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Well control analysis in Conventional and Riserless Reelwell Method

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This thesis symbolizes the end of my five years of studies at University of Stavanger. Studying for a masters of Science in petroleum has been an interesting journey, challenge and hard work where I have learned a lot and it has raised my understanding of how it works in the real world.

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I am also very thankful to Reelwell AS, and my supervisor, Ove Hole, who has given me the opportunity to work and study this new upcoming technology. Working with this thesis has given me a broader understanding of well control and the aspect around it together with a broad understanding of their technology. It has been five very interesting months.

I will also like to thank my fantastic family for always guiding me, being supportive in the choices I make and always being there during my years of studying.

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List of Abbreviations

RDM-R = riserless Reelwell drilling method
TVD = true vertical depth
DDS = dual drill string
MPD = managed pressure drilling
UBD = under balanced drilling
GOM = Golf of Mexico
BOP = blow out preventer
BHP = bottom hole pressure
ICP = initial circulating pressure
FCP = final circulating pressure
W&W = wait and weight
SICP = shut-in casing pressure
SIDPP = shut in drill pipe pressure
HPHT = high pressure high temperature
RCD = rotary control device
MODU = mobile offshore drilling unit
FCU = flow control unit
TDA = top drive adapter
DVA = downhole valve assembly
IPV = inner pipe valve
FXO = flow cross over
BV = booster valve
NRV = non return valve
FPU = flow partition unit
AAL = annular access line
ACV = annulus control valve system
AP = annulus pump system
SM = safety margin
CPD = control pressure drilling
BHA = bottom hole assembly
gpm = gallons per minute
FIT = formation integrity test
LOT = leak off test
WBM = water based mud
PP = pore pressure
FP = formation pressure
ID = inner diameter
OD = outer diameter
OH = open hole
HWDP = heavy weight drill pipe
DC = drill collar
SPM = stroke per minute
RDM = Reelwell drilling method
SPP = stand pipe pressure
CRM = conventional riser method
RM = conventional riserless method

List of Symbols

P_{pore} = Pore Pressure
P_{well} = Well Pressure
$P_{fracture}$ = Fracture Pressure
P_{IA} = Inner Annulus Pressure
P_{IP} = Inner Pipe Pressure
P_{BHP} = Bottom Hole Pressure
P_{choke} = Choke Pressure
$P_{friction}$ = Friction Pressure Loss
ρ_{mud} = Mud Density
P_{f} = Annular friction pressure due to circulation
h_{TVD} = True vertical depth of the well
h_{sea} = Depth to Seabed
ρ_{sea} = Seawater Density
$BHP_{connection}$ = Bottom Hole Pressure during connection
$P_{hydrostatic}$ = Hydrostatic Pressure
$BHP_{drilling}$ = Bottom Hole Pressure while Drilling
ρ_{heavy} = Heavy Mud Density
ρ_{light} = Light Active Drilling Mud
P_{csg} = Casing Shoe Pressure
ρ_{frac} = Fracture Gradient
h_{csg} = Casing Shoe Depth
ρ_{max} = Maximum Allowable Fluid Density
BHP_{IAPP} = BHP from Inner Annulus Pump Pressure
P_{IASCR} = Inner Annulus Pressure at Slow Circulation Rate
P_{OIPV} = Pressure to Open Inner Pipe Valve
ρ_{kill} = Kill Mud
P_{pump} = Maximum Pump Pressure
ρ_{max} = Max Allowable Fluid Density
ΔP_{over} = Formation Over Pressure
ΔP_{SP} = Increase in SPP
ΔP_{fann}= Friction Pressure Loss in Annulus
ρ_{mix}= Mixed Mud Density

ABSTRACT

The oil industry is nowadays facing several problems as hydrocarbon reserves are declining and challenging areas are forced to explore. Deepwater drilling is one of these challenging areas as increased target depth results in narrower working window between pore pressure and fracture pressure. Reelwell Riserless Drilling Method can solve these problems.

This thesis is written in cooperation with Reelwell AS. The unique technology developed by Reelwell is based on drilling with a dual bore string which provides optimum well control, resulting in long reach wells without the use of riser in deepwater environment. This thesis will focus on a well "Well A-1" which is regarded as typical for presalt reservoirs in the Atlantics. Both RDM-R and conventional drilling approaches are based on this well. The well control aspects described focus on kick causes, kick detection and the kill procedures.

Well Plan in Landmark simulator has been used to calculate kick tolerance and choke pressure behavior during kick circulation with given inputs from well A-1.

A well control comparison between RDM-R and Conventional Method, both riserless and with riser was made. The results showed that with riserless drilling approach a lot of time will be saved in order to circulate the kick out of the well. RDM-R further shows many beneficial advantages as listed in the summary, table 4-26.

1 INTRODUCTION

This thesis presents well control simulation study fot conventional and riserless drilling methods in deepwater environment. For the analysis a dummy well A-1 was considered. The simulation study is to investigate kick tolerance and choke pressure behavior during kick circulation. Simulation has been performed by means of an industry standardized program named WellPlan^{TM}/Landmark. In addition, kick sheet calculations has been performed in Excel worksheets for the two drilling methods.

1.1 Background and problem formulation

Nowadays oil and gas industry is facing several problems as hydrocarbon reserves are declining and challenging areas, which represent high economical risk, and technical problems are forced to explore. Deepwater drilling is one of the challenging areas, since increased target depth results in narrower working window between formation pressure and fracture pressure. Well control aspect is becoming increasingly important in these challenging areas, since lower fracture gradients than similar land or shallower water cases reduce the kick tolerance margin. For any drilling operation, early kick detection and circulation out of the well safely are therefore one of the major aspects of well control operations.

Reelwell AS is presently developing a concept for a new Riserless Drilling Solution, Reelwell Drilling Method - Riserless (RDM-R), with the aim of drilling in deep and ultra deep-water environments. The technology is due to be full scale pilot tested in 2016. The RDM system has, however, been field tested and regarded as a commercial available technology.

This thesis work focuses on the well control aspect for both RDM-R and conventional drilling, and address thus both riser and riserless systems. The case well used for the analysis is in deepwater area, having a water depth of 2048 m and the total well TVD is 5085 m where influx is assumed.

The RDM-R technology is a closed loop drilling system, where the drill sting (Dual Drill Sting -DDS) has two separate flow paths. High pressure mud (supply) is circulating down the DDS inner annulus, whereas the mud return is taking up the inner pipe. Since the return flow with cuttings is routed to surface through the DDS inner pipe, the operation is independent of a marine riser. From a safety perspective the system will enable improved safety related to the ability to performing Managed Pressure Drilling (MPD) and Under Balanced Drilling (UBD) operations with no pressurized equipment on surface[1]. Other benefit of RDM-R technology is significantly reduced drilling fluid requirement as the volume of the riser is removed.

For the RDM-R drilling concept, the hydrostatic head exerted on the well annulus is different than what is in the DDS. For the well annulus the hydrostatic head consists of two parts:

- Seawater density above seabed

- Heavy weight drilling fluid in well annulus (passive)

The hydrostatic head within the DDS in based on the drilling fluid inside the pipe.
This thesis therefore address question such as:

- What is the kick kill procedure and efficiency in conventional deep-water drilling?
- What is the kick kill procedure and efficiency in riserless RDM deep-water drilling?
- What is the kick tolerance in the conventional drilling with respect to various fluid densities?
- What is the choke pressure development with respect to various kick intensities?

1.2 Objective

The main objective of this thesis is to compare a well control procedure for RDM-R with conventional drilling. Kick tolerance and choke pressure behavior for conventional drilling is simulated.

Kick circulation calculations are performed to investigate well control procedure for RDM-R and compare the results with existing conventional drilling, to evaluate the beneficial or non-beneficial method of well control procedure with RDM-R.

For calculation and simulation following programs have been used:

- Drill-Sim, Reelwell simulator
- Well Plan, well control simulation for conventional well
- Excel, for kill sheet calculation

1.3 Readers guide

This thesis work consists of 6 chapters

Chapter 1: Presents background, problem formulation and objective of the thesis work.
Chapter 2: Presents a broad literature study on basis of well control.
Chapter 3: Presents literature study on Riserless Drilling and RDM-R technology.
Chapter 4: Presents well control simulation and calculations for RDM-R and Conventional Method, both riserless and with riser, with summary and discussion.
Chapter 5: Presents theory, background information, calculation and simulation of kick tolerance for the specific well together with choke pressure behavior simulation.
Chapter 6: Summary

2 Basics of Well control

Well control and blowout prevention has become a particularly important topic in the oil and gas industry as the industry is facing several challenges in the exploration of hydrocarbons. The industry has experienced major and also smaller incidents the latest years, which has increased number of governmental regulations placed on the oil industry. It is very important that drilling crew understand well control principles and the procedures followed to control potential blow out properly.[3] Figure 2-1 shows a blowout which turned in to a deadly fire explosion on Deepwater Horizon oil rig on the Macondo exploration well for BP in the GOM.[11]

Figure 2-1: Deepwater Horizon oilrig blowout and burning[11]

2.1 What is a kick

A kick is defined as uncontrolled release of formation fluid, (crude oil and/or natural gas), into an oil- or gas well. For a kick to occur pore pressure at the depth must be greater than the well pressure in an area with reasonable level of permeability.

$$P_{pore} > P_{well} \qquad 2.1$$

If the pore fluid here has sufficient low viscosity so that is can flow, the conditions for a kick occurrence is there. There are different causes to create a well pressure below the pore pressure, which will be discussed in chapter 2.2. An illustration of a kick situation, where pore pressure is greater than the well pressure, is showed in figure 2-2.

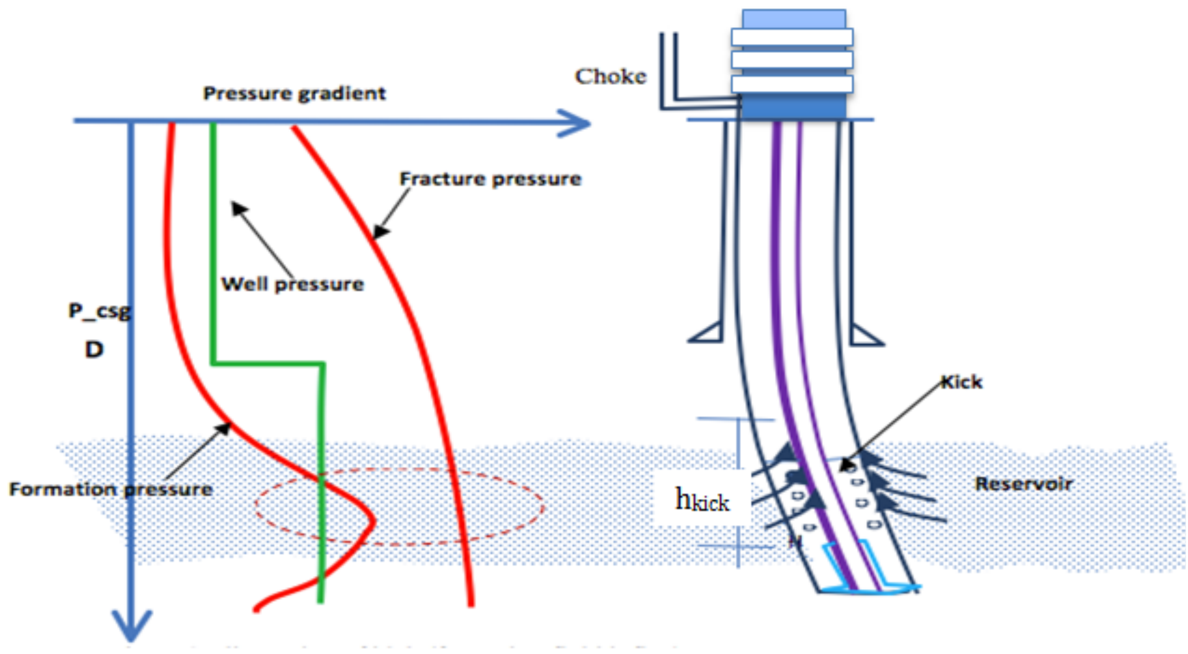


Figure 2-2: Illustration of a kick situation

For safe operation the well pressure should be held between pore pressure and fracture pressure, to maintain well control.

$$P_{pore} < P_{well} < P_{fracture} \tag{2.2}$$

2.2 Why kick occurs?

Kick can occur either due to unexpected changes in the well, or because of directly mistakes by the drilling crew so that the well pressure crosses the operational window. The different causes are listed below and will be further discussed in chapter 2.2.1 – 2.2.6:[2]

- Insufficient mud weight
- Improper hole fill-up during trips
- Swabbing
- Drilling gas
- Connection gas
- Lost circulation

2.2.1 Insufficient mud weight

Insufficient mud weight is one of the predominant causes of kicks. A mud weight, which exerts less pressure than the formation pressure is used within the zone, letting formation fluids able to flow into the wellbore. Whether or not a kick occurs depends upon the permeability and porosity of the rock.[3]

Before drilling, the pressure profile of the well must be known, either through calculations or information from wells drilled in the same area. If drilling in unknown formation pressure zones, it is important with pressure points to ensure mud weight is inside the pressure window at all times.

Formation pressure greater than normal is the greatest concern in well control. If these unexpected zones are encountered while drilling with insufficient mud weight, a potential situation for kick has developed.[3]

The obvious solution to prevent drilling underbalanced is to increase the mud weight. The fracture pressure gradient limits the maximum mud weight.

2.2.2 Improper hole fill-up during trips

Different situations can cause the need to trip out of the hole. As pipe is pulled out, the overall mud level in the well decreases. This will result in a pressure reduction in the well.
To prevent pore pressure to exceed the well pressure, the hole must be filled with mud as we trip out.[3] Tripping speed calculations must be performed on forehand to ensure formation fluid influx does not occur. It is very important with volume control during tripping, to ensure no influx in taken from the well.

2.2.3 Swabbing

While pulling the pipe out of the well swab pressures are created. Swab pressures reduce the effective hydrostatic pressure throughout the hole below the bit causing a temporary pressure reduction. If this pressure reduction lowers the well pressure below the formation pressure, a potential kick has developed.[3]

2.2.4 Drilling gas

As we drill through some gas-contained formations the gas entering the well will reduce the well pressure by reducing the mud density. The fluid mix equation is given in Appendix A, Eq 8. Although the mud weight is cut severely at the surface, the well pressure is not reduced significantly, since most gas expansion occurs near surface and not at the bottom of the well.[3]

2.2.5 Connection gas

During connections pump is shut down and the well pressure is reduced to the hydrostatic pressure at the current depth. Sufficient mud weight must be chosen to ensure that the hydrostatic pressure is above the formation pressure at all times.

2.2.6 Lost circulation

There is a chance of lost circulation in permeable zones while drilling. Mud lost to the formation will give a shorter mud column than desirable in the well, which will decrease the hydrostatic pressure.

When a kick occurs from lost circulation, the problem may be severe. A large volume of kick fluid may enter the hole before the rising mud level is observed at the surface.[3]

2.3 Warning signs to detect kick

Early kick detection is very important for any drilling operation, especially in deep water drilling where the BOP is placed on seabed. Normally there are two types of kick indicators.

2.3.1 Primary indicators

Primary indicators are signs observed which alone can be a clear indication of a kick. Signs are listed below and will be further explained in chapter 2.3.1.1 – 2.3.1.4.

- Increase in pit volume
- Increase in flow out
- Well is flowing with pumps off
- Improper hole fill-up during trips

2.3.1.1 Increase in pit volume

Volume control is one of the most important aspects during well operations. If one can observe a gain in the active pit volume, it is an indication a kick is occurring. The fluids, which enter the wellbore, will displace equal volume of well fluids at the flow line, which results in a gain in the active pit volume.[3]

2.3.1.2 Increase in flow out

While pumping at a constant rate the flow rate leaving the well should be constant. An increase in flow rate out of the well is interpreted to mean that the formation is aiding the rig pumps moving fluid up the annulus by forcing formation fluids into the wellbore.[3]

2.3.1.3 Well is flowing with pumps off

When the pumps are shut off, the well should not flow if there is equal mud weight in the drill pipe and well. If the well flows after stopping the pumps, there is an indication that formation fluid is entering the wellbore, which can be an indication of a kick.

2.3.1.4 Improper hole fill up on trips

As pipe is pulled out of the well, the fluid in the active pits should drop by an equal amount of steel body volume. If the level in the active pits does not enter the well, there is a clear indication that some foreign fluid is displacing the active volume.

2.3.2 Secondary indicators

Secondary indicators are signs observed which can be a good indicator of a kick if it is combined with primary indicator. Secondary signs to observe a kick is listed below, and will be further discussed in chapter 2.3.2.1 – 2.2.2.5:

- Pump pressure decrease and pump stroke increase

- Drop in BHP
- Increased hookload
- Drop in stand pipe pressure and drilling break

2.3.2.1 Pump pressure decrease and pump strokes increase

Initial fluid entering the well will cause the mud to flocculate and temporarily increase the pump pressure – as the flow continues, the low density influx will displace heavier drilling fluids and pump pressure may decrease. As the fluid in the annulus becomes less dense, the mud in the drill pipe tends to fall and the pump speed may increase.[3]

This sign may be caused due to other problems, such as hole in the pipe "washout" – but the first procedure is to check for a kick.[3]

2.3.2.2 Drop in BHP

As formations fluids enter the wellbore, the overall hydrostatic pressure in the well will decrease, as the wellbore fluids are heavier than the influx fluid.[2]

2.3.2.3 Increased hookload

As the overall density in the drilling fluid will decrease when lighter formation fluids enter the well, the buoyant force will decrease. Less force acting on the drill string will cause increased hookload.

2.3.2.4 Drop in standpipe pressure

The standpipe pressure will reduce as the hydrostatic head reduces when formation fluids enter the well.[2]

2.3.2.5 Drilling Break

A drilling break is an abrupt increase in bit penetration rate, which can be a warning sign of a possible kick in combination with primary indicators. NOTE: When the drilling penetration rate suddenly increases, it can be a sign of drilling into a new formation. Therefore it is recommended that the driller should drill 3-5 m of new formation, then stop to check for flowing formation fluids.[3]

2.4 Well Control Methods

Many well control procedures have been developed over the years. This thesis will focus on "drillers method" and "wait and weight" for conventional drilling, which are methods using concept of constant BHP. A kill procedure for RDM-R will be established and comparison between conventional will be discussed in chapter 4.5.

2.4.1 Drillers method

The main idea of driller's method is to kill the well with constant BHP, which requires two complete and separate circulations of drilling fluid in the well.

The first circulation removes influx with original mud weight. Pumps are brought up to kill rate speed with constant casing pressure. While influx in circulated out it is important with constant BHP to ensure pressure is held between pore pressure and fracture pressure.[4]

During first circulation kill mud is mixed, which is used to kill the well in second circulation. While circulating kill mud down the drill pipe, casing pressure must be held constant. When kill mud is circulated out the bit, drill pipe pressure must be held constant until kill mud is circulated to surface. Then the pumps are shut down while extra caution is held on drill pipe pressure and casing pressure, which should be zero if the well is successfully killed.[4]
The pressure in drill pipe is held constant to maintain constant BHP.

