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MASTER THESIS

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Abstract

Dual gradient drilling is a manage pressure drilling technique that may extend viability of deep and ultra- deep water drilling and production, in a manner that may be classified as safe or safer, than what can be achieved by conventional means. DGD is especially beneficial in wells with difficult wellbore targets, often characterized by narrow pressure windows. Dual gradient offers the potential to reach the target depth using fewer casing strings, potentially ending up with a hole better suited for completion. This is made possible by utilization of two or more fluid gradients from rig floor to total depth of the well, compared to the conventional single gradient.

Majority of the work completed through this thesis has been assigned around one dual gradient system in particular, the EC-Drill & CMP, which utilize a pumped riser principle. Introducing a subsea pump to take the well returns through an external conduit back to surface, the need for a continuous mud column back to surface is reduced. This fact leaves the mud level in the riser to be manipulated to fit the operation at hand, effectively mitigating wellbore controllability concerns. This system introduces a novel method for improved loss and kick detection, using the rpm/power output to detect unbalance to the system.

To describe how the operability of the EC-Drill & CMP system may be plausible, a Matlab script was created. Further introducing a PI-controller code, which to a large degree renders the system autonomous, even when imposing changes to any of the manipulated variables, mainly topside and subsea pump flow rate, the goal is to maintain as constant a bottom hole pressure as possible. To support the EC-Drill & CMP work, relevant literature covering hydraulic control has been reviewed.

Through extensive case studies provided by BG-Group, dual gradient application areas was outlined and discussed.

Acknowledgement

This thesis is the conclusion of my studies at the University of Stavanger, resulting in a MSc. in drilling engineering. I would like to thank Frode Lefdal and BG-Group for providing me with an interesting and challenging topic. Further thanks go to my supervisor at BG-Group, Rudi Fortman, for providing valuable input and guidance whenever needed.

At the onset of this thesis, my programming skills were very limited; however through the help of my faculty supervisor Professor Gerhard Nygaard, a suitable model was created. Although his passion for automated processes to some degree exceeds my own, it has provided valuable insight in processes outside that of a typical drilling engineer.

I would like to thank my pregnant girlfriend, Jo for allowing me to spend weekends, sunny or not, inside writing; without your support and advice none of this would be possible. Finally, I would like to thank my fellow students during my five years at the university. Teamwork and curiosity has helped us through many long hours and weekends, to the benefit of everybody.

Kristian Wærnes, June 2013

Table of content

List of Tables and Figures

List of Abbreviations:

Pre-BOP- Refer to operations done before a riser and BOP is run and installed
Post-BOP- Refer to operations completed after the BOP and riser is installed
GoM-Gulf of Mexico
BOP-Blow out preventer
LRMP: Lower Marine Riser Package
PID- Proportional-Integral-Derivative
DGD-Dual Gradient Drilling
MPD-Managed Pressure Drilling
SMD-Subsea Mudlift Drilling
RMR-Riser less Mud Recovery
NCS-Norwegian Continental Shelf
ECD-Equivalent Circulating Density
HTHP-High Temperature High Pressure
lpm- Litres Per Minute
ECD-Equivalent Circulating Density
UBD-Underbalanced Drilling
MLP-Mud Lift Pump
RCD-Rotating Control Device
SPU-Solids Processing Unit

1 Introduction

Approaching 2040 the world's population is expected to increase by 25%, making the earth home to around 9 billion people. This increase in population, urbanization, and mobility requirements together with rising electrical need will put a growing demand on the current and future energy suppliers. As of 2010 the oil, gas and other hydrocarbon sources constituted for 55% of the energy mix, this number is, however, expected to grow steadily towards approximately 60% in 2040. [1]This will force the oil and gas companies to broaden their exploration horizon, going into harsher and more hostile environments, developing new and improving existing technology to stay on top of the challenges that new and unconventional resources are expected to create.

In recent developments searching for hydrocarbons in deep water prospects in the Gulf of Mexico, Brazil, West and East Africa, the market has been looking for specialized technology that can address some of the challenges faced with deep water exploration and production. During the last decade we have seen a booming development in new and existing technology, pushing the boundaries of what was previously thought possible. Examples such as subsea compression and separation, ultra long tiebacks, massive floating production storing and offloading units, directional drilling systems, smart wells, automated systems, specialized intervention vessels, real time data transmission and finally dual gradient drilling systems.

Dual gradient drilling works under the fundamental principle of placing a heavier than conventional drilling mud down the hole. In doing so it is possible to generate pressure gradients that may better fit the natural pressure profile of the wellbore. By means of various mechanical devices, the drilling mud may be pumped back to surface through external conduits, effectively separating the well stream from any fluids in the riser.

The dual gradient drilling (DGD) concepts are trying to fill a gap in the deep water segment which has been created due to the steadily increasing number of deep water developments during the beginning of the 21st century. Many of these prospects face challenges such as and/or not limited to:

- Availability of deep water rigs
- Narrow margins between pore-and fracture pressure
- Depleted zones
- Equivalent Circulation Density, ECD
- Well control
- HTHP
- Deep water Access
- Flow assurance, hydrate

It is believed that Dual Gradient technology will provide the necessary tools to effectively drill these wells safely, on time and provide a hole that will match the requirements set by the production engineer.

1.1 Joint Industry Project: CMP-DEMO 2000

The background for this thesis is based upon analysing new and existing dual gradient drilling systems, special focus will however be given to AGR's EC-Drill & CMP drilling solution. The CMP, Controlled Mud Pressure, is effectively a deep water version of the EC-Drill, a concept that is based upon a pumped riser principle. Installed on the riser somewhere below the sea level, a subsea pump powers the return fluid through an external conduit back to surface. This concept reduces the need for a riser fully filled with mud, allowing the mud levels to be adjusted up and down accordingly. The method of controlling the mud levels in the riser provide a fast and efficient way of managing down-hole pressures, as well as providing means of early kick and loss detection. The CMP system enable the circulation of heavier drilling fluids, which in some cases might resemble drilling with kill-mud. Using a light weight blanket fluid/base oil or non-flammable gas on top of the heavy drill fluid, provide the dual gradient benefits.

A simplified sketch of the CMP version of the EC-Drill system is given in Figure 1-1. The EC-Drill-CMP is joint industry project receiving funding from: Demo 2000, Statoil, BP and BG Group. Since the start of the project, the development team has been building upon existing technology and experience gained during development of the well-known riser less mud recovery system, RMR, which AGR have already fully commercialized. Further discussion on the RMR system can be found in chapter 4.3.

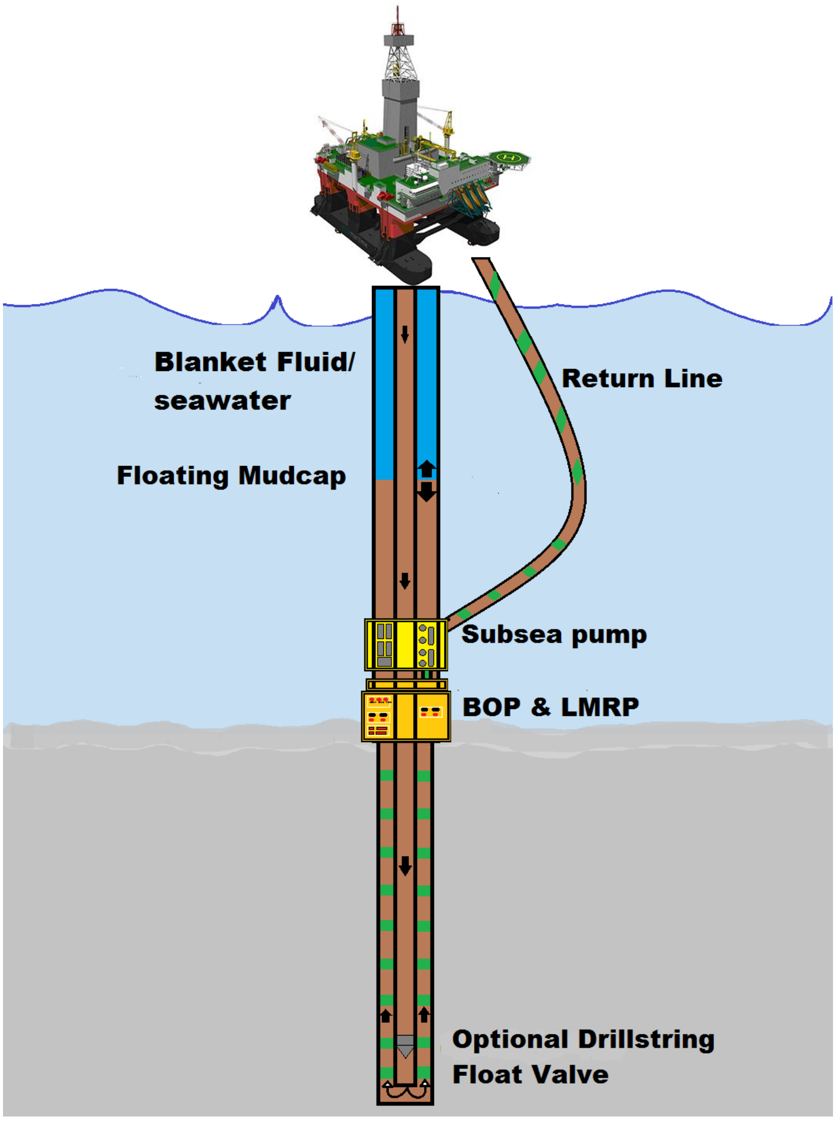

Figure 1-1: Simplified setup scheme for the CMP.

