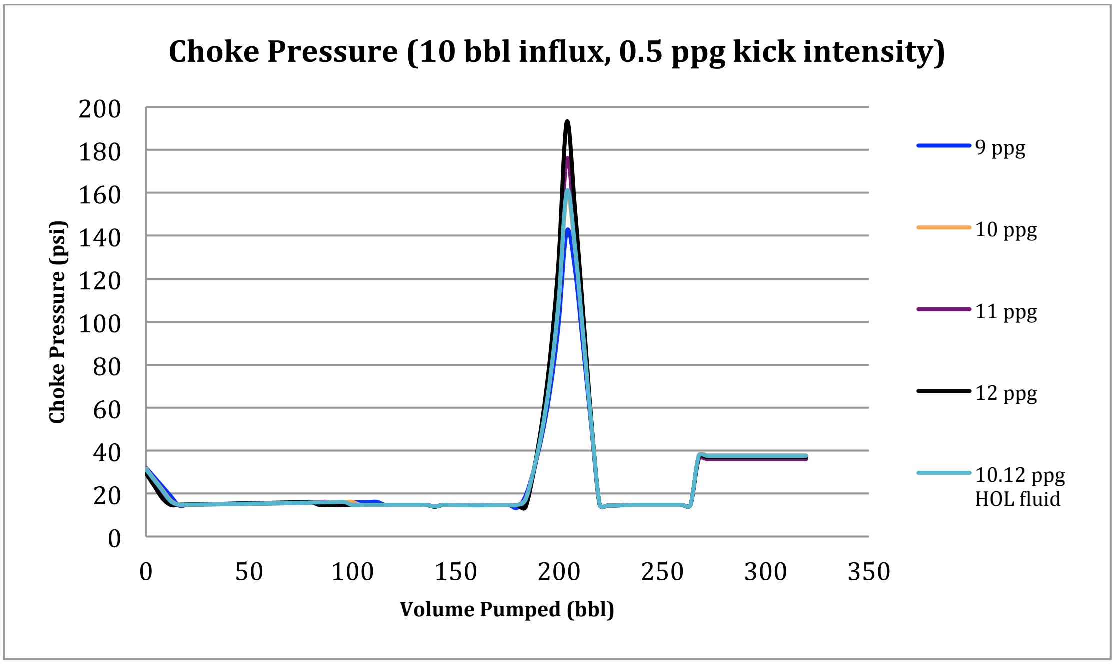

Figure 4.8: Choke pressure, well 1 (10bbl influx, 0,5ppg kick intensity)

Using a mud weight of 12 ppg and 10 bbl influx causes a max choke pressure from app. 195-220 for kick intensities 0,5-2,0 ppg (Figure 4.9). The different kick intensities doesn't cause a very big difference in max choke pressure, but a difference equivalent to the hydrostatic pressure difference of 0,5 ppg at the start (shut-in pressure) and end of the circulation. This is because the kick interval pressure has to be balanced by a higher choke pressure before the initial mud is displaced with kill mud.

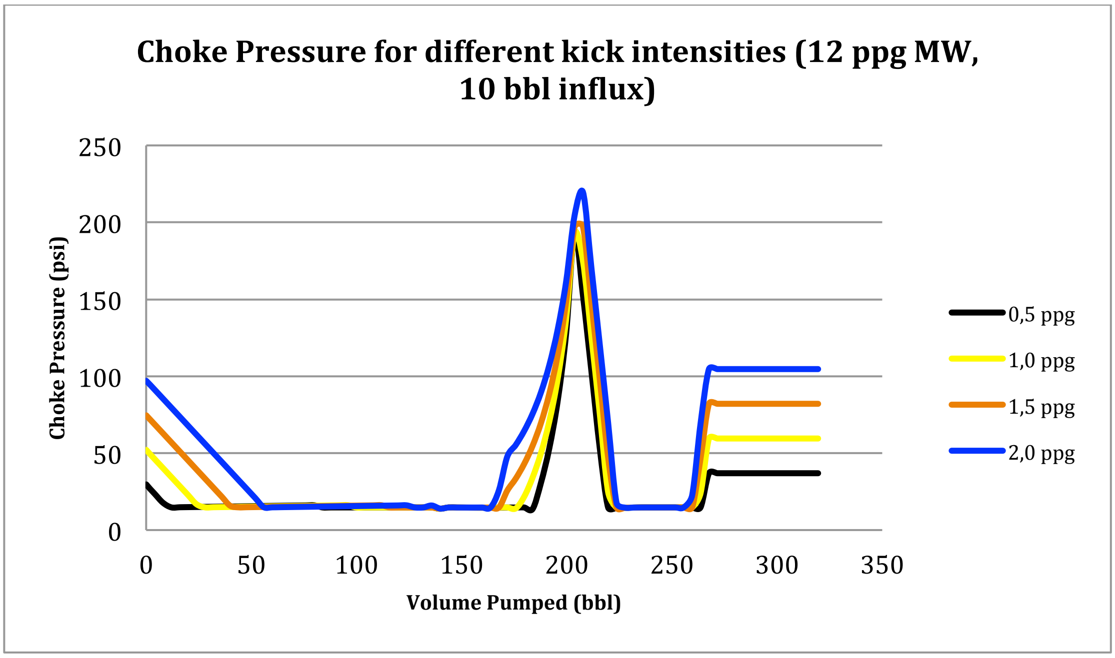

Figure 4.9: Choke pressure for different kick intensities, well 1 (12ppg MW, 10bbl influx)

Figure 4.10 presents the choke pressures for different influx volumes, when using a 12 ppg mud weight and 0,5 ppg kick intensity. Greater influx volumes causes higher choke pressures and the max pressure to occur earlier during the circulation.

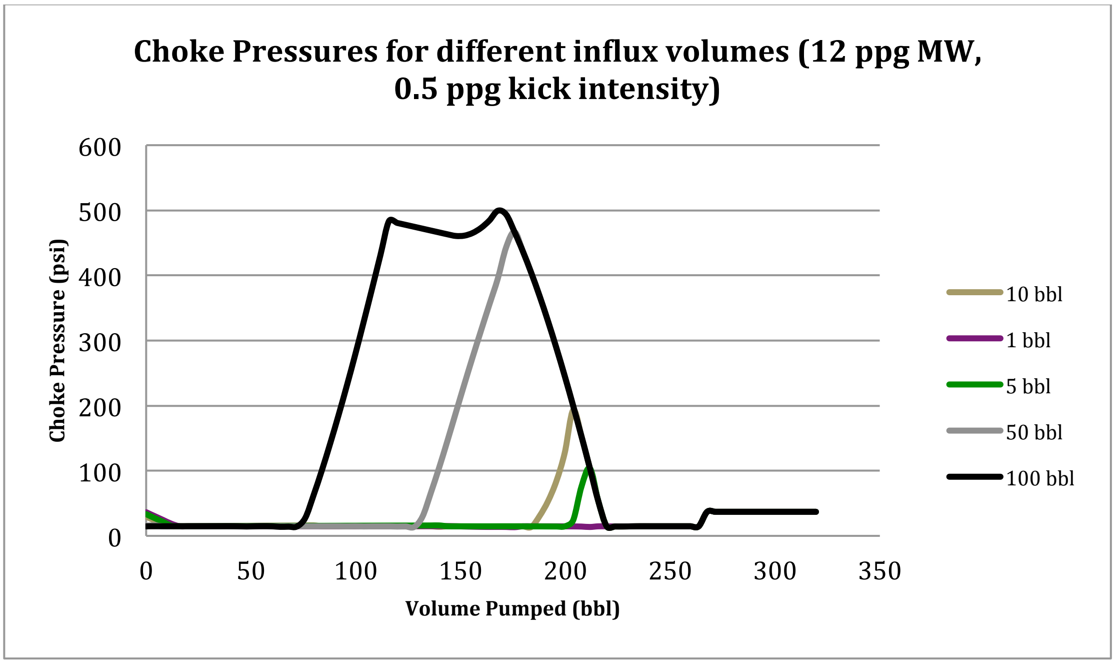

Figure 4.10: Choke pressure for different influx volumes (12ppg MW, 0,5ppg kick intensity)

Maximum obtainable choke pressure will occur if the entire annulus is evacuated to gas (Figure B.3 in appendix). This will cause a choke pressure slightly lower than the kick interval pressure, depending on the influx density. In this case the influx gradient was 0,011 psi/ft.

4.3.2 Simulation results Well 2

The simulation for this well was split into 2 different sections.

- Drilling at 5000m MD, with the entire build up section as open hole and casing set at 1000m in the vertical section.
- Drilling at 15800m MD, open hole section 91 degrees, casing set at 14000m.

Pore and fracture pressure gradient were assumed to be the same for all open hole sections. Used initial mud weights 9,5-12,5 ppg.

4.3.2.1 Section 1: Shoe at 1000m, TD at 5000m

Section 1 of well 2 is the only one with the casing shoe higher in the formation than the true depth. The shoe is located in the vertical section of the well at 1000m. As for well 1, both drilling rate and kill rate was set to 120 gpm, as the focus was on the effects of different mud weights, kick intensities and influx volumes.

Max allowable influx volume

Compared to well 1 section 1 of well 2 has obtainable values for max influx volume (Figure 4.11). This is because the shoe is located higher in the formation than the kick formation, which causes the shoe pressure to increase as the influx travels up the wellbore. The highest shoe pressure occurs when the top of the influx reaches the shoe, and this will be higher for larger influx volumes. The kick tolerance is defined as the max influx volume allowable without the formation at the shoe fracturing. The chart show kick tolerance for different mud densities, assuming 0,5ppg kick intensity. Higher density gives lower kick tolerance, because the difference between the mud and influx density is greater.

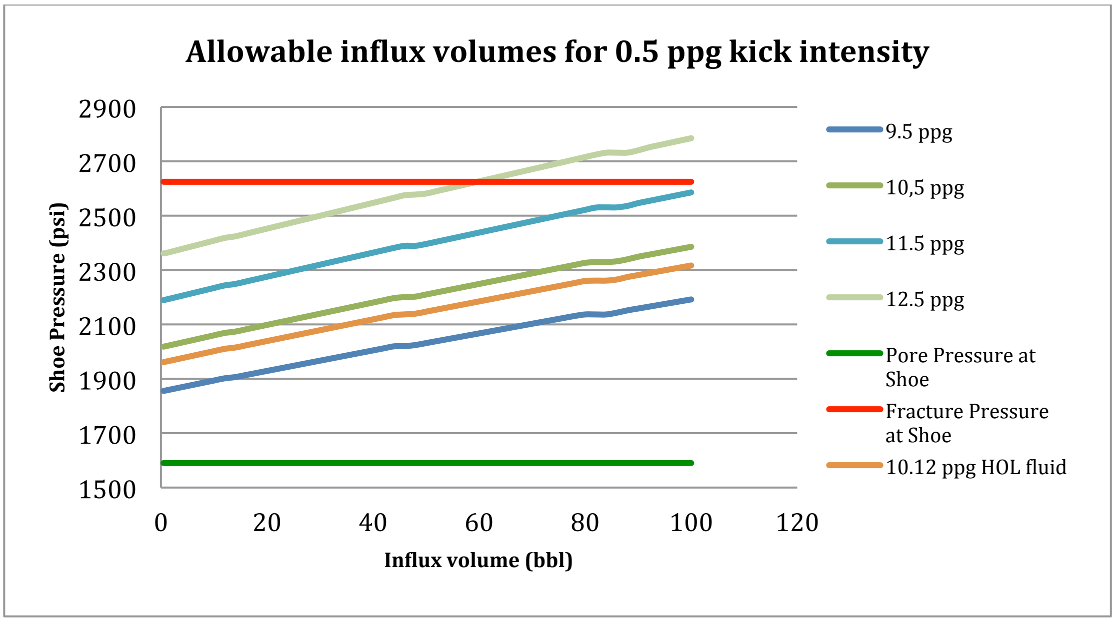

Figure 4.11: Allowable influx volume, well 2 section 1 (0,5ppg kick intensity)

Changing the kick intensity when using the same mud density gives a similar chart where the pressure difference between the curves is the additional hydrostatic pressure from the kick formation. When considering the same kick formation pressure a lower mud density gives a lower kick tolerance. (Figure B.4 in appendix)

Shoe pressure

Presented in Figure 4.12, the shoe pressures start of by decreasing as the influx moves along the horizontal section, then start to increase reaching the maximum value as it reaches the shoe before dropping to the initial pressure when the influx has passed the shoe.

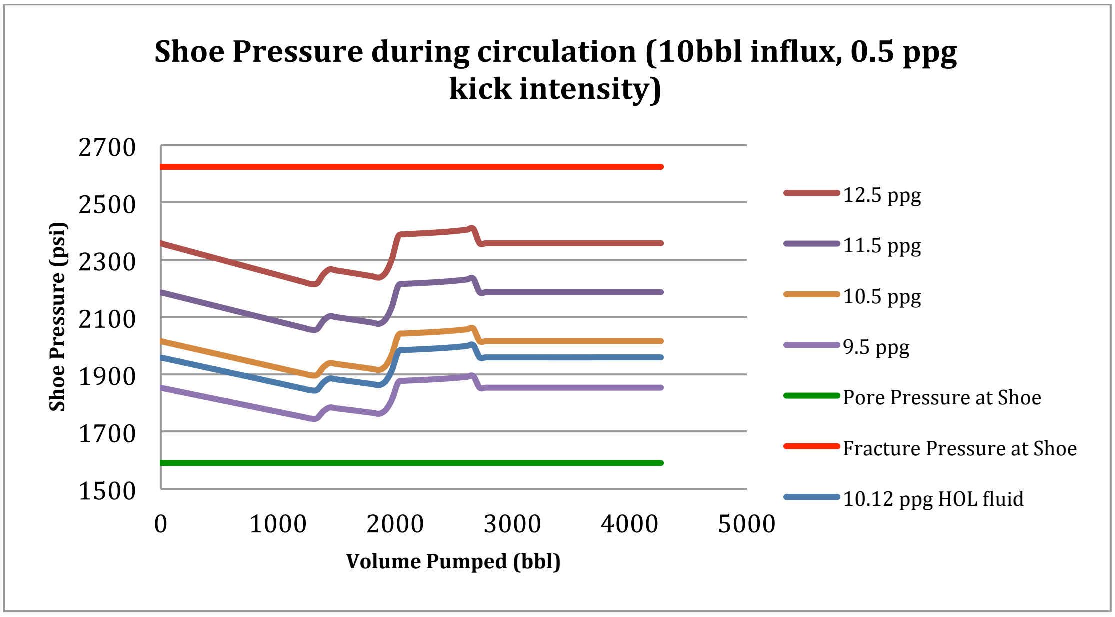

Figure 4.12: Shoe pressure, well 2 section 1 (10bbl influx, 0,5ppg kick intensity)

Figure 4.13 presents the shoe pressure when changing the influx volume. The pressure stays the same as long as the influx is located in the horizontal section of the well. The difference is shown from when the kick starts to move up the build/vertical section of the well until it has passed the shoe. Greater influx volumes show at faster increase in pressure and a higher max pressure as the influx reaches the shoe.

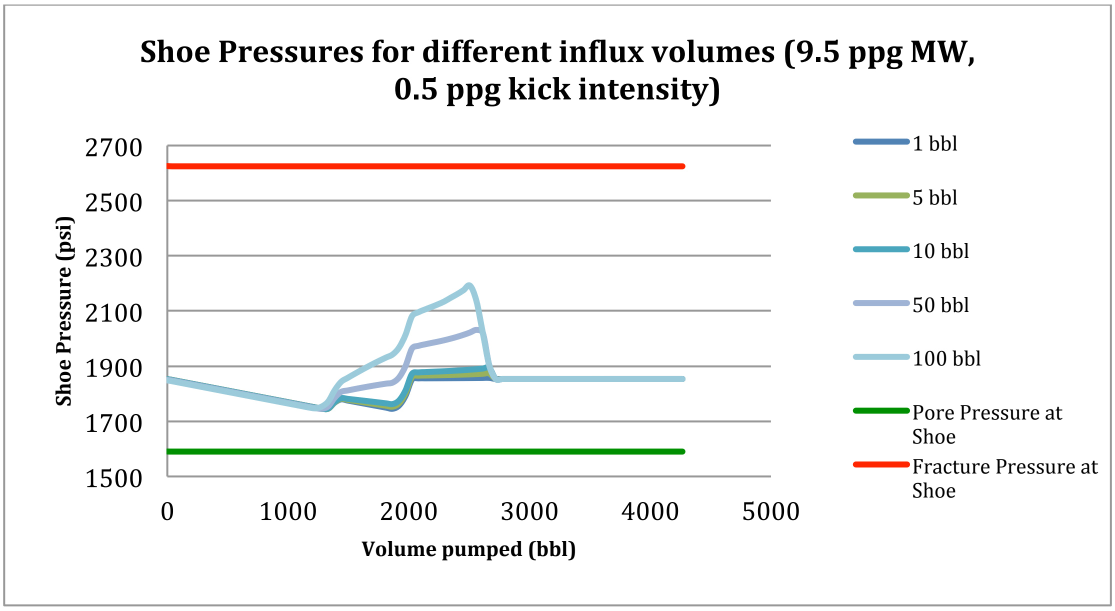

Figure 4.13 Shoe pressure for different influx volumes, well 2 section 1 (9,5ppg MW, 0,5ppg kick intensity)

Max annulus pressure

Figure 4.14 presents max annulus pressures. None of the pressures come close to fracturing the formation for a 10 bbl influx and 0,5 ppg kick intensity.

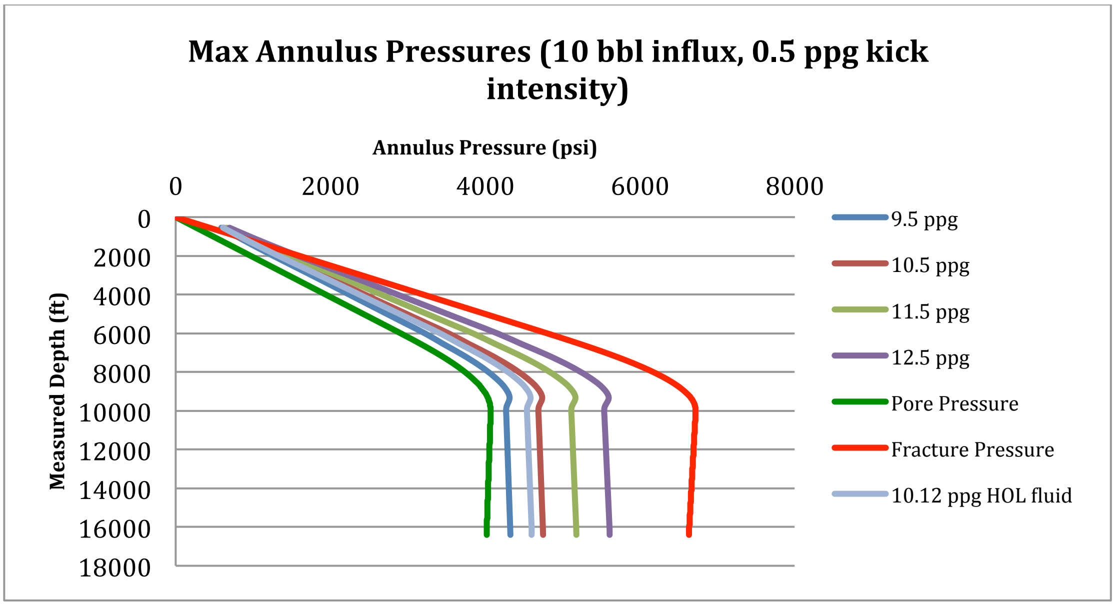

Figure 4.14: Max annulus pressure, well 2 section 1 (10bbl influx, 0,5ppg kick intensity)

Choke Pressure

The shut-in pressures at the choke are approximately 230psi for all fluid densities when assuming 10bbl influx and 0,5ppg kick intensity (Figure 4.15). The pressure decreases as the influx is pumped along the horizontal section and starts to increase as it enters the vertical section. Max pressure is obtained when the influx reaches the choke. Final choke pressure is equal to shut-in pressure.

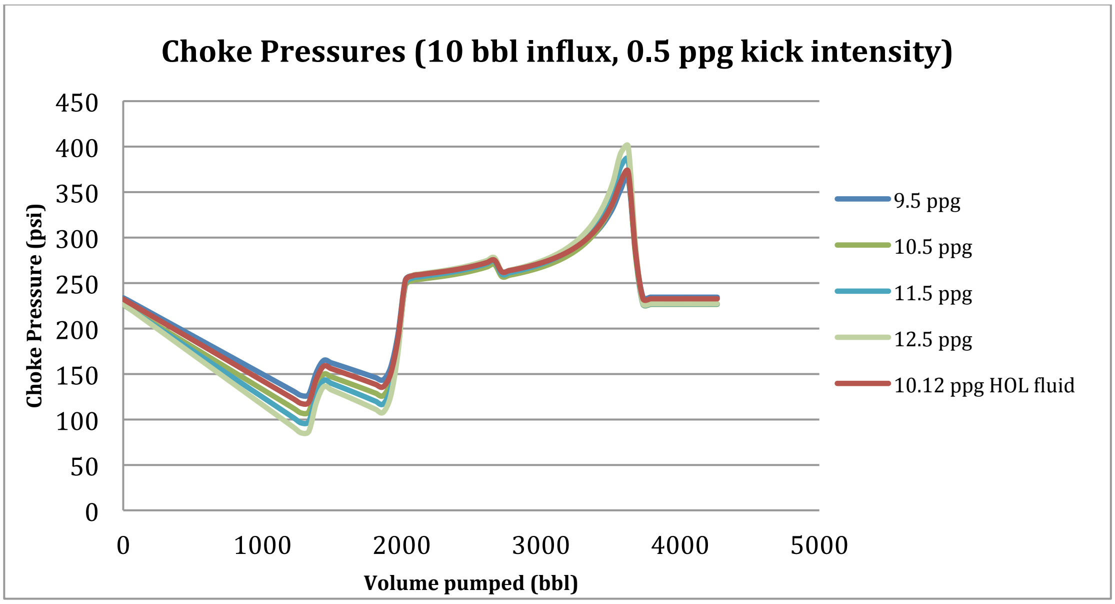

Figure 4.15: Choke pressure, well 2 section 1 (10bbl influx, 0,5ppg kick intensity)

The choke pressure presented in Figure 4.16 seems to develop in the same way when using different kick intensities, with shut-in and final pressure differences equal to the difference in kick formation pressure. However, the difference between shut-in and max pressure seems to decrease with higher kick intensities.