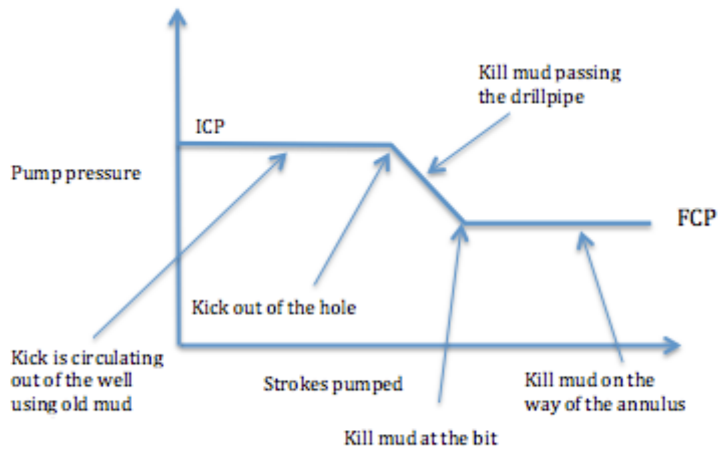


Figure 2-3: Kill sheet for driller's method

2.4.2 Wait and Weight Method

The main idea behind the wait and weight method is to circulate out the influx and pump kill mud into the well in one circulation. While pumping kill mud from surface to bit, a drill pipe pressure schedule has to be calculated and followed. The drill pipe pressure is held constant through proper choke adjustment thereafter until kill mud is observed returning to surface.[4]

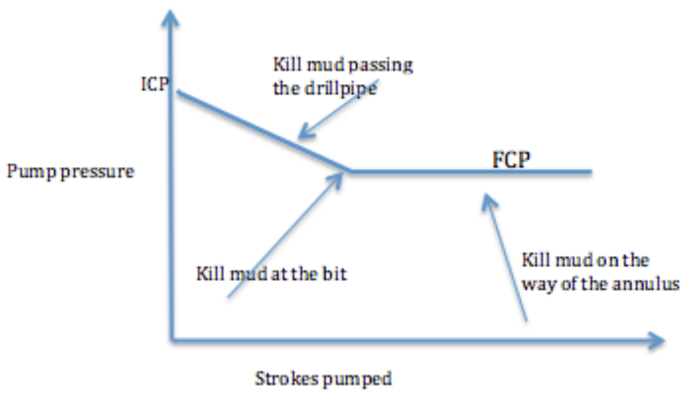


Figure 2-4: Kill sheet Wait and Weight method

2.4.2 Comparison of Drillers Method and Wait and Weight Method

To avoid confusion to the drilling crew of how to efficiently and safely circulate out a kick without creating major well control problem, drilling organization or company usually adopt one of the methods for the drilling crew – for the drilling crew to be more competent and not confused *if* a situation should occur.[4] The two methods are now discussed for different situations.

2.4.2.1 Deviated hole

Calculations needed for W&W method is fairly simple if the wellbore is vertical or if there is only one size of drill string.[4]

2.4.2.2 Hole problems

If the drill string is held static with no circulation over time, the pipe might get stuck in areas with significant hole instability problems. With W&W method the kill mud has to be mixed before the circulation can start. This period with no pipe movement or circulation can lead do stuck pipe in problematic hole sections. With driller's method, the circulation can start as soon as the well is shut in and SICP and SIDPP are established. This will reduce the time the drill string is held static.[4]

2.4.2.3 Capacity of drilling rigs

Drilling is sometimes performed with rigs with limited capacities. Kill weight mud may not be able to quickly prepare, leading to limitations performing W&W method. Driller's method may be preferred under these circumstances to avoid excessive increase in surface and shoe pressures due to gas migration.

2.4.2.4 Complications and friction changes during well control

Complications may occur during the process of killing a well. If the nozzles are plugged while killing the well with W&W method, the pressure schedule must be recalculated immediately. If complications like this arise while killing the well, rig personnel may panic and make poor decisions, which can lead to well control problems. But if nozzles are plugged while killing the well with driller's method, the choke operator response is fairly simple. The casing pressure is held constant while the drill pipe pressure is allowed to increase. When the drill pipe pressure has stabilized, the new circulating pressure is held constant during the rest of the circulation.[4]

2.4.2.5 Deepwater Wells

The high pressure and high temperature condition in deepwater wells are ideal for formation of hydrates when free water comes into contact with gas. Long periods of no circulation during W&W method in deepwater wells may cause a situation with hydrate formation in the BOP or choke/kill lines. With driller's method, circulation is established as soon as possible, which may prevent hydrate formation.[4]

2.4.2.6 Time to kill the well

If time required to mix kill mud is minimized, time will be saved if the well is killed using W&W method, as drillers method is performed by two circulations and W&W method involves one circulation. But as there is major focus in the oil industry on doing things right, rather than doing it faster, time element may not be significant since additional circulations are almost always required for complete removal of the influx and the addition of safety factors in the mud weight.[4]

3 Riserless Drilling

As water depth increases for drilling operations (such as deepwater areas in the GOM), the size of both the marine riser and wellhead must increase to withstand severe stresses resulting from the weight of the riser with mud inside, surface and subsea water currents and the movement of a floating vessel. These factors, along with others, will increase the cost of the riser and wellhead as water depth increases, which will be an important factor for if the drilling operation will be economical.[5] An other important problem with deepwater drilling is the narrower operating window as target depth increases as is showed in figure 3-1.

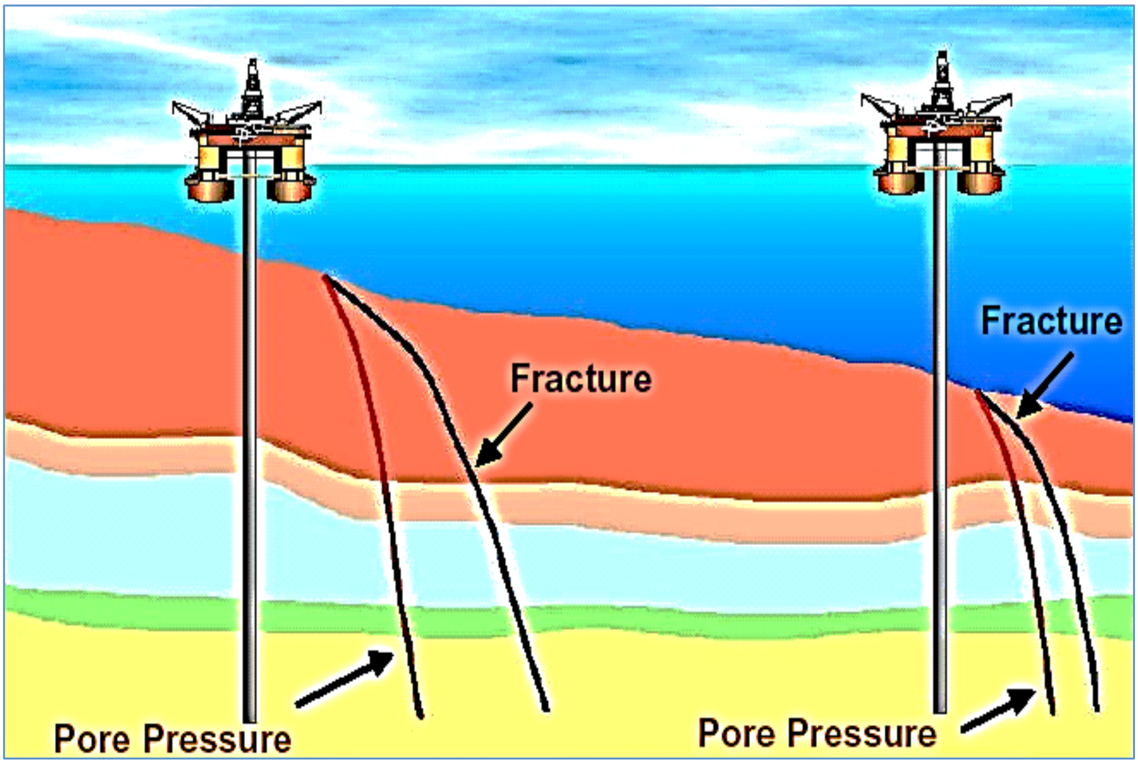


Figure 3-1: Formation pressure profile in deep water (Narrow operational margin between the curves of pore pressure and formation fracture)

Since the operational window is narrow in deepwater wells and also the drilling fluid will be affected in HPHT, a kick could result as a major problem.

Drilling operations with water depth beyond 200 m will result in different problems listed:[5]

- Riser Problems in deep water
- Huge weight and space requirements
- Large mud volume in a riser
- Severe stresses in a riser
- Difficult station keeping

- Long tripping time
- Numerous casing points due to narrow gap between pore and fracture pressures
- Highly limited fleet of rigs
- Inability to drill an adequate hole size

Many alternatives to the conventional marine riser system have been investigated for deepwater drilling[5], to make deepwater drilling beneficial. One of the new technologies developing is Reelwell Drilling Method Riserless (RDM-R).

3.1 Introduction and history for RDM-R solution

Reelwell has developed a closed loop drilling system, using a Dual bore Drill String (DDS) circulating down the DDS inner annulus, taking the returns up the DDS inner pipe. A rotary control device (RCD) positioned on top of the BOP closes and controls the well annulus and prevent well fluid of flowing up the well annulus. A conventional bottom hole assembly (BHA) is connected to the DDS. When drilling with a mobile offshore drilling unit, this operation is independent of a marine riser system, since the return flow is routed to surface through the DDS inner pipe. This will at the same time reduce the drilling fluid volume significantly in deepwater areas, as the volume of the marine riser is removed. Since the cutting returns are taken up the DDS inner pipe, the wellbore annulus is always free from cuttings. A cuttings free column in the well annulus makes it easier to hold the pressure in the well annulus static and easier to monitor and control.[6]

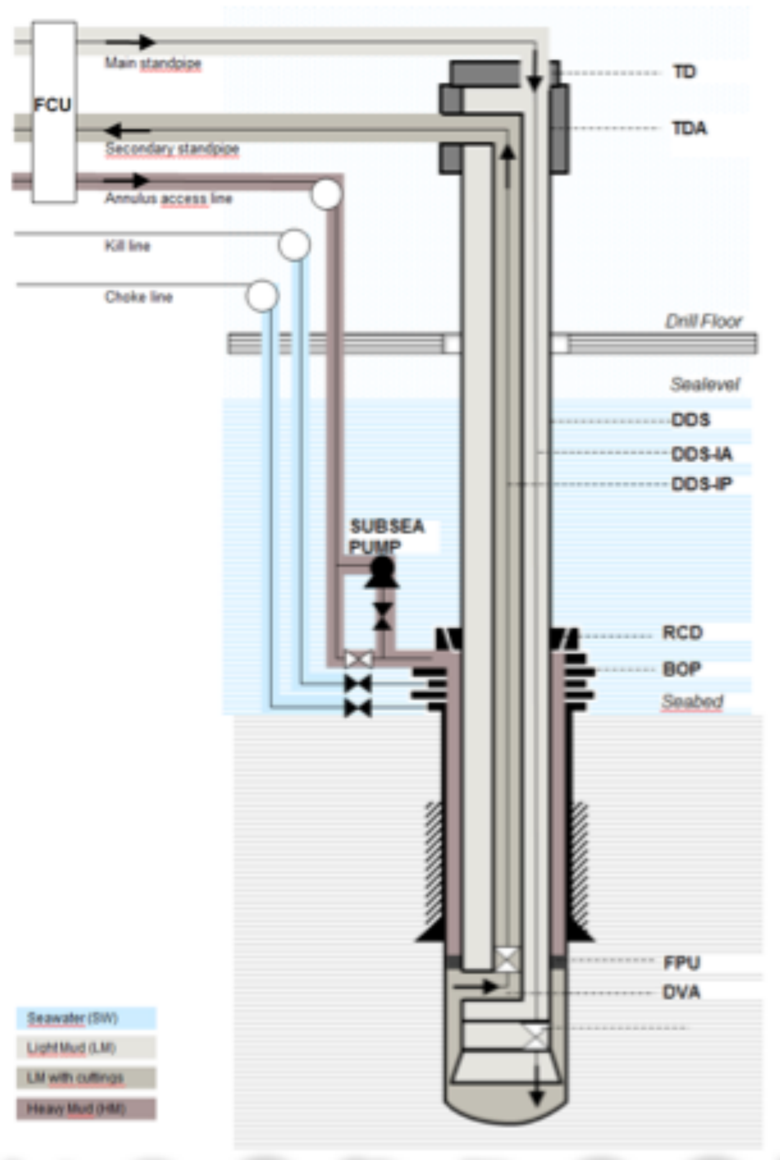


Figure 3-2: Overview of RDM-R system

This system description is meant to give an overview of the components/equipment that is required to perform RDM-R operation from a conventional Mobile Offshore Drilling Unit (MODU).

3.2 RDM-R Equipment

The Reelwell riserless system equipment can be split into three groups related to its location: topside, downhole or subsea. The topside equipment is installed and integrated with the drilling system on the rig.[7]

3.2.1 Topside Equipment

Flow Control Unit (FCU): The FCU includes valves, chokes, sensors and actuators for remote computer control. The unit is used for flow control of high pressure (supply) and low pressure (return) and measurements. The primary function of the FCU is to enable safe and controlled opening and closing sequence (further explained in chapter 3.3) of the downhole valves and to maintain a constant pressure profile in the well during operation. Therefore the FCU severs as an additional barrier in terms of well control. An operation panel for remote control is placed in the driller's cabin.[7]

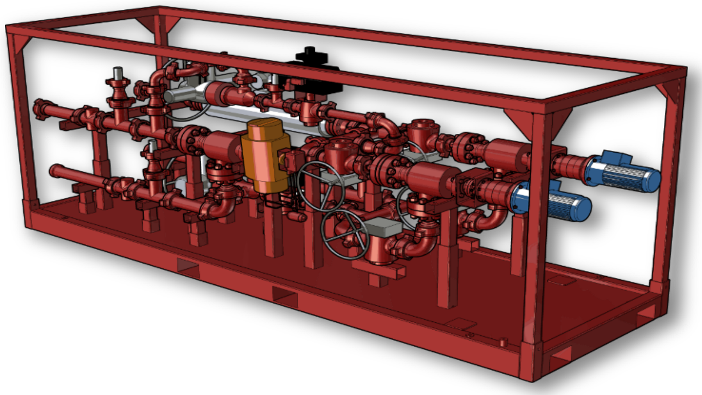


Figure 3-3: Flow Control Unit (FCU)[7]

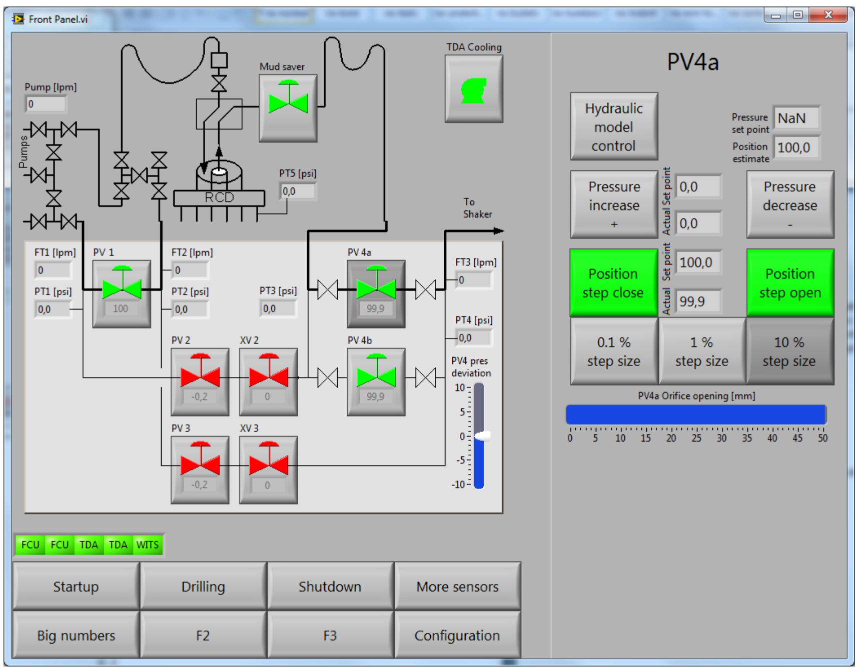


Figure 3-4: Screenshot of the DrillSim simulator showing the remote computer control of the valves and chokes in the FCU

Top Drive Adapter (TDA): The TDA is a dual conduit swivel, situated between the top drive and the DDS and allows rotation of the DDS. Drilling fluid from the top drive is routed to the DDS inner annulus and drilling fluid from the DDS inner pipe is routed to the FCU via a dedicated Kelly-hose and standpipe. The TDA outlet is equipped with a mud saver valve, which is hydraulic actuated, that isolates the system during pipe connection operations.[7]

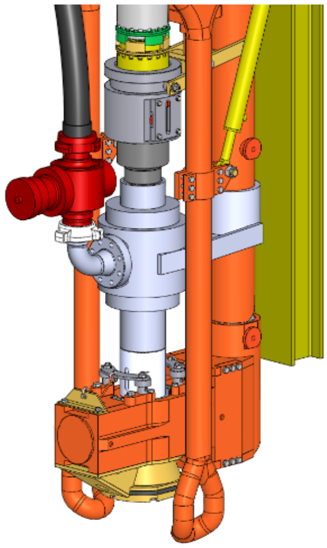


Figure 3-5: Top Drive Adapter swivel arrangement (TDA)[7]

Interconnecting piping: Interconnecting piping consists of all necessary components to hook up to and from the FCU for both high-pressure and low-pressure drilling fluid system.[7]

3.2.2 Downhole Equipment

Dual Drill String (DDS): Dual bore drill string consist of dual wall drill pipe where the outer pipe is the conduit for the fluid pumped into the well and the inner pipe is the route for the return flow from the well.