Notice how the subsea pump is installed just above the BOP and LMRP, other locations would typically be anywhere on the lower half of the riser. The EC-Drill setup however, one typically find the outlet closer to the surface, somewhere on the upper half of the riser section.

1.1.1 Troll Field Test

As part of the Demo 2000: Joint Industry Project (JIP), the final verification process of the EC-Drill & CMP system project boils down to a field test on the Troll field somewhere in Q2-Q3 2013. The field test is mainly a test of the operability of AGR's EC-Drill system, two days will however be allocated to test a novel well control system specially designed for the CMP system.

The main goal of the test is to accurately define the working boundary of the system and its ability to detect and operate during well control scenarios. To be able to simulate a well control incident, for safety reasons nitrogen gas, N_2, is used as the kick fluid. Nitrogen gas is a non-toxic, non-flammable gas, which shares similar PVT characteristics to methane gas, which is the most common kick fluid.

Why Troll? Today Troll is experiencing a reservoir pressure depletion of 1-2 bar every year. Since production started in 1995, reservoir pressures have steadily decreased, and parts of the reservoir are now as low as 1,07 sg. The low reservoir pressure has resulted in major problems with lost circulation during drilling and cementing. The pressure has reached levels where conventional drilling operations is becoming difficult. As the operator, Statoil, has been looking into ways of extending production from this giant in many years to come. The test of the EC-Drill & CMP will be the first on the NCS, and will provide valuable information about the sustainability of this new technology.

1.1.2 EC-Drill vs CMP

The EC-Drill is the original pumped riser system developed by AGR, however with it limited to shallow to medium water depths, a new system capable of operating in waters exceeding 2000 meters, the CMP has with a few exceptions, the same equipment installed. More on this will be described later in this thesis. For illustrative purposes, the subsea pump and its outlet is located fairly shallow on the riser, typically located 200-500 m below sea level, the option will also exist for shallower setting depths, depending on regulation demands. Due to relatively short regulation intervals, the EC-Drill will rely on conventional kick and kill procedures, circulating the kick fluid out through the original choke lines, which is made possible through effectively isolating the pump from the riser via a isolation valve. However, when the rams in the BOP is closed, using the EC-Drill will limit the annulus access.

Whereas EC-Drill rely on placing the subsea pump relatively shallow, the CMP, will place the pump just above the well control package (BOP and LMRP). The pump is designed to work effectively in water depths exceeding 2000m. In shallow waters, there will be no difference between a CMP and EC-Drill setup. The inherent difference between the two systems, outside the positioning of the pump and outlet lies in the way a influx is controlled and circulated out. The CMP will for small and medium kicks be able to circulate the kick fluid out through the subsea pump. Annulus access is granted even in cases where BOP is closed, due to choke line being tied in through the pump into the annulus.

Beside the setup scheme of systems, these concepts (EC-Drill /CMP) are not easily separable.

They are technologically similar, only differing in the stated above. Through the work of this thesis the name EC-Drill and CMP may be readily be used interchangeably. For most parts however it is the deep water version, CMP that is being used.

1.2 Scope of thesis

The scope of this thesis will be split into two parts:

1.2.1 Dual gradient drilling technology, what, where and how?

Part of the work has been to review existing or newly developed dual gradient technologies providing a short overview of the most promising concepts. Special focus was given to the EC-Drill- CMP technology.

For future interest, BG-Group has provided relevant well data for the work through this thesis. The data consisted of pressure data, lithology, mud and casing programs, operation duration, information that were extracted from drilling programs and end of well reports. The information was used to try and compare the conventional drilling operation, with that of the dual gradient technology (EC-Drill & CMP), to see if the latter would provide a competitive edge over the conventional way of drilling wells. If DGD technology proved favourable, the work would develop around trying to create a ranking matrix that later could be used to evaluate the benefits of implementing the DGD.

1.2.2 EC-Drill- Automated vs Manual control systems, challenges and benefits:

As an understanding for the EC-Drill-CMP technology developed, some of the major challenges for the technology was how to precisely and accurately regulate the subsea pump and subsequently control riser mud levels. With the help of Professor Nygaard, a simplified hydraulics model was developed in Matlab (Appendix B). The purpose of the model would be to show how the wellbore pressure could be regulated, given a set of imposed changes, namely the pump rate at the topside and subsea respectively. Furthermore, introducing a PI- controller to the model, the goal is to maintain a constant value to the controlled variable, bottom hole pressure respectively.

To achieve very clear data, a number of assumptions had to be made:

- Incompressible
- 1D
- Non rotating drill string
- Constant viscosity
- Constant density
- Quick response time

1.3 Deep Water Challenges

Words like HTHP, deep and ultra deep waters, are frequently mentioned in the media, which in the general public's opinion has become synonymous with risk, having "*Deep Water*" Horizon freshly in memory. Today it has become customary to use the deep water drilling label to distinguish a special kind of drilling. But is it so different than shelf or onshore drilling?

The answer is both yes and no. Firstly the common denominator shared between all drilling activities is the management of people, technology and locations. Although certain technology was firstly intended for offshore operations, more and more of these have found their way into onshore operations, and might very well be the enabling factor for marginal developments. Compliance of local laws, regulation, framework and guidelines, all underlie each well site. Lastly, though differing greatly from country to country, environmental spills will in some form result in legal ramifications. [2]

1.3.1 Narrow operational Window

Perhaps one of the most common and most recognized drilling challenges faced by deep water prospects, is the narrow window between pore and fracture pressure(Figure 2). This is caused by a reduction in fracture pressure gradient, and is generally due to a reduction of the overburden pressure gradient, which for deep water mainly gets its contribution from water. This results in overall reduction of the stress regimes in the rock, and reduction in fracture pressure. Additionally, the structurally weak, low compacted, and unconsolidated sediments commonly found in the shallower formations can often further reduce the facture gradient. Under these circumstances, the operational window formed by the pore- and fracture pressure gradient, will continually decrease as the water depth increases. As a consequence it is not uncommon to see wells having a large number of casing string, small hole sizes at target depth, excessive losses, hole problems or otherwise inability to reach target depth without exceeding fracture limits during well control operations.[3]

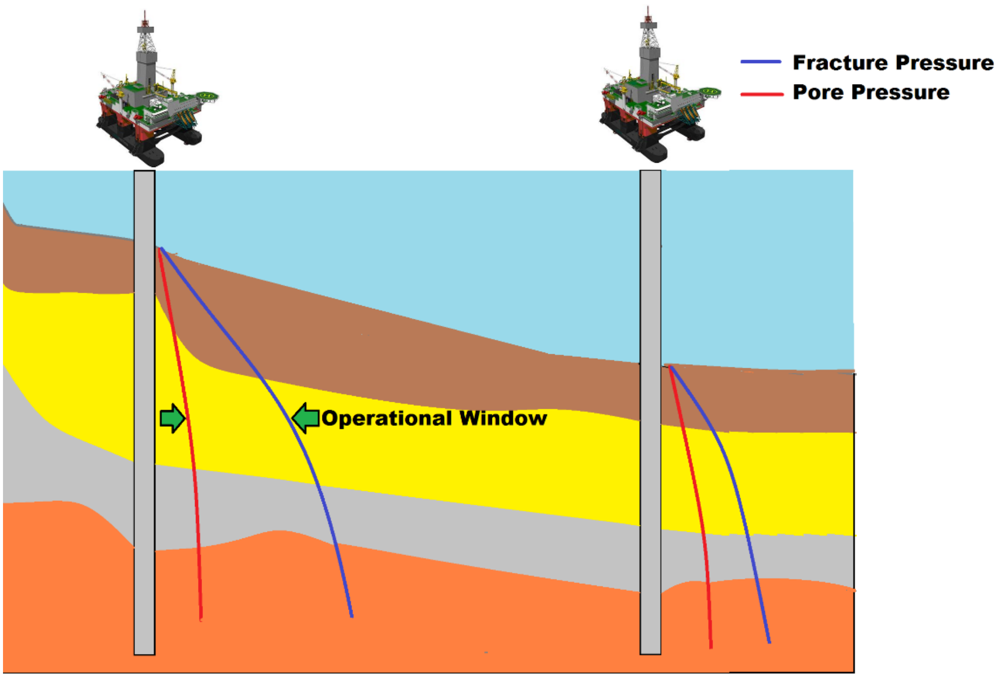

Figure 1-2: Shallow water pore and fracture pressure vs. deep water.