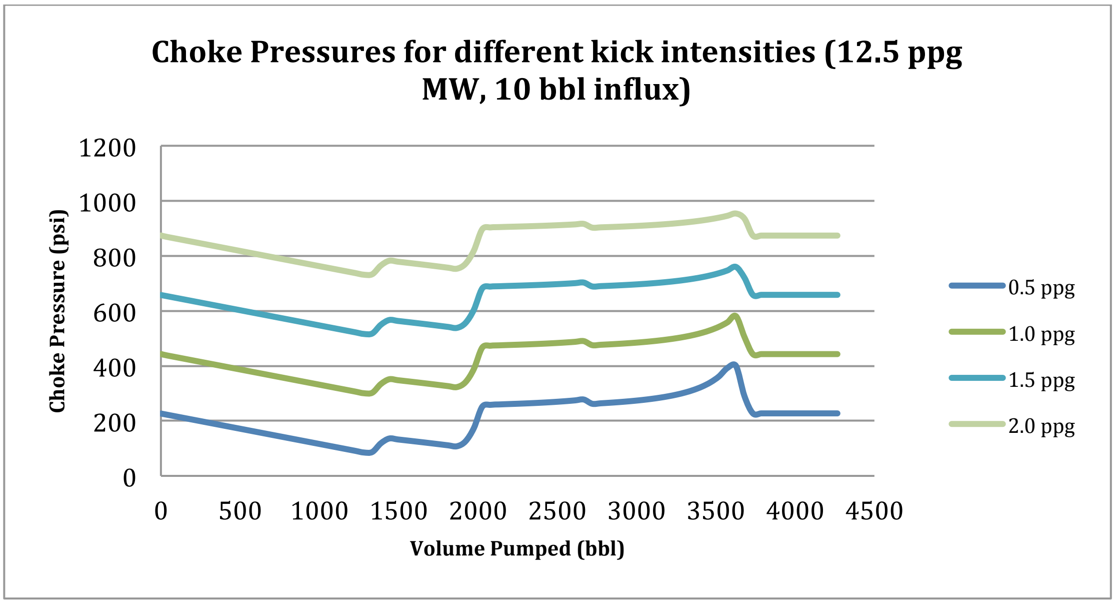

Figure 4.16: Choke pressure for different kick intensities, well 2 section 1 (12,5ppg MW, 10bbl influx)

The choke pressure presented in Figure 4.17 shows the same behavior as the shoe pressure when using different influx volumes, with the same pressure for all influx volumes before the influx enters the vertical section and is circulated out of the well. Max choke pressure occurs when the influx reaches the choke and increases with greater influx volumes.

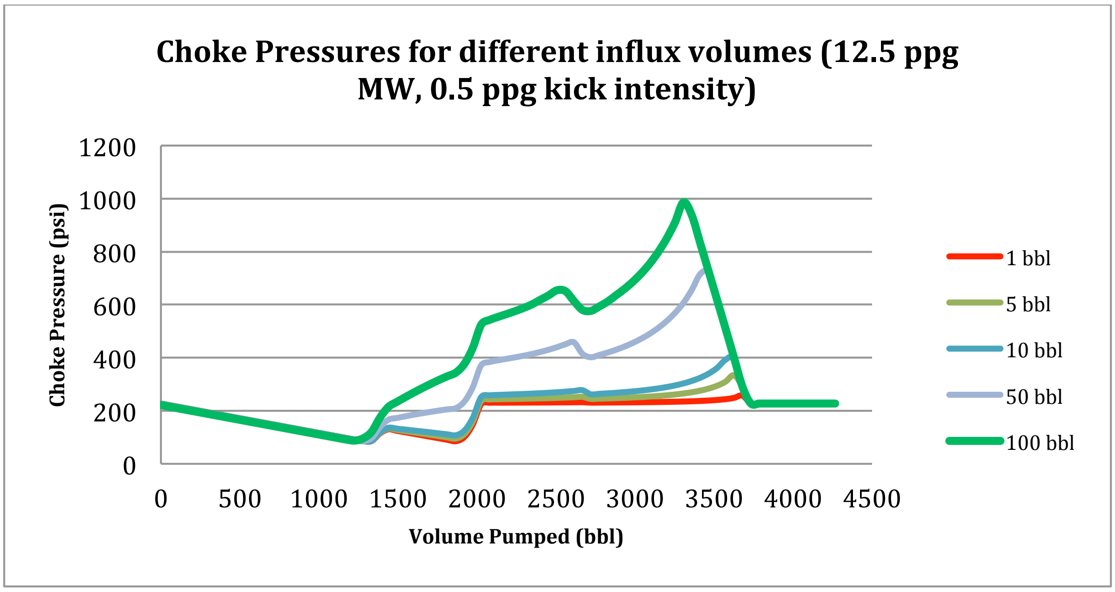

Figure 4.17: Choke pressure for different influx volumes, well 2 section 1 (12,5ppg MW, 0,5ppg kick intensity)

In the case of full evacuation to gas the choke pressure would be approximately 4900psi. That's about 700psi less than the kick formation pressure because of an influx density of 0,083psi/ft. (Figure B.5 in appendix)

4.3.2.2 Section 2: Shoe at 14000m, TD at 158000m

Section 2 of well 2 has a similar geometry to well 1, with the shoe at a greater depth than the influx formation. The same circulation and kill rate of 120gpm was used, and the same drilling fluids as for section 1.

Allowable influx volume

Figure 4.18 presents results similar to those for well 1, because the casing shoe is located in the horizontal section at a deeper point vertically than the influx formation.

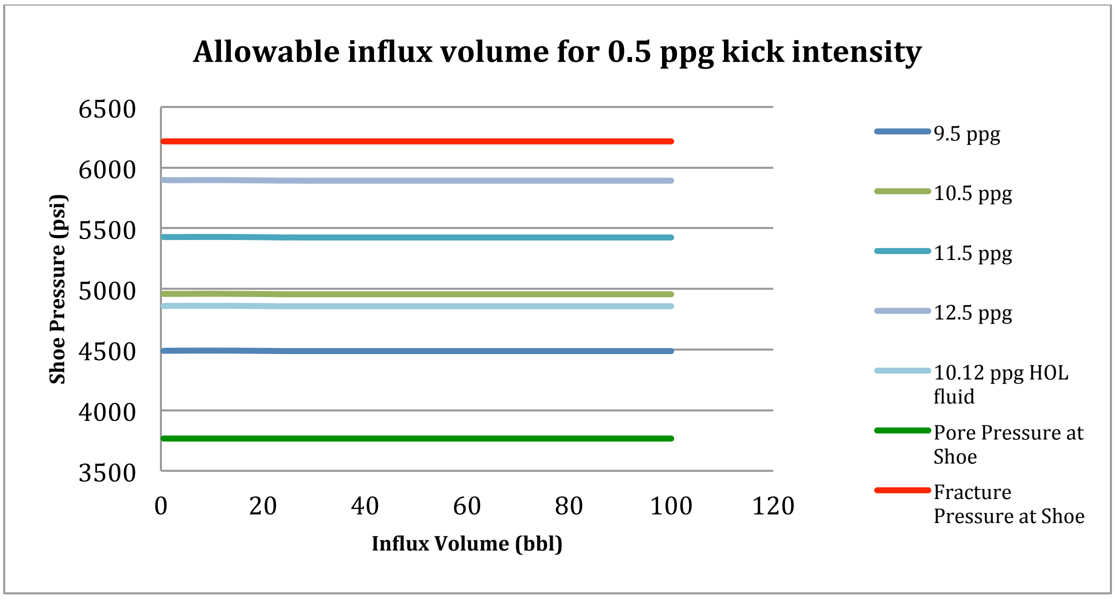

Figure 4.18: Allowable influx volume, well 2 section 2 (0,5ppg kick intensity)

Choosing kick intensities from 0,5 to 2,0 ppg gave no change in max shoe pressure, but for 2,5 and higher the maximum shoe pressure increased. However, the max pressure didn't increase with greater influx volumes. (Figure B.6 in appendix)

Shoe pressure

The shoe pressures presented in Figure 4.19 showed the same behavior as for well 1, with increasing pressure as the kick moved along the horizontal section, decreasing when moving up the vertical and another top when reaching the choke.

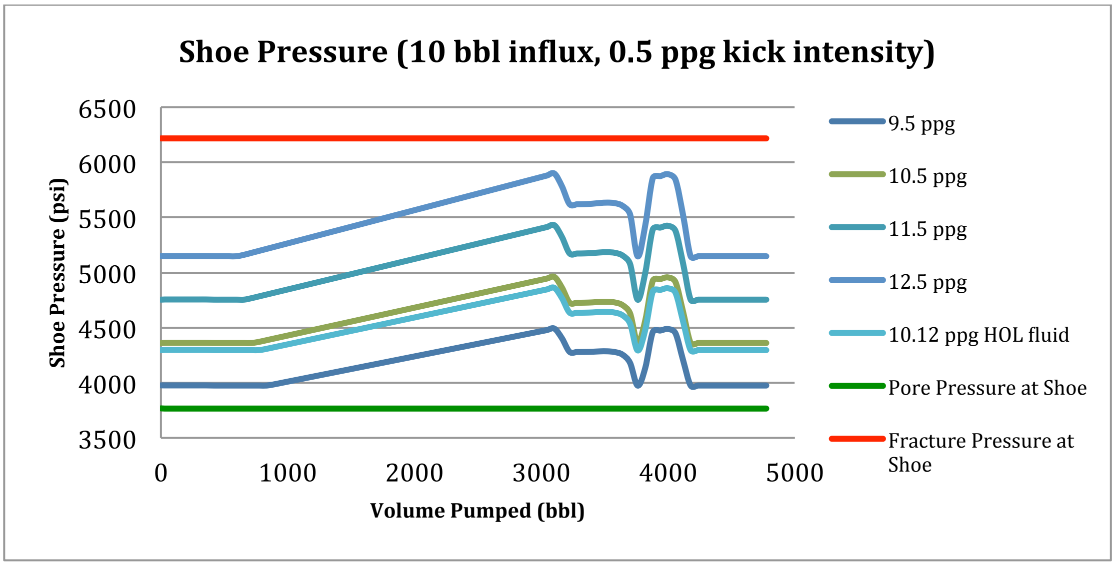

Figure 4.19: Shoe pressure, well 2 section 2 (10bbl influx, 0,5ppg kick intensity)

Using different influx volumes gives results similar to well 1. The max and min shoe pressure was the same for the different influx volumes, with different development when the influx moved up the vertical section. (Figure B.7 in appendix)

Maximum annulus pressure

Figure 4.20 presents similar results as for well 1, with max annulus pressures increasing with measured depth. None of the simulations did exceed fracture pressure for a 10 bbl influx and 0,5 ppg kick intensity.

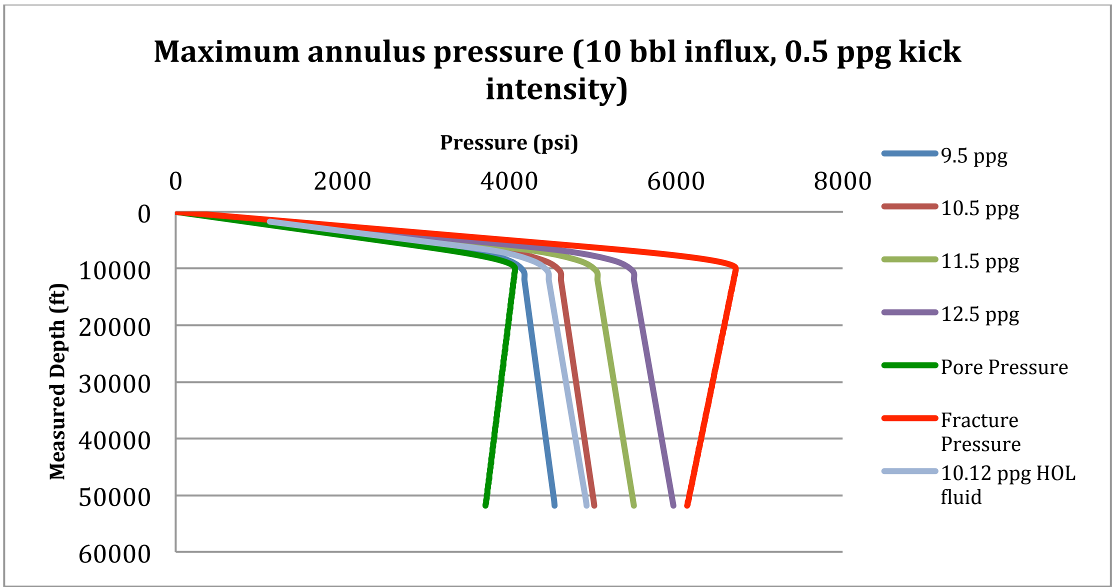

Figure 4.20: Maximum annulus pressure, well 2 section 2 (10bbl influx, 0,5ppg kick intensity)

Choke Pressure

Choke pressures presented in Figure 4.21 show small differences for the different mud densities, when using the same influx volume and kick intensity.

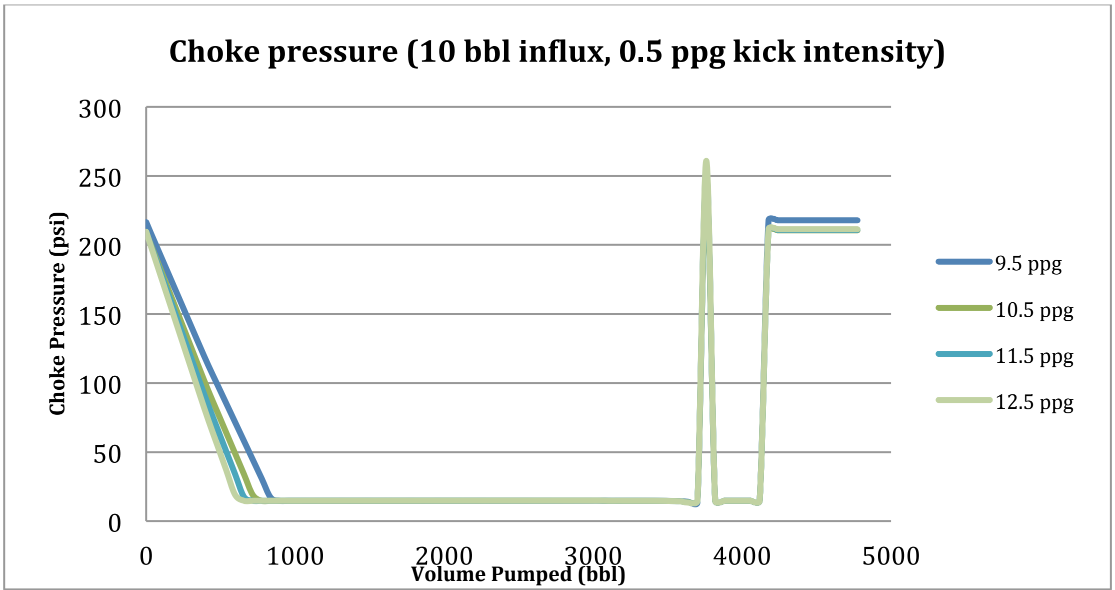

Figure 4.21: Choke pressure, well 2 section 2 (10bbl influx, 0,5ppg kick intensity)

Using different kick intensities gave a significant difference in choke pressure at the start and end of the circulation, as the kick formation pressure had to be balanced by the choke before the kill mud had been pumped (Figure 4.22).

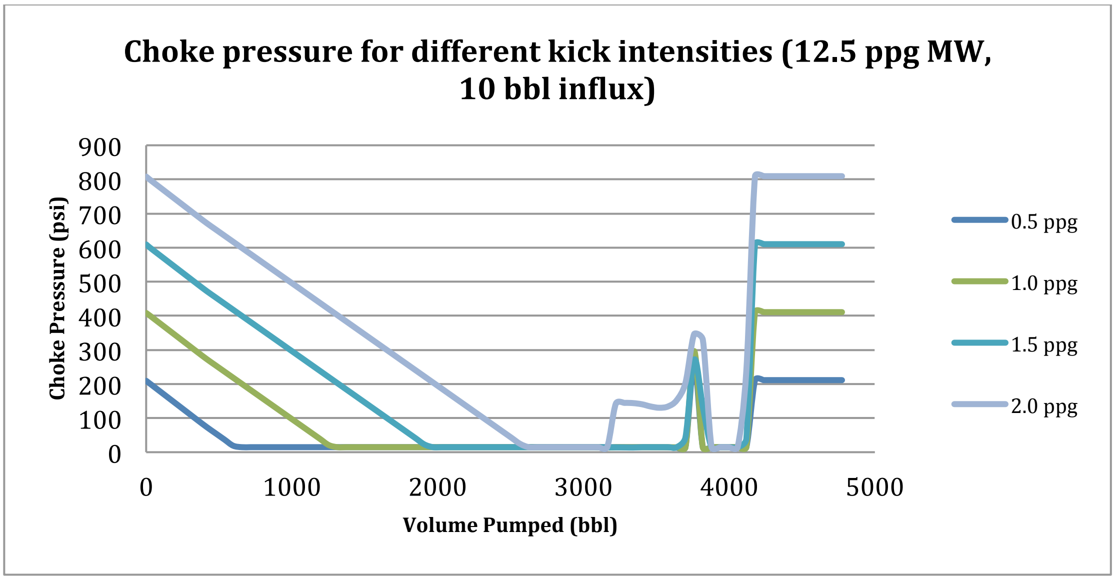

Figure 4.22: Choke pressure for different kick intensities, well 2 section 2 (12,5ppg MW, 10bbl influx)

An increase in influx volume gave no significant change in shut-in pressure but higher pressure as the influx reached the choke (Figure 4.23).

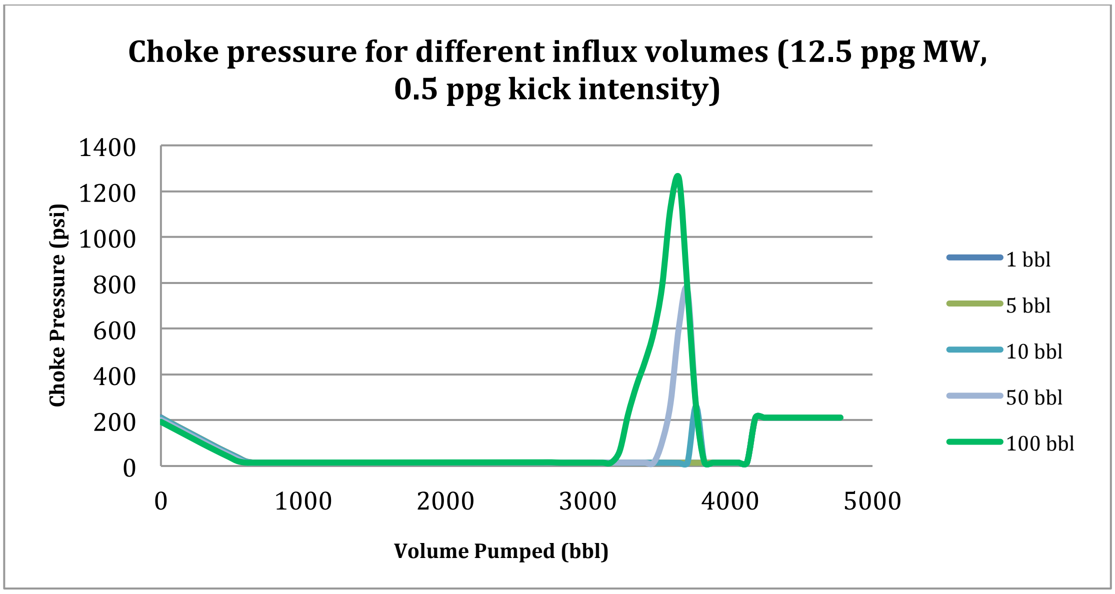

Figure 4.23: Choke pressure for different influx volumes, well 2 section 2 (12,5ppg MW, 0,5ppg kick intensity)

A full evacuation to gas gave a choke pressure of 4442 psi. In this case the influx had a density gradient of 0,079 psi/ft. (Figure B.8 in appendix)

4.4 RDM simulation using DrillSIM

The RDM simulations were performed by using DrillSIM-5 (version 5.132.103) by Drilling Systems Lt. This is a drilling and well control simulator mainly meant for training. It is more time consuming to use than Wellplan and simulation results will not be as accurate, as is is operated more manually and in real time. Therefore, only a few cases were simulated using DrillSIM, to get a general impression of the well control capabilities using the RDM.

The simulations performed included displacement of initial mud with lighter mud for HOL drilling, and HOL kill procedure. HOL was only used for well 1 and section 2 of well 2. The entire HOL kill procedure was only performed for well 1. For both sections of well 2 only the first circulation of the HOL kill procedure was performed, because of the time needed to do the entire simulation. Influx volumes used for well 1 was approximately 2, 5 and 14bbl, 2 and 10bbl for well 2 section 1 and 50 bbl for well 2 section 2. The accurate values are given in cuft in appendix C.

As simulations in DrillSIM are performed in real time with the option to pause or speed up the simulation the logging of the different pressures is different than for Wellplan. For all of the simulations the different pressures were recorded continually every 2 seconds, even when the simulation was paused or the speed of the simulation was increased. Because of this the time on the x-axis will not represent the real time used. Only pump rate in spm, drill pipe pressure, choke pressure and casing pressure was logged. Pump rate in gpm was calculated using 4,32 gal/stk for both pumps used. However, this gave a rate higher than the rate in gpm used during the simulations. BHP and shoe pressure was calculated from casing pressure:

$$\text{BHP}=\text{Casing pressure} + (\text{Bottom hole TVD})*12*0{,}052 \quad (8)$$

$$\text{Shoe Pressure}=\text{Casing pressure} + (\text{Shoe TVD})*12*0{,}052 \quad (9)$$

This was not possible for circulation 2 as the mud in the casing had to be static in order to use the casing pressure.

4.4.1 Well 1

The case simulated for the shallow extended reach well was a HOL kill procedure. The displacement of the mud in the well with lighter drilling mud prior to the kick is also included. An initial mud weight of 12 ppg was used. The active drilling fluid used was 9 ppg, leaving the well annulus filled with the initial weight mud. A kill mud density of 12,5 ppg was used.

4.4.1.1 Displacement of mud inside DDS with lighter drilling fluid

HOL was used for the simulations for well 1, and because the DDS was initially filled with the 12 ppg mud, this had to be circulated out prior to drilling.
At startup the pump rate was slowly ramped up until shoe pressure was about 810 psi, at this point the pump rate was 84 gpm. The pump pressure was increasing as the drilling fluid moved down the vertical and build section of the well, in order to keep BHP constant. The rate of 84 gpm was kept until the drilling fluid reached the end of the horizontal section on the way back through the inner pipe. As the drilling fluid started to move up the vertical section of the inner pipe the BHP started to drop and the pump rate was increased slowly. The BHP was kept at around 600 psi, 50 psi higher than static BHP in order to avoid the heavy mud of entering the drill string.

Figure 4.24 represents the pump rate during the HOL fluid displacement; the procedure was started at approximately 300 seconds. The rate was logged as strokes per minute. Gallons per minute were calculated using 4,32 gal/stk. The calculated value was higher than the input pump rate during the simulations (Found in tables in appendix C). This is the case for all of the simulations, but the reason is unknown.