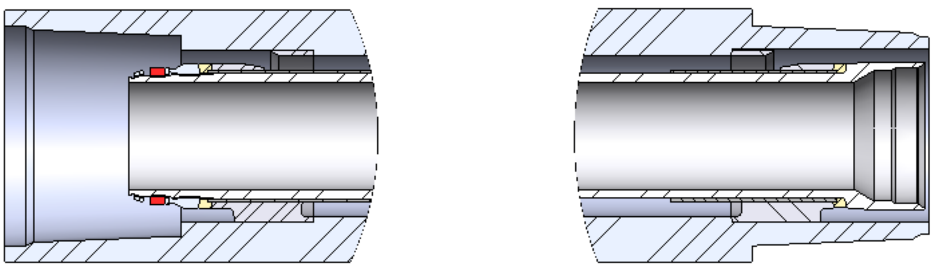


Figure 3-6: Dual bore drill string (DDS)[7]

Downhole valve assembly (DVA): The downhole valve assembly consists of Inner Pipe Valve (IPV), Flow X-over (FXO) and Booster Valve (BV). These valves are installed at the lower part of the DDS, connecting the top of the BHA.[7]

The IPV controls the return flow to surface by open and close the inner pipe access. The IPV is opened/closed by a sequence performed by the FCU explained in chapter 3.3. When the IPV is closed, the inner pipe will be isolated from the well bore thus enable pressure less connection of the drill pipe on surface. When the IPV is in open position, the inner pipe is connected to the wellbore allowing drilling fluid to flow to surface.[7]

A conventional float valve is used as part of the conventional BHA situated below the Downhole Valve Assembly (DVA), which isolated the DDS inner annulus from the well bore when mud pumps are stopped.

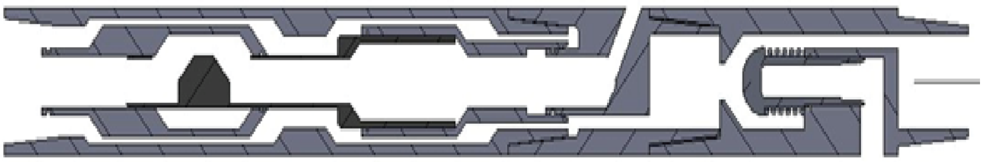


Figure 3-7: Downhole Valve Assembly (DVA)[7]

Flow Partition Unit (FCU): The flow partition unit is optional and will usually only be installed if the drilling operation requires it. FCU is a device that will separate to fluids with different density in the well annulus when we have a dual gradient system. The FCU can be installed as part of the DDS as a mechanical device or a fluid pill that has the characteristics of preventing mixing of different dense fluids. The FCU will typically be used of the well annulus consist of a heavier fluid than the active drilling fluid.[7]

Reelwell riserless operation can be advantageous with a FPU to allow a heavier fluid in the well annulus and lighter active fluid in the DDS to reduce the pressure force on the subsea wellhead.[7]

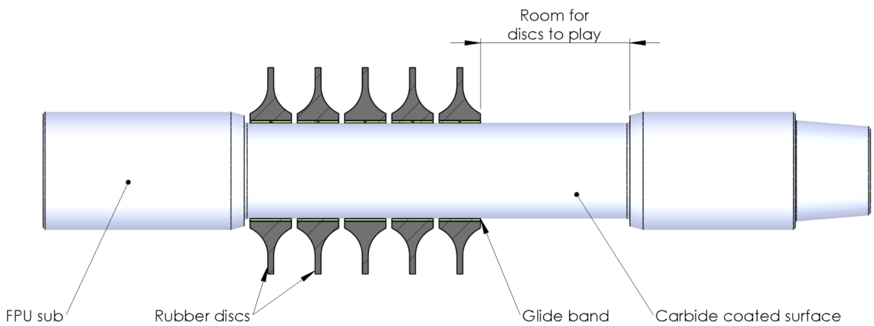


Figure 3-8: Flow Partition Unit (FCU)[7]

3.2.3 Subsea Equipment

Rotating Control Device (RCD): Rotating Control Device is another essential tool for RDM to operate safely and effectively. An RCD installed a top of the subsea BOP caps the annulus and seals against the drill string, making it possible to hold the pressure in the annulus of drill string/well bore. It is necessary to have the RCD installed for the whole drilling operations.[7]

Annulus Access Line (AAL): Annular access line connects the topside drilling fluid with the subsea wellhead. This enables a two-way flow path to the well annulus. During drilling it will be possible to fill the well annulus with a drilling fluid via the AAL, which also will be possible while POOH. While tripping in, the well fluid will flow upwards to the rig.[7]

Annulus Control Valve System (ACV): Annulus control valve system is installed subsea as part of the AAL terminating to the RCD to be able to control the valve arrangement.[7]

Annulus Pump System (AP): Annulus pump system is a pump, which is installed subsea. Its function is to reduce the pressure in the well annulus.[7]

3.3 Opening and closing sequence for Reelwell DDS

The DDS developed by Reelwell allows for a closed loop circulating system, where drilling fluids is pumped down the inner annulus and the returns flows up the inner pipe. During pipe connections and well control situations the flow paths in the DDS must be isolated from the well. This is done by means of a valve assembly sitting at the end (bottom) of the DDS. The valves open and close by means of a controlled sequences involving ramping up/down the mud pumps simultaneous with throttling/opening a surface choke system.

3.3.1 Opening sequence:

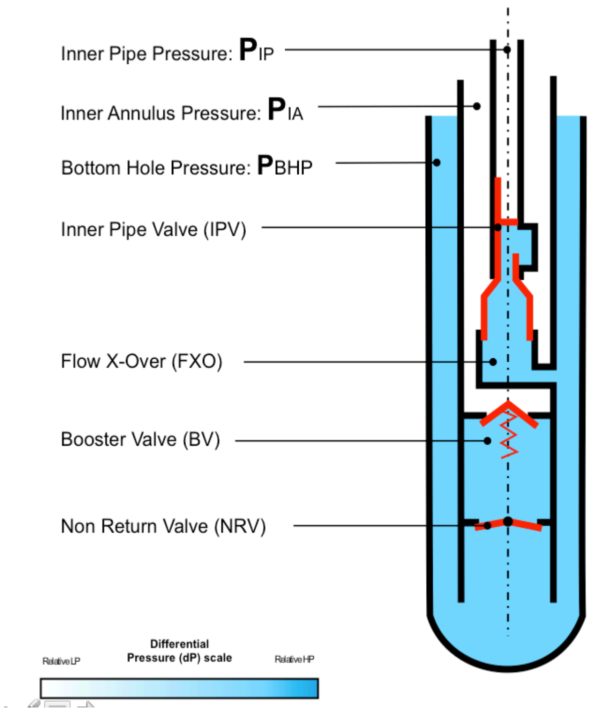


Figure 3-9: Reelwell DDS in a closed position

Figure 3-9 shows Reelwell DDS in a closed position. No access is allowed through inner annulus or inner pipe.

$$P_{IA} = P_{IP} < P_{BHP} \tag{3.1}$$

The first step to open the DDS, allowing circulation, is to equalize pressure in the inner annulus, inner pipe and the BHP by pumping into the inner annulus and inner pipe.

$$P_{IA} = P_{IP} = P_{BHP} \tag{3.2}$$

By pumping further into inner annulus creates a greater pressure in the inner annulus than the BHP, which open the IPV

$$P_{IA} > P_{BHP} \tag{3.3}$$

The flow into the inner annulus is ramped up in stages, which opens the NRV and BV allowing circulation through the system.

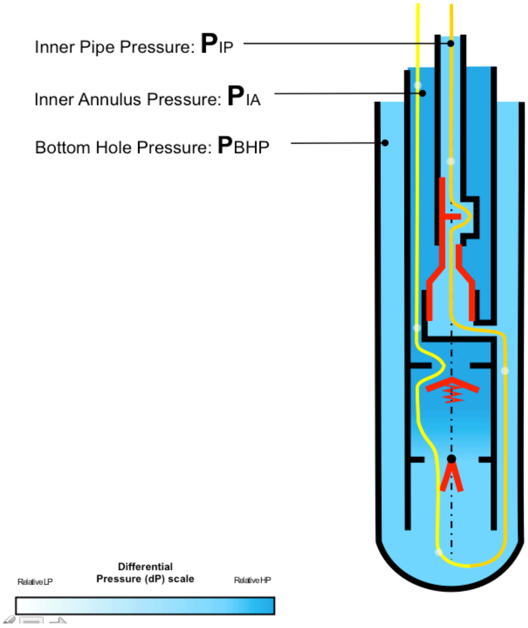


Figure 3-10: Reelwell DDS in an open position, allowing circulation down inner annulus with the returns up inner pipe

3.3.2 Closing sequence:

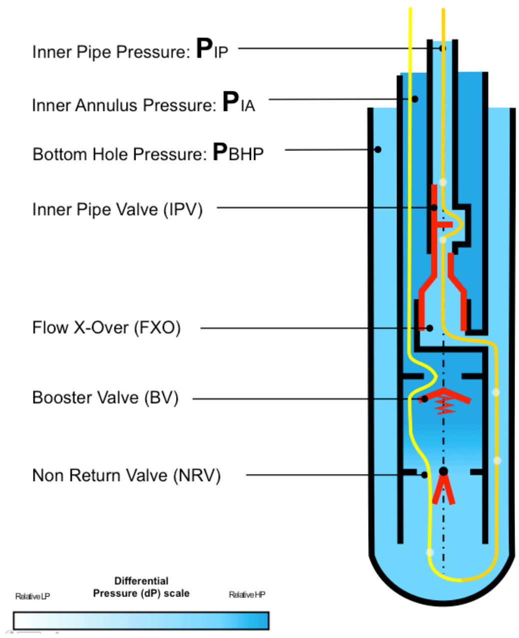


Figure 3-11: Normal circulation situation with DDS

The first step in the closing sequence is to close the non-return valve (NRV) and booster valve (BV); which is controlled by equalize BHP and inner pipe pressure.

$$P_{IA} = P_{IP} = P_{BHP} \qquad 3.4$$

When the pumps are slowly ramped down to zero, the pressures will equalize and NRV and BV close. Next step is to stop access form the well into the inner pipe; which is applied when pressure in the inner annulus is bleed off giving a pressure in the inner annulus less than bottom hole pressure.

$$P_{IA} < P_{BHP} \qquad 3.5$$

The IPV will pop in a position closing the access from the well into the inner pipe. Final the pressure in the inner pipe is bled off.

$$P_{IP} = P_{IA} < P_{BHP} \qquad 3.6$$

3.4 Well Control Method for RDM-R

With RDM-R influx will be circulated out up through the inner pipe. For this reason inner pipe must be designed to withstand any pressure increase exceeded by the influx. For conventional method, the casing must be able to withstand this increase in pressure. The possibility for the kick to move up through well annulus must be considered also for RDM-R.

When a kick is observed the drill pipe is pulled off bottom to shut in position, rotation is stopped and pumps are shut off to check if well flows - as for conventional drilling. Any pressure increase at the RCD will be checked after the pumps are stopped to ensure well annulus is not flowing. A closing sequence will be performed (Ref. chapter 3.3.2) with the FCU to close IPV, BV and NRV. Inner pipe and inner annulus is left depressurized which will close NRV and BV ensuring no flow to surface. Figure 3-12 shows the scenario with no access to surface.

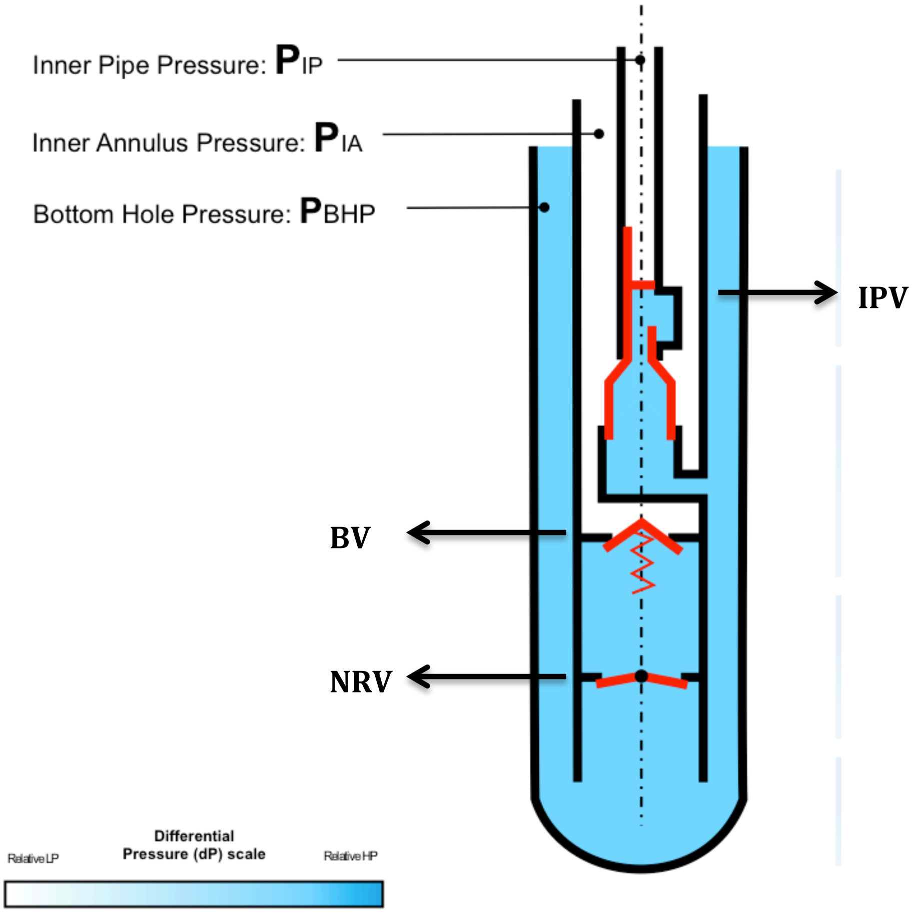


Figure 3-12: Reelwell DDS with no access to surface

Annular pipe ram is closed and access through choke line valve is opened. Shut-in casing pressure (SICP) is read of from RCD pressure and shut-in drill pipe pressure (SIDPP) is recorded by pumping slowly down inner annulus. Upper pipe ram must be closed and schematic for killing the well is completed before starting to kill the well.

First circulation: The mud is circulated out through the rig choke. An opening sequence by starting to pump mud down inner annulus and inner pipe opens the drill string valves downhole (IPV, BV and NRV). The return flow is taken up through inner pipe, using choke to maintain well control. The choke and/or flow rate is regulated to keep choke pressure equal to shut in casing pressure plus safety margin

$$P_{choke} = SICP + SM + P_{friction} \qquad 3.7$$

Where

$SICP$ = Shut-In Casing Pressure

SM = Safety Margin

$P_{friction}$ = Friction Pressure Loss

The choke pressure is kept constant until the influx is circulated out.

The heavy mud is weighted up during the first circulation. NOTE: The density of the active mud is not changed.

Second circulation: Kill mud is pumped down well annulus while choke is adjusted to inner annulus pressure. Meanwhile pump very slowly down inner annulus to read BHP and to keep IPV open. The choke and/or flow rate is regulated to maintain constant BHP through second circulation.
Kill mud is pumped down to the flow cross 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. No pressure should exist on inner annulus or inner pipe due to the IPV, NRV and BV are in open position, as only well annulus can be monitored for pressure. NOTE: To help in identifying the cause of potential problems, it is important to maintain an accurate record of times, pressures, volumes, etc.

Third Circulation: Only exist for RDM-R. Light mud is pumped down inner annulus to displace the heavy mud/kill mud out of the inner pipe. The returns are taken through inner pipe while choke and flow rate are regulated to maintain SICP/RCD/well annulus constant.

3.5 Conventional vs. RDM Technology

Figure 3-13 shows a schematic over conventional drilling vs. RDM-R drilling technology. As can be seen, mud is pumped into the well down the pipe taking the returns up the annulus for conventional drilling. While for RDM-R technology mud is pumped down the DDS inner annulus, taking the returns up the DDS inner pipe. This will leave the well annulus in a static situation, since it is free for circulation.

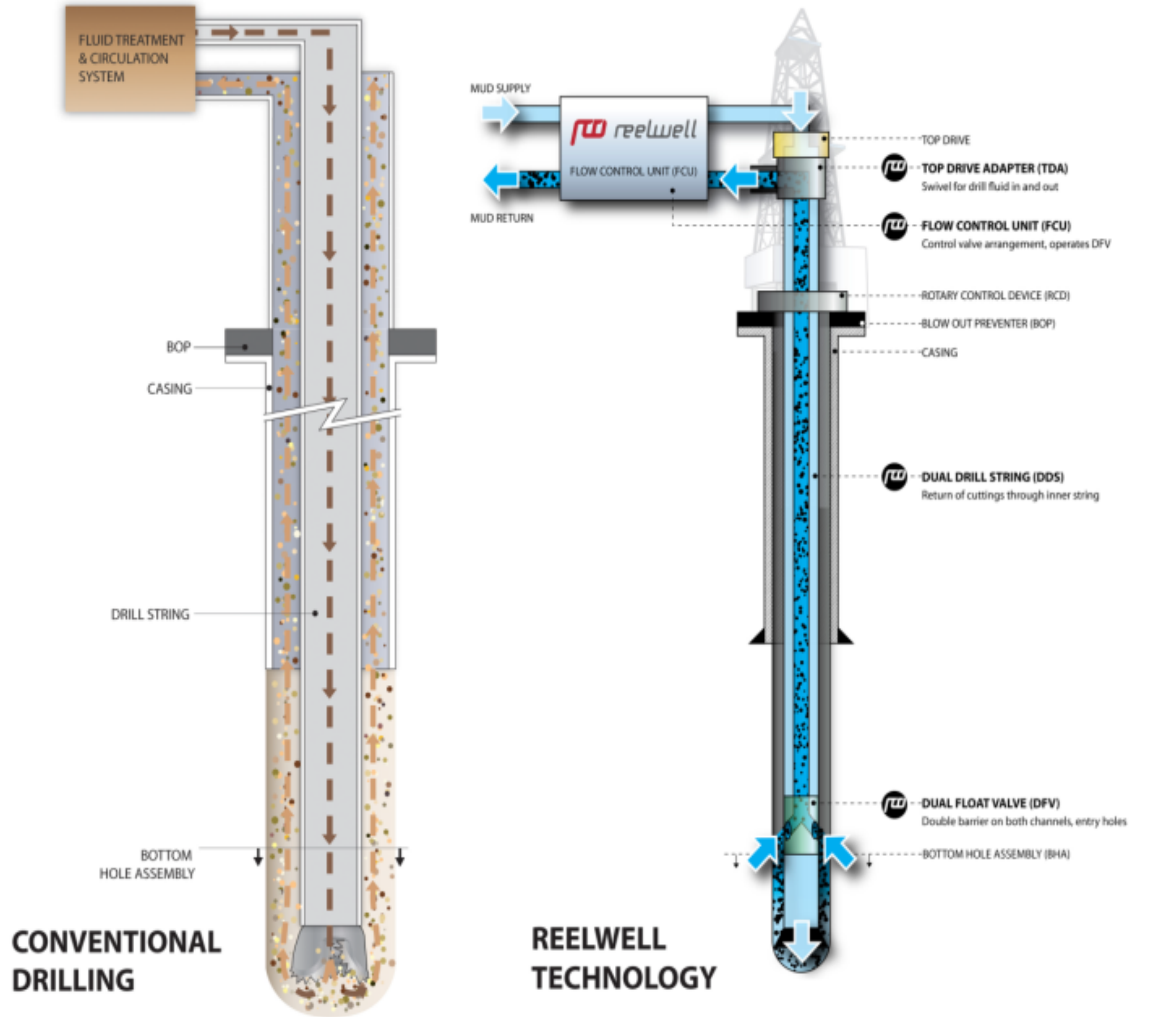


Figure 3-13: Conventional vs. RDM technology[8]

$$P_{well} = (\rho_{mud} * 0{,}0981 * h_{TVD}) + P_f \qquad 3.8$$

Where

P_{well} = Well Pressure [bar]

ρ_{mud} = Mud Density [sg]

h_{TVD} = True Vertical Depth of the well [m]

P_f = Annular Friction Pressure due to circulation [bar]

Equation 3.8 is calculated well pressure for conventional drilling. For RDM-R, well pressure is more complex because of the dual mud density. Equation 3.9 is calculated well pressure for RDM-R operation. Well fluid is static since it is free from circulation.

$$P_{well} = \left(\rho_{mud} * 0{,}0981 * (h_{TVD} - h_{sea})\right) + (\rho_{sea} * 0{,}0981 * h_{sea}) \qquad 3.9$$

Where

P_{well} = Well pressure [bar]

ρ_{mud} = Mud density [sg]

h_{TVD} = True vertical depth of the well [m]

h_{sea} = Depth to seabed [m]

ρ_{sea} = Seawater density [sg]

Figure 3.14 shows pressure profile in conventional drilling vs. hydrostatic pressure during a drilling operation. Since well annulus in RDM-R is free of circulation, well fluid will be static and behave as only hydrostatic pressure, which is beneficial of keeping well pressure inside the pressure window.