1.3.2 Flow assurance

Deep water exploration and development face yet another problem. As water depths increase, the potential for forming natural gas hydrates also increases. Hydrates with their solid appearance are a mix of natural gas and water that in many ways resemble ice. However, unlike ice, hydrate precipitation can occur at temperatures well above O°C when sufficient pressure is present. This together with the low seabed temperature, is often more than enough to increase the chances of having hydrates forming in and around equipment situated on the seabed, such as the well head, BOP, control valves, flow lines and risers. This problem is not only exclusive to drilling but also plays an important part in how the flow conduit and production system is designed and operated, if the well is to be put on production at some point.

Temperature has yet another effect on the drilling operation. Drilling fluid and cement slurries will be exposed to increasingly longer riser sections; these fluids may then experience a loss of some of its thermal energy. For fluids like cement this may increase the time it takes to set. At the mud line fluids typically thicken in the riser due to exposure to the cold seafloor temperatures. Down hole, the viscosity might be too low to provide sufficient hole cleaning properties, and problems with hole cleaning and barite sag might develop. For cases where longer circulation stops are required, it may be problematic to do a cold start, where the fluid at the mud line has become so viscous that it is hard to regain circulation without generating unwanted pressure pulses through the wellbore.

1.3.3 Marine Drilling Riser

As a result of moving into deeper waters, the design and integrity of the marine riser has become more important. Not only is the cost of acquiring an extra long riser high, but the time spent on running and retrieving the riser is much greater compared to normal water depths. Introducing a longer and subsequently heavier riser, will increase the loads experienced by the BOP and wellhead. Not just considering the static buoyed weight of the riser, but also the way it naturally moves with ocean currents, wave motion, pressure effects (burst/collapse), the rig moving in three dimensions (x,y,z), compressive and tensile loads, and thermal loads, are among some of the most reviewed by the literature. All of these are contributing to the overall stress regimes experienced at the wellhead and BOP, where maximum stresses are experienced. Not forgetting the load hanging from the drilling vessel when running or retrieving the riser, may require 5th and 6th generation drilling vessels. Special focus has however been put on developing slim, lightweight, strong and flexible systems to dampen the riser motion and related forces.

1.3.4 Shallow- Formation Hazards

The top soil of most formations share the risk of having multiple shallow hazards, including shallow gas, boulders, collapsing formations and shallow water flow, all of which are not exclusively deep water related problems, but however somewhat more risk associated when introducing greater water depths . For most cases however, as the overburden is reduced, which is the case for deep water, it naturally follows that the unconsolidated formations are highly sensitive to flow and pressure changes. Operators have so far relied on using seismic data to quantify the risk of encountering these shallow hazard phenomenon on any given well. Included in the name, most shallow hazards are typically located in the first 800m below the mud line and are often encountered while drilling in riser-less mode. Stopping the shallow water flows or gasses from flowing into the wellbore may in some cases can be difficult. Increasing the mud weight has in most cases been successful; the downside of this is the large quantities of weighted mud being lost to the ocean. If the shallow hazards are not properly accounted for, continuously flowing wells may undermine the structural integrity of the well and even affect neighbouring wells.[4]

2 Drilling Introduction

When drilling wells today, the basis for a large part of the well design is based upon how the formations will react when we drill through them. Some formations are extremely hard, stable and very predictable, while others might have gone through a series of geological changes that might render them weak, unstable and highly unpredictable. Perhaps one of the most important parameters to know when drilling, or planning to drill a well today are pore- and fracture pressure. The challenge for most operations is however to stay within this so called operational window, which pore and fracture pressure represents.

The primary focus of the following chapter will be to define all the necessary theory, enabling the wellbore pressure to stay within the pore, collapse and fracture window, namely the hydrostatic, frictional and back pressure. Stating the importance of pore and fracture pressures it might be worth mentioning, that not all is decided according to the drilling window, other parameters need to be considered, such as:

- Lithology, and how each will influence the operation
- Faults
- Permeable zones (hydrocarbon bearing, risk of going on losses)
- Rate of penetration
- Bit configurations
- Optimal drilling parameters (WOB, flow rates, rpm, etc)
- +++

These only represent some of the most predominant, some are more important than others. Taking all these eventualities into consideration might be difficult, but most necessary. Should initial plans fail, the importance of having contingency systems and equipment to deal with such an eventuality is essential.

2.1 Bottom Hole Pressure

For most conventional and managed pressure drilling operations, the operational window represents pressure boundary points where one is expected to have the well under control. To act as a point of reference, the bottom hole pressure is normally the part that is the most relevant to control of all the wellbore parameters.

During drilling, however, there exist a number of parameters that will influence the BHP, which sometimes makes it challenging to accurately predict or measure its size. These parameters include fluid properties such as density, rheology, viscosity and compressibility; true vertical depth, hole geometry, flow rates, ROP, drill string rotation, surface backpressure, drill string and bit configuration. All of which will affect the overall pressure distribution throughout the wellbore. The goal for most drilling operations is to have a constant wellbore pressure, set high enough to avoid influx, prevent hole instability while at the same time not to exceed the formation strength and to avoid losses.

Off all the parameters stated above, most can be further divided into three main categories:

- Hydrostatic pressure, P_h
- Circulating frictional pressure drop, P_f
- Surface backpressure, P_b

If applicable, all of these pressures will generate the overall bottom hole pressure equation that for the purpose of this thesis, is the entity most important to control, and may be written as:

$$P_{BHP} = P_h + P_f + P_b \text{ , } \qquad \text{(Eq 2.1)}$$

The following chapter will try to provide the reader with theory and principles enabling safe and effective hydraulic control.

2.1.1 Hydrostatic Pressure

Pressure is one of the most important parameters to understand when planning, drilling and producing from any given well. Scientifically, pressure is defined as the force acting perpendicular to a surface unit area, and has the SI-unit Pascal after the seventeenth-century philosopher and scientist Blaise Pascal.

There has throughout history been many ways of displaying pressure, some of which were developed simply because they were more practical in everyday life. For the remainder of this thesis, SI-units will be used if not stated otherwise.

In general pressure is defined as follows:

$$P = \frac{F}{A} \text{ , } \qquad \text{(Eq 2.2)}$$

P: Pressure [Pa]
F: Normal Force [kgm/s2] or [N]
A: Area [m2]

Although this expression is very important, it is not always possible to measure the force at any given point under the seabed. Hence a more useful expression for hydrostatic pressure has been derived. The pressure in question would have to be created by a fluid in equilibrium due to the force of gravity. In equation 2.1, the pressure is defined as the force exerted on a given area, it is possible to determine the hydrostatic pressure using a control volume analysis. This method is built on the principle of dividing the entire fluid column system into infinitesimally small cubes that represent the property of that exact cell and then summing the properties of each and every one of these individual cells, represented by the integral of the entire system. The hydrostatic pressure can be calculated according to the following formula[5]:

$$\Delta P = \frac{1}{A}\int_{zo}^{z} \rho A g dz \text{ , } \qquad \text{(Eq 2.3)}$$

ΔP: Represent the difference in pressure between the initial and end point value
z: height above an arbitrary datum
A: force Area

ρ: Density of each cell
g: gravitational acceleration

Applying the assumptions that the fluid system is incompressible and that the height of the fluid column is so small compared to the radius of the earth, making g≈ *constant.* It is possible to develop the hydrostatic pressure equation as we know it:[6]

$$P = \rho g z \, , \quad \text{(Eq 2.4)}$$

P: Pressure[Pa]
ρ: Density of fluid [kg/m^3]
g: Gravitational acceleration≈ 9,8 m/s2
z: True vertical depth, TVD [m]

For convenience sake, the drilling industry have made their own way of denoting pressure, often using the mud density as a reference. To convert from pressure into something more conceptual, the hydrostatic pressure equation is transformed to equivalent density:

$$\rho_e = \frac{P}{g\,Z} \, , \quad \text{(Eq 2.5)}$$

In metric units, the gradient equation is transformed into:

$$\gamma(SG) = \frac{P}{0{,}0981\,Z} \, , \quad \text{(Eq 2.6)}$$

where z is meters and P is in bar.

$$\gamma_{(SG)} = \frac{\rho_e}{\rho_{water}} \, , \quad \text{(Eq 2.7)}$$

The specific gravity is the ratio of the actual density to the density of water. This way of denoting the pressure is preferred in most drilling applications, because it is depth-independent and can be directly compared with the static mud weight. Although certain situations where transient fluid processes are taking place, such as circulating out kicks and displacement of cement, it is preferable to use pressure as generally stated in equation 2.4. [7, 8]

2.1.1.2 Density

As the wells drilled today become more extreme, the down hole conditions follow the same trend, often resulting in higher temperature and pressure regimes in which the drilling fluids has to endure. These large conditional differences from the surface to the reservoir can result in changes to the drilling fluid properties that, if not accounted for, in worst cases, can lead to well control issues and /or excessive non-productive time.