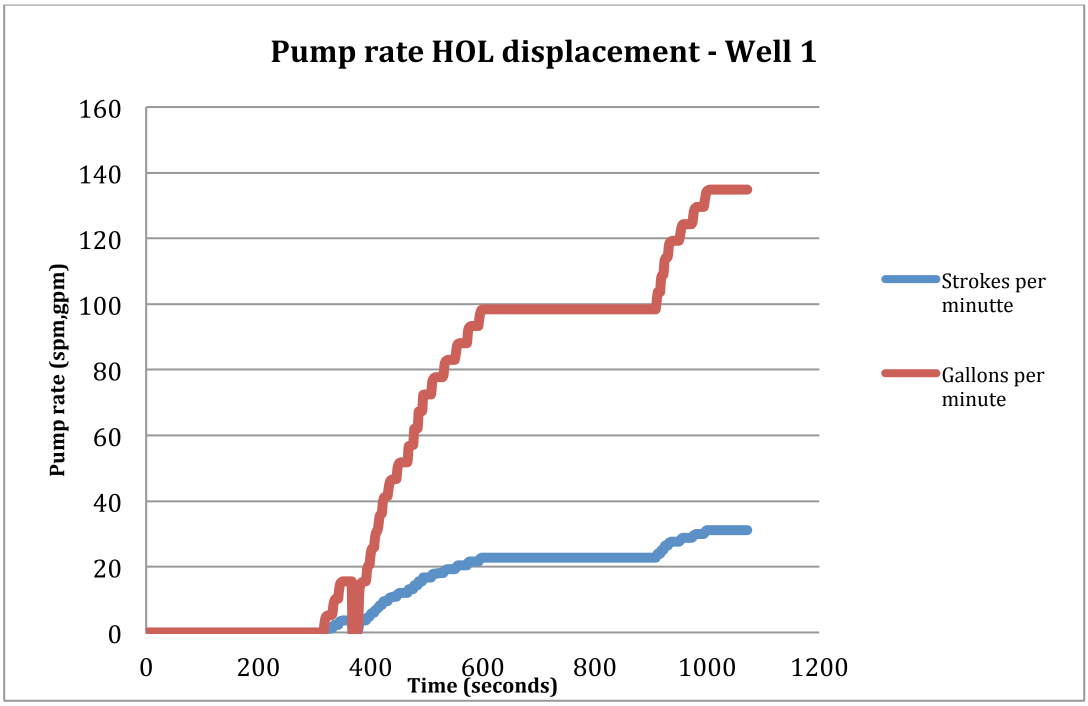

Figure 4.24: Pump rate HOL displacement, well 1

Figure 4.25 represents casing, choke and drill pipe pressures from the HOL fluid displacement, as well as shoe pressure and BHP calculated from casing pressure.

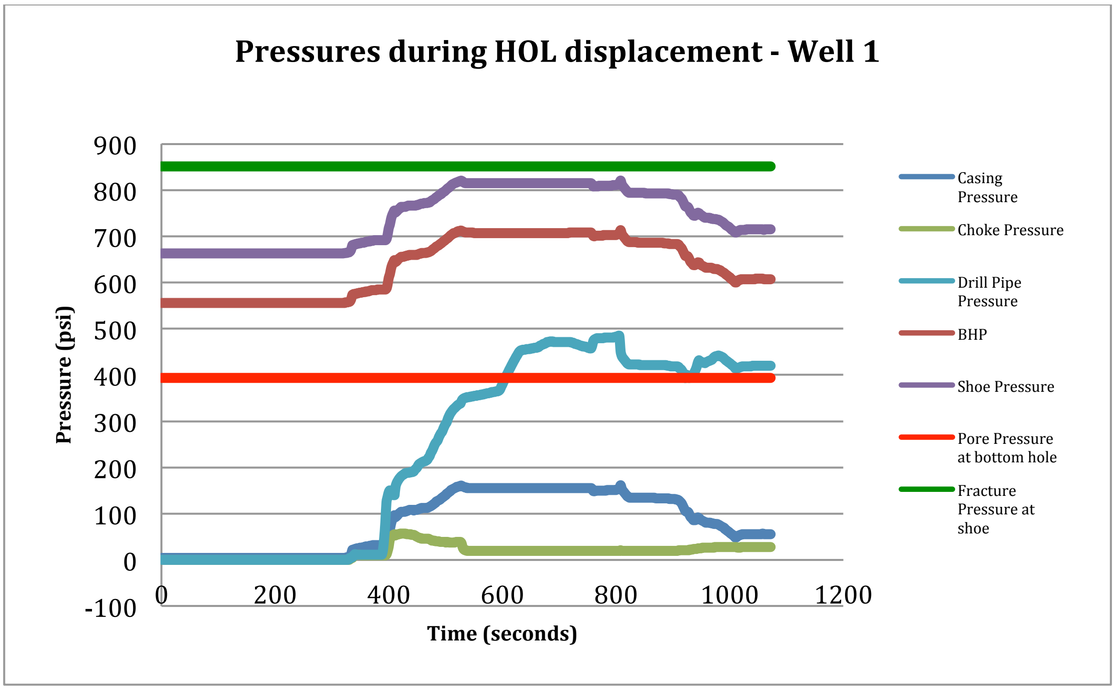

Figure 4.25: Pressures during HOL displacement, well 1

4.4.1.2 Circulation 1 – Circulate out influx through Inner Pipe

The kick was taken at 1500 m MD during drilling at a 115 gpm pump rate. The influx was gas with 0,2 ppg density. The total influx volume after shutdown was 10,78 cuft. When the pressures had stabilized circulation 1 was started. The kick was circulated out the Inner Pipe by pumping down inner annulus at 115gpm. When the influx reached the vertical section, the flow rate was decreased and the choke was adjusted to keep the BHP as constant as possible until all of the influx was circulated out.

DrillSIMs malfunctions mode was used to induce kick during the simulation. The kick was set at 1500m, with an influx rate of 1 cuft/s and an influx density assumed to be 0,2 ppg. In order to stop the influx, the malfunctions mode had to be turned off, causing the BHP to drop after the first circulation stage was initiated. Because of the bottom hole pore pressure being unaffected by the kick, the behavior would be more similar to a kick taken while swabbing, even though it happened while drilling.

Figure 4.26 represents pump rate for circulation 1, for a 2 bbl kick. (Accurate volume is 10,78 cuft)

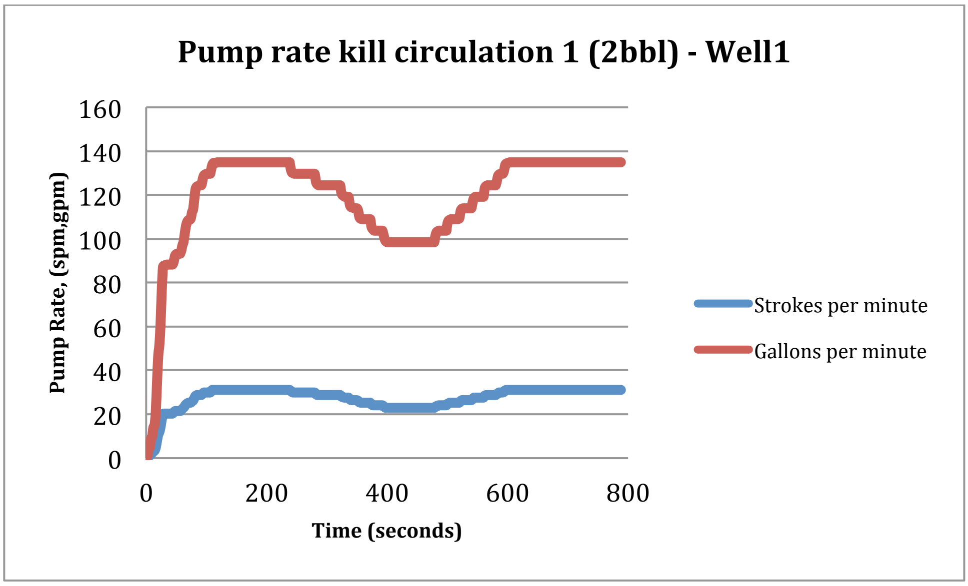

Figure 4.26: Pump rate HOL kill circulation 1 (2bbl), well 1

Figure 4.27 represents well pressures during circulation 1 of a 2bbl kick. The choke pressure reached a maximum of approximately 300 psi.

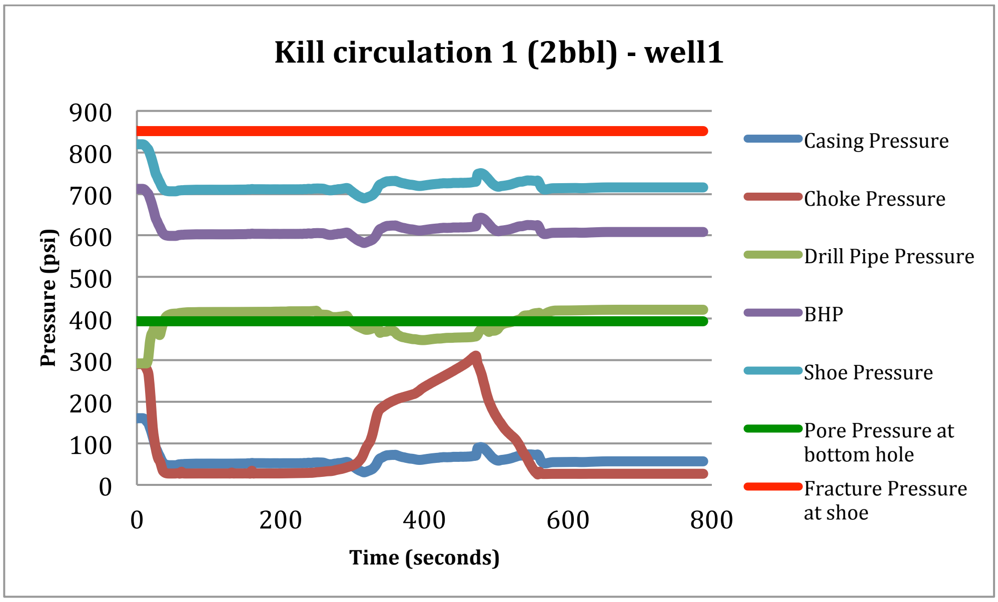

Figure 4.27: HOL kill circulation 1 (2bbl), well 1

Two additional simulations were performed for circulation 1, assuming approximately 5 and 14 bbl influx volume. Other than the influx volume the same input parameters was used. When using greater kick volumes, the influx wouldn't stay concentrated in one slug, and was therefore circulated out as several separate slugs.

5 bbl influx (28,5 cuft)

Figure 4.28 represents pump rate for circulation 1 of a 5 bbl kick. The pump rate was adjusted to keep the BHP stable during the circulation.

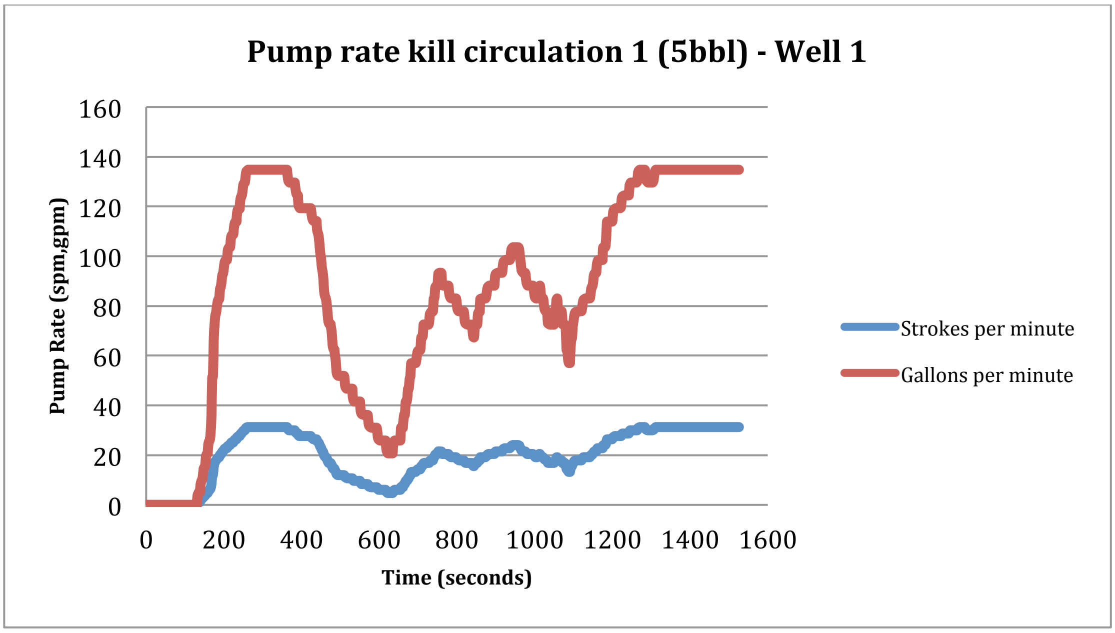

Figure 4.28: Pump rate HOL kill circulation 1 (5bbl), well 1

Figure 4.29 represents well pressures during circulation 1 for a 5 bbl kick. The kick was circulated out as 3 separate slugs, giving 3 spikes in choke pressure.

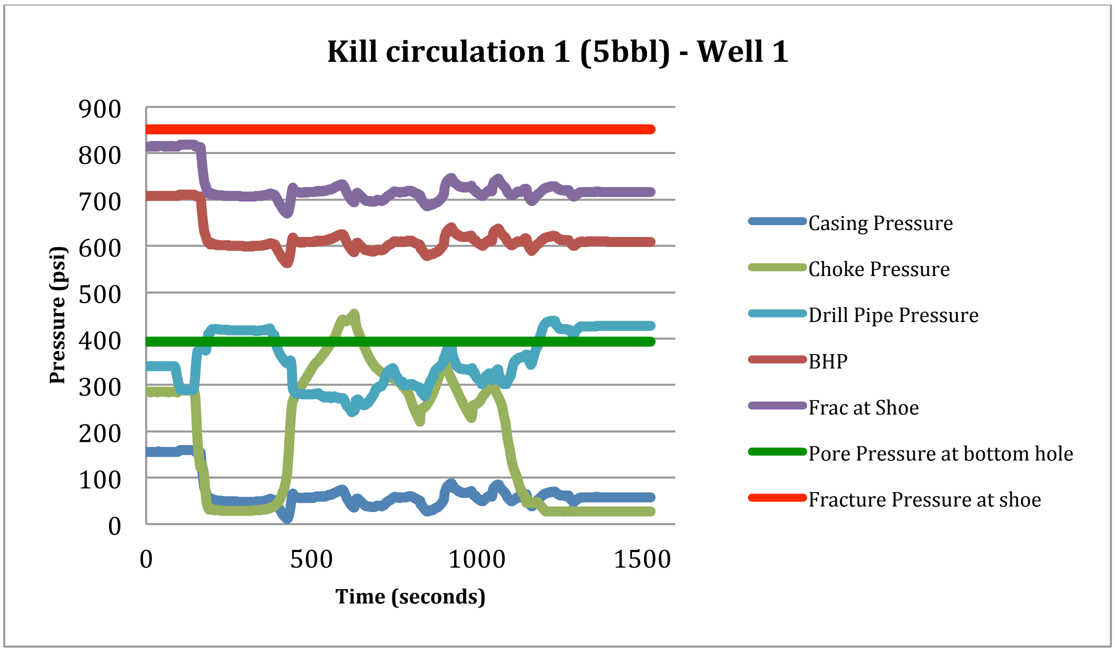

Figure 4.29: HOL kill circulation 1 (5bbl), well 1

14bbl influx (75,02 cuft)

For the 14 bbl kick the pump rate was kept stable during circulation 1, using the choke to control BHP (Figure 4.30).

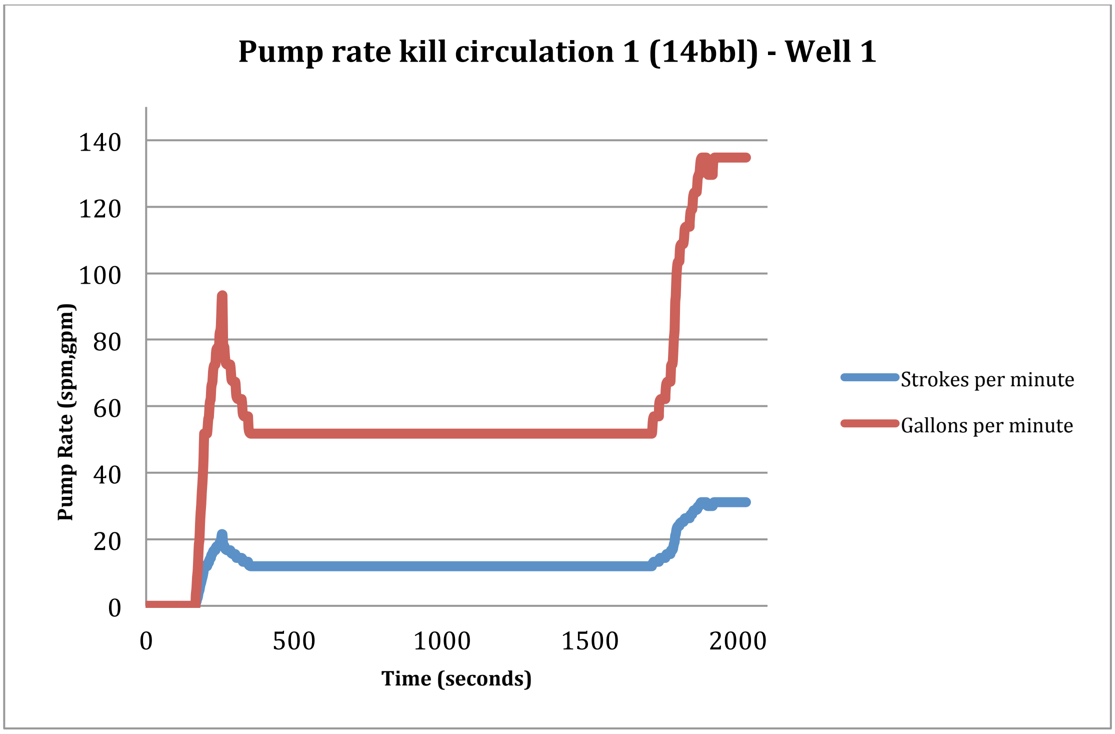

Figure 4.30: Pump rate HOL kill circulation 1 (14bbl), well 1

The kick was circulated out as 5 separate slugs, giving 5 spikes in choke pressure represented in Figure 4.31.

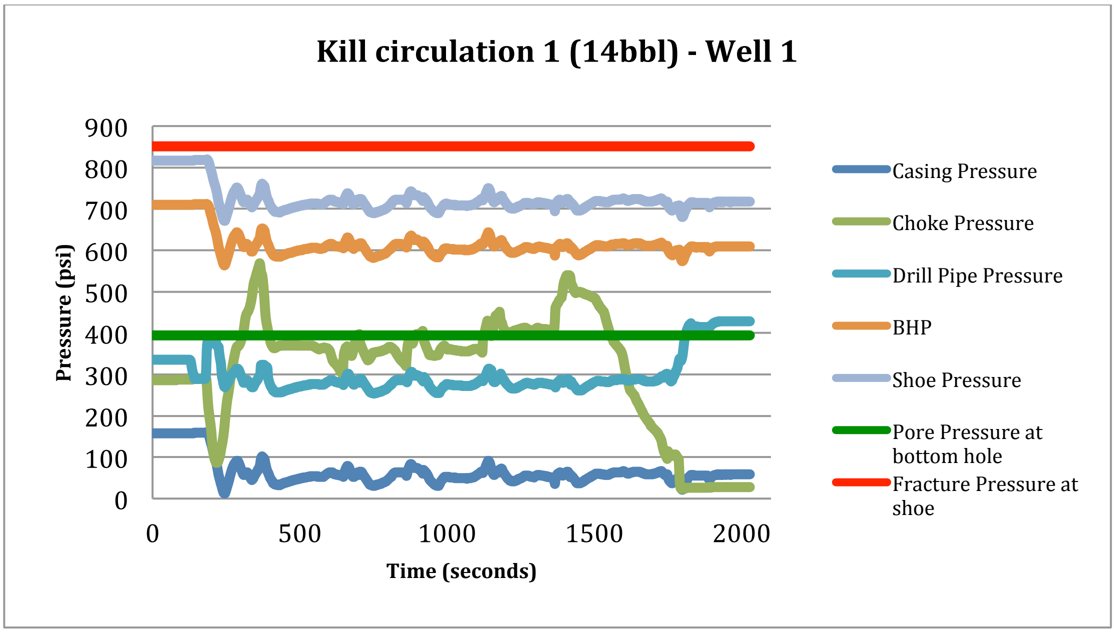

Figure 4.31: HOL kill circulation 1 (14bbl), well 1

4.4.1.3 Circulation 2 – Pump Kill Mud down Well Annulus

Because of the constant bottom hole pore pressure, a heavier kill mud shouldn't be necessary, but was still performed in order to simulate all steps of the HOL kill procedure. A kill mud of 9,5 ppg was chosen and started to circulate down the well annulus as soon as the kick was circulated out the inner pipe. To keep a stable BHP, the circulation rate was slowly increased as the circulation down the inner annulus was decreased, until the wanted rates was reached. When the entire well annulus was filled with kill mud, the circulation was slowly shut down, while increasing the circulation down the inner annulus.

Figure 4.32 represents pump rates for circulation 2 and 3. Pump 2 was ramped up during circulation 2, pumping kill mud down the well annulus. During circulation 2 the pump rate down the drill pipe was kept at a minimum. For circulation 3 only pump 1 was used.

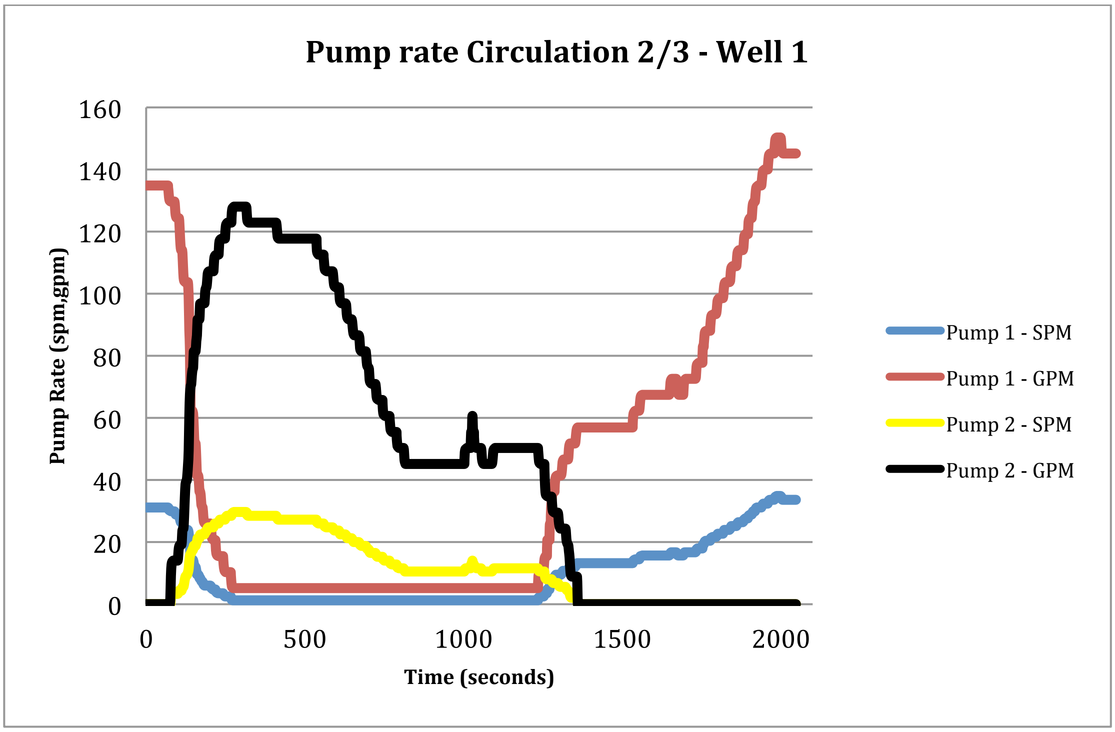

Figure 4.32: Pump rate HOL kill circulation 2/3, well 1

Figure 4.33 represents casing, choke and drill pipe pressures for circulation 2 and 3. Due to pumping kill mud down the well annulus, accurate values for shoe pressure and BHP couldn't be calculated from casing pressure.