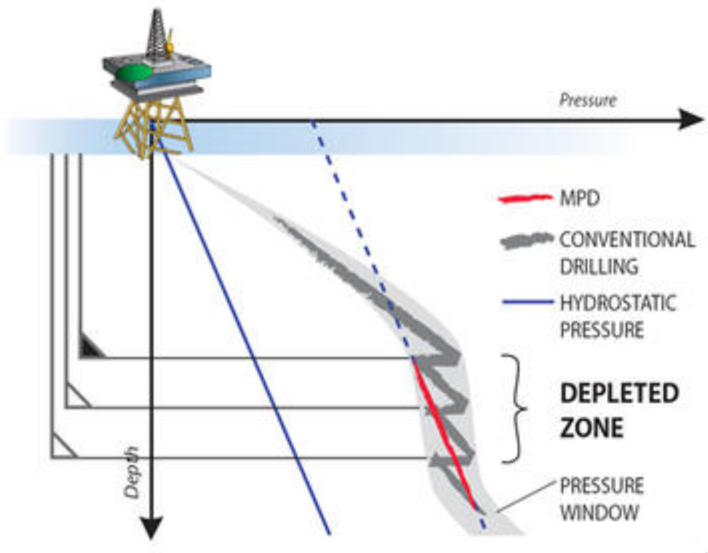


Figure 3-14: Pressure during drilling operation

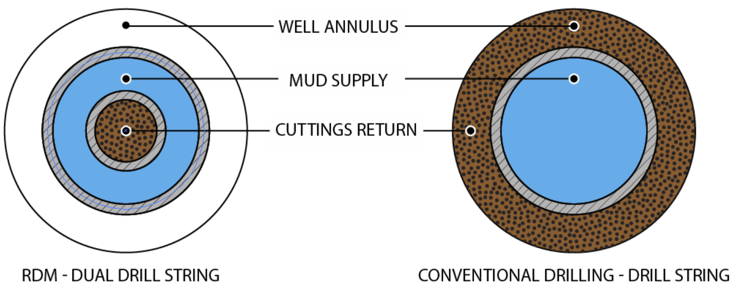


Figure 3-15: Schematic of top view section – RDM-R vs. conventional[7]

3.5.1 Advantages of RDM-R:

This chapter will highlight advantages of drilling with RDM-R in deepwater area compared to conventional drilling method.

3.5.1.1 Fewer Casing Strings

As the well is drilled with a "heavy" static mud in the well annulus this will allow the pressure profile in the well to be adjusted such that one can drill longer sections before setting a new casing.

3.5.1.2 Well Control

As there is no riser connected the emergency disconnection is faster and less complicated. The drill string is in emergencies hung off in the subsea BOP and can be cut from above the pipe ram by the shear ram.

The FCU allows precise control of the returning flow and pressure, which will immediately detect any small amount of influx or loss of fluid. This is very important in deepwater drilling where working pressure window and kick tolerance is significantly reduced.

Connection gas is avoided due to the shut-in sequence performed by the FCU before connections. The shut-in sequence closes downhole valves which results in unchanged BHP. As the BHP is unchanged the well pressure will not decrease below formation pressure, avoiding to get an underbalanced situation that can cause connection gas.

3.5.1.3 Environmental benefit

In emergency disconnection less volume of pollution mud may enter the sea since the marine riser is not cut off.

3.5.1.5 Time and Cost Saving

In deepwater areas the time required to run riser, pull riser and time to get the riser established is significant. This time consuming operation that also requires use of a large and expensive drilling vessel becomes a significant cost for the overall drilling operation. With RDM.R this time is voided, as the system is riserless.[9]

As the system is riserless the large volume of mud required to fill the riser is avoided. Thus reduce the volume of active mud during drilling and kill mud in well control situation. This will reduce the volume of active mud needed during drilling and also kill mud needed in well control situation.

RDM operation typical requires 50% less flowrate than conventional drilling operation, as the fluid velocity in the DDS inner pipe is significantly higher than what is normal in conventional drilling. This thus has an impact on the power requirement and fuel consumption for the drilling vessel.

3.5.1.6 Weight & Space Limitation and Station keeping

In deepwater environment the size of the wellhead and riser increases, which substantially increases the weight and space requirements for floating drilling vessels. The weight of the riser filled with mud in this environment will result in a heavy riser content, which will further result in vessel tensioning system not being able to tension the riser and an auxiliary buoyancy of one kind or another is required. This will result in more expensive vessels, which is not linear with depth.[9]

With RDM-R the large volume of mud required to fill up the riser is avoided. The required mud tank capacity will thus be reduced, which result in more available space or even use of a smaller drilling vessel. Mud treatment system may also be downscaled as the flowrate is reduced. Use of chemicals and mud additives will also be less due to smaller total mud volume requirement.

To maintain station keeping a gigantic vessel with an expensive mooring or dynamically positioning system is required to handle this huge and heavy riser accurately and keep the rig in operational range.[9]

3.5.1.7 Problems With Increased Riser Length

Increasing length of the riser as the water depth increases will lead to certain problems, which all will require variations of very costly measures that must be taken for successful drilling. Such problems are fatigue damage due to Vortex Induced Vibration, rapid riser wear by drill pipe due to large curvature of the riser and due to certain current speed to subsea BOP fatigue damage will apply on conductor pipe.[9]

3.5.1.8 Tensioning System

As water depth increases a rig with higher tension capacity is required as the weight of the riser increases to withstand loading from waves, current, riser weight and weight of mud in the riser. This is to drill without damaging the riser and wellhead equipment. As no riser is used in RDM-R the expensive tension requirement is not needed, resulting in cheaper and smaller floating rigs.[9]

3.5.1.9 Drilling In Narrow Pressure Working Window

As water depth increases the pressure-working window will be narrowed. It will be more crucial to control the well pressure; this is done by proper well control monitoring by RDM-R (chapter 3-5).

3.6 Well Control With RDM-R

MPD

RDM-R is providing a closed loop circulating system, which is essential for Controlled Pressure Drilling (CPD) technology. Return pressure is controlled precisely, dynamically and automatically by a computer system as mud along with cuttings enters a choke manifold on surface. If the well pressure starts to exceed the fracture pressure at the depth, a computerized control system open the choke to reduce backpressure and bring the pressure down below the critical fracture pressure. Otherwise, if the well pressure starts to drop below the pore pressure at the depth, the computerized control system will close the choke resulting in increased backpressure.[9]

During connections the circulation is stopped, which will reduce the BHP to hydrostatic pressure, equation 3.10.

$$BHP_{connection} = P_{hydrostatic} \qquad 3.10$$

While circulating, the BHP (equation 3.11) is composed of the wells hydrostatic head plus circulating friction pressure and choke pressure.

$$BHP_{drilling} = P_{hydrostatic} + P_{friction} + P_{choke} \qquad 3.11$$

For MPD the well pressure must be precisely controlled at any time to prevent any formation influx into the wellbore. During connections the choke is closed to apply backpressure to replace the lost returning friction pressure when circulation is stopped, which will keep well pressure above the pore pressure and prevent fluid influx.
By adjusting the active mud weight and applying backpressure, a driller would be able to keep the pressure inside the pressure window at any time.[9]

A RCD is both used in RDM-R and conventional drilling, but the functionality is different for the two drilling operations. In conventional drilling, the RCD is used to cap the annulus and divert the flow to the choke manifold for application of desired backpressure to the annulus. In RDM-R the RCD is used to seal around the drill string and contain the pressure inside the wellbore and do not have anything to do with flow diversion as the conventional RCD.[9]

4 WELL CONTROL SIMULATION CALCULATION

4.1 Well Design

The example well, A-1 is drilled vertically. Water depth is 2148 m and influx will be assumed at 5085 m in open hole. Three sections are drilled before 12 ¼” open hole where influx is assumed. 30” conductor is set before 20” and 13 3/8 x 13 5/8” intermediate casings.

Pore pressure and fracture pressure at casing shoe are 9.3 ppg and 12 ppg respectively and active drilling mud used for conventional drilling is 10.3 ppg. Figure 4-2 shows the pressure profile for well A-1.

For calculations a “simple” drill string with drill pipe, heavy weight drill pipe, drill collars and an average geometry of BHA is used.

Chapter 4.2 starts with calculating for RDM-R before well control calculations for conventional method, both with riser and riserless, are performed in chapter 4.3 and 4.4.

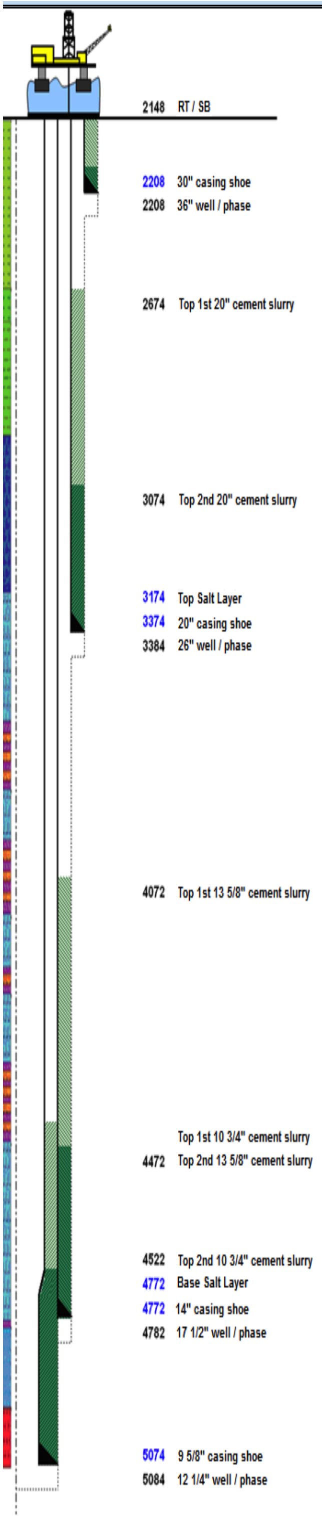
Well Geometry

Table 4-1: Well geometry for well A-1

	Size	Start [m]	End Depth [m]
Conductor	30”	2148	2208
Casing	20”	2148	3374
Casing	13 3/8” x 13 5/8”	2148	4772
Open Hole	12 ¼”	4772	5084

- Sea bed at 2148 m with water density 8,6 ppg

Well Schematic



PHASE	CASING	TOP	BASE	"N.M."
I	1 Tube 30" x 1 1/2", X-60, Pn LC x 30" "Alojador"	CABP		to be confirmed
30"	1 Tube 30" x 1 1/2", B Grade, C x LC x H-60 MT			10.812.236
	2 Tubes 30" x 1", B Grade, C x x Pn H-60 MT			10.774.875
	1 Tube 30" x 1", B Grade, C x H-60 MT x Float Shoe		2208	10.169.892
II	1 Short tube 20" x 1", 209 lb/ft, X-70, Pn TER x 18 3/4" "Alojador"	CABP		to be confirmed
13 5/8"	1 Tube 20" x 1", 209 lb/ft, X-70, Dr. 17,812, C x x Pn TER			10.990.540
	95 Tubes 20" x 3/4", 156 lb/ft, X-80, Dr. 18,312, C x x Pn TER		3174	10.990.541
	25 Tubes 20" x 1", 209 lb/ft, X-70, Dr. 17,812, TER	3174		10.642.366
	1 Tube 20" x 1", 209 lb/ft, X-70, Dr. 17,812, C x Tenaris ER x Float. Shoe		3374	11.075.581
III	1 Hanger 13 3/8" ; Premium	CABP		to be confirmed
14"	1 Short tube 13 3/8"; 72 lb/ft ; P-110 ; Pn Premium ; Pn New Vam			
	95 Tubes 13 3/8"; 72 lb/ft; P-110 ; Dr. 12,250 ; New Vam			10.330.561
	1 Reduction 13 3/8" ; 72 lb/ft ; P-110 ; C x New Vam x Pn 13 5/8" ; 88,2 lb/ft New Vam		3174	
	100 Tubes 13 5/8"; 88,2 lb/ft; P-110 ; Dr. 12,250 ; New Vam			10.390.115
	1 Reduction 14" ; 115 lb/ft ; Q-125 HC ; C x 13 5/8" New Vam x Pn SLIJ2		4373	
	50 Tubes 14"; 115 lb/ft; Q-125 HC ; Dr. 12,250 ; SLIJ2			10.957.271
	1 Float collar 14"; SLIJ2			11.188.970
	4 Tubes 14"; 115 lb/ft; Q-125 HC ; Dr. 12,250 ; SLIJ2			10.662.191
	1 Float shoe 14"; SLIJ2		4772	11.188.971
IV	1 Hanger 10 3/4" ; Premium	CABP		to be confirmed
9 5/8"	1 Short tube 10 3/4"; 71,1 lb/ft ; C-110 HCSS; Pn Premium ; Pn SLIJ2			
	95 Tubes 10 3/4"; 71,1 lb/ft; C-110 HCSS ; Dr. 9,294 ; SLIJ2			10.946.453
	1 XO 10 3/4" ; 71,1 lb/ft ; C-110 HCSS ; C x SLIJ2 x Pn 10 3/4" ; 85,3 lb/ft SLIJ2		3174	
	150 Tubes 10 3/4"; 85,3 lb/ft; C-110 HCSS ; Dr. 9,000 ; SLIJ2			10.946.456
	1 XO 10 3/4" ; 85,3 lb/ft ; C-110 HCSS ; C x SLIJ2 x Pn 9 5/8" ; 53,5 lb/ft Vam 21		4722	
	N Tubes 9 5/8" ; 53,5 lb/ft; SDSS-125; Dr. 8,5000 ; Vam 21			NEW
	1 XO 9 5/8" ; 53,5 lb/ft ; SDSS-125 ; C x Vam 21 x Pn 9 5/8" P-110 BTC			
	1 Float collar 9 5/8" ; BTC			10.203.896
	4 Tubes 9 5/8" ; 53,5 lb/ft; P-100; Dr. 8,5000 ; New Vam			10.366.459
	1 Float shoe 9 5/8" ; BTC		5074	10.138.429
V				
7 5/8"				
VI				
9 5/8"				

Figure 4-1: Well Schematic

Pressure Profile

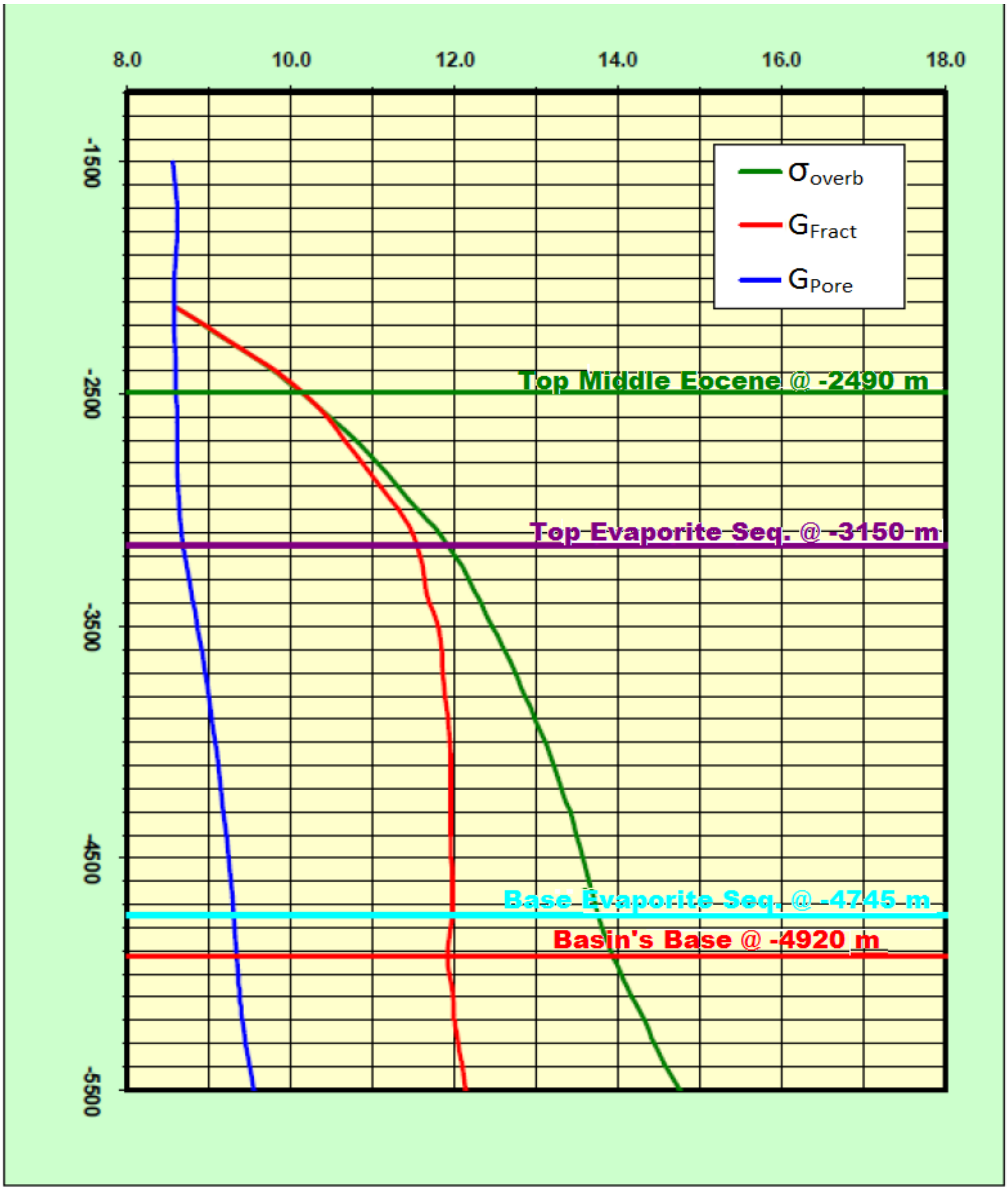


Figure 4-2: Pressure Profile for well A-1

Pore Pressure, Fracture Pressure and Well Pressures

Table 4-2: PP, FP and well pressure for well A-1

Phase	Depth [m]	Pore Pressure [ppg]	Fracture Pressure [ppg]	Hydrostatic Well pressure [psi]
#1	2148 - 2204	8,6	8,8	8,65x0,052x2204x3,28 = 3225 psi
#2	2204 - 3364	8,8	9,2	SW: 5049 Brine/SCOL: 6311
#3	3364 - 4772	8,8	11,7	9359
#4 OH	4772 - 5074	9,3	12	9087

4.2 Simulation – RDM-R

4.2.1 Simulation arrangement – RDM-R

Calculations are based on well A-1, and assumed, drilled conventional. General info is given in chapter 4.1. Influx is assumed at 5085 m. Calculations for well control in chapter 4.2 is made for RDM-R case with heavy mud in well annulus and light active drilling mud in DDS.