Although the majority of liquids are described as incompressible, fixed density, which in everyday life might be a fair assumption. For a drilling system, however, introducing fluids (liquid/gas/solid) having different chemical, thermal and compressible properties might fail to align with the constant density assumption. The industry has yet to develop suitable PVT (pressure-volume-temperature) correlations for these fluids, primarily due to great variation from one type of fluid system to another, furthermore there is lacking availability of test equipment capable of testing in the HTHP range.[9]

When comparing the density of liquids with that of gases or gaseous fluids, the liquid density is typically to a small degree affected by pressure and temperature. Hence it might be beneficial to differentiate between the two systems, due to the inherent difference in characteristics. For non-gaseous fluids however, capturing the temperature and pressure effects can be made through the full linearized equation of state and can be written as:

$$\rho = \rho_0 + \frac{\rho_0}{\beta}(P - P_0) - \rho_0 \alpha (T - T_0) \text{ , ... (Eq 2.8)}$$

Contained within the equation, P_o, ρ_0 *and* T_0 define the reference points for the linearization, meanwhile β denotes the isothermal bulk modulus of the liquid and α is the cubical expansion coefficient. Note, the negative sign in front of the expansion coefficient,α. Logically an increase in temperature during constant pressure conditions, will if calculated with the linearized equation of state, create a drop in density. Whereas the bulk modulus is trying to capture the effects of changing density as a result of increasing pressure, and this time with constant temperature.

The stiffness or compressibility of a fluid is denoted by the inverse of the bulk modulus, C=1/ β. And may in some applications like MPD be a very important property to capture, more so than the cubical expansion factor. Whereas the pressure transient/pressure wave moves through the well in matter of seconds, thermal pressure transients however work in the matter of minutes or hours, and might may only be reason for concern during prolonged circulation stops, or stopping for connections. Moving into high temperature environments, temperature effects cannot however be fully ruled out, as the following example will clarify.

As an example, two wells, both 5000 mTVD, bottom hole temperature of 165 degree Celsius, both wells contain a fluid with atmospheric (1 atm, 15 deg C) density ρ_0= 2000 kg/m^3. The only difference between these wells is the compressibility of the fluids. One is incompressible ($\beta \rightarrow \infty$), while the other have a bulk modulus and cubical expansion coefficient equal to that of diesel oil (β=16500 & *α=0,00082/deg C*). Diesel is one of the most common base fluids in oil based muds and is normally used in highly reactive formation or HTHP environments.

The accuracy of the linearized equation is not unlike most other empirical data sets, and become less accurate with wider range. For most drilling fluids however, this equation is fairly accurate within the 0 / 500 bar and 0 / 200 degree Celsius range

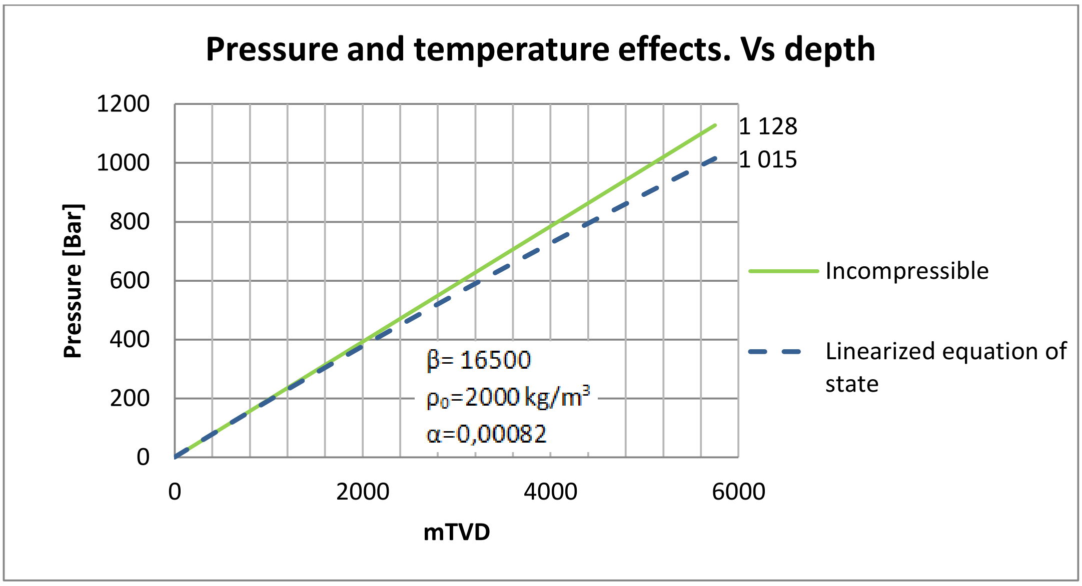

Figure 2-1: Combining temperature and pressure effects for a incompressible and compressible fluid. Linearized equation of state.

Figure 2-1 displays an idealized example, designed to show the reader the importance of considering the compressibility or expandable properties of conventional drilling fluids. There may however be other properties that can affect this plot in other ways, such as free or disolved gas, temperature variations in the formations, solids content in the wellstream, mud additives, circulation rate, and backpressure. It is however important to keep in mind that the values for bulk modulus and cubical expansion factors are values generated in a laboratory environment, which does not represent the effective values out in the field. An important property with any drilling hydraulic system, is that the compressibility is greatly increased (β is reduced) with small amounts of entrained gas, or conduit elasticity (casing/pipe). However outside the scope of this thesis, the bulk modulus for a gas can be derived from the ideal gas equation, while the bulk modulus of a container can be derived from material elasticity formulas.[10]

One more thing to keep in mind is when circualtion is stopped and the wellbore becomes static, the temperature of the wellbore mud will start to equal that of the geothermal gradient of the formation. Typically resulting in a overall temperature increase of the mud. Since the wellbore is typically a fixed volume, the mud volum has no other option than to expand as density is reduced. This increase in volume can, if not properly understood, help to disguise or mimic a flowing well. To prevent the wellbore being closed in on a regular basis, based on errorusly assumtions of a flowing well, the technique of fingerprinting is normally used. Fingerprinting, further described in chapter 4.5.2.5, is used to record the response of the wellbore at stages through the operations, as a tool to impose limits for what is normal or abnormal behavior of the well. Other wellbore behavior that is typically monitored, besides temperature and pressure effects are, ballooning effects and hole fill up during tripping.

2.1.1.3 Rheology, Shear Rate, Shear Stress

Rheology deals with deformation and flow of matter, and provides a description of the relationship between shear stress, τ, experienced by the fluid, and the shear rate, γ, of the fluid.

Considering the classical case of two parallel plates, sufficiently large, so edge conditions can be neglected. Plates are at a distance Y from each other, having a fluid fill the space between them. The lower plate is stationary, while the upper moves with a constant velocity U. The force required to maintain the constant speed is given by:

$$F = \mu A \frac{U}{Y}, \quad \text{(Eq 2.9)}$$

Where the constant µ represents the dynamic viscosity. The ratio U/Y is the shear velocity.
By introducing the shear stress as described:

$$\tau = \frac{F}{A}, \quad \text{(Eq 2.10)}$$

Where shear stress has the annotation, Pa or N/m^2. Inserting into equation 2.9 , readily creates the expression:

$$\tau = \mu \frac{U}{Y} = \mu \frac{dU}{dY}, \quad \text{(Eq 2.11)}$$

Where the shear rate has the annotation, s^{-1}, and is written:

$$\dot{\gamma} = \frac{dU}{dY}, \quad \text{(Eq 2.12)}$$

Plotting shear stress against shear rate for different fluids, generates the following graph [11]:

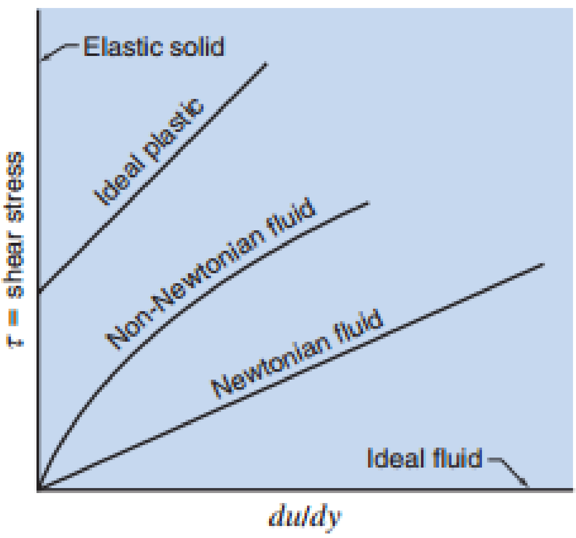

Figure 2-2: Show how shear stress varies with shear rate for various types of fluid. [12]

Where the slope of the graphs gives the viscosity:

$$\mu = \frac{\tau}{\gamma}, \quad \text{(Eq 2.13)}$$

If the viscosity is independent of the shear rate, the fluid is called a Newtonian fluid. Water, brines, and gases are examples of Newtonian fluids. Most drilling fluids and their viscosity however are to a large degree shear rate dependent, and they exhibit a non-Newtonian, pseudo plastic behavior. Over time and by applying a shear stress, the fluid structure is continuously broken down, before rebuilding the original structure as soon as the fluid comes to rest. For drilling fluids this is a very important and desirable property, which is called shear-thinning. This property helps lower the frictional pressure drop in the drill pipe where shear rate is high. However when the fluid enters the annulus where the shear rate is significantly lower, the fluid rebuilds its structure and exhibits yield stress. The presence of yield stress will keep the drill cuttings suspended if circulation is stopped, effectively preventing settling of solids.