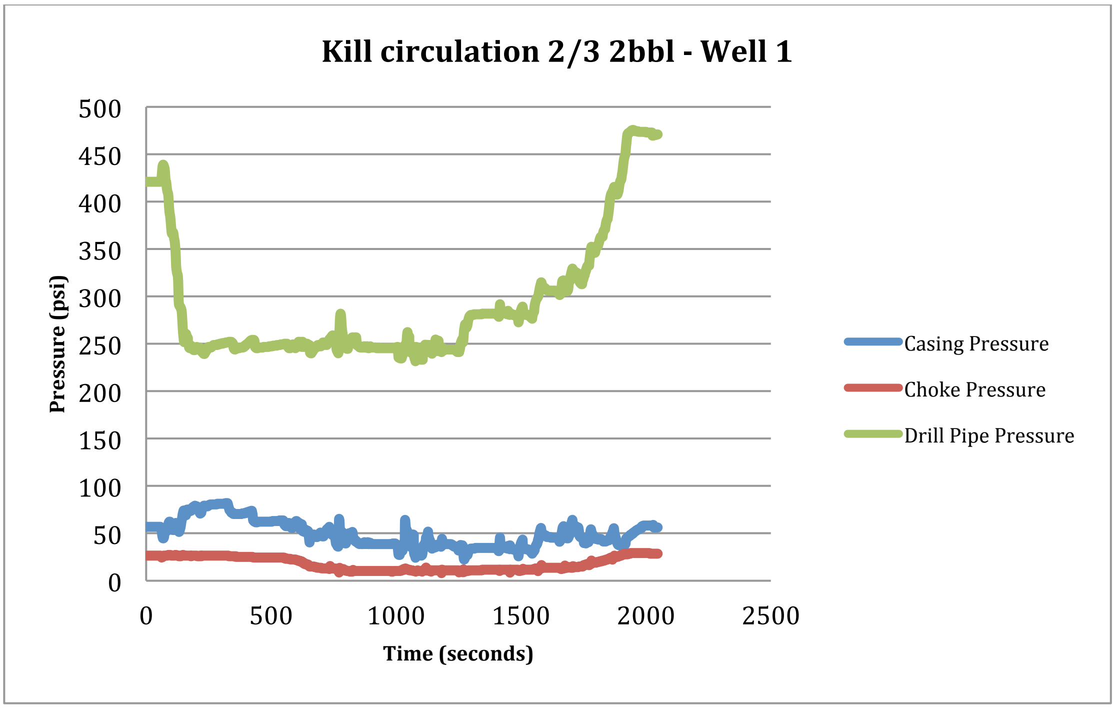

Figure 4.33: HOL kill circulation 2/3, well 1

4.4.1.4 Circulation 3 – Circulate out any remaining Kill Mud

When the entire well annulus was filled with kill mud one more circulation was performed by pumping down the inner annulus. The purpose is to circulate out the remaining influx and kill mud inside the drill string. The same fluid density was used as the bottom hole formation pressure was the same as before the kick, but in the case of drilling into an over pressured formation the density of the active fluid should also be increased in order to balance the new formation pressure. The pump rate down the inner annulus was slowly increased as the rate down the well annulus was decreased. The pump rate was increased during the entire circulation, in order to keep the BHP from dropping. Because of the increase in static fluid density, the final BHP was kept at about 630 psi at a pumping rate of 124 gpm.

New BHP = Old BHP + (0,5*TVD*0,052) (10)

(Increase BHP by hydrostatic increase of new static mud)

4.4.2 Well 2 section 1

Only circulation 1 was performed for section 1 of well 2. Two different influx volumes of approximately 2 and 10 bbl were used. As section 1 can't be considered extended reach it was driller without HOL, using the same fluid density of 12ppg in the entire well. Both kicks were taken at 4971m MD at a drilling circulation rate of 89 gpm. The influx density was set to 0,2 ppg.

4.4.2.1 2bbl influx

The pump rate was kept constant during the entire circulation (Figure 4.34), using the choke to control the pressures.

Figure 4.34: Pump rate HOL kill circulation 1 (2bbl), well 2 section 1

Figure 4.35 represents the well pressures when circulating out the 2bbl kick. The maximum choke pressure was approximately 500 psi.

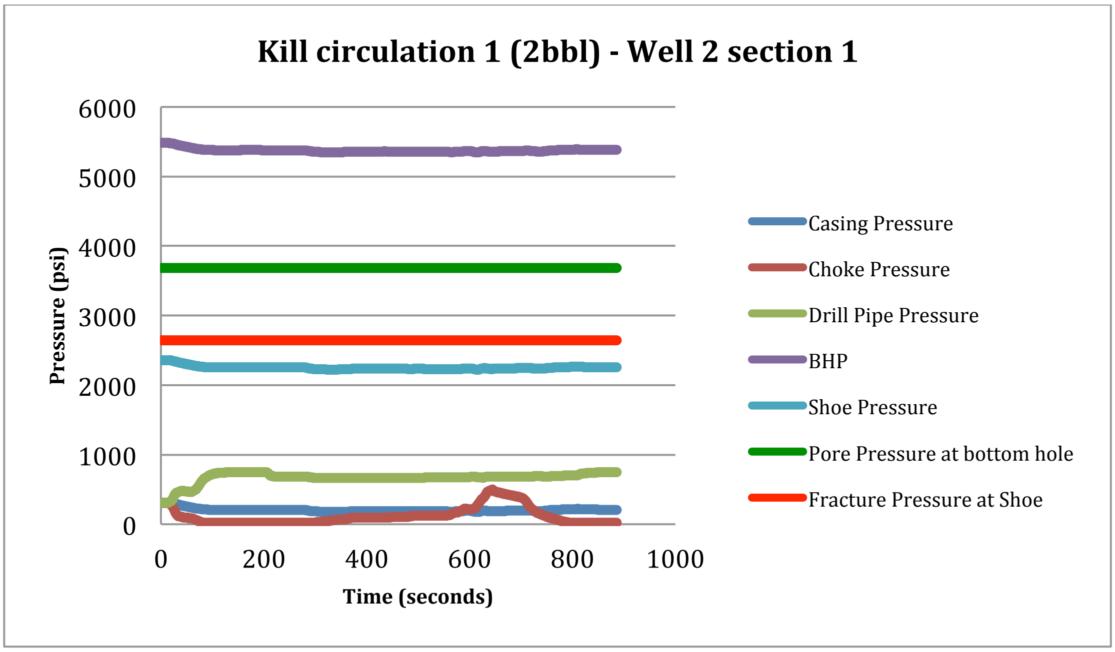

Figure 4.35: HOL kill circulation 1 (2bbl), well 2 section 1

4.4.2.2 10bbl influx

The 10 bbl kick was circulated out the same way, by keeping the pump rate constant (Figure 4.36).

Figure 4.36: Pump rate HOL kill circulation 1 (10bbl), well 2 section 1

The maximum choke pressure obtained when circulation the 10 bbl kick was approximately 800 psi (Figure 4.37).

Figure 4.37: HOL kill circulation 1 (10bbl), well 2 section 1

4.4.3 Well 2 section 2

For section 2 HOL was used, so the fluid displacement was included. Only one kick of approximately 50 bbl was simulated, taken at MD 15770 m.

4.4.3.1 HOL mud displacement

For the HOL fluid displacement the pump rate was increased during the entire circulation (Figure 4.38). The BHP was kept as close to fracture pressure as possible in order to avoid heavy mud from the annulus to enter the inner pipe. Due to high drill pipe pressure the max pump rate used was 182 gpm (Figure 4.38 shows a rate over 200 gpm). At this point the drill pipe pressure was approximately 5500 psi. (Pump limit was 7000 psi)

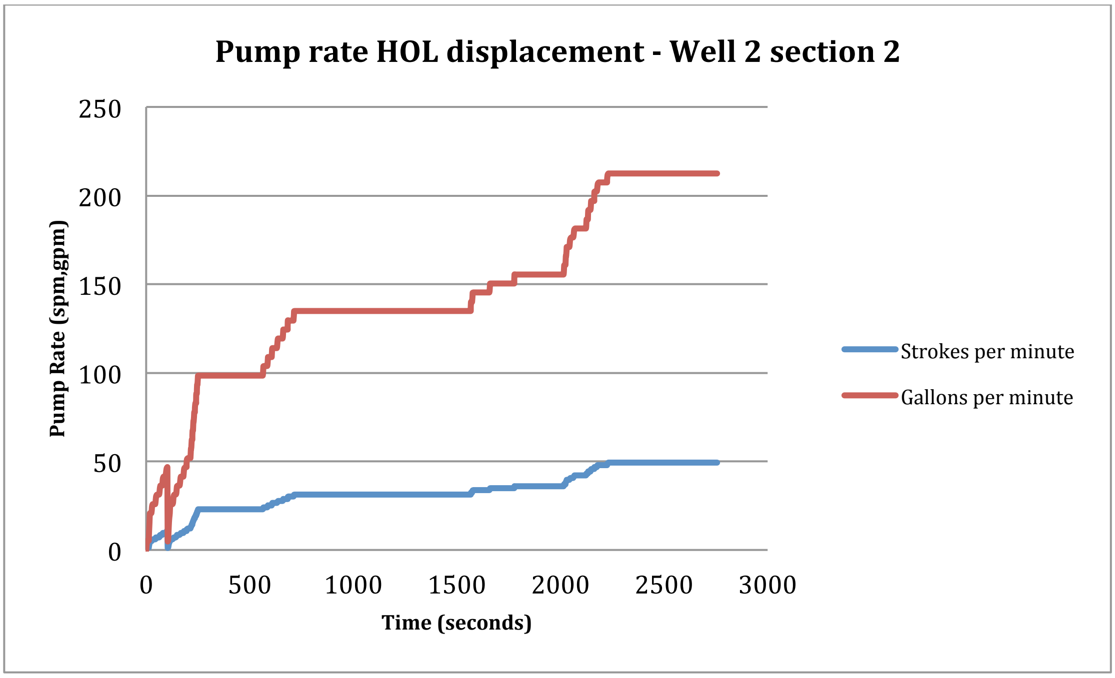

Figure 4.38: Pump rate HOL displacement, well 2 section 2

Figure 4.39 represents the well pressures during the HOL fluid displacement for well 2. Casing pressure was kept close to the fracture pressure in order to avoid annulus fluid flowing into the inner pipe. Drill pipe pressure is increasing during most of the circulation, reaching a maximum value of approximately 5500 psi.

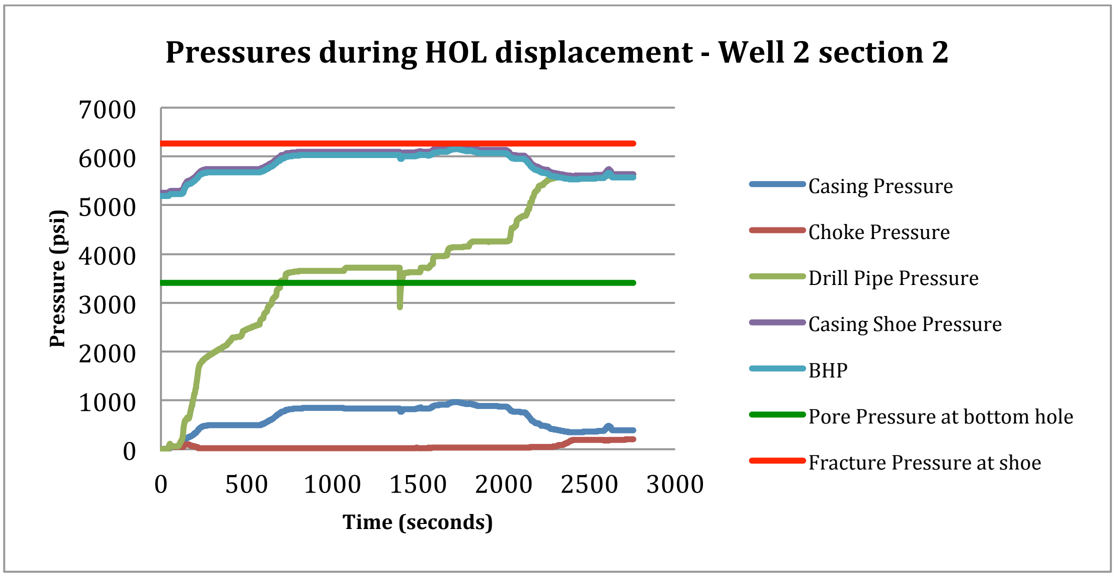

Figure 4.39: HOL displacement, well 2 section 2

4.3.3.2 Circulation 1 – Well 2

For the kick circulation the initial pump rate was 160, then decreased to 125 for the rest of the circulation (Figure 4.40).

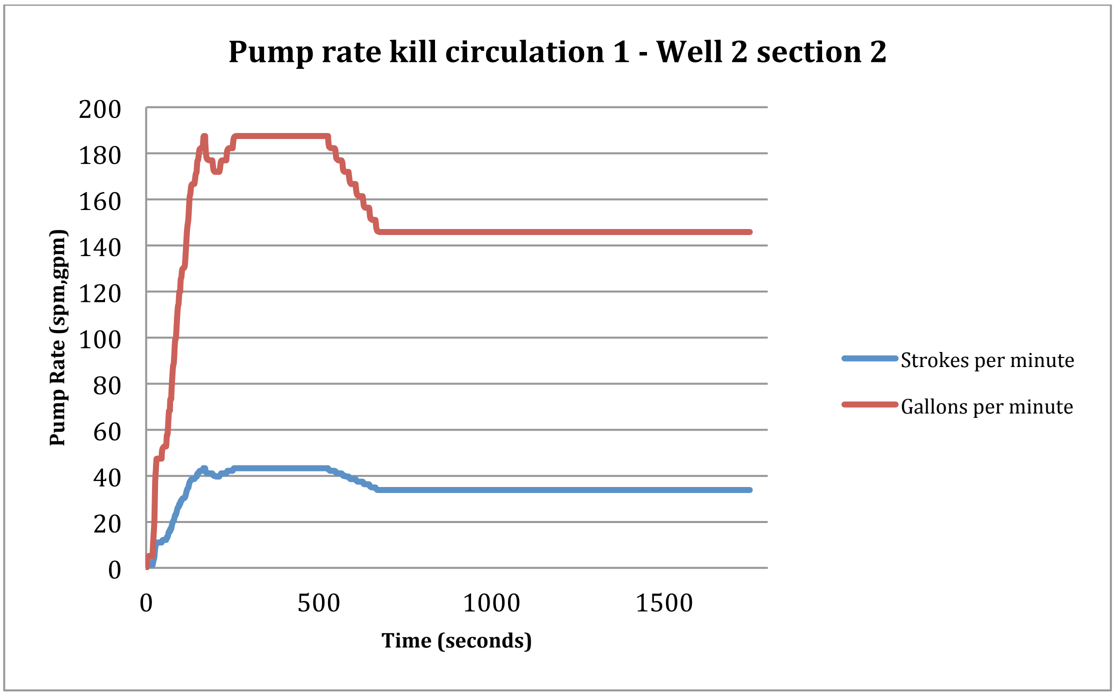

Figure 4.40: Pump rate HOL kill circulation 1, well 2 section 2

A maximum choke pressure of approximately 3000 psi was obtained during circulation of the 50bbl kick. (Figure 4.41)

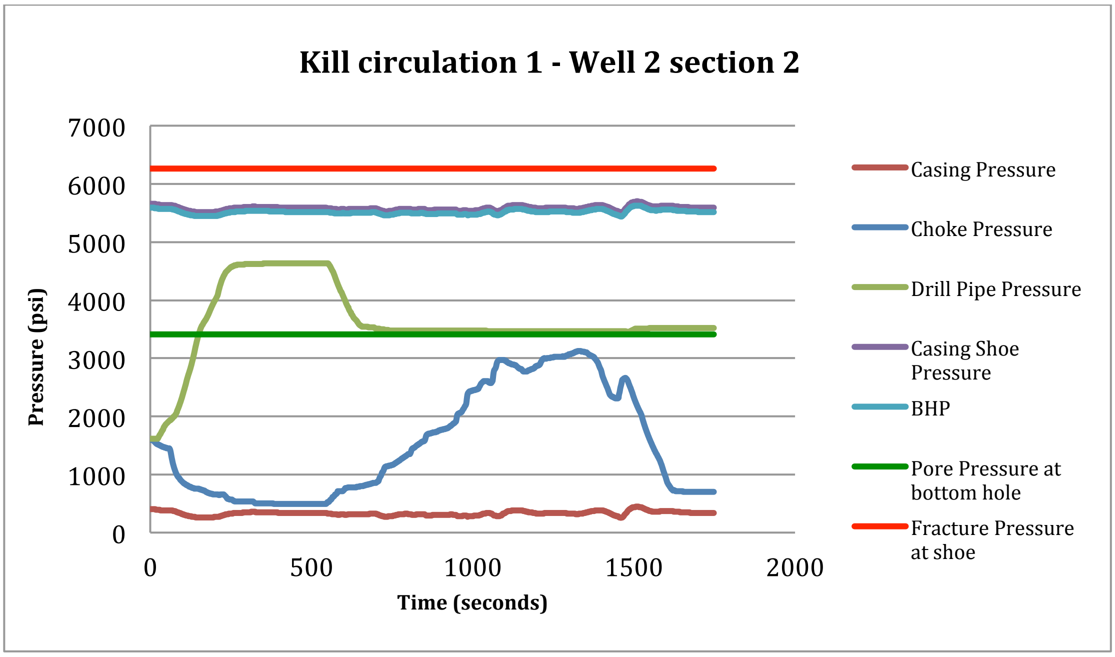

Figure 4.41: HOL kill circulation 1, well 2 section 2

4.5 Comparison of DrillSIM and Wellplan simulations using similar inputs

A simulation using similar input parameters in Wellplan was performed, to compare results for RDM and conventional.

While the bottom hole formation pressure was constant during the entire DrillSIM simulation, it had to be set at 0,468 psi/ft (9 ppg) when using Wellplan, to be able to get the wanted outputs. Both driller's method and wait & weigh were considered for the comparison.

Wellplan inputs well 1		
Circulation Flow Rate	115 gpm	
Kick Interval Gradient	0,624 psi/ft	12 ppg
Type of Influx	Gas	
Kill Rate	115 gpm	
Total Influx Volume (bbl)	2, 5 and 14	
Kill Mud Gradient	0,65 psi/ft	12,5 ppg
Influx Gradient	0,011 psi/ft	0,2 ppg

Table 4.9: DrillSIM Wellplan comparison input, well 1

Wellplan inputs well 2	Section1 /section 2	
Circulation Flow Rate (gpm)	89/182	
Kick Interval Gradient	0,624/0,676 psi/ft	12/13 ppg
Type of Influx	Gas	
Kill Rate (gpm)	89/125	
Total Influx Volume (bbl)	2 and 10/50	
Kill Mud Gradient	0,65/0,702 psi/ft	12,5/13,5 ppg
Influx Gradient	0,083/0,079 psi/ft	1,6/1,5 ppg

Table 4.10: DrillSIM Wellplan comparison input, well 2

Wait & Weigh was also included in the simulations, but only section 1 of well 2 showed any significant differences between Driller's and W&W. The rest of the charts from the simulations can be found in the appendix B.

4.5.1 Well 1 comparison

Same as for the previous Wellplan simulations, the casing shoe pressures show large variations during the circulations (Figure 4.42).

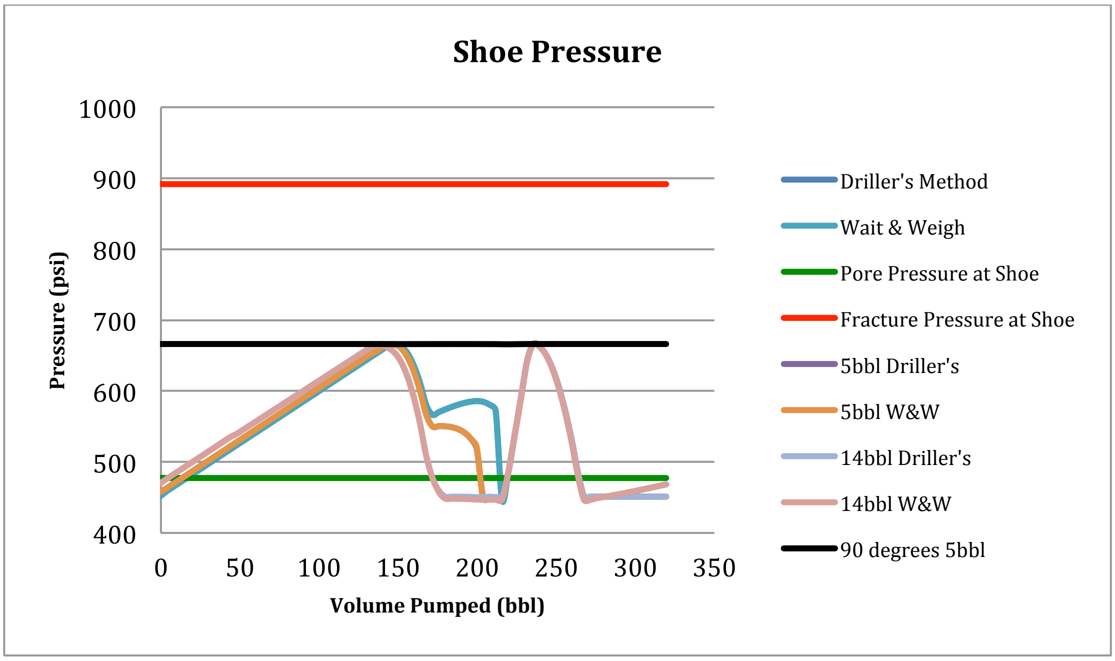

Figure 4.42: Shoe pressure Wellplan comparison, well 1

The BHP shows the same pressure development (Figure 4.43), even though the BHP is supposed to be constant during the circulation. The pressure variations decreased when increasing the kick intensity, and a kick intensity increase equal to the difference between the max and min BHP was required in order to get a constant BHP. By changing the inclination of the horizontal section from 93 to 90 degrees, both the shoe pressure and the BHP development changed to constant for the entire circulation.