Open Hole Data

Table 4-3: Open hole data for well A-1

Hole Size [in]	12 ¼
Depth [m MD]	5085
Capacity [l/m]	76

Casing Data

Table 4-4: Casing data for well A-1

Casing ID [in]	13-3/8”
Depth [m MD]	4772
Capacity [l/m]	90,6

BHA Data

Table 4-5: BHA data for well A-1

Average OD [in]	6,21
Average ID [in]	2,89
Length [m]	90
Average Capacity [l/m]	4,23
Average closed end Displacement [l/m]	19,53

Note: Average OD and ID of the BHA is used due to the “complexity” of the changes in ID and OD for the different components in the BHA. 90 m of the total length of the DDS at 5085 is 1,8% - meaning exact values will have little impact on the calculations

DDS Data

Table 4-6: DDS data for well A-1

Outer Pipe OD [in]	7,01
Outer Pipe ID [in]	6 ¼
Inner Pipe OD [in]	4 ¼
Inner Pipe ID [in]	3,15
Capacity Inner Pipe [l/m]	5,02
Capacity Inner Annulus [l/m]	10,64
DDS Displacement	24,88

Pump Data

Table 4-7: Pump data for well A-1

Pump #1 Displacement [l/stk]	16
Pump #2 Displacement [l/stk]	21
Pump #3 Displacement [l/stk]	12

- Pump #1 is lined up on well annulus
- Pump #2 is lined up on inner annulus

Surface Line Volumes

Table 4-8: Surface line volumes for well A-1

Pump to TDA Volume [l]	245
Pump to RCD Volume [l]	578
TDA to Rig Choke Volume [l]	239

4.2.2 Kill Sheet Calculation – RDM-R

Volume Calculations

Figure 4-3 shows where the different components for volume calculation in table 4-9 – 4-11 are located. Volume calculations are performed in excel, calculated using volume calculation

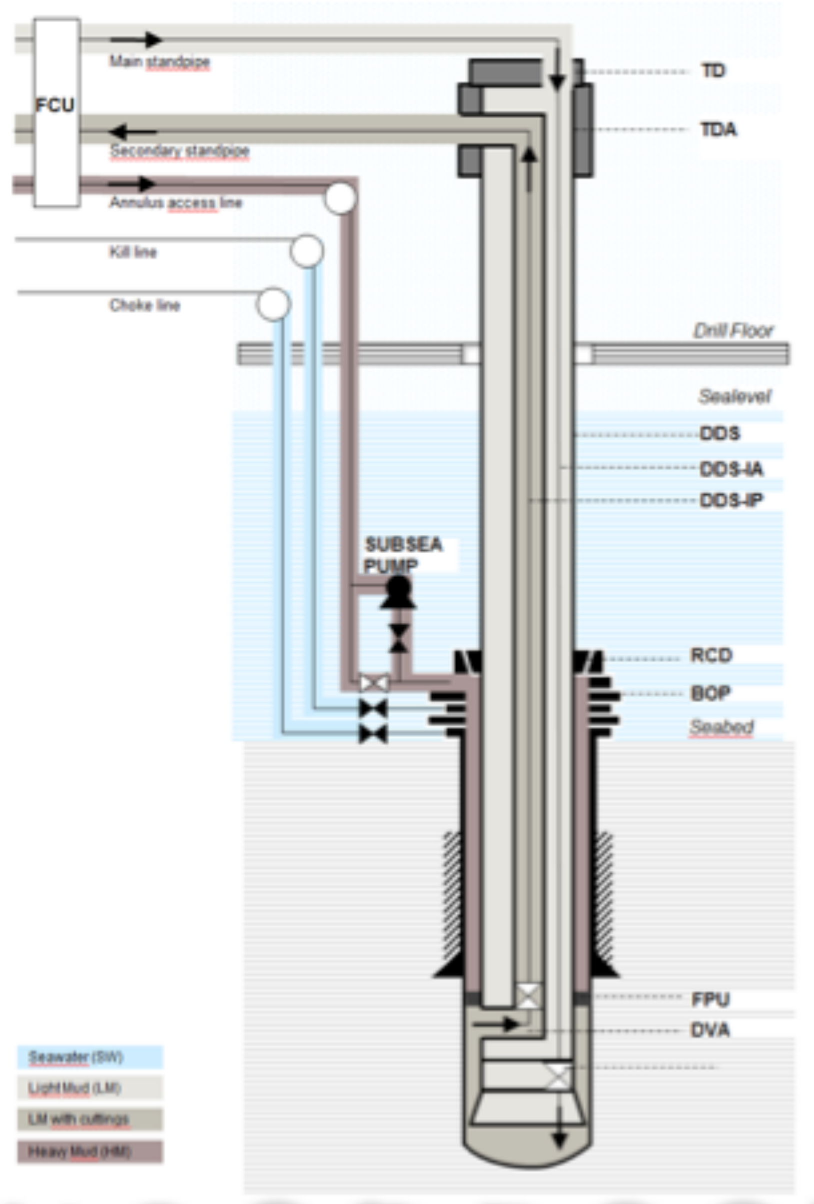


Figure 4-3: RDM-R schematic

Well Annulus

Table 4-9: Well annulus volumes for well A-1

	Length [m]	Capacity [l/m]	Volume [m3]	Pump strokes [stk]
Pump to RCD			0,58	28
RCD to casing shoe	2624	57,0	149,6	7122
Casing shoe to FXO	223	51,1	11,4	543
Total			**161,5**	**7692**

Inner Annulus

Table 4-10: Inner annulus volumes for well A-1

	Length [m]	Capacity [l/m]	Volume [m3]	Pump strokes [stk]
Pump to TDA			0,3	15
TDA to FXO	4995	10,6	53,2	3322
FXO to bit	90	4,2	0,4	24
Total			**53,8**	**3361**

Inner Pipe

Table 4-11: Inner pipe volumes for well A-1

	Length [m]	Capacity [l/m]	Volume [m3]	Pump strokes [stk]
Bit to FXO	90	56,5	5,1	318
FXO to TDA	4995	10,6	53,1	3322
TDA to rig choke			0,2	15
Total			**58,5**	**3654**

Input for well control calculations

ρ_{heavy} = Heavy Mud density in well annulus = 1,4 sg

ρ_{light} = Light Active drilling mud circulated in DDS = 1,1 sg

Calculations

Minimum prognosis for fracture pressure in well A-1 is found from figure 4-2. Casing shoe depth is at 4772 m giving a fracture gradient at 12 ppg = 1,44 sg.

$$P_{csg} = \rho_{frac} * h_{csg} * 0{,}0981 \qquad 4.1$$

Where

P_{csg} = Casing Shoe Pressure [bar]

ρ_{frac} = Fracture Gradient [sg]

h_{csg} = Casing Shoe Depth [m]

With current inputs equation 4.1 equals

$$\boldsymbol{P_{csg}} = 1.44 * 4772 * 0{,}0981 = \boldsymbol{674\ bar}$$

For RDM-R dual mud gradient calculations must be performed. Having heavy mud density from seabed and down, while seawater displaces riser volume. Max allowable fluid density in well annulus is then calculated from equation 4.2

$$\rho_{max} = \frac{P_{csg} - (\rho_{sea} * h_{sea} * 0{,}0981)}{(h_{csg} - h_{sea}) * 0{,}0981} \tag{4.2}$$

Where

ρ_{max} = Maximum Allowable Fluid Density in Well Annulus [sg]

P_{csg} = Casing Shoe Pressure [bar]

ρ_{sea} = Seawater Density [sg]

h_{csg} = Depth to Casing Shoe [m]

h_{sea} = Depth to Seabed [m]

With current inputs equation 4.2 equals

$$\boldsymbol{\rho_{max}} = \frac{674 - (1{,}03 * 2148 * 0{,}0981)}{(4772 - 2148) * 0{,}0981} = \mathbf{1{,}78}\ \boldsymbol{sg}$$

When influx is noticed and RDM-R well control method is started, RDM-R method requires pumping down inner annulus at very slow circulation rate to record following parameters listed:

Inner annulus pressure

Casing pressure; which in deepwater wells is read from RCD pressure

Pressure to open IPV

A safety margin must be applied to heavy mud in annulus.

Recorded values:

- $P_{\text{Inner Annulus @ slow circulation rate}} = P_{IASCR}$ = 110 bar
- P_{csg} = 20 bar
- $P_{\text{to open IPV}} = P_{OIPV}$ = 10 bar

$$BHP_{IAPP} = (P_{IASCR} - P_{OIPV}) + (\rho_{light} * h_{TVD} * 0{,}0981) \tag{4.3}$$

Where

BHP_{IAPP} = BHP from Inner Annulus Pump Pressure

P_{IASCR} = Inner Annulus Pressure at Slow Circulation Rate

P_{OIPV} = Pressure to Open Inner Pipe Valve

ρ_{light} = Active mud Density in DDS

h_{TVD} = True Vertical Depth

With current inputs equation 4.3 equals

$$\boldsymbol{BHP_{IAPP}} = (110 - 10) + (1{,}1 * 5085 * 0{,}0981) = \boldsymbol{649\ bar}$$

$$BHP_{csg} = P_{csg} + \left(\rho_{heavy} * (h_{TVD} - h_{sea}) * 0{,}0981\right) + (\rho_{sea} * h_{sea} * 0{,}0981) \qquad 4.4$$

Where

BHP_{csg} = BHP from Casing Pressure

P_{csg} = Casing pressure monitored from RCD pressure

ρ_{heavy} = Mud Density in Well Annulus

h_{TVD} = True Vertical Depth where influx is taken

h_{sea} = Sea Depth

ρ_{sea} = Seawater Density

With current inputs equation 4.4 equals

$$\boldsymbol{BHP_{csg}} = 20 + (1{,}4 * (5085 - 2148) * 0{,}0981) + (1{,}03 * 2148 * 0{,}0981) = \boldsymbol{640\ bar}$$

Then minimum and maximum casing pressures are calculated to ensure proper well control while circulating out the influx.

$$P_{\min csg} = P_{csg} + SM \qquad 4.5$$

Where

$P_{\min csg}$ = Minimum Casing Pressure while circulating out the influx

P_{csg} = Casing Pressure monitored from RCD Pressure

SM = Safety Margin

With current inputs equation 4.5 equals

$$\boldsymbol{P_{\min csg}} = 20 + 15 = \boldsymbol{35\ bar}$$

$$P_{\max csg} = \left[\left(\rho_{max} - \rho_{heavy}\right) * (h_{TVD} - h_{sea}) * 0{,}0981\right] + (\rho_{sea} * h_{sea} * 0{,}0981) \ 4.6$$

Where

$P_{\max csg}$ = Maximum Casing Pressure while circulating out the influx

ρ_{max} = Max Allowable Fluid Density

ρ_{heavy} = Mud Density in Well Annulus

h_{TVD} = True Vertical Depth where influx is taken

h_{sea} = Sea Depth

ρ_{sea} = Seawater Density

With current inputs equation 4.6 equals

$$\boldsymbol{P_{\max csg}} = [(1{,}78 - 1{,}4) * (5085 - 2148) * 0{,}0981] + (1{,}03 * 2148 * 0{,}0981) = \boldsymbol{325\ bar}$$

The new heavy mud density (kill mud) in well annulus is calculated from equation 4.7

$$\rho_{kill} = \rho_{heavy} + \frac{P_{csg}+SM}{(h_{TVD}-h_{sea})*0,0981} \qquad 4.7$$

Where

ρ_{kill} = Kill Mud [sg]

ρ_{heavy}= Mud Density in Well Annulus [sg]

P_{csg} = Casing Pressure monitored from RCD Pressure [bar]

SM = Safety Margin [bar]

h_{TVD} = True Vertical Depth where influx is taken [m]

h_{sea} = Sea Depth [m]

With current inputs equation 4.7 equals

$$\rho_{kill} = 1,4 + \frac{20+15}{(5085-2148)*0,0981} = 1,52\ sg$$

A new maximum well annulus/casing pressure is then calculated by equation 4.8

$$P_{\max csg} = [(\rho_{max} - \rho_{kill}) * (h_{TVD} - h_{sea}) * 0,0981] + (\rho_{sea} * h_{sea} * 0,0981) \qquad 4.8$$

Where

$P_{\max csg}$ = Maximum casing pressure while circulating out the kill mud[bar]

ρ_{max} = Max Allowable Fluid Density [sg]

ρ_{kill} = Kill Mud [sg]

h_{TVD} = True Vertical Depth where influx is taken[m]

h_{sea} = Sea Depth [m]

ρ_{sea} = Seawater Density

With current inputs equation 4.8 equals

$$\boldsymbol{P_{\max csg}} = [(1,78 - 1,52) * (5085 - 2148) * 0,0981] + (1,03 * 2148 * 0,0981) = \mathbf{290\ bar}$$

First Circulation

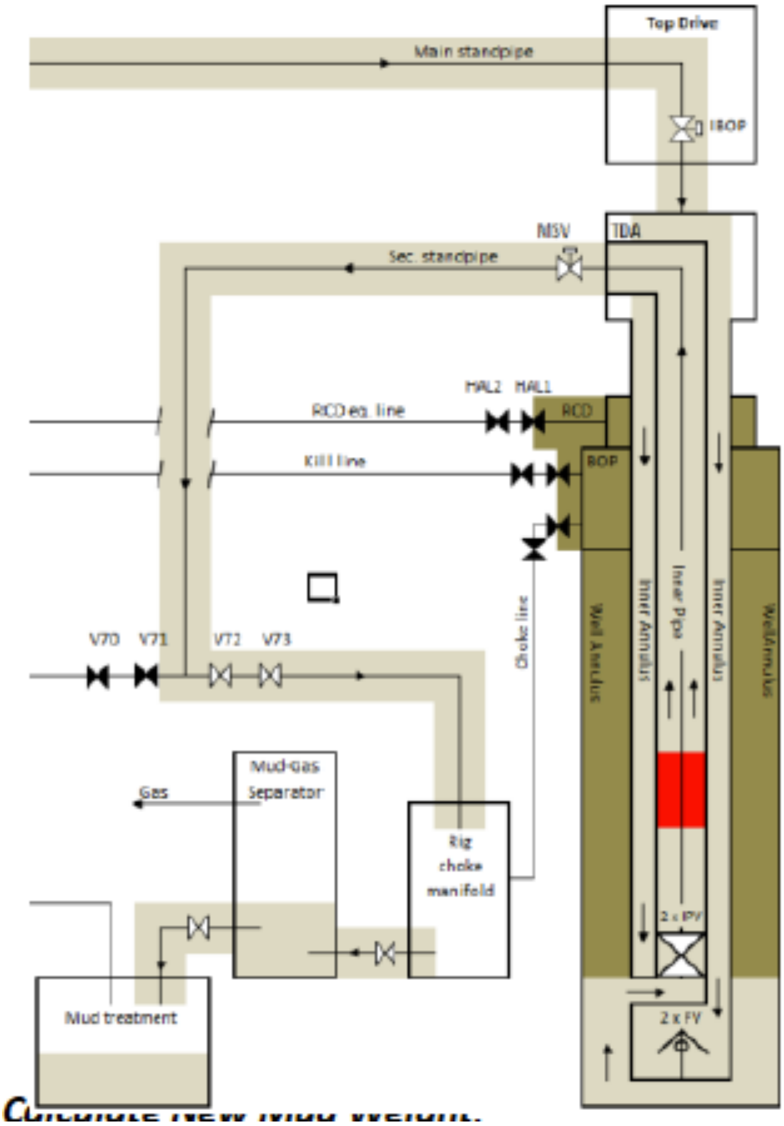


Figure 4-4: Schematic for first circulation

The first circulation consists of circulating out the influx with light mud down inner annulus taking the return flow up the inner pipe. A combination of regulating the rig choke and flow rate is used to keep well control. Casing pressure should be regulated to stay in-between minimum and maximum casing pressure calculated in equation 4.5 and 4.6. During circulation valves must be aligned according to figure 4-4.

Influx will be at surface after 3654 strokes (table 4-11), circulation must continue until the gas reading is down. This will give a total pumping time at 122 minutes before the influx is at surface, assuming we are pumping with 30 SPM.