To accurately create hydraulic models for a wellbore system, it is important to understand how the drilling fluid will behave during different flowing conditions. In light of this, the Fanning friction factor is defined as the ratio of wall shear stress to kinetic energy of the fluid element, and plays a determining factor in fluid dynamics analysis.

$$f_f = \frac{\tau_w}{K_E} = \frac{2\tau_w}{\rho\, U^2} \text{ , ...} \text{ (Eq 2.14)}$$

Where

$$\tau_w = \frac{\Delta P\, D_h}{4L} \text{ , ...} \text{ (Eq 2.15)}$$

Substituting the wall shear stress, τ_w, into the fanning friction factor equation, in turn make the well-known the Fanning Friction equation:

$$\left(\frac{dP}{dX}\right) = \frac{2\, f_f\, \rho\, U^2}{D_h} \text{ , ...} \text{ (Eq 2.16)}$$

$\frac{dP}{dX}$: frictional Pressure loss [Pa/m]
Dh: hydraulic pipe diameter [m]
f: friction factor
ρ: density [kg/m3]
U: fluid velocity [m/s]

In order to use the frictional pressure drop equation above, the friction factor at laminar or turbulent flow must be calculated.[13] This will be explained later in this chapter.

2.1.1.4 Viscosity

The viscosity of a fluid is a measure of its resistance to shear or angular deformation. The easiest way of explaining what is meant by this is perhaps by using examples of fluids with low and high viscosity. High viscous fluids, such as honey, exhibit a high resistance to shear, are cohesive and feel sticky, while a low viscous fluid like water, exhibits completely opposing properties.[12, 14] The governing equation for viscosity is derived in equation 2.13.

For a real life drilling system the viscosity of the drilling fluid plays an important part in cuttings transport, pump force, but more importantly, contributes to the size of the frictional pressure drop of a drilling fluid system. Viscosity is however one of the parameters which is seemingly always set to a constant. In some drilling applications this assumption may seem fair, but moving into HTHP environments where temperatures can exceed 200 degree Celsius and down hole pressure above 15,000 psi, the assumption of constant viscosity might no longer be valid.

The viscosity of a liquid drastically decreases with increasing temperature, whereas pressure to some degree works in the opposing direction- an increase in pressure will increase the viscosity. Furthermore, figure 2-7, shows how the viscosity of liquid and gases vary as a function of temperature. The properties of viscosity in general can be written as:

$$\mu = \mu(Pressure, Temperature, time) \text{ , } \ldots\ldots \text{ (Eq 2.17)}$$

Where time in general indicates that drilling fluids are non-Newtonian, shear rate and time dependent.

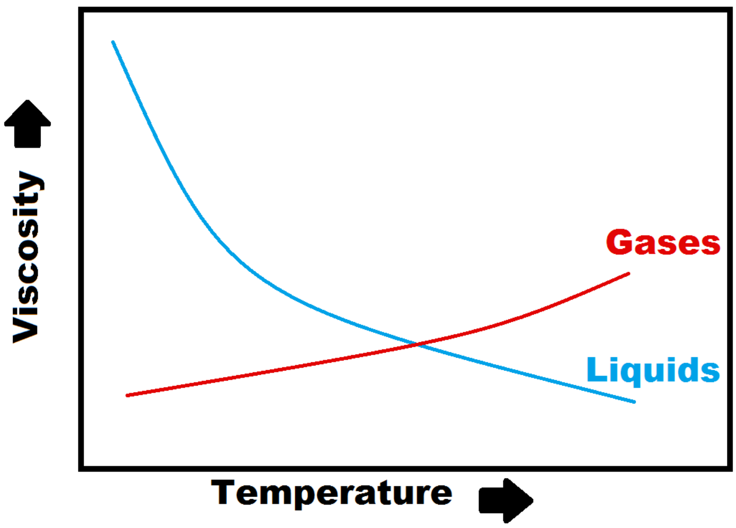

Figure 2-3: Viscosity vs temperature, liquid and gas.

For fluids, the effects of pressure is typically negligible compared to temperature, making viscosity highly temperature dependent. Viscosity of gases are however more perceptible to pressure variations. Viscosity of gases is for the purpose of this thesis neglected. Moving away from standard conditions (15 degC/1atm), the equation for absolute viscosity can be denoted by:

$$\mu = \mu_o e^{-\lambda(T-T_0)} \text{ , } \ldots\ldots \text{ (Eq 2.18)}$$

μ: Absolute viscosity
μ_0: Viscosity at reference temperature
λ: Constant dependent on fluid
T_0: Reference temperature
T: Temperature at area of interest

To a high level of accuracy equation 2.19, enables the prediction of the viscosity profile throughout the wellbore. This calculation can help create mud systems that account for the varying change in viscosity, which in turn will affect cuttings transport and frictional pressure profile through the well.

2.1.2 Circulation Frictional Pressure Drop

Due to the complex nature of most drilling systems, it is very hard to produce accurate models that will account for all the varying parameters. This will often result in having to make a number of assumptions, such as:

- The drill string is placed concentrically in the casing or open hole
- It is a non-rotating drill string
- The section of the open hole are circular in shape and of known diameter
- The flow is 1D
- Isothermal flow
- The drilling fluid is incompressible

None of the assumptions stated above are fully valid, but enable the creation of simple and fairly accurate systems that can be described mathematically. From a drilling engineer's perspective, it is more important to be able to calculate the frictional pressure drop and if the annulus flow is sufficient to effectively transport the cuttings out of the wellbore.

To obtain the frictional factor and hence the frictional pressure drop, certain factors need to be known:

- Pipe Diameter, D
- Fluid viscosity, μ
- Fluid Density, ρ
- Wall roughness, ϵ
- Flow velocity, U

Modelling fluids in motion is a very challenging topic, due to the ever changing properties, nothing ever stays constant. The work through this thesis will however be based upon assuming 1D single phase flow and incompressible fluid, the Reynolds number can readily be calculated as:

$$\mathrm{Re} = \frac{\rho\, U\, D_h}{\mu}\,, \quad \text{(Eq 2.19)}$$

ρ: density [kg/m^3]
U: fluid velocity [m/s]
D_h: hydraulic diameter [m]
μ: viscosity [$N \times S/m^2$)]

For the wellbore annulus, the hydraulic diameter is given by

$$D_h = D_w - D_{DP}\,, \quad \text{(Eq 2.20)}$$

where, D_W is the wellbore diameter, and D_{DP} is the drill pipe OD. Although the absolute values of the defining range for the Reynolds number vary somewhat through the literature. The limits between laminar, transient and turbulent are often listed as follows:

- $Re \leq 2300$: Laminar flow
- $2300 < Re \leq 4000$: Transition between laminar and turbulent flow
- $4000 < Re$: Turbulent flow

The friction factor, f, is obtained by applying a set of different equations based on the type of flow regime (laminar or turbulent flow).[15]
For low Reynolds numbers ($Re \leq 2300$) the flow is said to be most laminar. For laminar flow, Fanning friction factor holds most valid, and is calculated as follows:

$$f_{(laminar)} = \frac{16}{Re}, \quad \text{(Eq 2.21)}$$

Insert the friction factor into equation 2.17 we readily calculate the frictional pressure drop per unit length of the wellbore. By further multiplying the same equation with the length of the wellbore, it is possible to obtain the total frictional pressure drop. Using the Fanning friction factor as described in equation 2.22, is only applicable for one-phase, incompressible, laminar flow; most flows however are to a large degree turbulent.