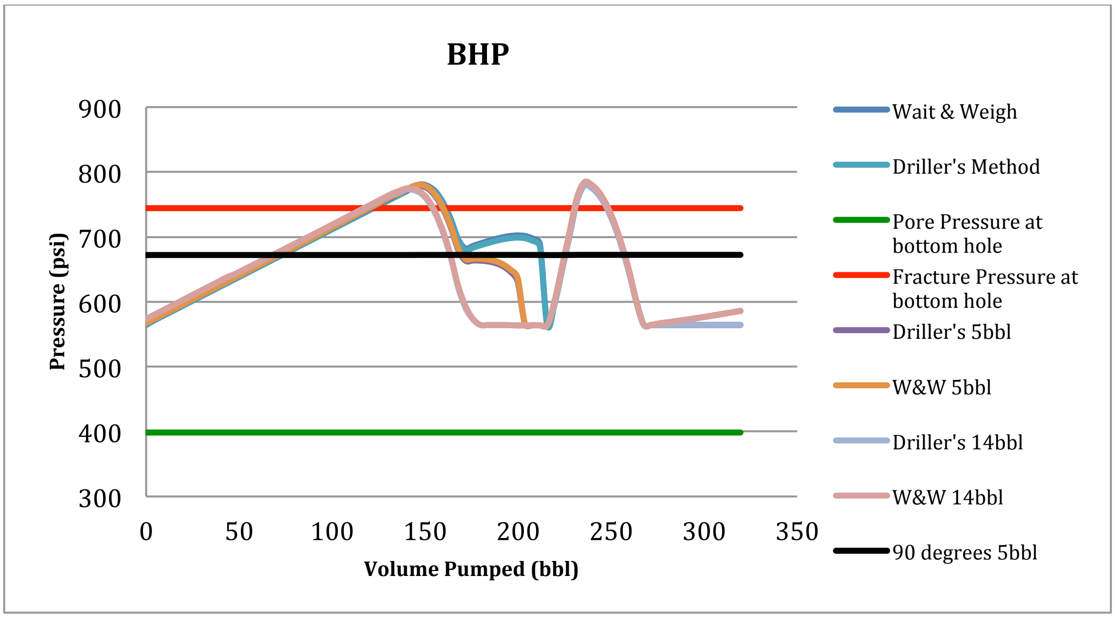

Figure 4.43: BHP Wellplan comparison, well 1

The maximum choke pressure obtained from well 1 was approximately 225 psi (Figure 4.44), significantly less than for the RDM simulations.

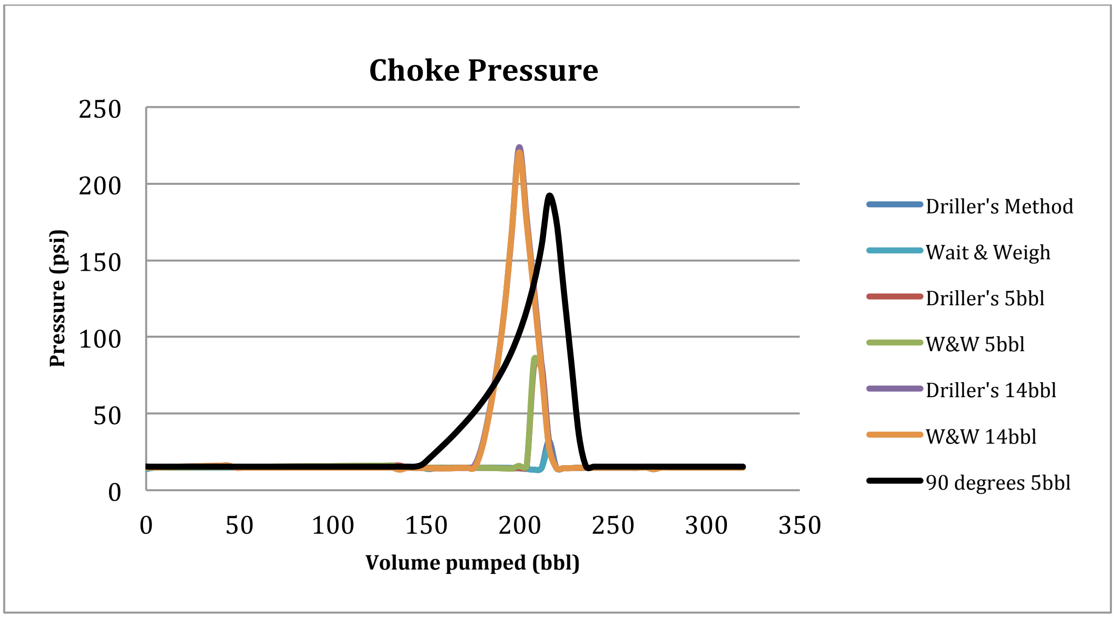

Figure 4.44: Choke pressure Wellplan comparison, well 1

4.5.2 Well 2 comparison

For Well 2 the choke pressures also showed much lower values than for the RDM simulations. Figure 4.45 represent the choke pressures for section 1, with a maximum pressure of approximately 290 psi for the 10 bbl kick.

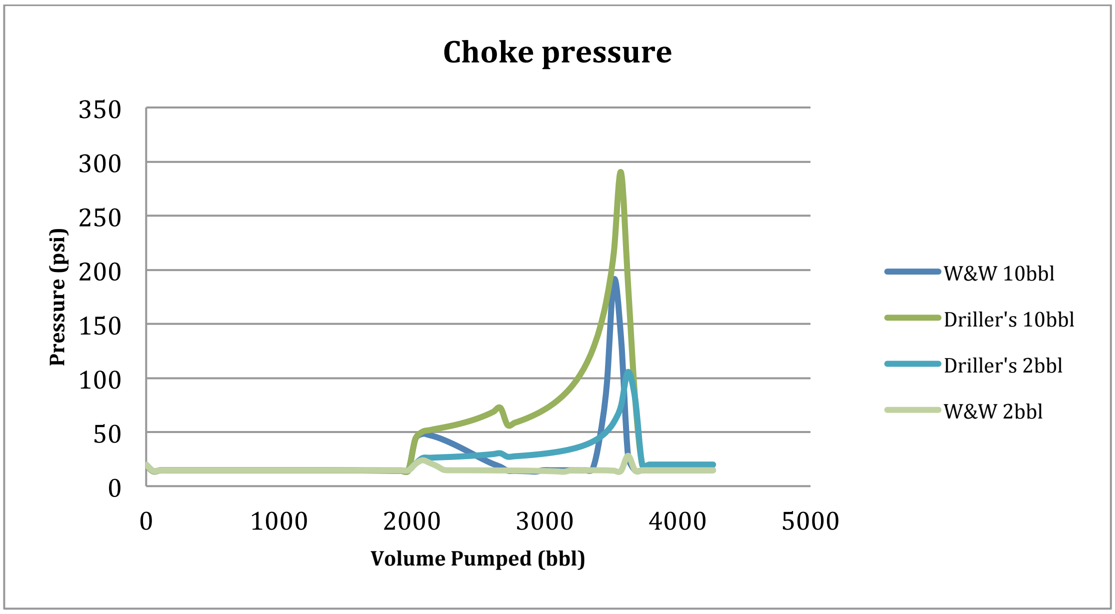

Figure 4.45: Choke pressure Wellplan comparison, well 2 section 1

The choke pressure from section 2 is represented in Figure 4.46, and shows a maximum pressure of approximately 620 psi.

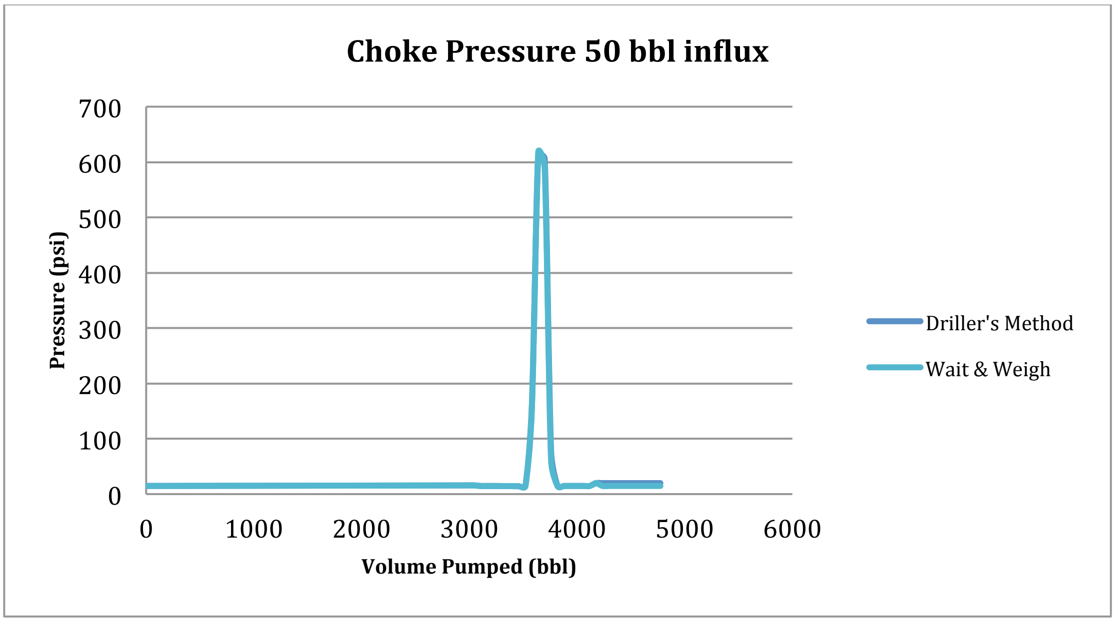

Figure 4.46: Choke pressure Wellplan comparison, well 2 section 2

5. Discussion

Several simulations were performed, both in Wellplan and DrillSIM, comparing well pressures when using several different inputs. The same well geometries and similar inputs were used for both simulators, in order to get comparable results.

The Landmark simulations concerned conventional extended reach drilling, and the simulations were performed using different values for fluid density, influx volume and kick intensities. Mainly Driller's method was used as kill procedure, due to better extended reach capabilities. A few results using Wait & Weigh were also included, for comparison.

The DrillSIM simulations focused more on the general pressure development during the HOL returns up inner pipe kill procedure, using kicks of different volumes. Displacement of the mud inside the DDS with a lighter drilling fluid used for HOL was also included.

The question that will be discussed:

Wellplan:

- Kick tolerance
- Shoe pressures
- Choke pressures

DrillSIM:

- Development of well pressures
- Methods used for kill procedure

Comparison:

- Kick tolerance, shoe and choke pressures
- Mud volumes and circulation times

5.1 Wellplan

5.1.1Kick tolerance

Kick tolerance is defined as the maximum influx volume allowed into the wellbore without fracturing the formation at the casing shoe during the kick circulation. For extended reach wells, the shoe is usually located in the horizontal section, and a vertical depth similar to any kick formations drilled into. This means that as long as the kick formation pressure doesn't exceed the fracture pressure at the shoe, the amount of influx will not affect the risk of fracturing at the shoe. The simulation results for well 1 and well 2 section 2 confirm this, with constant shoe pressures unaffected by the influx volume. By increasing the kick intensity to 3,5ppg or more, the shoe pressure in well 1 started getting affected by the amount of influx, but at this point the kick formation pressure was close to the fracture pressure at the shoe, making the influx volume less important.

For section 1 of well 2, the shoe was located in the vertical section of the well. When using the same kick intensity and different mud weights, it was shown the heavier mud caused the kick tolerance to decrease. Using the same mud but different kick intensities showed similar results, with higher kick intensities causing the kick tolerance to decrease. It can be seen form the charts that when comparing the same kick interval of 11ppg, the 9,5ppg mud gives a lower kick tolerance than the 10,5ppg mud due to the difference in hydrostatic pressure.

5.1.2 Shoe pressure

When using driller's method, the BHP is supposed to be constant for the entire circulation. Due to the shoe being in the horizontal section for both extended reach wells the shoe pressure was expected to be similar to the BHP, without much pressure variations. However, this was not the case. For both well 1 and section 2 of well 2 the shoe pressure showed big fluctuations, with max pressures occurring when the kick was at the bottom of the vertical section and at the choke. The minimum pressures occurred at the start of the circulation, when the kick was in the vertical section and after the kick was circulated out of the well. For well 1 the pressures ranged between approximately 473psi and 667psi, and for well 2 between 5147 and 5892 (10bbl influx, 0,5 ppg kick intensity). Later simulations showed that this was also the case for the BHP. The reason for this seemed to be the inclination of the wells, which were 93 and 91 degrees. By changing the inclination to 90 degrees, both shoe pressure and BHP was constant for the entire circulation. Changing the kick intensity affected the shoe pressure behavior. By increasing the kick intensity the minimum pressure increased, while the max pressure stayed the same. By increasing the kick intensity enough, the min pressure eventually became equal to the max pressure, giving a close to constant shoe pressure. This occurred at a kick intensity of approximately 0,248psi/ft (4,77ppg) for well 1 and 0,124psi/ft (2,38ppg) for well 2. For kick intensities above these values the shoe pressure development stayed the same.

For section 1 of well 2 the shoe pressure was more as expected. The pressure decreased until the influx reached the end of the horizontal section, where it started to increase. Max pressure was reached when the influx was at the choke, before dropping to shut-in pressure, which stayed constant for the rest of the circulation. This section of the well also had an inclination of 91 degrees, but the results didn't seem to get as much affected by it as it showed constant BHP for low kick intensities.

5.1.3 Choke pressures

The choke pressures showed more expected behavior for the extended reach wells, with a small decrease at the start of the circulation, and then constant until the influx reached the vertical section. Max pressure occurred when the influx was at the choke. The pressure at the end of the circulation was slightly higher than shut-in pressure, in order to balance the kick formation pressure. Using different kick intensities didn't cause a very big increase in pressure when influx was at the choke, but caused an increase of shut-in and final pressures equal to the increase in kick formation pressure. Increasing the influx volume didn't cause any increase in shut-in or final pressure but a significant increase in max pressure, equal to the hydrostatic pressure of the mud displaced by the additional influx.

Section 1 of well 2 showed different behavior than the extended reach wells, with a decrease in choke pressure until the influx reached the end of the horizontal section. The pressure then increased until max value when the influx reached the choke. Dropped then to a final pressure slightly higher than shut-in when the influx was circulated out. When using different kick intensities the pressures for each value were separated for the entire circulation, meaning a choke pressure difference of approximately the same as the kick intensity difference. Using different influx volumes gave results similar to the other wells; with the same choke pressure before the influx entered the vertical section and after it was circulated out. However, the increase in choke pressure as the influx moved up the vertical section was more gradual than for the extended reach wells.

5.2 DrillSIM

Due to the different flow configuration of the Reelwell Drilling Method it's not directly comparable to conventional. By taking the influx through the inner pipe the kick tolerance question is eliminated, as the influx volume doesn't directly affect the annulus volume. Of course this is under the assumption that none of the influx migrates up the well annulus. Because of this, the shoe pressure isn't of the same importance, as it will follow the same development as the casing surface pressure and the BHP, due to the well annulus fluid being static. During the simulations drill pipe, casing and choke pressure was logged, while shoe pressure and BHP was calculated from casing pressure.

5.2.1 HOL displacement

For well 1 and section 2 of well 2, the entire well was initially filled with the same mud, and in order to use Heavy Over Light the mud inside the DDS had to be displaced by a lighter drilling fluid. First the pump rate was ramped up as much as possible without letting the shoe pressure get to close to the fracture pressure. The same fracture gradient was used for the entire open hole section, and because of the annulus fluid being static is was equal risk of fracturing along the entire open hole. For well 1 the pump rate was then kept constant until the drilling fluid entered the vertical section on the return up the inner pipe. For well 2, problems occurred when the drilling fluid reached the bit and started the

return through the inner pipe. Even with a BHP significantly higher than the hydrostatic pressure of the annulus fluid, some of the heavy fluid from the annulus entered the inner pipe. This was solved by slowly ramping up the pressure when the drilling fluid entered the inner pipe, to keep the BHP from dropping and as close as possible to the fracture pressure.
As the drilling fluid entered the vertical section, the BHP started to drop and the pump rate was increased in order to keep it from dropping to low, risking annulus fluid to enter the inner pipe. The pump rate was kept as high as possible, while keeping the BHP stable between the hydrostatic annulus fluid pressure and the fracture pressure. For well 2, increasing the pump rate caused an excessive drill pipe pressure, so the rate wasn't increased above 182gpm. For the rest of the displacement the choke was used to adjust the pressures.
For well 1 and well 2 the total strokes of the displacement circulation was 1498 and 22718, respectively (at 4,32 gal/stk). Converting to barrels this gives 154 and 2337 bbl. In comparison the calculated values for the DDS volume was 150 and 1616 bbl.

$$BBL=STK*4,32/42 \tag{11}$$

5.2.2 Circulation 1

Circulation 1 of the HOL kill procedure was the only step performed for all wells and influx volumes. For all simulations BHP, casing and choke pressure experienced a drop and drill pipe pressure an increase as the circulation was initiated.

Well 1

3 different influx volumes was used, approximately 2, 5 and 14 bbl. Due to problems with adjusting the influx rate the kicks of 5 and 14 bbl got separated into several slugs.
Slightly different methods were used for circulating out the kicks. For the two smallest only the pump rate was adjusted during the circulation. For the 2bbl kick the pump rate was decreased as the kick moved up the vertical section, and then increased as it went through the choke ending up at the initial pump rate.

The choke pressure reached a maximum of approximately 300psi, while the other pressures stayed quite stable through the circulation. The 5bbl kick was circulated the same way, but due to being separated into 3 slugs, it was experienced 3 spikes in choke pressure, of approximately 450,350 and 300 psi. If the kick had been concentrated in only one slug the max choke pressure would have been expected to be higher. Due to more variations in pump rate, the drill pipe pressure fluctuated more than for the 2bbl kick. The 14bbl kick was separated into 5 slugs and was circulated out by keeping a constant pump rate of 44 gpm until the entire influx was circulated out, only adjusting the choke. The max choke pressure of slightly more than 550psi occurred when the first slug reached the choke, followed by 4 pressure spikes as the other slugs reached the choke. For some reason pressure spike 2-4 increased from about 400psi to slightly less than 450psi, respectively. This was the opposite of the 5bbl simulation where there was a decrease in pressure for each pressure spike. The reason might have been the size of each slug, but these volumes were not recorded. Total strokes pumped for each of the simulations was 319, 297 and 425. In comparison the calculated inner pipe volume is 43bbl/418stk. Total strokes were higher for the 14bbl kick due to annulus fluid entering the inner pipe, which needed to be circulated out. Compared to the volume calculations the volume pumped for the 2 smallest kicks wouldn't be sufficient to displace the entire volume of the inner string.

Well 2 section 1

For this section two kicks of approximately 2 and 10bbl were simulated. HOL was not used for this section, meaning the same fluid was used in the entire well. Both kicks were circulated out at a constant pump rate of 89gpm, using the choke to control the pressures. The pressure development was similar for both cases, with no significant fluctuations except for the max choke pressures, of approximately 400 and 800 psi. However, of the initial influx volumes of 12,81 and 51,84 cuft, 4,97 and 26,92 cuft was still left. This would have been circulated out during circulation 2, but this was not simulated for this well. Because of the 91-degree inclination, the remaining influx was kept from migrating up the annulus risking excessive shoe pressures. Total strokes pumped were 1904 and 1695.

Well 2 section 2

For the last section only one influx volume of approximately 50bbl was simulated. Due to problems with keeping the influx as a single slug for volumes any larger than a few barrels the pump had to be shut off while allowing the influx to accumulate before shut in. When the circulation was started the pump rate was ramped up to 160gpm and kept constant until the influx reached the end of the horizontal section. The pump rate was decreased to 125gpm and the choke used to control the pressures. The choke pressure experienced a steady increase and reached a maximum pressure of about 3100psi. 20,5 of initially 271,89 cuft influx was left in the well after the circulation. Total strokes pumped were 5813. In comparison the calculated inner pipe volume was 631bbl/6135stk.

5.2.3 Circulation 2

This step of the HOL kill procedure was only performed on well 1, in the same simulation as the 2bbl kick. After the kick was circulated out a second pump started circulating kill mud down the well annulus. Since the formation pressure was the same as before the kick, a heavier mud wasn't required but was increased with 0,5 ppg in order to check how the pressures would change. The BHP was kept stable by keeping the total pump rate constant. The kill mud pump rate was ramped up to a maximum of 29 and the rate down the drill pipe was kept at a minimum of 1spm. The kill mud rate was decreased during the circulation. When the kill mud reached the bit the pump rate was ramped down to 0 at the same time the rate down the drill pipe was ramped back up. The drill pipe pressure experienced a drop as the rate was ramped down at the start of the circulation and the casing pressure increased as the kill mud rate was increased. Total strokes were only 156 due to only pumped volume from pump 1 was being recorded.

5.2.4 Circulation 3

The last step of the kill procedure was to circulate out the remaining kill mud from the inner pipe. The pump rate was increased during the entire circulation. Because of the drilling fluid density not being increased the final BHP was increased by an equal amount to the increased hydrostatic pressure of the kill mud. The total strokes pumped were 375.

5.3 Comparison

A few simulations using similar inputs as for DrillSIM was performed in Wellplan, mainly to compare the shoe pressure, BHP and choke pressure of well 1. As for the previous Wellplan simulations the shoe pressure and BHP showed big fluctuations. When changing the inclination to 90 degrees, both shoe pressure and BHP changed to being constant, where shoe pressure (666,25psi) was equal to the max pressure for the 93-degree inclination and BHP between max and min (672,11psi). By comparison the pressures were approximately 700 psi (shoe) and 600 psi (BHP). However, this is not a good basis for comparison as the difference in shoe pressure and BHP for the 90 degree well is only due to pressure loss and none because of vertical difference.

As for the choke pressures Wellplan gave pressures of approximately 30, 85 and 220 psi for influx volumes of 2, 5 and 14bbl. In comparison DrillSIM gave 300, 440 and 550 psi for the same influx volumes, even though the kick was circulated out in several smaller slugs, giving lower values than expected. Over all the results were as expected due to the return going through the low capacity inner pipe for the RDM. The HOL fluid arrangement will also have an effect on the pressure, as the annulus fluid controls the BHP. When circulating out the kick, the hydrostatic pressure of the light active fluid will not be enough to balance this pressure, causing higher choke pressure. A high choke pressure will cause less volume fluctuations from expanding gas, making it easier to keep the well pressure constant. This is because of significantly reduced differential flow volume out of and into the well during the kick circulation. Because the aim of ERD is to drill as far as possible horizontally, the TVD will be relatively shallow, and excessive choke pressure shouldn't normally be an issue. However, the comparison cannot be considered accurate due to too many uncertainties and differences between the simulations.