Second Circulation

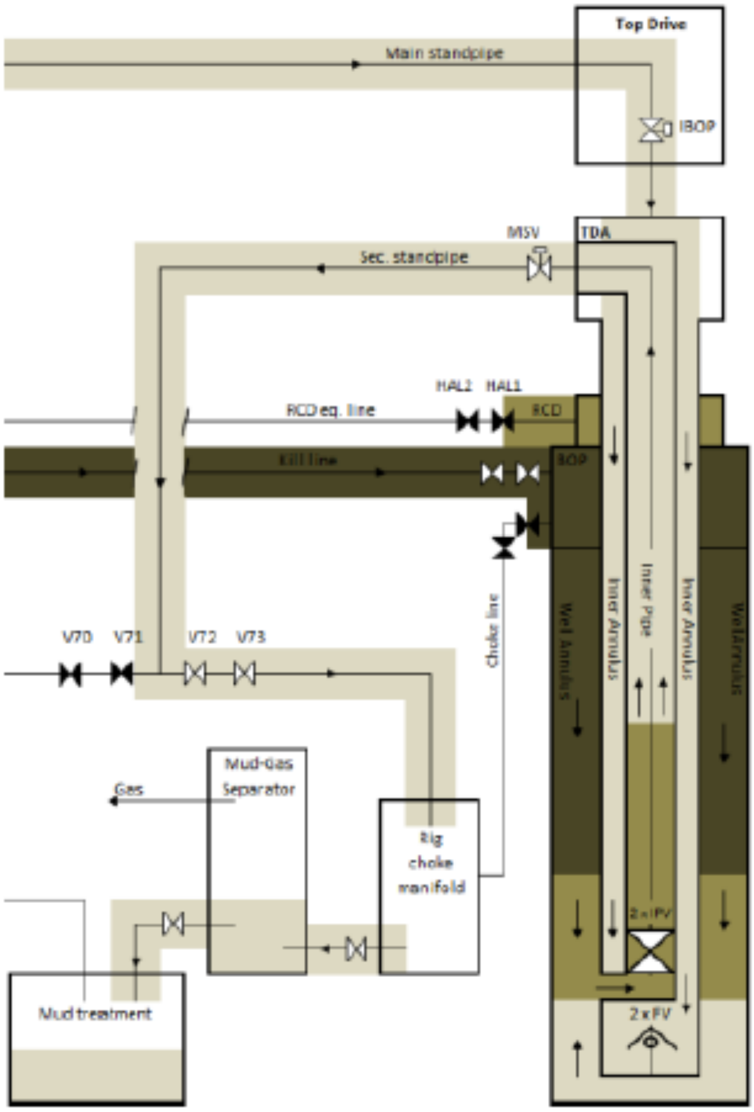


Figure 4-5: Schematic for second circulation

The second circulation consists of pumping kill mud down well annulus to kill the well to ensure no further influx is taken. Return flow is taken up inner pipe. Light mud is slowly pumped down inner annulus at a constant rate to monitor BHP, while kill mud is pumped down well annulus. During second circulation valves must be aligned according to figure 4-5. While kill mud is pumped, the rate can be increased until maximum pressure is reached (Equation 4.9).

$$P_{pump} = \left[(\rho_{max} - \rho_{kill}) * \left(h_{csg} - h_{sea}\right) * 0,0981\right] + (\rho_{sea} * h_{sea} * 0,0981) \qquad 4.9$$

Where

P_{pump} = Maximum Pump Pressure [bar]

ρ_{max} = Max Allowable Fluid Density [sg]

ρ_{kill} = Kill Mud [sg]

h_{csg} = Casing Shoe Depth [m]

h_{sea} = Sea Depth [m]

ρ_{sea} = Seawater Density [sg]

With current inputs equation 4.9 equals

$$\boldsymbol{P_{pump}} = [(1,78 - 1,52) * (4772 - 2148) * 0,0981] + (1,03 * 2148 * 0,0981) = \boldsymbol{283\ bar}$$

A combination of regulating the rig choke and flow rate is used to keep inner annulus pump pressure in-between minimum and maximum inner annulus pressures, calculated from equation 4.10 and 4.11.

$$P_{min} = [(\rho_{kill} * (h_{TVD} - h_{sea}) * 0,0981)] + (\rho_{sea} * h_{sea} * 0,0981) - \left(\rho_{light} * h_{TVD} * 0,0981\right) \quad 4.10$$

Where

P_{min} = Minimum Inner Annulus Pump Pressure [bar]

ρ_{kill} = Kill Mud [sg]

h_{TVD} = True Vertical Depth where influx is taken [m]

h_{sea} = Sea Depth [m]

ρ_{sea}= Seawater Density [sg]

ρ_{light} = Active Mud Density in DDS

With current inputs equation 4.10 equals

$$\boldsymbol{P_{min}} = [(1,52 * (5085 - 2148) * 0,0981)] + (1,03 * 2148 * 0,0981) - (1,1 * 5085 * 0,0981)$$
$$= \boldsymbol{107\ bar}$$

$$P_{max} = \left[\left(\rho_{max} * \left(h_{csg} - h_{sea}\right) * 0,0981\right)\right] + (\rho_{sea} * h_{sea} * 0,0981) - \left(\rho_{light} * h_{csg} * 0,0981\right) \; 4.11$$

Where

P_{max} = Maximum Inner Annulus Pump Pressure [bar]

ρ_{max} = Max Allowable Fluid Density in Well Annulus [sg]

h_{csg} = Casing Shoe Depth [m]

h_{sea} = Sea Depth [m]

ρ_{sea} = Seawater Density [sg]

ρ_{light} = Active Mud Density in DDS [sg]

With current inputs equation 4.11 equals

$$P_{max} = [(1{,}78 * (4772 - 2148) * 0{,}0981)] + (1{,}03 * 2148 * 0{,}0981) - (1{,}1 * 4772 * 0{,}0981) = \mathbf{159\ bar}$$

Kill mud will be at FXO after 7692 strokes (table 4-9). This will give a total pumping time at 256 minutes, assuming we are pumping with 30 SPM.

Third Circulation

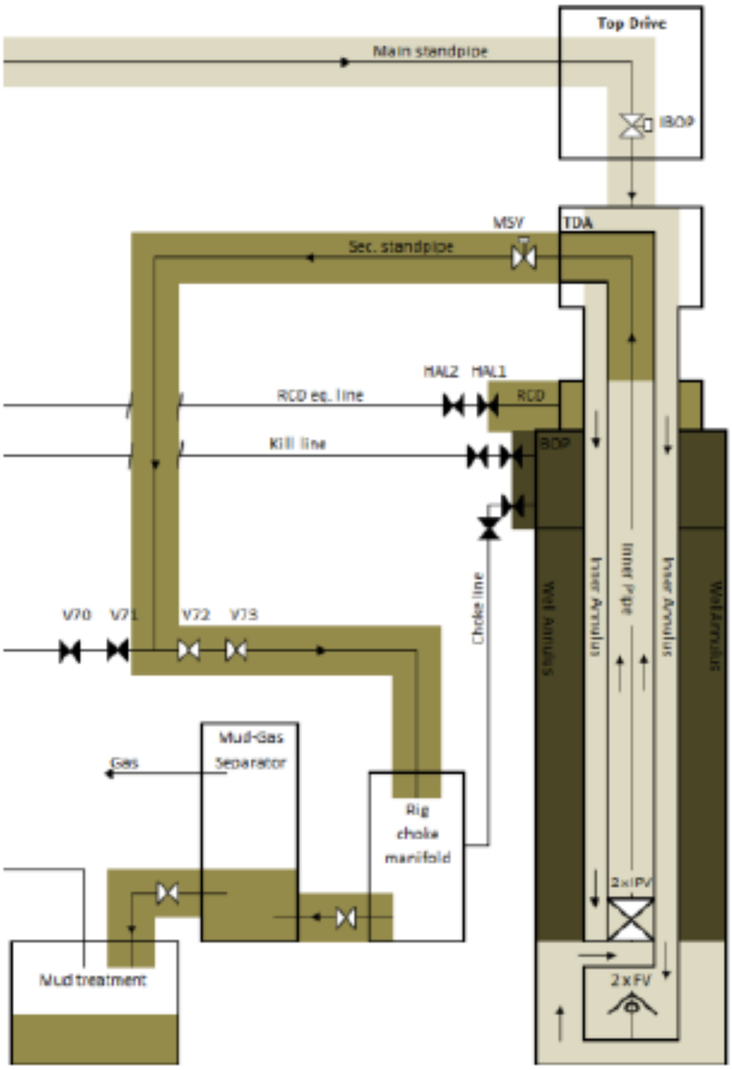


Figure 4-6: Schematic for third circulation

The third circulation consists of pumping light mud down inner annulus taking the return flow up inner pipe. This is to displace kill mud out of inner pipe. Valves must be aligned according to figure 4-6 during third circulation. A combination of regulating the rig choke and flow rate is used to keep pressure below well annulus/casing pressure from equation 4.8

Kill mud is displaced out of inner pipe after 3654 strokes (Table 4-11). This will give a total pumping time at 122 minutes, assuming we are pumping with 30 SPM.

Total time to kill the well

Time taken for the three circulations is listed in table 4-12

Table 4-12: Total strokes and time for circulating out the influx with RDM-R method

	Strokes	Time [min]	Pump Pressure [bar]
First Circulation	3654	122	45
Second Circulation	7692	256	145
Third Circulation	3654	122	45
Total Circulating Time	**15000**	**500**	

Table 4-12 shows that the total time to circulate out a kick with RDM-R method is 500 minutes = 8,3 hours

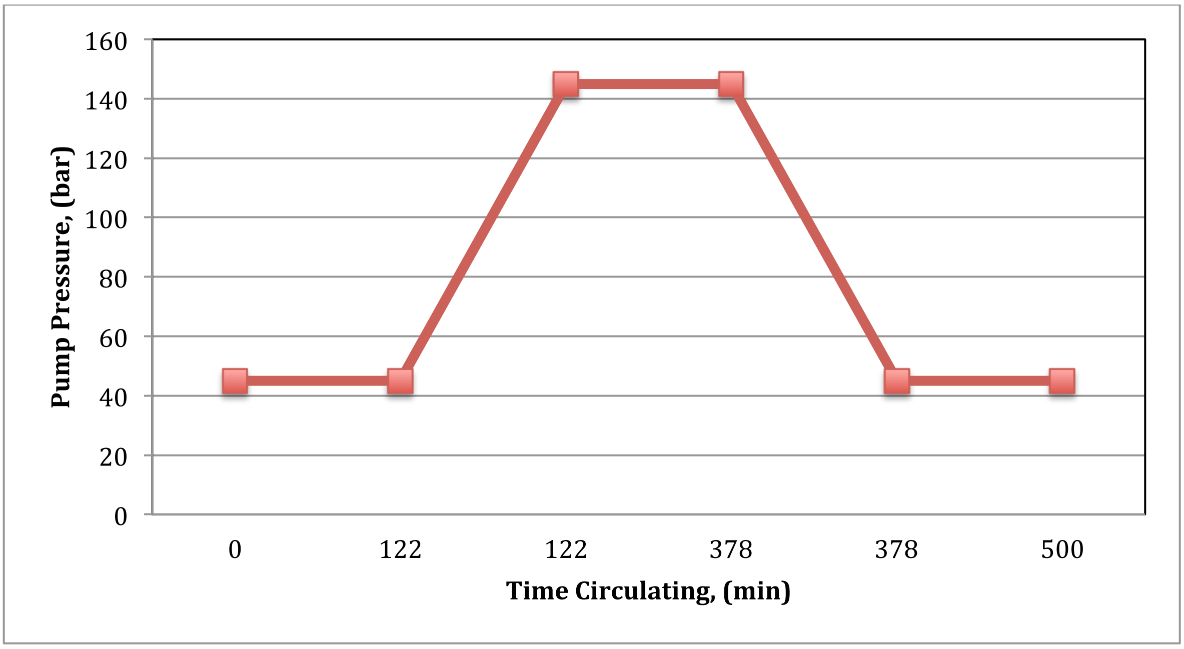


Figure 4-7: RDM-R kill sheet

4.3 Simulation – Conventional Method

4.3.1 Simulation Arrangement – Conventional Method

Data inputs are repeated to prevent having to flip pages back and forth.

Pump Data

- Triplex mud pump
- Power rating: 1194
- Max pressure: 4669
- Efficiency: 97%
- Stroke length: 12"
- Liner size: 6"
- Capacity; 16.18 l/stk

Open Hole Data

Table 4-13: Open hole data for well A-1

Hole Size [in]	12 ¼
Depth [m MD]	5085
Capacity [l/m]	76

- Capacity = $\frac{\pi}{4} * hole\ size^2$

Casing Data

Table 4-14: Casing data for well A-1

Casing OD [in]	13-3/8
Casing ID [in]	12.715
Depth [m MD]	4772
Capacity [l/m]	90,6

BHA Data

Table 4-15: BHA data for well A-1

Average OD [in]	6,21
Average ID [in]	2,89
Length [m]	90
Average Capacity [l/m]	4,23
Average closed end Displacement [l/m]	19,53

Note: Average OD and ID for BHA is used due to the “complexity” of the changes in ID and OD for the different components in the BHA.
90 m of the total length of the DDS at 5085 is 1,8% - meaning exact values will have little impact on the calculations

Conventional Drill String Data

Table 4-16: Conventional drill string data used in calculations

HWDP OD[in]	5 ½”
HWDP ID [in]	3
Length of HWDP [m]	150
Drill Collar OD [in]	6 ¾
Drill Collar ID [in]	2 ¼
Length of Drill Collar [m]	150
Drill Pipe OD [in]	5 ½
Drill Pipe ID [in]	4.516
Length of Drill Pipe [m]	4695
Capacity HWDP [l/m]	4.56
Capacity Drill Collar [l/m]	2.56
Capacity Drill Pipe [l/m]	4.99

4.3.2 Kill Sheet Calculation – Conventional Method

Calculated Volumes

Volume calculations in table 4-17 and 4-19 are performed in excel, calculated using simple volume calculation formulas.

Well Annulus

Table 4-17: Volume calculations for well annulus

	Length [m]	Capacity [l/m]	Volume [m3]	Pump strokes [stk]
Pump to Riser			0,4	20
Drill Pipe/Casing	4695	66.6	312.5	14762
DC/Casing	77	58.8	5.1	242
DC/OH	73	52.9	3.9	183
HWDP/OH	150	60.7	9.1	430
Bit/OH	90	56.5	5.1	240
Total			**330.6**	**15857**

Well annulus to circulate out influx

Table 4-18: Volume calculations for circulate out influx

	Length [m]	Capacity [l/m]	Volume [m3]	Pump strokes [stk]
Choke Line			9,8	463
Drill Pipe/Casing	2547	66.6	169,5	8009
DC/Casing	77	58.8	5.1	242
DC/OH	73	52.9	3.9	183
HWDP/OH	150	60.7	9.1	430
Bit/OH	90	56.5	5.1	240
Total			**330.6**	**9566**

Drill String

Table 4-19: Volume calculations for drill string

	Length [m]	Capacity [l/m]	Volume [m3]	Pump strokes [stk]
Pump to Drill Pipe			0,3	15
Drill pipe	4695	11.6	54.3	5264
Drill Collar	150	2.6	0.4	18
HWDP	150	4.6	0.7	32
Bit	90	4	0,38	18
Total			**54,7**	**2638**

When influx is observed and the well is shut in, following parameters are recorded and applied:

- SIDPP: 220 psi
- SICP: 300 psi
- Safety factor: 145 psi
- Well friction during pumping kill mud: 145 psi

Calculations

First the kill mud is calculated using equation 4.12

$$\rho_{kill} = \rho_{well} + \frac{SIDPP+SM}{0{,}0981*h_{TVD}} \qquad 4.12$$

Where

ρ_{kill} = Kill Mud Density

ρ_{well} = Mud Density in Well

$SIDPP$ = Shut-In Drill Pipe Pressure

SM = Safety Margin

h_{TVD} = True Vertical Depth

With current inputs equation 4.12 equals

$$\boldsymbol{\rho_{kill}} = 1{,}24 + \frac{15+10}{0{,}0981*5085} = \mathbf{1{,}29\ sg}$$

Then pore pressure is calculated from equation 4.13

$$PP = SIDPP + (\rho_{well} * 0{,}0981 * h_{TVD}) \qquad 4.13$$

Where

PP = Pore Pressure

$SIDPP$ = Shut-In Drill Pipe Pressure

ρ_{well} = Mud Density in well

h_{TVD} = True Vertical Depth

With current inputs equation 4.13 equals

$$\boldsymbol{PP} = 15 + (1{,}24 * 0{,}0981 * 5085) = \mathbf{342\ bar}$$

To create kill-sheet ICP and FCP are calculated (equation 4.14 and 4.15)

$$ICP = SIDPP + SM + P_{friction} \tag{4.14}$$

Where

ICP = Initial Circulation Pressure

SIDPP = Shut-In Drill Pipe Pressure

SM = Safety Margin

$P_{friction}$ = Well Friction while pumping Kill Mud

With current inputs equation 4.14 equals

$$\boldsymbol{ICP} = 15 + 10 + 10 = \mathbf{35\ bar}$$

$$FCP = \frac{\rho_{kill}}{\rho_{well}} * P_{friction} \tag{4.15}$$

Where

FCP = Final Circulating Pressure

ρ_{kill} = Kill Mud Density

ρ_{well}= Mud Density in well

$P_{friction}$ = Well Friction while pumping Kill Mud

With current inputs equation 4.15 equals

$$\boldsymbol{FCP} = \frac{1{,}27}{1{,}24} * 10 = \mathbf{10\ bar}$$

Calculations for circulating out the kick

- Pump rate: 30 SPM
- Down time = $\frac{Down\ strokes}{SPM} = 88\ min$
- Up time for kill mud = $\frac{Up\ strokes}{SPM} = 529\ min$
- Full circulation time $= \frac{Circulation\ Stokes}{SPM} = 608$ min
- Time to circulate out influx = $\frac{Well\ Annulus\ to\ Citculate\ out\ Influx}{SPM} = 319$ min

Drillers Method

Table 4-20: Total strokes and time to circulate out the influx with conventional drillers method

	Strokes	Time [min]	Pump Pressure [bar]
Kick out of the well	9566	319	ICP
Kill mud at bit	12204	407	FCP
Kill mud in whole well	28061	935	FCP

4-20 shows that the total time to circulate out a kick with drillers method is 935 minutes = 15,6 hours.

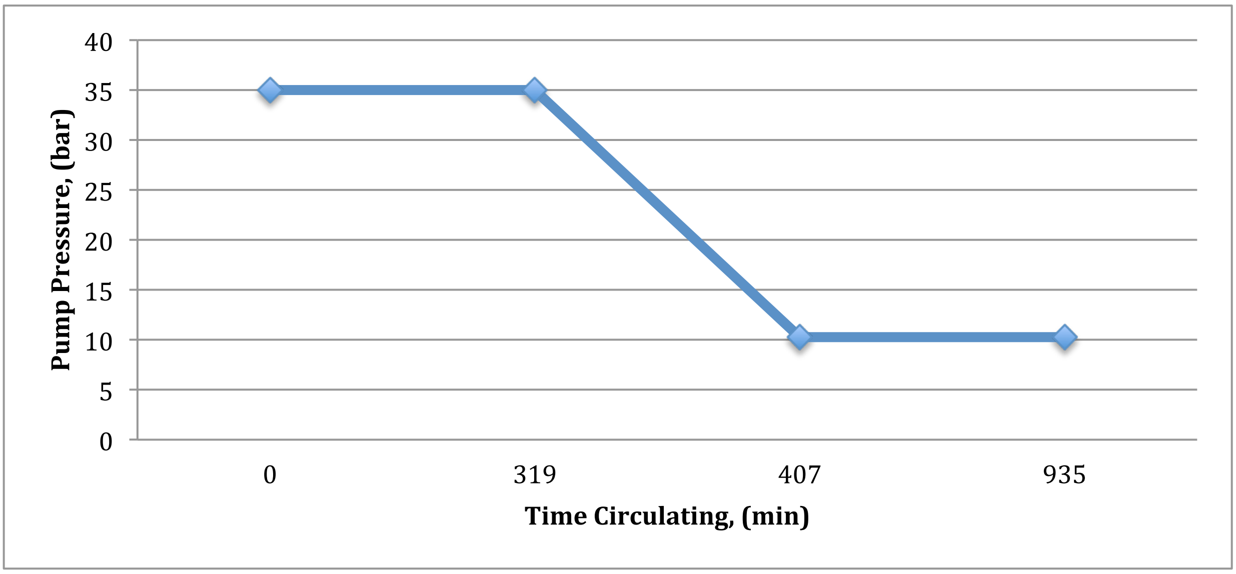


Figure 4-8: Kill sheet for driller's method

4.3.3 Simulation – W&W Method

Table 4-21: Total strokes and time for circulating out the influx with conventional W&W method

	Time [min]	Pump Pressure [bar]
Kill mud at bit	88	35
Kill mud in whole well	608	10

Table 4-21 shows that the total time to circulate out a kick with W&W method is 608 minutes = 10,1 hours.