During circulation the goal is to have an annular flow that is within the turbulent range throughout the entire well interval, to provide best cuttings transport properties. To accurately account for being within the turbulent range of the scale, a new friction factor equation needs to be deduced. It is not surprising that a large number of turbulent flow equations exist that try and give the most accurate factor. Some of the equations are fairly straight forward, allowing you to simply enter the numerical values, while other require some more work in the form of iterations. Out of all, the Haaland (1983) friction factor is thought to give the most accurate numerical value of the friction factor:

$$\frac{1}{\sqrt{f}} \approx -1{,}8 \log_{10}\left(\left(\frac{\frac{\varepsilon}{D}}{3{,}7}\right)^{1{,}1} + \frac{6{,}9}{Re}\right), \quad \text{(Eq 2.22)}$$

After giving a brief review of the literature into one phase flow, it might be useful to mention that most systems however, contain two or more fluids, or so called multiphase flow, not unlike most drilling fluid systems. For this thesis however, multiphase flow is not discussed.[16]

2.1.2.2 Equivalent Circulating Density

As in the static fluid case, the drilling industry likes to refer to pressures as something more conceptual, using specific mud gravity. The same is valid for the frictional pressure drop. Creating a specific gravity that accounts for both the hydrostatic of the system and the frictional pressure is beneficial. This value is called equivalent circulating density or ECD and is calculated accordingly:

$$ECD = \frac{P_{friction}}{0{,}0981 TVD} + \gamma_{mud}, \quad \text{(Eq 2.23)}$$

ECD: equivalent circulating density [S.G]
$P_{friction}$: annulus frictional pressure drop [bar]

TVD: true vertical depth [m]
γ_{mud}: specific gravity of annulus mud [S.G]

Failure to accurately predict the ECD may in some cases result in well control and well instability issues, which may result in extra rig time and cost. Later in this thesis some of the concepts being described, was developed purely as a measure of managing the wellbore pressure profile more closely, or accurately account for the ECD.

2.1.3 Pipe Rotation and Movement

During normal drilling operations, the drill string and the equipment in the bottom hole assembly is subjected to enormous loads. These loads may with time require for some equipment to be changed due to breakdowns or excessive wear.

An operation where drill string or other equipment is being run into hole or pulled out of hole, is normally called tripping. Problems associated with tripping are the positive (trip in) or negative (trip out) pressure surges that occur as the drill string is run in/out of the hole. Irregular tripping practices are one of the major reasons for well control related issues. A kick occurring while tripping out of hole is called a swabbed kick. Generating higher pressures while tripping in may result in lost circulation or fracturing the formation. The best way of indicating if a kick has been taken while tripping, is to measure if the volume of mud required to fill the hole completely (conventional) or to a preset level(LRRS), is the same as the volume of steel removed (normally tested after pulling 4-5 drill pipe stands). The pressure surges can typically be reduced by introducing novel tripping practices which typically resolve around reduced tripping speeds or circulation while tripping.

Drilling does not only evolve running the drill string up and down, but also to a large degree rotation of the drill string. Predominantly the only way of transferring energy from topside to the bit down hole has been to put weight on bit and rotating the entire string, unless a down hole bit motor is used. Many experiments have been conducted to see how cuttings transport and fluid friction is affected when rotation is initiated.

So far it seems like the research has not come to a clear and concise answer. But most agree that drill string rotation will generate two opposing effects, one being that the rotation increases the absolute velocity of the circulating mud, resulting in an increase in friction loss, and a higher BHP. While the other effect is by increasing the velocity generally improve the cuttings transportation, which leads to improved hole cleaning, which results in a lower BHP. Which one of these opposite effects are the dominating depends on the magnitude of RPM, ROP and cutting size, but usually it is the lowering of the BHP that dominates. Rotation of the drill string also has other beneficial effects such as lowering the torque and drag, reducing the likelihood of the pipe becoming stuck.

2.1.4 Rate of Penetration

Drilling with a high ROP may generate sufficiently large volumes of cuttings preventing proper hole cleaning. In this case, cuttings might start to accumulate in the drilling fluid. Generally, the cuttings generated have a much higher density than that of drilling fluid. Having large quantities of cuttings accumulate in the wellbore may result in a large increase in the hydrostatic and frictional pressures;

additionally the risk of having a stuck pipe or twist off is significantly increased. Practices ensuring proper hole cleaning should always be in place. Balancing high flow rates and resulting increase in friction and chances of washing out formation, against low flow rates that might not be sufficient to clear the cuttings from the wellbore, increasing the hydrostatic bottom hole pressure.

2.1.5 Wellbore Geometry

The geometry of the well and how the drill pipe is located will to some degree affect the overall flow profile of the wellbore. Applying the principle of conversation of mass, incompressible 1-D, steady state flow it is possible to deduce the following expression:

$$Q_{inn} = Q_{out} \;, \quad \text{(Eq 2.24)}$$

where the flow into one end is equal to that coming out at the end. Furthermore the flow velocity is given by:

$$V = \frac{Q}{A} \;, \quad \text{(Eq 2.25)}$$

$$A_1 V_1 = A_2 V_2 \;, \quad \text{(Eq 2.26)}$$

Here the subscript 1, represents the flow area and velocity before the restriction, and the subscript 2 represents the same parameters, only here at the restriction respectively.

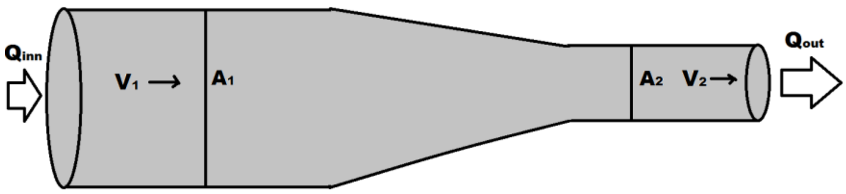

Figure 2-4: Flow through a restriction.

This expression is helpful to measure the fluid speed through orifices or other restriction in the wellbore. Generally, narrow flow paths as a result of bulging formation and/ or down hole equipment, will typically generate higher flow velocities than open sections where the clearing between pipe and formation/casing is larger. Additionally, an uneven formation wall will generate more turbulent flow, compared to a smooth surface wellbore bearing in mind that the speed of the fluid plays an important part for cuttings transport, flow regime and subsequently fluid friction.

2.1.6 Surface Backpressure

The last and final part affecting the bottom hole pressure, also represents the fastest way of regulating down hole pressure profiles. The method of back pressure is the enabling factor for both underbalanced operations and managed pressure drilling. Although fundamentally different, both concepts work as a closed pressurized system, routing the return flow through a choke manifold. By regulating the choke it is possible to generate a backpressure. Since this pressure transient is in the order of second, it normally only takes a few seconds before the backpressure is felt by the bottom hole.

It is possible to deploy a fully manual, semi or fully automated choke or a combination of those. During circulation the choke is sufficient to generate the back pressure. When circulation is stopped most concepts employ the use of a back pressure pump to generate flow across the choke alone.

2.2 Computer modelling, the way forward

With the formulas and theories derived in this chapter, it is possible to do most hydraulic calculations, subsequently by hand or by using more advanced methods. Many of the assumptions that were made to derive the frictional pressure drop equation for example, are far from real life conditions. Most oil companies and research institutes readily rely on more advanced models which to a large degree capture these variations. It is however important to remember that any model, complex or not, is only as accurate as the input it receives. Models are also designed to provide answers at a given abstraction level - the more detailed the model, the more detailed the output. Therefore it may be important to firstly determine what level of accuracy your output data should have, before creating a computer model.

By introducing data modelling tools, it is possible to have the computer do multiple calculations over a large number of data sets. Calculations that would take a human operator a long time to complete, such as reservoir characterization, which for the petroleum industry perhaps is the most common field to implement models and simulation. Models use a series of algorithms and equations to try and capture the behaviour of the system of interest. The model consists of a generic code, a series of logical commands telling how, when and under what conditions certain equations, parameters or other input data are valid.

The next task, once a model has been developed, is to execute the model on a computer or a series of computers. For many large-scale models, this is the only feasible way of getting answers back in a reasonable amount of time. By executing a model, it is possible to create a simulation that shows how a system will develop with time. Simulation proves a tool to explore real world phenomenon without having to resort to running extensive physical, on site, experiments which tend to be expensive both in time and money. Simulations are not only used for petroleum, but have wide spread application in all areas of engineering, finances, games, weather forecast, etc. For the purpose of this thesis however, areas outside drilling applications will be neglected.[17]

The foundation behind any model is the code consisting of logical commands telling the computer how to interpret the data and the commands set by the operator. It is up to the operator to define the operating range of the model, assign values to the data, and construct the logic that the computer needs to follow for the desired outcome. For drilling applications, the basis for all models is to split the system into a large number of cells, and readily apply a set of conditions to each and every one of these. The reviewed literature still holds valid for all of these individual cells. By doing so, the model can account for varying parameters in every cell and readily capture the behaviour of the entire system.

In summary, a wellbore simulator should have a wide range of capabilities. These typically fall within four categories:

- Transient effects
- Fluid models
- Wellbore geometry
- Flow types

Chapter 2 has to a large degree described the highly transient behaviour of most wellbore fluids, where fluid temperatures can change on the order of 40-50 degrees Celsius in a matter of minutes. Fully transient thermal response should hence be modelled in the flowing stream, the wellbore assembly, and the formation. The model should handle changing flow conditions, including changes in flow rate, temperature and pressure effects, fluid type, and flow direction.