Mud volumes and circulation times

Due to the already mentioned differences between the simulators there is no easy way of comparing mud volumes and circulation times from the simulations. For the Wellplan simulations the total volume pumped is shown in barrels but only the first circulation of Driller's method is considered. For DrillSIM only the pump rate was logged automatically. The total strokes pumped for the different circulations were manually recorded, but due to uncertainties and differences between the simulations there are limited benefits from direct comparisons. As for circulation times this is not given in the Wellplan result but can be calculated using volume pumped and pump rate. In DrillSIM the time was recorded in real-time, which was recording both when the simulation was paused and the speed set to 50 times normal.

Due to the lack of results in terms of comparing mud volumes and circulation times for conventional and RDM, some simple calculations were performed (appendix A). The same drill pipe, casing and open hole diameters as for the simulations was used. Pipe connections and any open hole irregularities was not considered in the calculations.

The calculations showed that for well 1 the active volume of mud when using RDM was less than the half of conventional (151:327). For a circulation rate of 120 gpm this meant circulation times of 15 min compared to 84 min for circulating out a kick, and 53 min compared to 114 min for displacing the entire active mud volume. For an entire kill operation in conventional using driller's method (2 circulations), the required time was 198 minutes. The total time needed to perform the entire HOL kill procedure (3 circulations) was in comparison 120 minutes, less than 2/3 of the time require for driller's method.

For well 2 (only section 2 considered) the active mud ratio was 1616:4759. Assuming the same pump rate of 120 gpm this gave circulation times of 220 vs 1039 minutes to circulate out a kick and 566 vs 1666 minutes for the entire active mud volume. HOL kill procedure and driller's method were performed in 1825 and 2705 minutes respectively, meaning just over 2/3 of the time for RDM.

The times calculated are theoretical, assuming constant circulation rate and not considering any stops or delays during the procedures.

6. Conclusion

The main points of the literature review can be summarized as:

Conventional

- Horizontal reach limited by the ECD in the open hole wellbore
- Drilling through pressurized faults causing risk of both kick and loss
- Greater influx volumes due to more exposed kick formation
- Higher kick tolerance
- Driller's method preferred kill procedure

Reelwell Drilling Method

- ECD problem eliminated due to return flow through inner pipe
- Built-in MPD for better pressure control
- Less active fluid volume – quicker reaction times
- Kick tolerance and gas pocket problem eliminated due to kick circulation through inner pipe
- Reduced hole problems due to cuttings transported through inner pipe
- Higher choke pressure due to low capacity IP and HOL configuration
- Different kill procedure

In short, return through inner pipe has the potential of solving several well control problems, but will cause higher choke pressure during kill procedures.

From the simulations, the main findings can be summarized as:

Wellplan (conventional):

- Confirmed high kick tolerance in horizontal wells
- Choke pressures lower compared to RDM
- Unreliable results due to inclinations over 90 degrees

DrillSIM (RDM):

- Problems with "Influx" of heavy annulus fluid during displacement
- Max pump rate limited by drill pipe pressure
- High choke pressure can help keeping the well pressures stable

Mud volumes and circulation times:

- From calculations: Well killed in approx. 2/3 of the time with RDM

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APPENDIX

APPENDIX A: Mud volume calculations

Simple calculations comparing the mud volumes and circulation times for conventional and RDM. For the calculations the drill pipe is assumed to go all the way to total well depth, and pipe connections are not considered in the calculations.

Conventional

$$Drill\ pipe\ capacity\ \left[\frac{bbl}{ft}\right] = \left(\frac{\pi}{4} * (ID^2) * 12\right)/9702 \tag{A1}$$

$$Annulus\ capacity\ \left[\frac{bbl}{ft}\right] = \frac{\frac{\pi}{4} * \left((Annulus\ Diameter)^2 - (Drill\ pipe\ OD)^2\right) * 12}{9702} \tag{A2}$$

$1\ bbl = 9702\ in^3$

RDM

The same calculations apply when using RDM. The difference is that the mud is pumped down the inner annulus and returning up the inner string.

$$Inner\ string\ capacity\ \left[\frac{bbl}{ft}\right] = \left(\frac{\pi}{4} * (ID^2) * 12\right)/9702 \tag{A3}$$

$$Inner\ annulus\ capacity\ \left[\frac{bbl}{ft}\right] = \frac{\frac{\pi}{4} * \left((Inner\ annulus\ Diameter)^2 - (Inner\ pipe\ OD)^2\right) * 12}{9702} \tag{A4}$$

$$Well\ annulus\ capacity\ \left[\frac{bbl}{ft}\right] = \frac{\frac{\pi}{4} * \left((Annulus\ Diameter)^2 - (Drill\ pipe\ OD)^2\right) * 12}{9702} \tag{A5}$$

Well 1

Well 1		
Casing shoe MD	1640,419948	ft
Total MD	4921,259843	ft

Table A.1: Well 1 MD

Conventional		
Drill pipe OD	5	in
DP ID	4,276	in
DP capacity (cu in/ft)	172,2369379	
DP capacity (bbl/ft)	0,017752725	
DP volume	87,36577262	bbl
Casing ID	9,001	in
Cased annulus cap (cu in/ft)	527,6895694	
Cased annulus cap (bbl/ft)	0,054389772	
Cased annulus volume	89,22206718	bbl
Open hole diameter	8,5	in
Open hole annulus cap (cu in/ft)	445,095	
Open hole annulus cap (bbl/ft)	0,045876623	
Open hole annulus volume	150,5138562	bbl
Total annulus volume	239,7359234	bbl
Total Mud Volume	327,101696	bbl

Table A.2: Well 1 conventional mud volume calculations

Reelwell Drilling Method		
Inner string OD	3,5	in
Inner string ID	3	in
Inner string capacity	84,78	cu in/ft
Inner string capacity	0,008738404	bbl/ft
Inner string volume	43,00395892	bbl
Outer string OD	6,625	in
Outer string ID	5,901	in
Outer string capacity	212,6263654	cu in/ft
Outer string capacity	0,021915725	bbl/ft
Outer string volume	107,8529781	bbl
Cased well annulus capacity	349,7398819	cu in/ft
Cased well annulus capacity	0,036048225	bbl/ft
Cased well annulus volume	59,13422786	bbl
Open hole well annulus capacity	267,1453125	cu in/ft
Open hole well annulus capacity	0,027535077	bbl/ft
Open hole well annulus volume	90,33817759	bbl
Total active mud volume	150,856937	bbl
Total static mud volume	149,4724055	bbl

Table A.3: Well 1 RDM mud volume calculations

Well 2

Well 2 section 2		
Casing shoe MD	45931,76	ft
Total MD	51837,27	ft

Table A.4: Well 2 section 2 MD

Conventional		
Drill pipe OD	6,625	in
DP ID	5,965	in
DP capacity (cu in/ft)	335,1751395	
DP capacity (bbl/ft)	0,034547015	
DP volume	1790,822944	bbl
Casing ID	10,192	in
Cased annulus cap (cu in/ft)	565,0703714	
Cased annulus cap (bbl/ft)	0,058242669	
Cased annulus volume	2675,188279	bbl
Open hole diameter	9,75	in
Open hole annulus cap (cu in/ft)	482,0390625	
Open hole annulus cap (bbl/ft)	0,049684504	
Open hole annulus volume	293,4123381	bbl
Total annulus volume	2968,600617	
Total Mud Volume	4759,423561	bbl

Table A.5: Well 2 conventional mud volume calculations

Reelwell Drilling Method		
Inner string OD	4	in
Inner string ID	3,54	in
Inner string capacity	118,047672	cu in/ft
Inner string capacity	0,012167354	bbl/ft
Inner string volume	630,7224331	bbl
Outer string OD	6,625	in
Outer string ID	5,965	in
Outer string capacity	184,4551395	cu in/ft
Outer string capacity	0,019012074	bbl/ft
Outer string volume	985,5340001	bbl
Cased well annulus capacity	565,0703714	cu in/ft
Cased well annulus capacity	0,058242669	bbl/ft
Cased well annulus volume	2675,188279	bbl
Open hole well annulus capacity	482,0390625	cu in/ft
Open hole well annulus capacity	0,049684504	bbl/ft
Open hole well annulus volume	293,4123381	bbl
Total active mud volume	1616,256433	bbl
Total static mud volume	2968,600617	bbl

Table A.6: Well 2 RDM mud volume calculations

Circulation times

To get the circulation times required equation A6 is used.

$$Time\ (minutes) = \frac{Volume(bbl)*42\ (\frac{gal}{bbl})}{Circulation\ rate\ (\frac{gal}{minute})} \quad (A6)$$

Well 1 volumes (bbl)	Conventional	RDM
Inner string (RDM)	-	43,00395892
Outer string (RDM)	-	107,8529781
Drill pipe (Conventional)	87,36577262	-
Well annulus	239,7359234	149,4724055
Active mud	327,101696	150,856937
Total mud	327,101696	300,3293425

Table A.7: Well 1 mud volumes

Time required at 120gpm (minutes)	Conventional	RDM
Circulate out kick	83,90757319	15,05138562
Circulate entire string	114,4855936	52,79992796
Driller's method (2 circulations)	198,3931668	-
HOL kill procedure (3 circulations)	-	120,1666555

Table A.8: Well 1 circulation times

Well 2 volumes (bbl)	Conventional	RDM
Inner string (RDM)	-	630,7224331
Outer string (RDM)	-	985,5340001
Drill pipe (Conventional)	1790,822944	-
Well annulus	2968,600617	2968,600617
Active mud	4759,423561	1616,256433
Total mud	4759,423561	4584,85705

Table A.9: Well 2 mud volumes

Time required at 120gpm (minutes)	Conventional	RDM
Circulate out kick	1039,010216	220,7528516
Circulate entire string	1665,798246	565,6897516
Driller's method (2 circulations)	2704,808462	-
HOL kill procedure (3 circulations)	-	1825,452819

Table A.10: Well 2 circulation times

APPENDIX B: Charts from Wellplan simulations

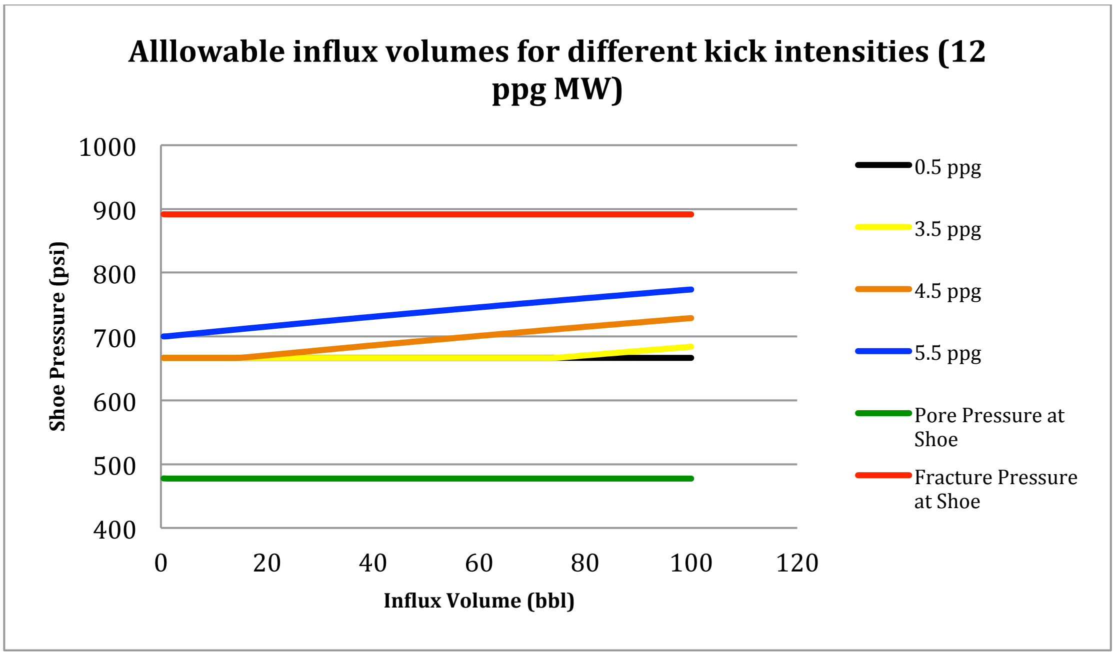

Figure B.1: Allowable influx volume for different kick intensities, well 1 (12ppg MW)

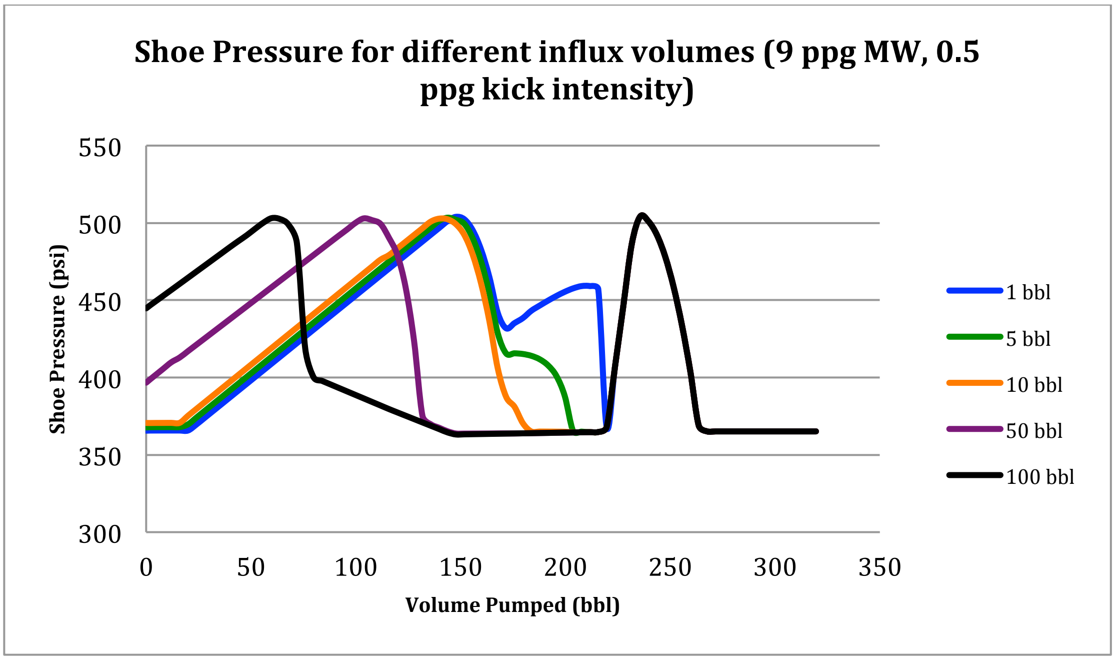

Figure B.2: Shoe pressure for different influx volumes, well 1 (9ppg MW, 0,5ppg kick intensity)

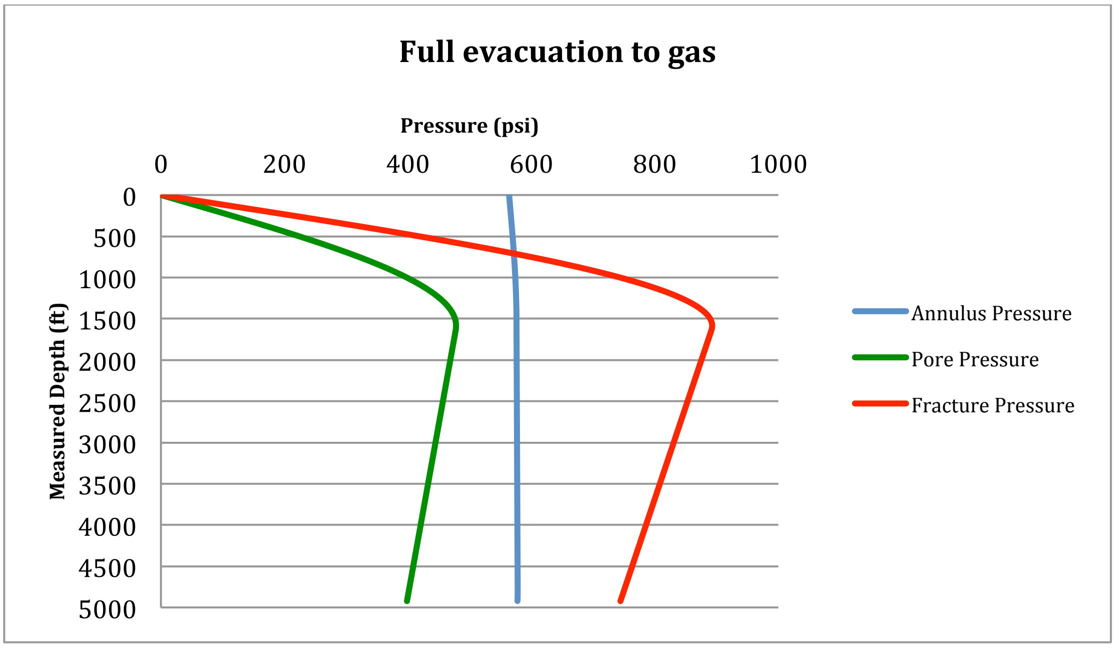

Figure B.3: Full evacuation to gas, well 1 (12,5ppg kick interval)

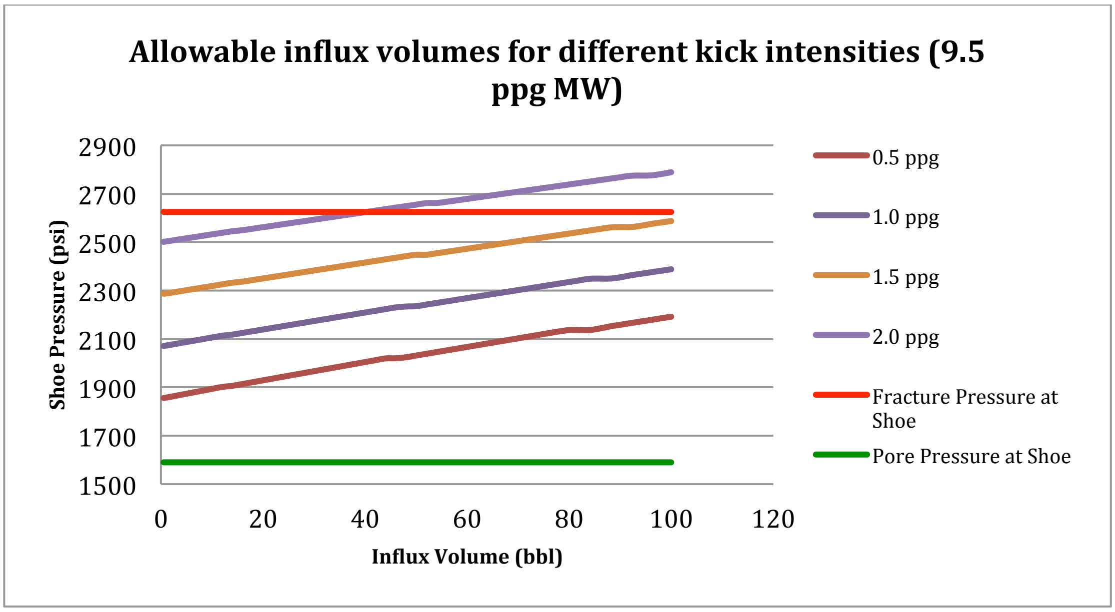

Figure B.4: Allowable influx volumes for different kick intensities, well 2 section 1 (9,5ppg MW)

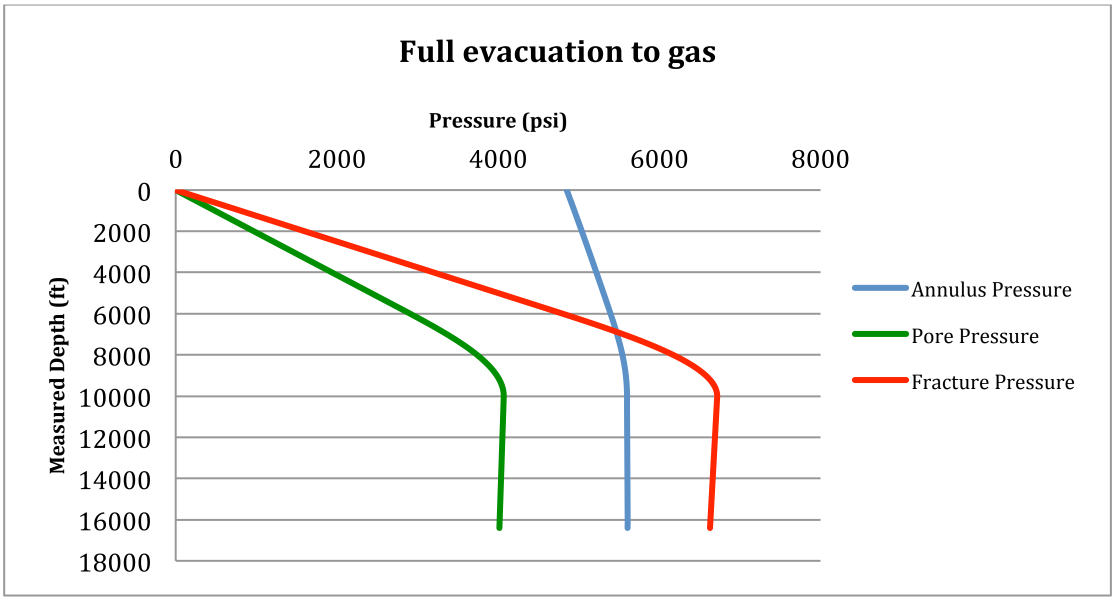

Figure B.5: Full evacuation to gas, well 2 section 1 (13ppg kick interval)

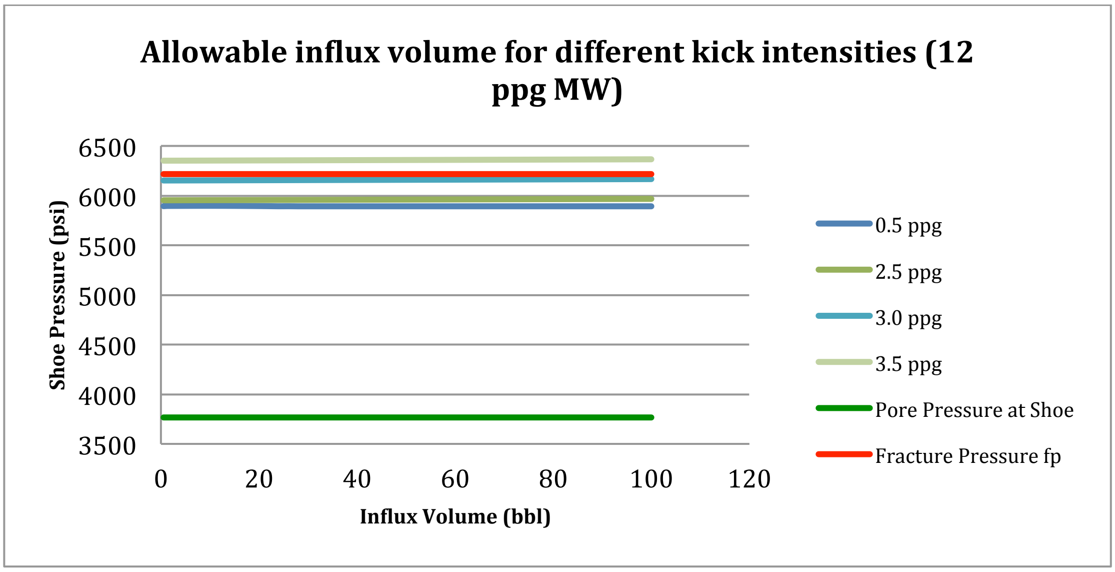

Figure B.6: Allowable influx volume for different kick intensities, well 2 section 2 (12ppg MW)