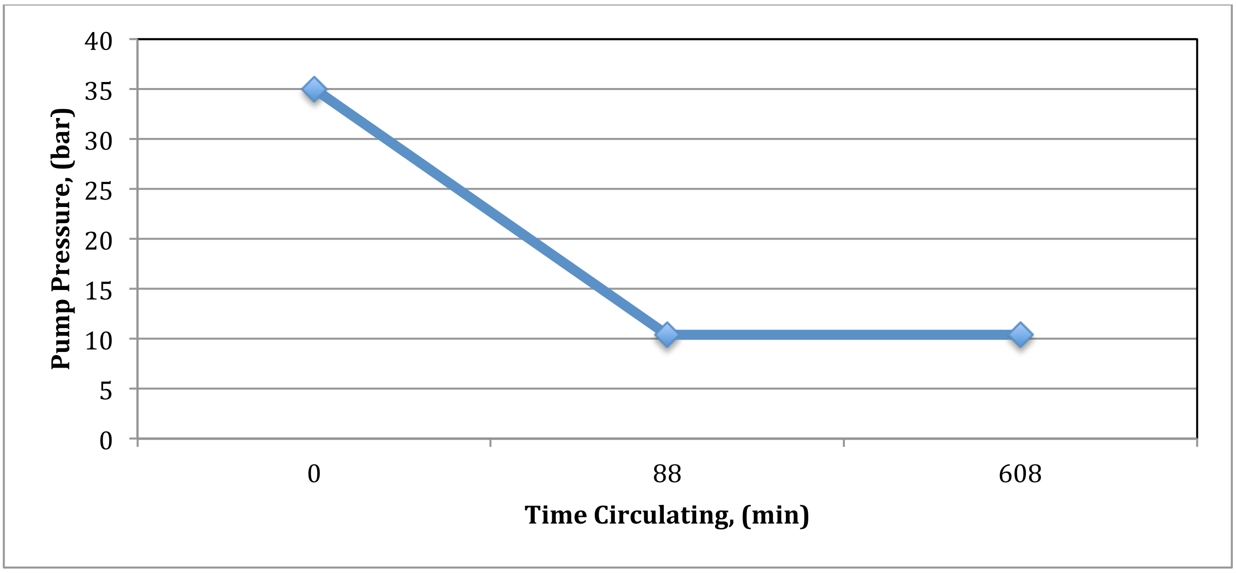


Figure 4-9: Kill sheet for W&W method

4.4 Kick Simulation – Conventional Riserless Method

4.4.1 Simulation Arrangement

The same data given for the well in chapter 4.3 is used in this riserless case, except that seawater depth is at 2148 m.

Apparent mud weight used in chapter 4.3 is 1,24 sg to stay in-between pore pressure and fracture pressure gradient of 1,11 sg and 1,44 sg respectively (figure 4-2).

4.4.2 Kill Sheet Calculation

The kill sheet calculations for riserless operation are based on reference 12.

$$\Delta P_{over} = \Delta P_{SP} + \Delta \mathrm{P}_{fann} \tag{4.16}$$

Where

$\Delta P_{over} =$ Formation Over Pressure [bar]

ΔP_{SP} = Increase in SPP [bar]

$\Delta \mathrm{P}_{fann}$= Friction Pressure Loss in Annulus [bar]

With current inputs equation 4.16 equals

$$\boldsymbol{\Delta P_{over}} = 15 + 10 = \boldsymbol{25\ bar}$$

Kill mud weight can then be calculated from equation 4.17

$$\rho_{kill} = \rho_{well} + \frac{\Delta \mathrm{P}_{over}}{0{,}0981*(h_{TVD}-h_{sea})} \tag{4.17}$$

Where

ρ_{kill} = Kill Mud Weight [sg]

ρ_{well} = Mud Density in well

$\Delta \mathrm{P}_{over}$ = Formation Over Pressure [bar]

h_{TVD} = True Vertical Depth [m]

h_{sea} = Seawater Depth

With current inputs equation 4.17 equals

$$\boldsymbol{\rho_{kill}} = \rho_{well} + \frac{\Delta \mathrm{P}_{over}}{0{,}0981*(h_{TVD}-h_{sea})} = \boldsymbol{1{,}33\ sg}$$

ICP = ΔP_{over} = **25 bar**

FCP = $\frac{\rho kill}{\rho well} * \mathrm{P}_{\mathrm{friction}} = \frac{1{,}33}{1{,}24} * 10 =$ **11 bar**

Calculated Volumes

Volume calculations in table 4-22 are performed in excel, calculated using simple volume calculation formulas. Drill string data will be the same as for conventional case with riser (table 4-19) while annular volume for riserless case are listed in table 4-22.

Well Annulus

Table 4-22: Volume calculations for well annulus

	Length [m]	Capacity [l/m]	Volume [m3]	Pump strokes [stk]
Return Line 6”			39,2	1850
Drill Pipe/Casing	2547	66.6	169,5	8009
DC/Casing	77	58.8	5.1	242
DC/OH	73	52.9	3.9	183
HWDP/OH	150	60.7	9.1	430
Bit/OH	90	56.5	5.1	240
Total			**231,9**	**10953**

Calculations for circulating out the kick

- Pump rate: 30 SPM
- Down time $= \frac{Down\ strokes}{SPM} = 88\ min$
- Up time $= \frac{Up\ strokes}{SPM} = 365\ min$
- Full circulation time $= \frac{Circulation\ Stokes}{SPM} = 453\ min$

Table 4-23: Total strokes and time for circulating out the influx with riserless case

	Strokes	Time [min]	Pump Pressure [psi]
Kick out of the well	10953	365	ICP
Kill mud in whole well	24545	818	FCP

Table 4-23 shows that the total time to circulate out a kick with riserless case is 818 minutes = 13,6 hours.

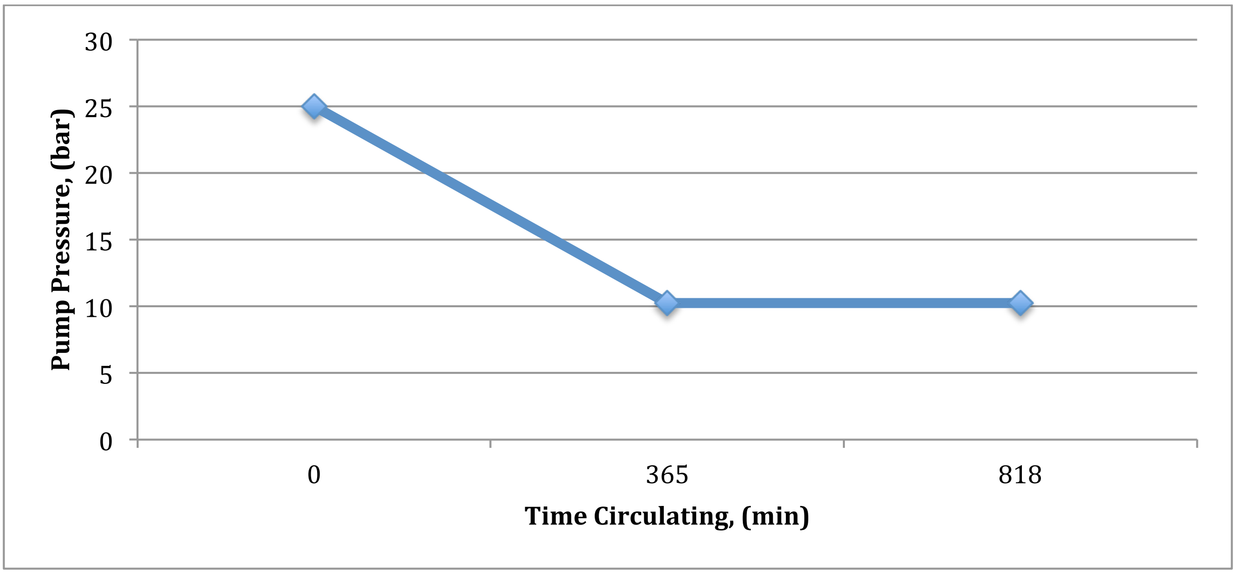


Figure 4-10: Kill sheet for riserless case

4.5 Summary and Discussion – RDM-R vs. Conventional Method

This chapter will discuss pros and cons for the different well control methods evaluated in chapter 4.2 to 4.4 and a table with summary is listed at the end. In the discussions following shortenings are used for Reelwell Riserless Method, Conventional Riser Method and Conventional Riserless Method: RDM-R, CRM, RM.

Time to kill the well

The time from the kick is detected by primary and secondary indicators and the influx is stopped, till the influx is circulated out and kill mud is pumped is less with RDM-R than for CRM and RM, (Table 4-24).

$t_{CRM} > t_{RM} > t_{RDM-R}$

Table 4-24: Time to kill the well

	CRM	RM (hr)	RDM-R
Time [min]	15,6	13,6	8,3

With RDM-R the influx is circulated out through the inner pipe using rig choke, which has less volume than well annulus where RCM and RM circulate out the influx. With RDM-R, kill mud is pumped using annulus access line to fill only well annulus, not the entire well as for RCM and RM, which will reduce the time to kill the well.
With RDM-R a third circulation is required to displace kill mud out of the inner pipe, but the extra time needed for the third circulation does not exceed the total time for the two circulations required for CRM and RM.

Kill mud volume

Kill mud volume required is significantly less for RDM-R, than for CRM and RM, (table 4-25).
$\rho_{kill\ DMR} > \rho_{kill\ RM} > \rho_{kill\ RDM-R}$

Table 4-25: Kill mud volume required

	CRM (m^3)	RM (m^3)	RDM-R (m^3)
Kill mud volume [m^3]	≈ 400	≈ 250	≈ 160

NOTE: Volumes in table 4-25 is with string volume in the well. A safety margin should be applied to the volume required.

With RDM-R, kill mud is only pumped into well annulus through annular access line. This will give a reduced kill mud volume compared to RCM and RM where kill mud volume is pumped down the pipe to fill the entire well volume. For RCM a significantly higher kill mud volume is required since riser volume also must be filled with kill mud.

Logistics on rig – space

For RDM-R and RM the deck space needed for the riser is neglected, which will be beneficial on rigs with limited space. For deepwater wells more joints of riser is required compared to shallow water environment, which will benefit on using smaller rigs for the operation.

Reduced kill mud volume required will result in fewer/smaller mixing and storage tanks and also less chemicals stored on the rig.

Kick detection time

The time to detect the kick is improved for RDM-R as the FCU allows precise control of the returning flow and pressure, which will immediately detect any small amount of influx or loss of fluid. This is very important in this case of deepwater drilling where working pressure window and kick tolerance margin is significantly reduced.

Do not need time to establish SICP, SIDPP but do need the closing sequence time.

With RDM-R the SICP is directly read of the RCD pressure and SIDPP is monitored by slowly pumping down the DDS – therefore time to establish SICP and SIDPP is neglected by RDM-R, which is beneficial when "stand-still" time is crucial.

Smaller rigs can be used

The benefit of being able to use smaller rigs is many. One reason of being possible to use smaller rigs is that a lot of space is removed from conventional drilling since the riser is removed. As the rig is smaller, it will require less expensive station keeping equipment.

Overall costs

The costs of the mud required to fill up the riser in CRM is significantly high, which will be neglected for RDM-R and RM. Day rate on smaller rigs is significantly lower than bigger floating rigs.

Table 4-26 is a summary of chapter 4.5

Table 4-26: Comparison of the tree methods used

Conventional Method With Riser (CM)	**Conventional Method Riserless (CRM)**	**Reelwell Riserless Method (RDM-R)**
Total volume of kill mud greatest (≈ 410 m^3)	Total volume of kill mud greater than for RDM-R, but less than for CM (≈ 260 m^3)	Total volume of kill mud significantly less than for CM and CRM (≈ 150 m^3)
Time to detect kick requires more time compared to RCM and RDM-R	Kick can be stopped without shutting in the well using surface and subsea pump[12]	Quicker to detect the kick with FCU than for CM and CRM
Requires more space: kill mud, riser, BOP…		
	Formation overpressure (SIDPP) can be estimated without shutting in the well[12]	Do not need time to establish SICP and SIDPP.
		Will require smaller rigs

5 WELL CONTROL SIMULATION

5.1 Simulation – Well Plan

As this thesis is focusing on well control, Well Plan has been used to calculate kick tolerance for a specific well. Active mud densities have been changed to look at the different behavior for each of them. The Well Plan results are plotted and the results are showed in graphs.

Choke pressure is simulated in Well Plan to look at the choke pressure behavior for the two different kick control methods previously described (Drillers and Wait and Weight). Graphs are plotted from simulation results in Well Plan where choke pressure behavior for different densities assuming a fixed influx is taken.

5.1.1 Input

Inputs used in this simulation are based on the conventional well previous used in the thesis. The main inputs are repeated below, to avoid having to flip pages back and forth.

Well geometry

	Size (inch)		**Start Depth (m)**	**End Depth (m)**
	OD	ID		
Riser	13 5/8”	13.375”	0	2148
Casing	13 5/8”	12 ¼”	2148	4772
Open Hole	12 ¼”		4772	5084

- Seabed at 2148 m with water density 8,3 ppg

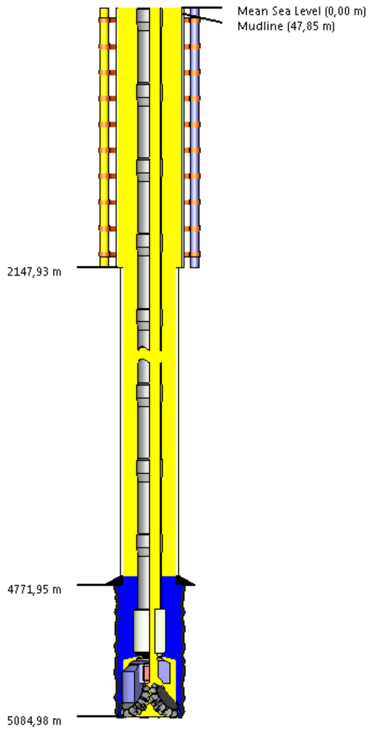


Figure 5-1: Well Schematic

Conventional Drill String Data

Bit OD [in]	12 ¼”
Bit ID [in] - average	3”
Length of bit	90
HWDP OD[in]	5 ½”
HWDP ID [in]	3 ¼”
Length of HWDP [m]	150
Drill Collar OD [in]	6 ¾
Drill Collar ID [in]	2 ¼
Length of Drill Collar [m]	150
Drill Pipe OD [in]	5 ½
Drill Pipe ID [in]	4.67
Length of Drill Pipe [m]	4695
Capacity HWDP [l/m]	4.56
Capacity Drill Collar [l/m]	2.56
Capacity Drill Pipe [l/m]	4.99

The simulation is assuming geothermal gradient and following inputs are used for the calculations:

Initial mud gradient	0.442 psi/ft
Circulation flow rate	250 gpm
Kick interval gradient	0.6 psi/ft
Influx type	Gas
Kill rate	250 gpm
Depth of interest	4772 m

Variables used for simulation:

- Kick volume taken
- Mud densities (8.5 ppg, 9.5 ppg, 10.3 ppg and 10.7 ppg)

Fluid Rheology:

Speed [RPM]	Dial [°]
600	65
300	57
200	42
100	38
6	10
3	8

NOTE: Same parameters for all calculations are used. Simulation with changed fluid rheology showed very small differences. The model used is Power law.