Typically drilling for hydrocarbon in any application, evolve the use of fluids with differing fluid properties. The heat transfer characteristics and temperature-pressure coupling vary with fluid type. Oil- and water-based liquids and polymers behave differently from compressible systems. Multiple fluids in the wellbore, including spacers and displacement fluids, are an important consideration. Temperature dependent properties must be updated as temperatures and rheological properties change with time and depth. Even with drilling muds, the viscosity and density changes with temperature and pressure during the mud's circuit down the drill pipe and up the annulus, affecting the overall hydraulics of the system.

Flexibility in wellbore geometry is needed to accommodate different configurations such as deviated wells, liners, dual completions, and offshore risers. Additionally, caving formation and uneven wellbore wall will in turn affect the flow characteristics of the wellbore. In general the geometry determines the cross-sectional flow area and the fluid velocity, which, in turn, governs the heat transfer. The heat transfer is strongly dependent on cement thickness, size of the casing and annular clearance.

Flow types include production, injection, forward circulation, reverse circulation and drilling. Drilling is a special case of forward circulation, in which the depth of circulation and the wellbore thermal resistance change as the well is drilled and casing is set.[18]

3 Drilling Concepts

Before going in depth into the dual gradient concept, a brief description of the various types of drilling concepts that are available in the market today.

3.1 Conventional Drilling

Drilling as we know it today originated from the Beaumont area of Texas in the early 1900's. Some of the technology that was developed by the early pioneers has shaped how we drill wells today. Specialized technologies such as; rotary drive, roller cone bits and drilling mud are amongst some of the most predominant. There have of course been made some quantum leaps in design and technology since then, but the rough sketch is more or less the same. On the Norwegian Continental shelf, the conventional method has been the preferred way of drilling wells since the first big oil discoveries back in the late 1960's. Since then, drilling and its control and regulation systems have become more automated, to some degree removing the need for human interface. This has effectively reduced the risk of major incidents, that a majority of the time can be related back to operator error.

One of the major benefits with a conventional drilling system is the relative simple setup and amount of equipment required to completing the loop. The system is open to atmospheric conditions, which means that the mud is returned up through a fully open annulus throughout the well. At surface the mud and cuttings is being separated over the shakers, before re-injecting the conditioned mud back into the well.

Today conventional wells are generally drilled in an overbalanced fashion, which means that the hydrostatic pressure in the wellbore will have to exceed the formation pore pressure at any point of the exposed formation, hence preventing unwanted influx of formation fluids. The main way of achieving this when drilling conventionally is to fill the hole with a weighted fluid, normally a base fluid, mixed with different weighting agents. [19]

During static wellbore conditions, for the well to be in overbalance, the wellbore pressure (P_{well}) should always be larger than formation pore pressure:

$P_{(well)} \geq P_{(pore)}$, …… (Eq 3.1)

Yet it has not always been so, the pioneers in early days of drilling, drilled most wells underbalanced. Either because they were far away from any water source that could work as weighting agent, or they didn't know any better. This often would result in spectacular blowouts (uncontrolled discharges to the environment). In many cases the degree of a wells success would be how high into the atmosphere the oil would spray. Today we don't think of these incidents as a success, but rather something gone terribly wrong.

Equation 3.1 shows the pressure balance for a static well. Most wells however are not just static- there are moving parts and fluids being circulated. Hence for conventional drilling operations we need to add a part that takes the dynamics of the system into consideration. Using the initial static pressure balance equation and adding friction, the equation becomes:

$P_{(Pore)} \leq P_{(wellbore)} = [P_{(Hydrostatic)} + P_{(Friction)}] \leq P_{(Frac)}$ ……………………………………………………………………….(Eq 3.2)

The frictional part of the equation is created due to the interaction between the fluid molecules in the annulus and the formation wall/and or casing. Pump rate, wellbore geometry and restrictions also contribute considerably to the annulus pressure profile. The exact size of the frictional pressure drop may in some cases be hard to model and calculate, mostly due to changing fluid properties, flow velocities, pipe and formation roughness. Though when it comes to circulation of a wellbore, it is generally preferred to have turbulent flow, which will provide better cuttings transport. Having turbulent flow however strongly affects the size of the frictional pressure drop. Sometimes the drilling engineer has to choose between having high flow rates which will provide good cuttings transport out of the well, and risk going on losses or fracturing the formation, resulting from the added frictional pressure loss.

The theory for calculating pressure drop has been reviewed, as a result, defining parameters and making some assumptions it should be possible to do some simplified hand calculations or more advanced computer simulations using for example Matlab. However more complex simulation programs exist (Drillbench, OLGA, +++), that have been specially developed for flow modelling and hydraulics. These programs are always used in the well planning phase, for running kick simulations, ECD calculations, torque and drag calculations, mud weight, etc. All of which will play important factors in the overall well design. [20]

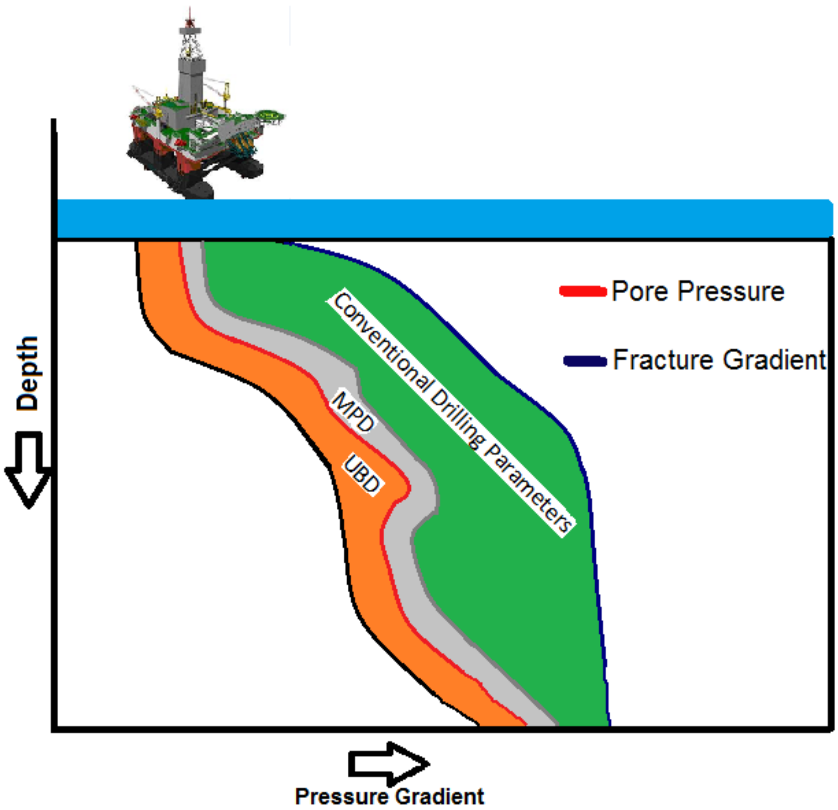

Figure 3-1: Approximate pressure regimes according to which drilling system is selected.

3.2 Underbalanced Drilling

The general principle of underbalanced drilling, UBD, is to keep the hydrostatic pressure in the well below the pore pressure.

$P_{(Hydrostatic)} + P_{(friction)} + P_{(back\ pressure)} \leq P_{(pore)}$………………………………………………………………………………… (Eq 3.3)

This is achieved by using light weight drilling fluids, or if called upon nitrogen infused liquids or foams. The reason for choosing nitrogen is because it is non-flammable and noncorrosive, unlike air that are both. Having a hydrostatic pressure lower than the formation pore pressures normally results in a continuous influx of formation fluids. The influx of gasses or fluids cannot be returned to surface through a system that is open to the atmosphere. Instead it utilizes an enclosed pressurized system, very much like the managed pressure drilling system. Since underbalanced operations encourage influx of formation fluid, the drilling system has to be designed for handling the produced fluid as it reaches the surface. In addition to the complexity of the system, the requirement for flaring or storing the produced formation fluid is one of the main reason for why especially the offshore industry have been reluctant to implement this technology. The system, consisting of large 4-phase separators, re-injection loop, flaring units, transportation lines or other storage equipment has been a limiting factor on offshore installation.

UBD was developed as a way of enhancing reservoir productivity. However, during normal or conventional drilling operations, the reservoir is typically being drilled in an overbalanced fashion. This can cause an influx of mud filtrate into the formation closest to the wellbore. This migration of mud particles and filtrate can in some cases clog up entire pores and the connecting pore throats, dislodge formation particles, chemically alter the rock, chemical precipitation, or in some extreme cases change the wetting properties of the rock itself. All of which may result in severely reduce the porosity and connectivity between the different pore systems, reducing the potential for flowing hydrocarbon. This type of formation/ reservoir damage is all too common in the industry, and have been given a general name, skin damage (S).

When looking at initial or untouched conditions, we can calculate an expected pressure profile radially in towards the well, this will tell us something about expected production profile for this well. If the well gets damaged, the skin is positive. This usually indicates there is a pressure decline in the near vicinity of the well that is more than expected based on the radial flow equation.[21] Simply put, a positive skin will normally reduce the flow potential of a reservoir, whereas a negative skin will create the opposite, actually increasing the near wellbore flow potential. A number of mechanisms exist that can induce skin on a formation. UBD might not mitigate all of them, but is proven to reduce the interaction between drilling fluid and formation.