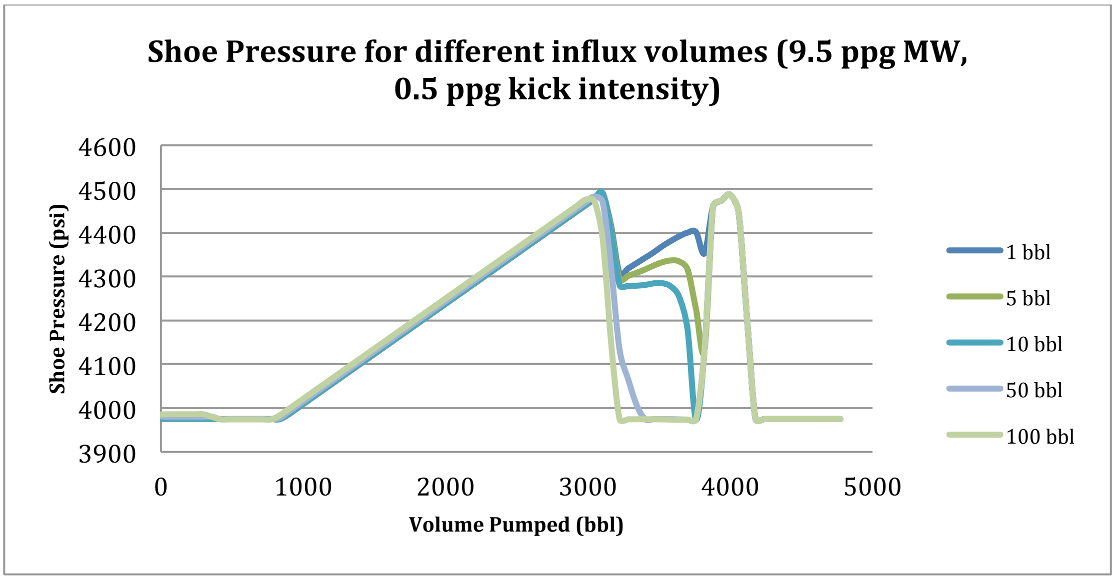

Figure B.7: Shoe pressure for different influx volumes, well 2 section 2 (9,5ppg MW, 0,5ppg kick intensity)

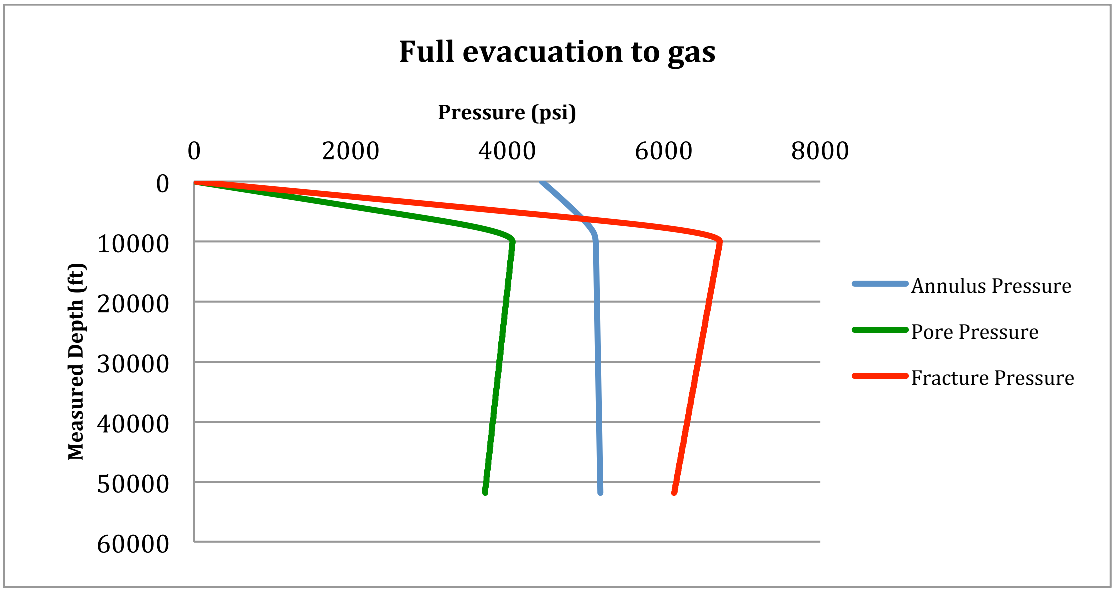

Figure B.8: Full evacuation to gas, well 2 section 2 (13ppg kick interval)

Comparison simulation charts

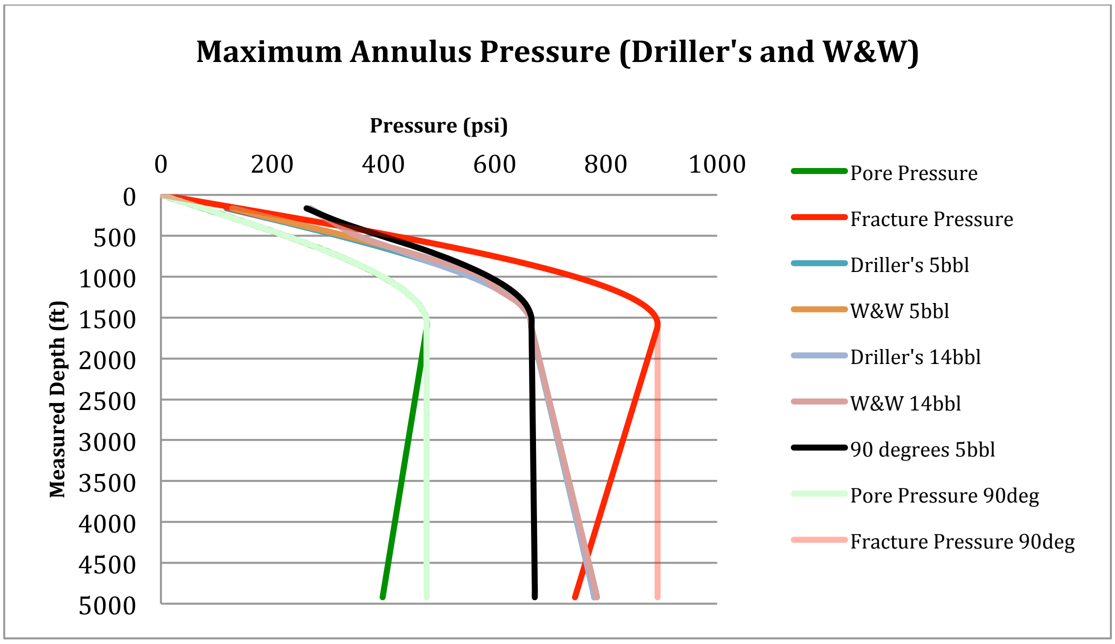

Figure B.9: Maximum annulus pressure Wellplan comparison, well 1

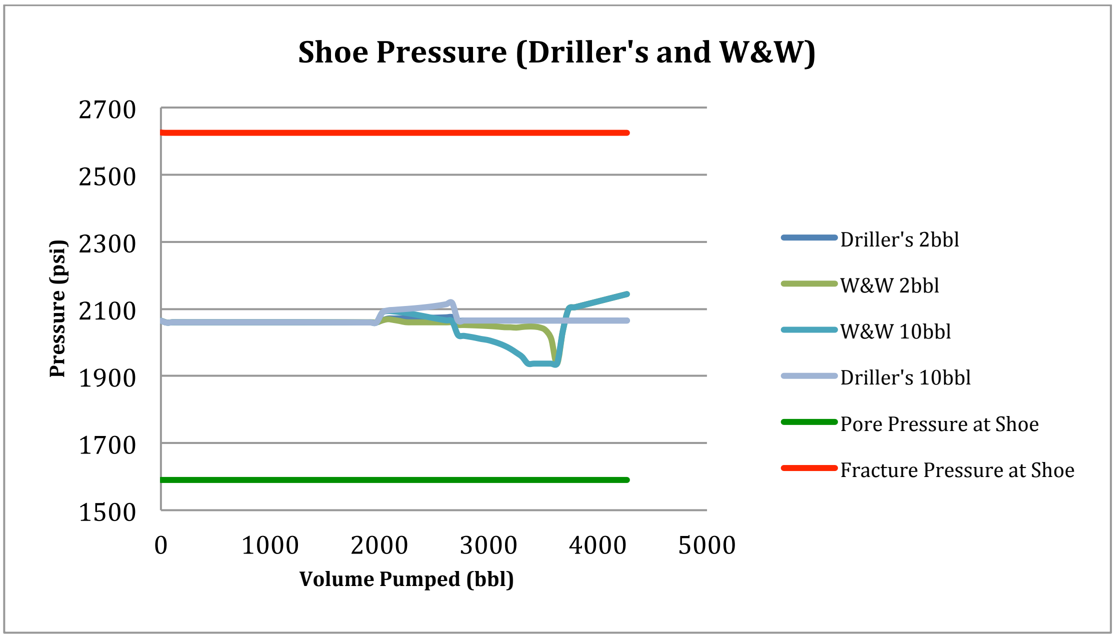

Figure B.10: Shoe pressure Wellplan comparison, well 2 section 1

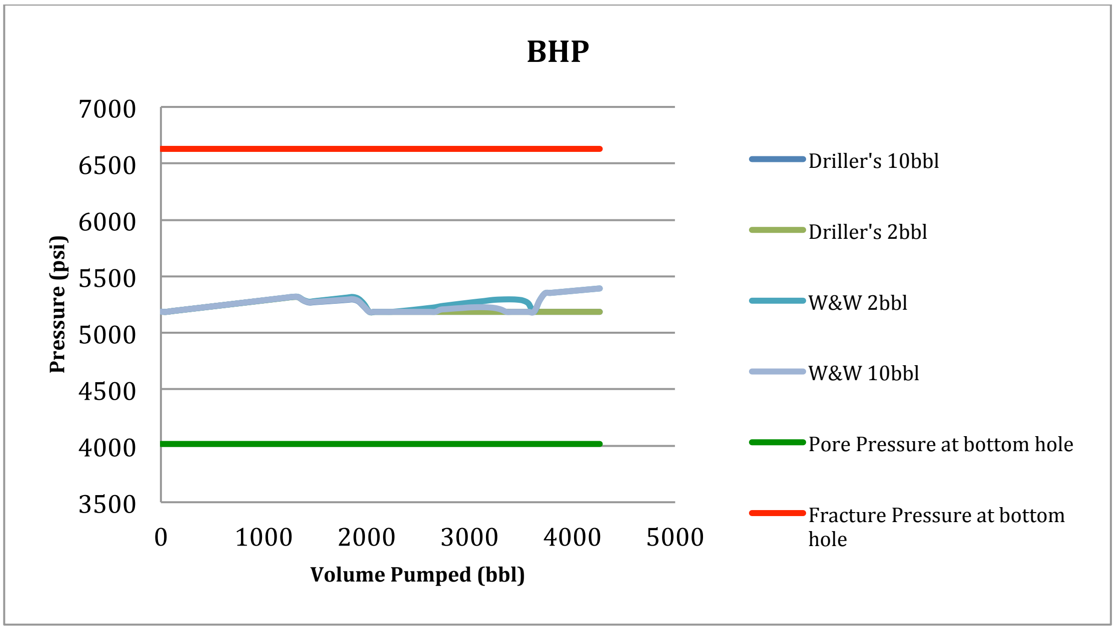

Figure B.11: BHP Wellplan comparison, well 2 section 1

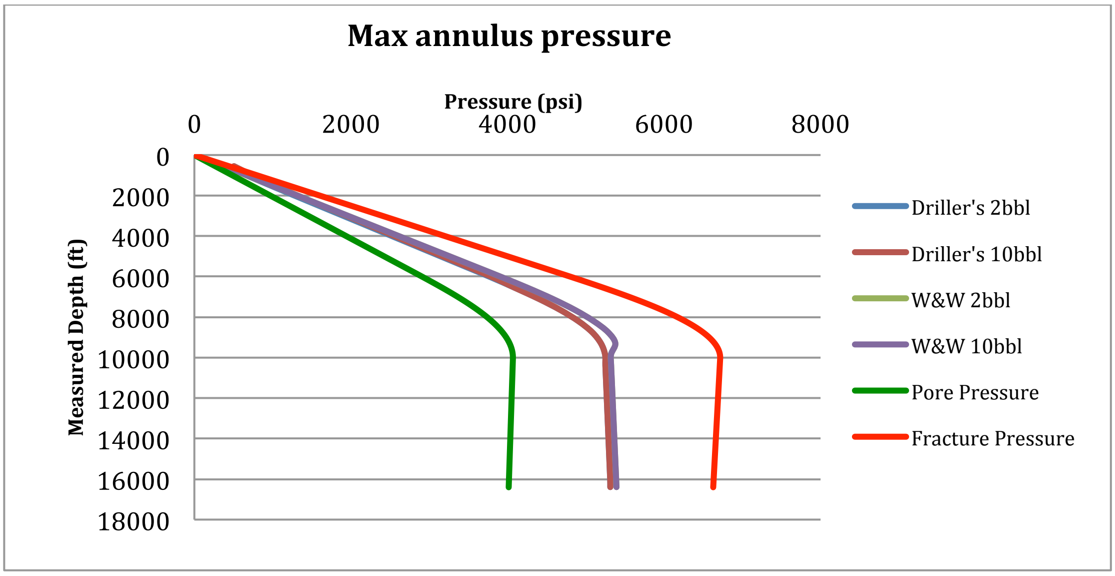

Figure B.12: Maximum annulus pressure Wellplan comparison, well 2 section 1

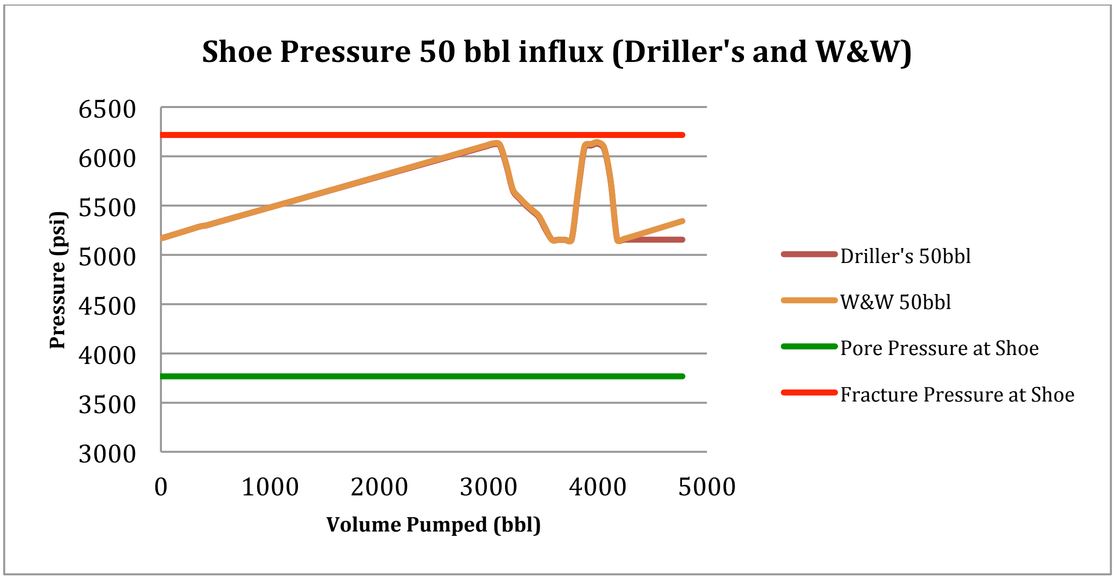

Figure B.13: Shoe pressure Wellplan comparison, well 2 section 2

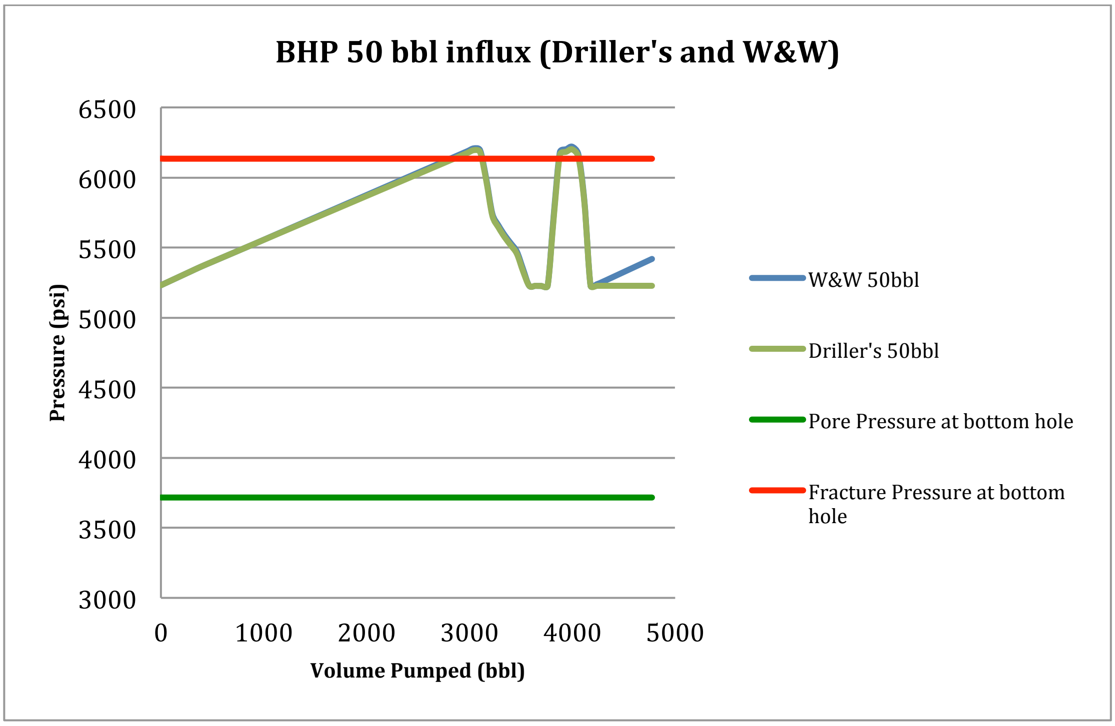

Figure B.14: BHP Wellplan comparison, well 2 section 2

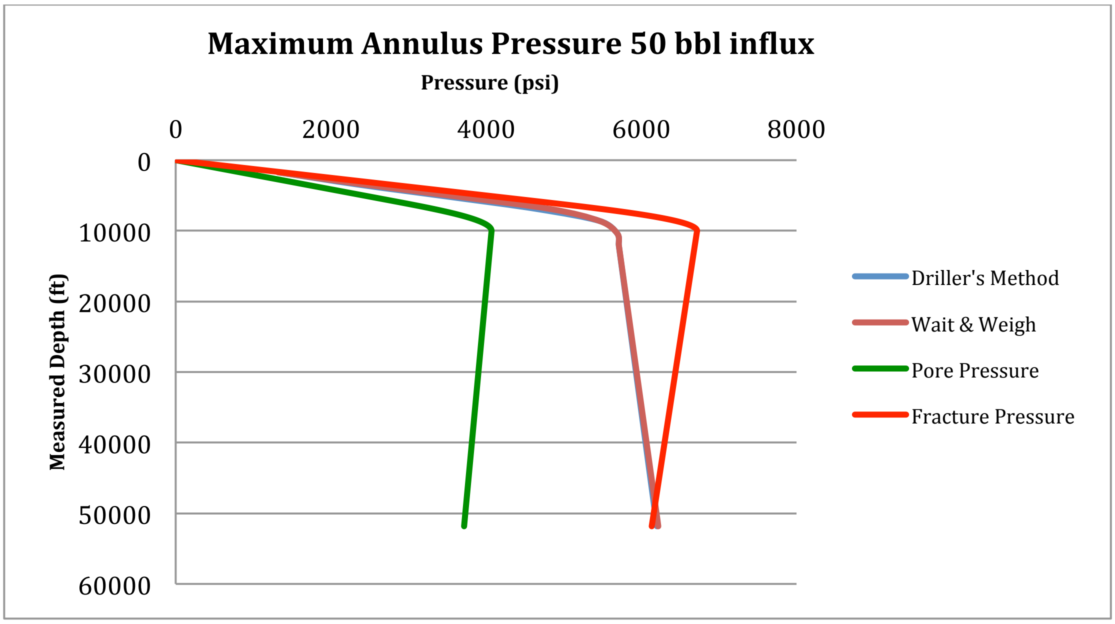

Figure B.15: Maximum annulus pressure Wellplan comparison, well 2 section 2

APPENDIX C: Tables from DrillSIM simulations

HOL mud displacement	No Circulation	Circulation at Rate	Drilling Fluid at Shoe (Inner annulus)	Drilling Fluid at Bottom Hole	Drilling Fluid at Shoe (Inner pipe)	Displacement Finished
Casing Shoe Pressure	659,45	763,12	811,47	809,62	790,13	710,54
Bottom Hole Pressure	552,52	656,2	704,55	702,7	683,21	603,62
Pump Rate (gpm)	0	84	84	84	84	115
Total Strokes Pumped	0	44	371	1063	1357	1498

Table C.11: HOL displacement, well 1

Circulation 1 – 2bbl	Shut-in	Circulation at rate	Kick at shoe	Kick at choke	Circulation 1 finished
Casing Shoe Pressure	813,79	706,37	707,54	723,51	712,09
BHP	706,77	599,34	600,51	616,48	605,06
Pump rate (gpm)	0	115	115	84	115
Total strokes pumped	0	15	223	288	319
Influx Volume in Well (cuft)	10,78	12,5	12,9	22,41	1,07

Table C.12: HOL kill circulation 1 (2bbl), well 1

Circulation 1 – 5bbl	Shut-in	Kick at shoe	Kick 1 at choke	Kick 2 at choke	Kick 3 at choke	Circulation 1 finished
Casing Shoe Pressure	811,66	703,24	700,28	695,36	710,25	712,4
BHP	704,59	596,12	593,12	588,18	603,06	605,18
Pump rate (gpm)	0	115	22	89	71	115
Total strokes pumped	0	95	176	213	238	297
Influx Volume in Well (cuft)	28,5	39,93	59,34	36,71	24,05	5,75