5.1.2 Kick Tolerance – General Theory

Kick tolerance is the maximum volume of gas kick that successfully can be circulated out in a safe manner. Meaning that formation at casing shoe depth does not break or overcome the weakest anticipated fracture pressure in the wellbore.[10]

To calculate kick tolerance, kick intensity is assumed (ppg) at casing shoe depth. Kick volume taken is a variable changed, to calculate maximum allowable volume of gas, which can be taken and circulated out in a safe manner for fixed kick intensity.[10]

Figure 5-2: Kick tolerance limit exceeded

5.1.3 Kick Tolerance – Calculations

Calculations are performed with Well Plan and plotted in excel. The graphs show pressure at casing shoe depth with variable volume of influx taken before the well is shut in. Calculations are performed with Well Plan for different mud densities.

$$P_{csg} = BHP - \left(\rho_{mix} * 0{,}0981 * h_{TVD\ csg}\right) \qquad 5.1$$

Where

BHP = Bottom Hole Pressure [psi]

ρ_{mix} = Active Mud Density with influx [ppg]

$h_{TVD\ csg}$ = Depth difference between true vertical depth and casing shoe [ft]

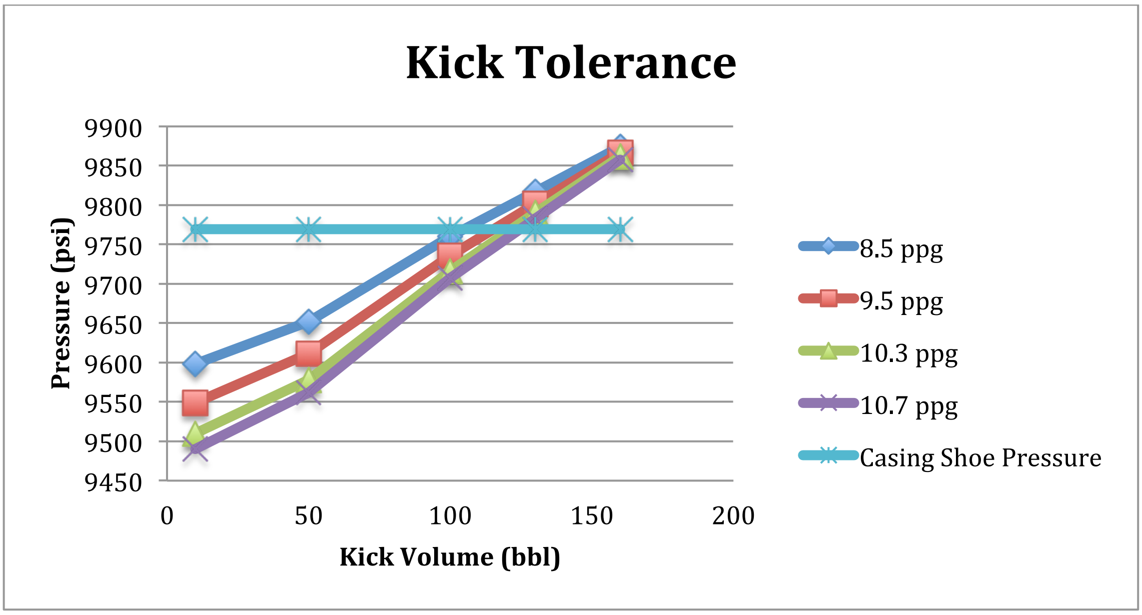


Figure 5-3: Graph based on Landmark Calculation

Graph 5-1 shows kick tolerance for four different mud densities (8.5 ppg, 9.5 ppg, 10.3 ppg and 10.7 ppg). The pressure lines plotted in the graph is based on a fixed kick interval gradient input at 0.6 psi/ft giving listed static BHP, kick interval pressure and following underbalance kick interval after pump shut down:

Table 5-1: Calculated numbers with Well Plan

	8.5 ppg	**9.5 ppg**	**10.3 ppg**	**10.7 ppg**
Static BHP [psi]	7381	8248	8941	9288
Kick Interval [psi]	10 024	10 024	10 024	10 024
Underbalance Kick Inerval [psi]	2643	1776	1083	736

$$BHP = \rho_{mud} * 0{,}052 * h_{TVD} \quad 5.2$$

Where

ρ_{mud} = Active mud density [ppg]

h_{TVD} = True vertical depth, where influx is assumed [ft]

$$Kick\ interval = 0{,}6 \left[\frac{psi}{ft}\right] * h_{TVD} \quad 5.3$$

Where

0.6 = Kick interval gradient [psi/ft]

h_{TVD} = True vertical depth, where influx is assumed [ft]

$$Underbalance\ kick\ interval = Kick\ Interval - BHP \qquad 5.4$$

5.1.3.1 Summary and discussion

As expected pressure at casing shoe increases with increased volume of influx and/or lower density of the active mud (equation 5.1). Increased volume of influx and/or lower density of the active mud lower the overall density in the well, as the influx density is lower than the active mud density.

$$\rho_{mix} = (\rho_{mud} * a) + (\rho_{influx} * b) \qquad 5.5$$

Where

ρ_{mix}= Mixed Mud Density

ρ_{mud} = Active Mud Density

a = Mass Fraction of ρ_{mud}

ρ_{influx}= Influx Mud Density

b = Mass Fraction of ρ_{influx}

$a + b$ = 1

5.1.4 Choke Pressure behavior during kick circulation

As the kick is detected, the well is shut in, and the kick is safely circulated out by controlling the choke pressure. This thesis focuses on two different well control methods, “Drillers Method” and “Wait and Weight Method”. Section 5.3.5.1 and 5.3.5.2 focuses on choke pressure behavior for the different well control methods.

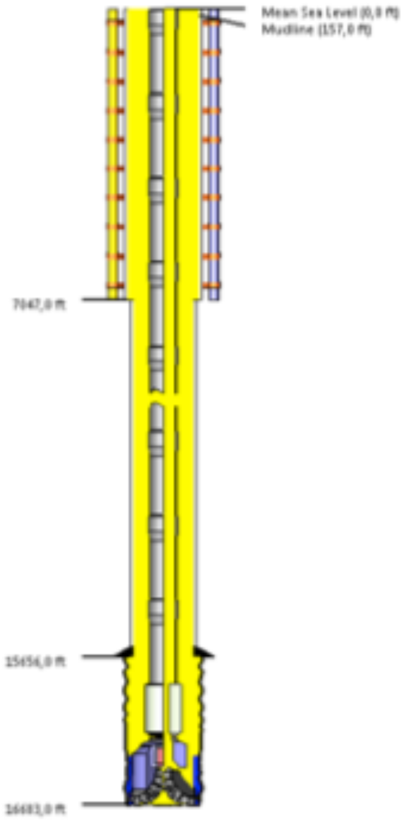


Figure 5-4: Kick influx taken at bit

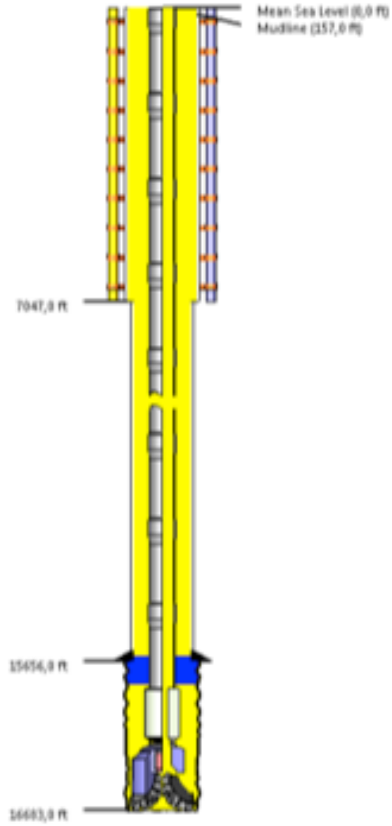


Figure 5-5: Influx at casing shoe

Figure 5-4 and 5-5 show the influx volume movement from where the influx is taken until it is located at casing shoe.

5.1.4.1 Choke Pressure behavior with Drillers Method

The graphs show how the choke pressure behaves as the influx is safely circulated out of the well with Driller's Method. The graphs are plotted based on Well Plan simulation with different mud densities with a fixed influx volume.

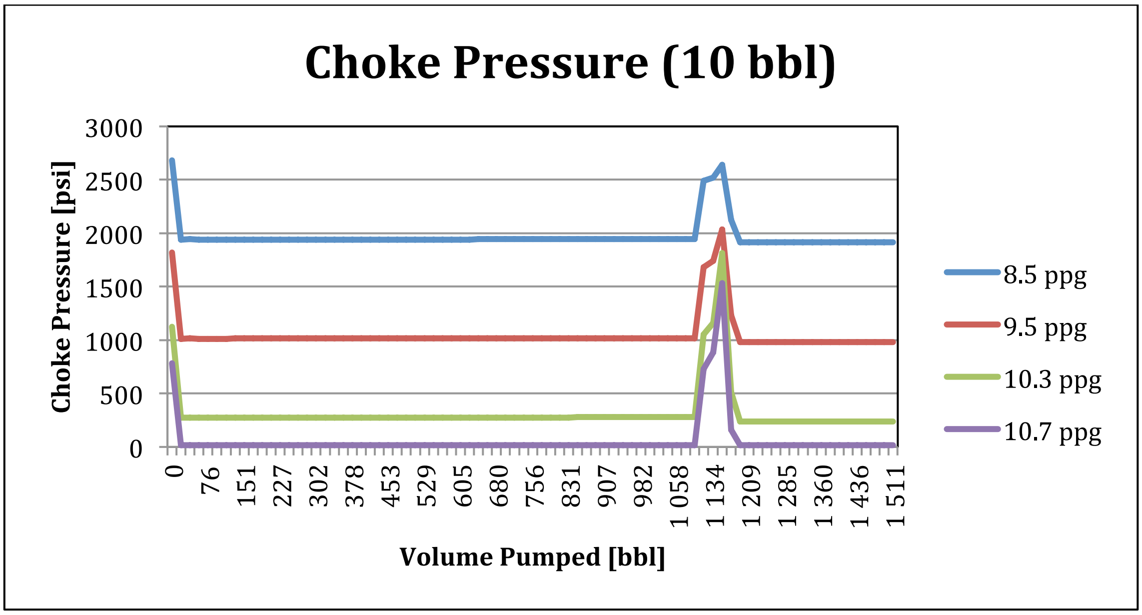


Figure 5-6: Drillers Method - choke pressure behavior when 10 bbl influx is choked out

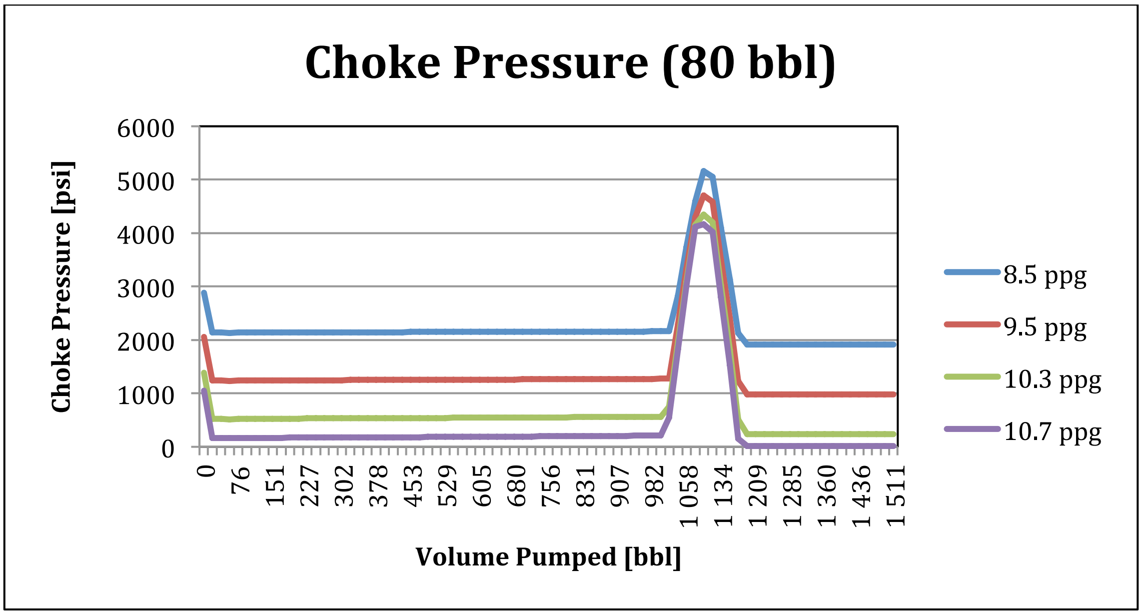


Figure 5-7: Drillers Method - choke pressure behavior when 80 bbl influx is choked out

5.1.4.2 Choke Pressure behavior with Wait and Weight Method

The graphs show how the choke pressure behaves as the influx is safely circulated out of the well with wait and weight method. The graphs are plotted based on Well Plan simulation with different mud densities with a fixed influx volume.

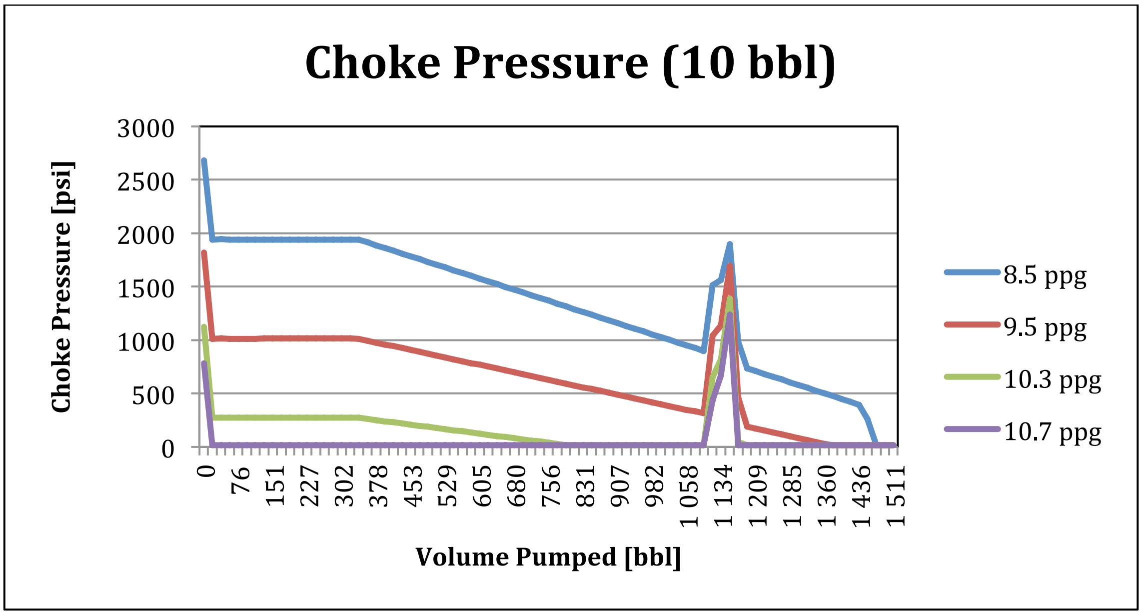


Figure 5-8: W&W - choke pressure behavior when 10 bbl influx is choked out

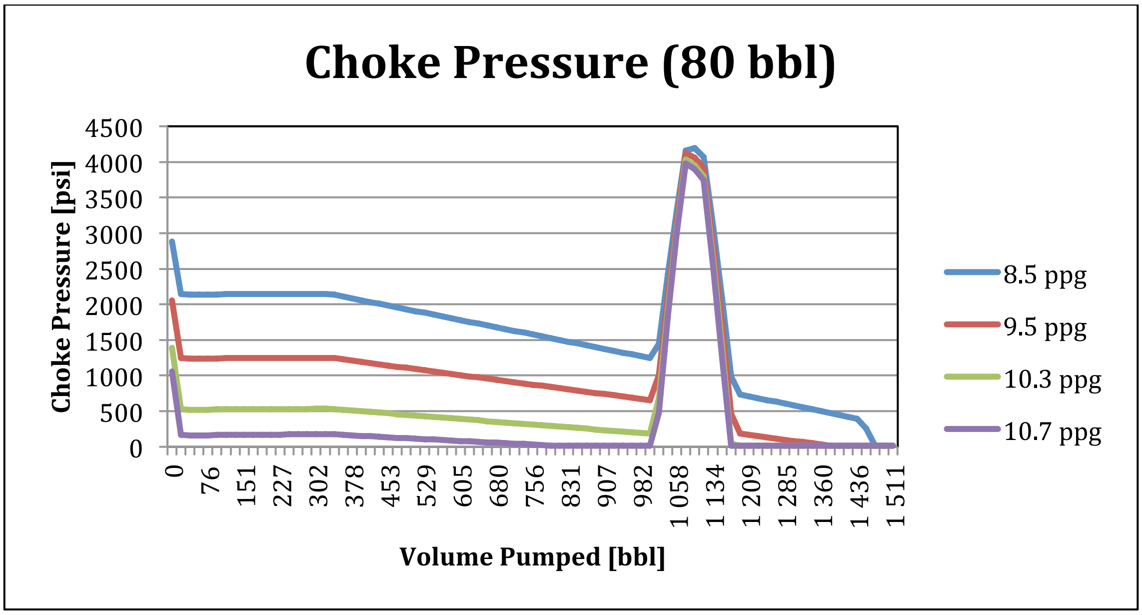


Figure 5-9: W&W - choke pressure behavior when 80 bbl influx is choked out

5.1.4.3 Summary and discussion

As the active mud density in the well increases, the choke pressure decreases for both Drillers Method and Wait and Weight Method, as can be seen in figure 5-6 to 5-9.

6 SUMMARY

Drilling with conventional method in a depleted reservoir, deep-water, HPHT and extended reach wells is very challenging. In order to manage these challenges, the oil industry is developing new technologies such as riserless managed pressure and under balanced drilling methods. However the depth of drilling with the present drilling method is about 12.3km record.

Reelwell As is a new drilling concept with the aim of drilling over 20km. The Riserless Reelwell (RDM-R) method is based on closed loop system. This system allows drilling without riser.

The results show that drilling with the new RDM-R technology saves a lot of kick circulation time.

The costs are significantly reduced due to:

- The use of smaller rigs with lower day rate
- Wait on weather time reduced
- Non-productive time reduction due to precise and reliable well control tools.
- Reduced kill mud volume
- Neglect the reed of the riser

Deepwater environments with narrow pressure working window reduces the kick tolerance margin, which will improve the importance of well control. FCU installed for the RDM-R operation allows precise control of the returning flow and pressure, which immediately detect any small amount of influx or loss of fluid.

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APPENDIX A [13]

The common approach solving flow model in a well is by discretizing the well into segments. The flow is calculated in time through each segment. The transient flow models in each segment is described by a non-linear partial differential equations of conservation of mass and momentum. The equations are then solved numerically.

Conservation of liquid mass:

$$\frac{\partial}{\partial t}(A\rho_l\alpha_l) + \frac{\partial}{\partial z}(A\rho_l\alpha_l v_l) = s_1 \qquad \text{A1}$$

Conservation of gas mass:

$$\frac{\partial}{\partial t}\left(A\rho_g\alpha_g\right) + \frac{\partial}{\partial z}\left(A\rho_g\alpha_g v_g\right) = s_2 \qquad \text{A2}$$

Conservation of mixture momentum:

$$\frac{\partial}{\partial t}\left(A(\rho_l\alpha_l v_l + \rho_g\alpha_g \square_g)\right) + \frac{\partial}{\partial t}\left(A\left(\rho_l\alpha_l v_l^2 + \rho_g\alpha_g v_g^2\right)\right) + A\frac{\partial}{\partial z}p = -A(\rho_{mix}g + \frac{\Delta p_{fric}}{\Delta z}) \qquad \text{A3}$$

where A is area, ρ_i is phase densities (liquid i=l, gas i = g), v_i is phase velocities, p is pressure s_l is source (inflow, leakage, phase transfer between phases), g is gravity constant, α_i is phase volume fractions taking values between 0 and 1

Fluid mix systems

Density and viscosity mixes are given as:

$\rho_{mix} = \rho_l\alpha_l + \rho_g\alpha_g$,

$v_{mix} = \alpha_l v_l + \alpha_g v_g$,

$\mu_{mix} = \mu_l\alpha_l + \mu_g\alpha_g$,

μ_l is phase viscosities

$\alpha_l = 1 - \alpha_g$

Gas slippage model (simple):

$$v_g = Kv_{mix} + S \quad \text{A4}$$

where K =1.2 and S = 0.55

Liquid density model (simple):

$$\rho_l(p) = \rho_{lo} + \frac{(p - p_{0)}}{a_L^2} \quad \text{A5}$$

A6

Gas density model (simple):

$$\rho_g(p) = \frac{p}{a_g^2} \quad \text{A7}$$

Pressure loss/friction loss for a fluid mix system

For density and velocity mixtures, the friction loss term written as:

$$\Delta P = \frac{f.v_{pmix}^2.\rho_{mix}}{D_H} \Delta L$$

Reference Appendix: Steinar Evje and Kjell Kåre Fjelde: "Hybrid Flux-Splitting Schemes for a Two-Phase Flow Model", Journal of Computational Physics 175, 2002, p. 674-701.