Table C.13: HOL kill circulation 1 (5bbl), well 1

Circulation 1 – 14bbl	Shut-in	Kick 1 at choke	Kick 2 at choke	Kick 3 at choke	Kick 4 at choke	Kick 5 at choke	Circulation 1 finished
Casing Shoe Pressure	813,12	715,39	713,64	725,1	720,2	719,82	713,04
BHP	706,01	608,27	606,51	617,94	613,03	612,63	605,79
Pump rate (gpm)	0	44	44	44	44	44	115
Total strokes pumped	0	27	82	132	184	246	425
Influx volume in well (cuft)	75,02	116,3	94,64	85,43	75	54,15	4,97

Table C.14: HOL kill circulation 1 (14bbl), well 1

Circulation 2	Circulation at rate	Remaining Kick at Shoe	Remaining Kick at Choke	Kill Mud at Shoe	Kill Mud at Bottom Hole
Casing Shoe Pressure	727,58	723,21	720,61	713,86	717,4
Bottom Hole Pressure	609,97	606,91	610,88	606,78	604,85
Pump Rate (spm) Pump 1/2	1/29	1/27	1/14	1/10	1/11
Total Strokes Pumped	353	361	367	388	475
Influx Volume in Well (cuft)	1	1	1	0	0

Table C.15: HOL Kill circulation 2, well 1

Circulation 3	Circulation at rate	Remaining KM at Shoe	Circulation 3 finished
Casing Shoe Pressure	716,78	727,92	740,18
Bottom Hole Pressure	605,29	616,44	628,69
Pump Rate (gpm)	49	58	124
Total Strokes Pumped	486	700	850

Table C.16: HOL kill circulation 3, well 1

Circulation 1 – 2bbl	Shut-in	Kick at end of horizontal section	Kick at shoe	Kick at choke	Circulation finished
Casing Shoe Pressure	2349,89	2230,16	2229,13	2227,56	2253,29
BHP	5471	5351,26	5350,23	5348,65	5374,39
Pump rate (gpm)	0	89	89	89	89
Total strokes pumped	0	1231	1478	1776	1904
Influx volume in well (cuft)	12,81	15,08	19,83	64,81	4,97

Table C.17: HOL kill circulation 1 (2bbl), well 2 section 1

Circulation 1 – 10bbl	Shut-in	Kick at end of horizontal section	Kick at shoe	Kick at choke	Circulation finished
Casing Shoe Pressure	2359,08	2255,93	2264,07	2299,45	2255,6
BHP	5480,19	5377,03	5385,17	5420,54	5376,7
Pump rate (gpm)	0	89	89	89	89
Total strokes pumped	0	537	1215	1500	1695
Influx volume in well (cuft)	51,84	52,43	68,55	124,56	26,92

Table C.18: HOL kill circulation 1 (10bbl), well 2 section 1

Well 2 HOL displacement	No circ.	Circ. at rate	Drilling fluid at horizontal section	Drilling fluid at bit	Drilling fluid at end of horizontal section (inner string)	Circ. finished
Casing Shoe Pressure	5244,71	5690,75	5873,4	6043,5	6124,28	5552,91
BHP	5176,27	5622,31	5804,96	5975,06	6055,84	5484,45
Pump rate (gpm)	0	84	84	115	133	182
Total strokes pumped	0	600	2017	9998	15008	22718

Table C.19: HOL displacement, well 2 section 2

Circulation 1 – 50bbl	Shut-in	Circulation at rate	Kick at KOP	Kick at choke	Circulation finished
Casing Shoe Pressure	5734,11	5593,35	5540,19	5566,42	5602,79
BHP	5665,64	5524,89	5471,73	5497,96	5534,33
Pump rate (gpm)	0	160	125	125	125
Total strokes pumped	0	500	4702	5254	5813
Influx volume in well (cuft)	271,89	276,86	291,39	362,45	20,5

Table C.20: HOL kill circulation 1, well 2 section 2

APPENDIX D: RDM down hole valve system and hydraulic WOB description

Down hole valve system

The down hole valve system consists of 3 different valves and the flow x-over. These valves makes it possible close the inner and outer pipe, which in turn makes it possible to bleed off the pressures without affecting the bottom hole pressure (P_{BHP}).

Opening sequence

When both inner and outer string is empty, all the valves are closed. At this point inner pipe pressure (P_{IP}) and inner annulus pressure (P_{IA}) is equal, and lower than P_{BHP}.

The first step is to pump fluid into inner pipe and inner annulus until $P_{IP}=P_{IA}=P_{BHP}$. Then fluid is pumped into the inner annulus until $P_{IA}>P_{BHP}$, which will cause inner pipe valve (IPV) to open. The pump rate through the inner annulus is then ramped up until the booster valve (BV) and non-return valve (NRV) opens. The flow will return trough the FXO and IPV up the inner string.

The complete opening sequence is shown in Figure D.1.

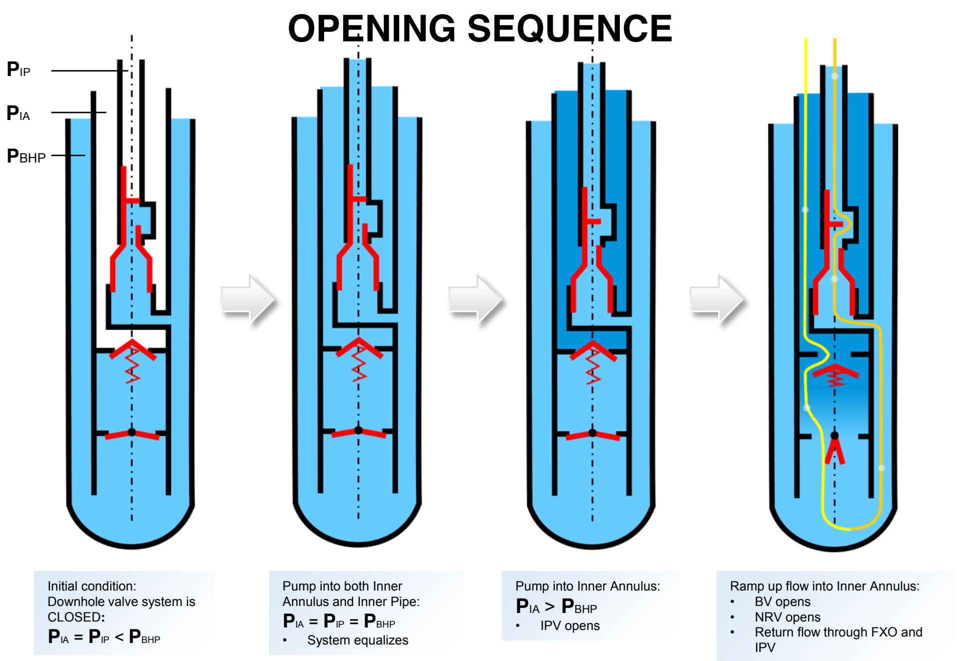

Figure D.1: Down hole valve opening sequence

Closing Sequence

When the pumps are running and all the valves are open $P_{IA}>P_{BHP.}$ To start the closing sequence the pump is ramped down until $P_{IP}=P_{IA}=P_{BHP}$. This will cause the BV and NRV to close. The next step is to bleed off inner annulus, IPV will close when $P_{IA}<P_{BHP}$. The last step is to bleed off the inner pipe. When finished the pressures should be $P_{IP}=P_{IA}<P_{BHP.}$

The closing sequence is shown in Figure D.2.

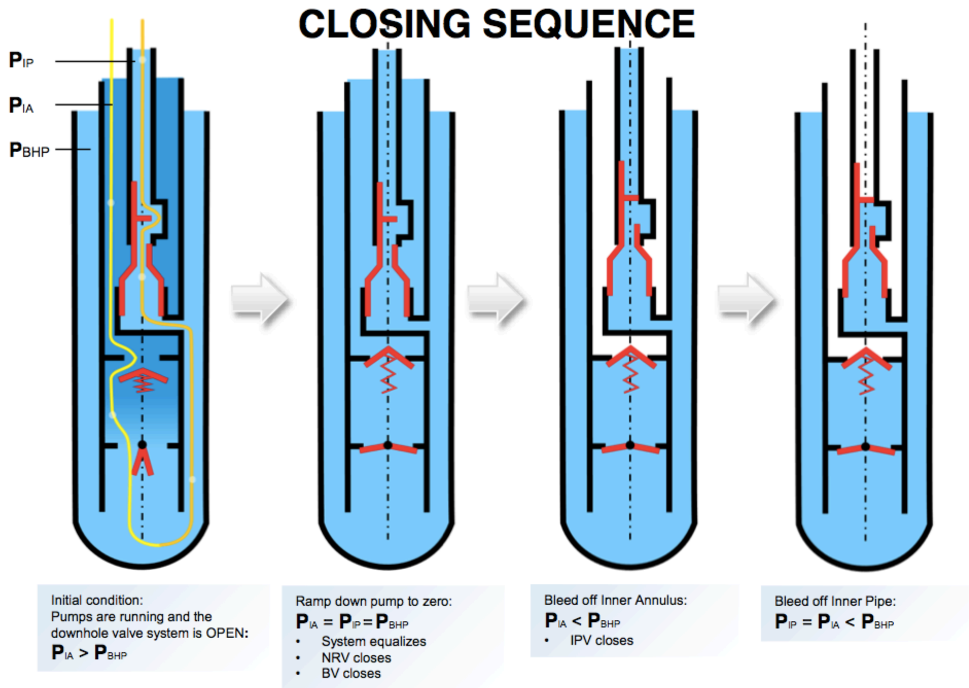

Figure D.2: Down hole valve closing sequence

Hydraulic WOB

The sliding piston is an optional component attached to the drill string in the cased section of the wellbore. Its purpose is to provide hydraulic WOB and pressure control, and isolate the fluids in the upper annulus from the rest of the well. By increasing the casing pressure at surface, the sliding piston is forced down the well giving an additional WOB. This solution is independent of gravity, increasing the possible horizontal reach. As the piston seals off the annulus, different fluids can be used above and below it.

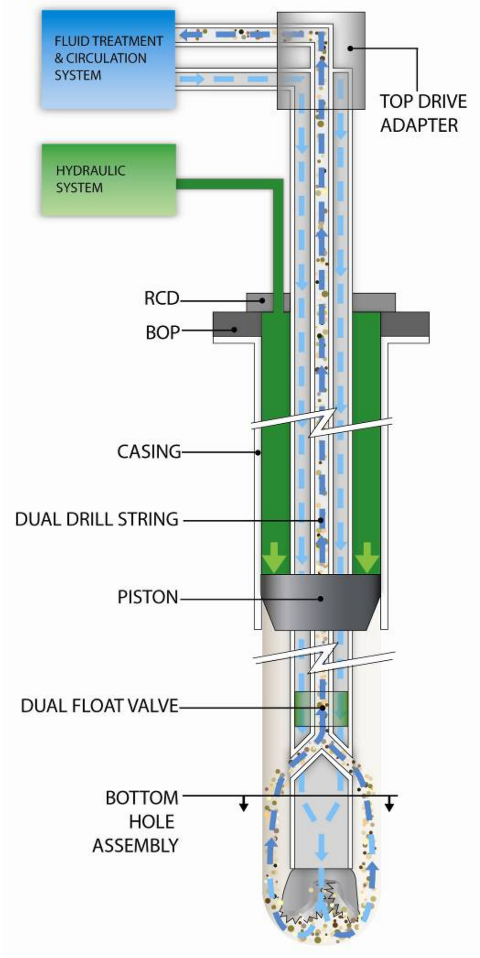

Figure D.3: Sliding Piston used for additional WOB

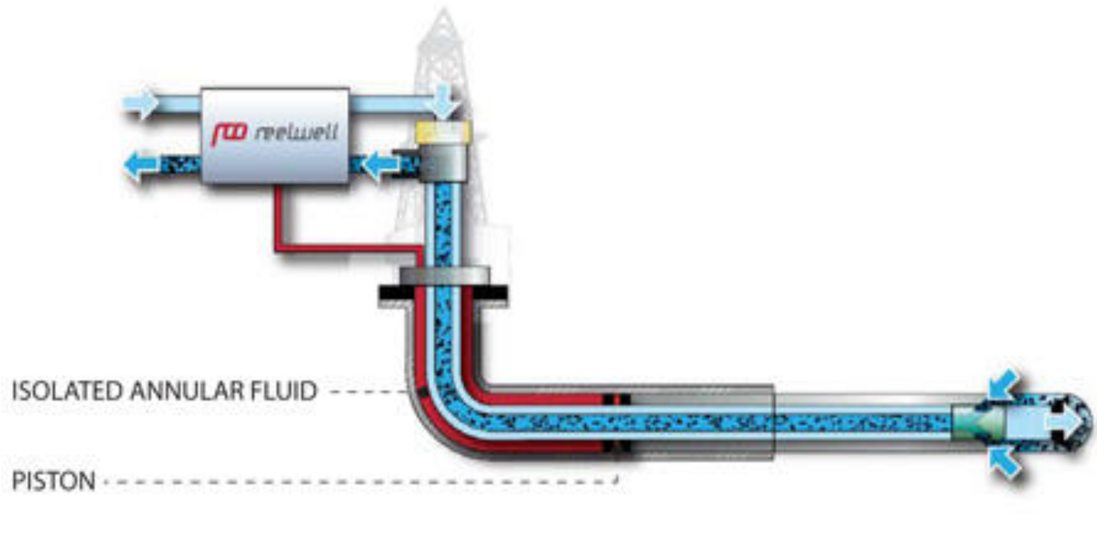

Figure D.4: Well fluids separated by Sliding Piston

APPENDIX E: Well Control Procedure Comparison - Influx while drilling

Subject	Driller's Method	RW Heavy Over Light
Well control action drill - Kick while tripping ("pit drill")	Recognize the kick and alert the crew	No change.
	Pick up off bottom	No change.
	Stop the pump(s)	No change.
	Flow check. If the trip tank can be lined up quickly (i.e. remotely), check the well for flow on the trip tank with the trip tank circulating	Must open the RCD valve to check for flow. NOTE: There may be pressure in the Well Annulus.
	Simulate shutting in the well using the Annular Preventer. **Do not** shut the well in if in open hole	No change.
	Simulate opening the HCR / 'fail-safe' valves in the choke line at the BOP stack	No change.
	Simulate setting the DSC at mid-stroke or engaging active heave mode for rigs equipped with AHD (floating rigs)	No change.
	Take readings of the shut-in casing and drill pipe pressures (SICP, SIDPP)	Must pump slowly down Inner Annulus to read the SIDP pressure. SICP can be read of as the Well Annulus/RCD pressure.
	Measure the gain in the active tanks (confirm with the mud logging unit)	
	Double check the space-out is correct, simulate hanging off the pipe and close and lock the hang-off rams (on floating rigs)	No change.
	Check all valves on choke manifold and BOP stack for correct position	No change.
	Simulate stopping all hot work	No change.
Well control action drill - Choke drill	Perform prior to drill out of casing with pressure in the well. To give the choke operator a "feel" of the choke operation and pressure lag times in the well.	Dependent on Dual Drill String (DDS) used to drill the shoe track. Can be included in the crew training performed at shalow depth.
MAASP	(LOT-MW)*0,0981*TVDshoe	Use MW of the heavy mud in the equation.

Slow Circulation Rates (SCR)	Slow circulating rate pressures for each pump must be taken: • If practical, at the beginning of every tour. • Any time the mud properties are changed. • Any time the bit nozzle configuration or bottom hole assembly is changed. • As soon as possible after bottoms-up from any trip. • At least every 1000 ft (305 m) of new hole. This must be reduced to at least every 500 ft (150 m) in known hydrocarbon bearing hole sections. • After MAJOR mud pump or surface equipment changes/repairs. A minimum of two circulating rates must be obtained for all pumps. When determining slow circulation rates, consider wellbore geometry, water depth, choke line lengths and equipment limitations. If a kill assembly and/or the cement unit are planned to be used for well kill operations, SCRs should be taken using this equipment. The pressures must be recorded using the gauge that will be used during well kill operations.	SCR are not required when drilling HOL. • The rig choke is regulated to keep the Well Annulus pressure constant during first circulation (circulate kick out of Inner Pipe), • The rig choke is regulated to keep the pump pressure constant on Inner Annulus during second circulation (Circulate kill mud down to the Flow X-Over (FXO), • The rig choke is regulated to keep the Well Annulus pressure constant during third circulation (circulate heavy mud and kill mud out of Inner Pipe).
Choke Line Friction Losses (CLFL)	Choke line pressure losses at Slow Circulation Rates should be taken: • Before drilling out first casing string after BOP installation. • After any significant change in mud weight or other mud properties. It is important that the CLFL is known for a wide range of circulating rates. From this information the additional pressure on the well can be assessed at a range of displacement rates and the most suitable circulating rate chosen.	CLFR are not required when drilling HOL. The choke is regulated to keep the pump pressure on Inner Annulus constant. Choke must be operated if taking CLFL
Kill Sheet	Updated each SCR are taken.	Kill sheet for HOL drilling is prepared.

Line up - Drilling	Insert schematic	Insert schematic
Secure well - "Hard" shut-in **Surface BOP**	Pick up the drill string to shut-in position.	No change.
	Stop rotation.	No change.
	Stop the pumps and flow check - if the well flows:	The Flow Control Unit (FCU) shut down sequence will close the Inner Pipe Valve (IPV) and leave the Inner Pipe and Inner Annulus depressurized. The Rotating Control Device (RCD) seals off any flow from the Well Annulus. A flow check would thus be equivalent to check for a RCD pressure increase, after stopping of the pumps.
	- Close annular and open remote control choke line valve (HCR).	No change.
	- Notify the Toolpusher and OIM (who must notify the Operator Representative).	No change.
	- Record and monitor shut-in drill pipe and casing pressures, pit gain and time.	Must pump very slowly down Inner Annulus to read/monitor Drill Pipe pressure. NOTE: The density of the fluid in the drill pipe (light fluid) is different from the density of the fluid in the annulus (heavy fluid).
	- Check space-out and close upper pipe rams and ram locks.	No change.
	- Bleed off pressure between pipe rams and annular (if possible without risking further kick).	No change.

Line up - Killing	Insert schematic	Insert schematic
Choke and Kill Manifold	The choke and the valve(s) immediately upstream of chokes on the choke manifold are to be kept in the closed position. If the valve downstream of the choke is of same pressure rating as the manifold upstream, then this may be closed instead. • Choke and Kill manifold valves must be lined up to obtain immediate pressure readings after well is shut-in. • Choke and Kill manifold low-pressure valves must be lined up to direct the flow of the well through the mud gas separator (MGS).	No change, using rig choke to circulate out the influx.
Driller's Method - First circulation	Once the pressures have stabilized, the pump is brought up to kill rate speed while holding the casing pressure constant (less CLFL for subsea BOPs). For subsea well control operations, reduce the casing pressure by an amount equal to the choke line friction loss (CLFL)	Pump light mud down Inner Annulus and choking on the return in Inner Pipe. Choke is regulated on SICP + safety factor. Pump rate is not critical. SICP + safety margin can be reulated by the choke or the pump rate. (Increase pump rate - decrease choke pressure.)
	If the observed pressure is greater or lower than the expected pumping pressure, subsequent calculations will be based on this new value of ICP	This is checked on second circulation

	When the kill rate speed is established, the choke operator should switch to the drill pipe gauge and hold this pressure constant until the influx is removed from the well.	Adjust choke according SICP + Safety margin.
	Shut-in the well and record SIDPP and SICP prior to beginning the second circulation (they should be approximately equal).	N/A. Still the same fluids in the well.
	The active mud system should be weighted up to the proper kill mud weight and lined up on the selected mud pump.	Weighing up the heavy mud. The density of the active (light mud) is not changed.
	Prepare a drill pipe pressure schedule, as was done with the 'Wait and Weight' method.	N/A.
Driller's Method - Second circulation	The pump is brought up to kill rate speed while holding the casing pressure constant (less CLFL for subsea BOPs). For subsea well control operations, reduce the casing pressure by an amount equal to the choke line friction loss (CLFL).	Pump kill mud down Well Annulus. Adjust choke according to Inner Annulus pressure. Pump very slowly down Inner Annulus to read BHP (and to keep IPV open). (Choke is adjusted to maintain BHP constant.)
	When the kill rate speed is established, switch to the drill pipe gauge and follow the drill pipe pressure schedule until the kill mud reaches the bit.	Rate is not critical. BHP can be adjusted by a combination of choke and pump rate down Well Annulus.
	At this point hold drill pipe pressure (FCP) constant until the mud returns at surface. On subsea wells in deeper water, due to the increase in CLFL caused by the kill mud, the drill pipe pressure will increase towards the end of circulation.	Hold BHP constant. BHP can be adjusted by a combination of choke and pump rate down Well Annulus.
	Once uncontaminated kill mud is observed at surface, shut-in the well and monitor drill pipe and casing for pressure.	Pump kill mud down to the Flow X-Over (FXO). NOTE: For well control it is sufficient to pump only down to the casing shoe (if the shoe is set in past the fluid trap / deepest TVD of the wel profile). Only Well Annulus can be monitored for pressure. No pressure should exist on Inner Annulus or Inner Pipe due to the Inner Pipe Valve (IPV) and the float valves in the string.
	If any pressure is found, the reason for it must be investigated and additional steps taken.	No change.
	If no pressure is registered, the well must be flow checked through the choke before opening the BOPs.	No change.
	On floating rigs, the riser must be displaced to the kill weight mud and any gas trapped in the BOPs removed before the BOPs are opened.	N/A when using a land rig.
	To help in identifying the cause of potential problems, it is important to maintain an accurate record of times, pressures, volumes, etc. on the well control report. Normally the Driller or his assistant will be assigned this task.	No change.
Driller's Method -Third circulation	N/A	Pump light mud down Inner Annulus to displace the heavy mud / kill mud out of the Inner Pipe. Choke on the returns in the Inner Pipe and adjust choke to maintain SICP / RCD / Well Annulus constant.
	N/A	Circulate until clean light mud in the returns
	N/A	Stop circulation
	N/A	Switch back to Flow Control Unit (FCU) choke

APPENDIX F: LIST OF FIGURES

APPENDIX G: LIST OF TABLES

APPENDIX H: NOMENCLATURE

BHA - Bottom Hole Assembly
BOP - Blow Out Preventer
BUR - Build Up Rate
BV - Booster Valve
DDS – Dual Drill String
DFV – Dual Float Valve
ECD - Equivalent Circulating Density
ERD – Extended Reach Drilling
FCU – Flow Control Unit
FXO - Flow X-over
HD - Horizontal Displacement
HOL - Heavy Over Light
IA - Inner Annulus
IP - Inner Pipe
IPV - Inner Pipe Valve
KOP - Kick Off Point
MD - Measured Depth
MWD - Measurement While Drilling
NRV - Non-Return Valve
RCD - Rotary Control Device
RDM – Reelwell Drilling Method
SICP - Shut-in Casing Pressure
SIDPP - Shut-in Drill Pipe Pressure
TDA – Top Drive Adapter
TVD - True Vertical Depth
WOB - Weight On Bit