UBD is a preventive technology, meant to minimize problems such as[22]:

- Formation damage
- Lost circulation
- Differential sticking
- Low ROP

It is easy to understand, that in a challenging market where the daily rig rates can exceed 500,000 USD, any time spent to go down and do corrective work, might represent a major cost, especially in economically marginal developments. Additionally, a lot of the time this corrective work involves the utilization of chemicals that are harmful for part of the completion, hazardous to handle as well as harmful to the environment.

3.3 Managed Pressure Drilling

Managed pressure drilling (MPD) is taking well control a step further compared to conventional operations, by using a closed and pressurized fluid system to provide a more accurate way of controlling the well pressure. Ways of controlling the well pressure conventionally have been to weigh up heavier mud and circulate this through the well, which in many cases can take hours. The MPD system however, is a pressurized system where a topside choke is used to generate a back pressure. By adjusting the choke opening, the pressure throughout the wellbore can be instantaneously monitored and controlled at surface. This precise way of controlling the annular pressure profile will enable fast detection of lost circulation and influx, which makes it possible to drill wells utilizing mud that provide a BHP marginally higher than the pore pressure.

The MPD system has seen its wide spread applications in wells which experience[20]:

- Lost Circulation
- Well Instability
- Well control incidents
- Stuck pipe

A well using MPD is designed to be operated slightly overbalanced, and an influx of formation fluid is not encouraged. Although sharing a lot of similarities with conventional drilling system, the MPD technology is generally a more complex system. Sharing similarities with the underbalanced drilling concept, MPD requires some additional equipment when being compared to conventional systems:

- Choke (non-, partly- or fully automated)
- Back pressure pump (non-, partly- or fully automated)
- Flow meter
- Rotating Control Device
- Topside Power unit
- Surface Separation Equipment
- Non return valve
- Additional Specialized Personal

3.3.1 MPD system

The MPD takes advantage of the fact that it is a closed pressurized system and by installing a choke it is possible to generate a back pressure to the system. Accordingly, the well bore pressure equation acquires an additional top pressure or choke pressure, making the equation:

$P_{(Pore)} \leq P_{(wellbore)} = [P_{(Hydrostatic)} + P_{(Friction)} + P_{(Choke)}] \leq P_{(Frac)}$, ... (Eq 3.4)

One of the strengths to the MPD system comes to light when it is time for making connections, which is making up new pipe. This results in temporarily stopping circulation through the drill pipe, and subsequently stopping the annulus flow. Losing annular friction will with a conventional system, only leave the hydrostatic to balance the well pressure. However for the MPD system, loss of annular friction is combated by ramping up a backpressure pump that will generate a flow across the topside choke. Operating the choke and the backpressure pump, it is possible to some degree replace the pressures that were lost during circulating conditions. To date, one of the major limitations for the MPD system is that, it has problems to accurately account for large heave effects. This for the NCS and other similar parts of the world can be substantial.

There exist two basic approaches to MPD, namely reactive and proactive MPD. These are described in more detail in the following.

3.3.2.1 Reactive MPD

Reactive MPD is the application where MPD is used as an operational contingency; in case of unexpected pressure regimes are encountered. When drilling with reactive MPD, one has all the equipment to drill in MPD mode installed, but it is only utilized after encountering a problem. The well is therefore planned conventionally with regards to well construction and fluid programs, with the possibility of introducing MPD should the need for such occur. This category of MPD is related to normal operating windows, meaning that there is a large enough margin between the pore pressure and the fracture pressure to drill the well using conventional methods.

3.3.2.2 Proactive MPD

Proactive MPD plans to take full advantage of the ability to more precisely manage the annular pressure profile, with designing the fluid, casing and open hole drilling plan to MPD mode. The proactive MPD method is often referred to as “walk the line” category of MPD technology, and is the MPD method that has been used for most offshore applications. But what is actually meant about this walk the line expression? MPD is designed to be capable of maintaining the predefined wellbore parameters ensuring that many of these challenging narrow operating windows can be drilled where conventional means would fail. While reactive MPD has been practiced on problem wells for several years, it is only during the last couple of years that proactive MPD have been taken into use.[23]

3.3.2.3 Variations of MPD

The Bottom Hole Pressure Profile Method, Point of Constant Pressure Method, Pressurized Mud Cap Method, Constant Flow Method, Casing Drill, ECD reduction, and the Dual Gradient are among numerous proactive concepts reviewed by the literature. Each has its own way of operating, but the common goal is to try and manipulate the wellbore pressure profile diminishing or eliminating drilling related problems, many of which can be related back to poor wellbore pressure management.

When managed pressure drilling was re-invented in the early 2000’s, expressions like “walk the line” and “we will drill the un- drillable” were often mentioned in the same sentence. Has the technology however been all it was promised to be? It is fair to say that well control took a step towards the better, and MPD has been unprecedented when it came to well control. With time and experience however, it seems like big service providers seem more reluctant to hold on to the un-drillable label. The sales pitch has gone from “drill the un-drillable” to “drill the drillable, faster”. This might be a good thing, keeping in mind that a large percentage of the wells still being drilled, are conventional.

4 Dual Gradient Technology

In the following chapter a brief explanation of dual gradient will be given, the most promising technologies available in the market today, before finally ending up with a more in depth description of AGR’s EC-Drill and CMP technology

4.1 Dual Gradient Definition

IADC currently defines dual gradient as:

“Creation of multiple pressure gradients within select sections of the annulus to manage the annular pressure profile. Methods include use of pumps, fluids of varying densities, or combination of these”

4.1.1 Dual Gradient

Dual gradient drilling is a MPD technique that has been around since the early 1970’s, although on a more conceptual level. It was wishful thinking back then, and still is, that someday the riser would be fully removed. This would not only save time in rig up and rig down, it would also release valuable deck space. It would to a great extent reduce the considerable load that the riser inflicts on the wellhead and BOP. Additionally, the removal of the riser, would mean that riser margin would always be accounted for. Environmentally, drilling with a partly or fully evacuated riser will reduce the risk of spills from the riser to the sea, in case of an emergency disconnect. Finally the removal of the riser would reduce the mud volumes required, which also would reduce the logistical demands for the supply vessels. The companies have been aware of many of these benefits for some time. The question faced by most however was, how long would it take before the demand for such a technology would arise, seemingly the existing technology was doing the job sufficiently?

After the West Vanguard accident in 1985, where a gas diverter failed to lead gas away from the rig, resulting in blowout, killing one, it was decided that all top hole sections on the NCS should be drilled without a BOP and riser installed. This adjustment of operational procedures following the incident, directed how we drill top hole sections today. Most people might not realize, but following the accident every top hole section is now drilled with the use of dual gradient methodology. Briefly explained, until the BOP and riser is installed the bottom of the well will feel the pressure from the hydrostatic of both the water column spanning from seabed to surface, and the mud column from seabed down the well.

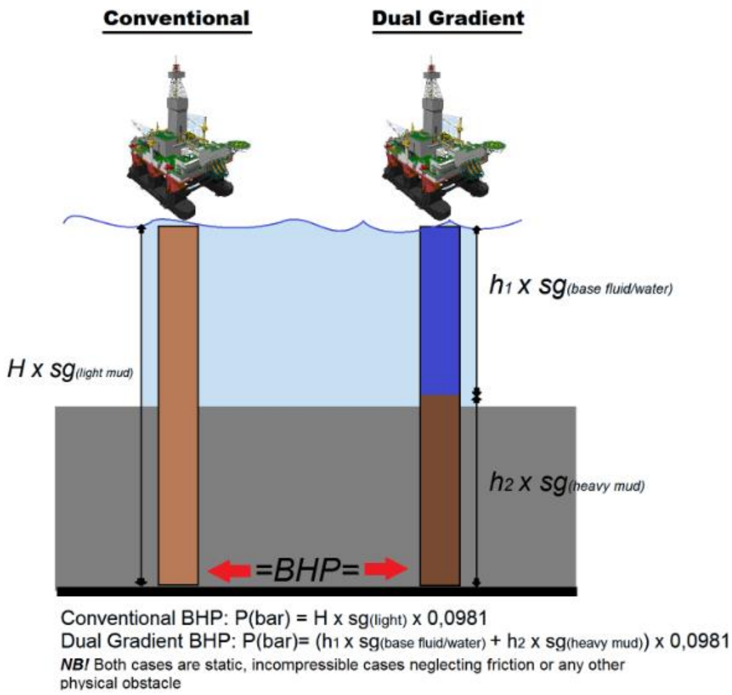

Figure 4-1 Conventional drilling vs. Dual Gradient Drilling.

For top hole drilling it is consequently important to remember to sum the density of both fluids to acquire an accurate value for the bottom hole pressure (BHP). Figure 4-1, displays a simplified static case comparing the conventional way of thinking against the dual gradient way. Unlike the static conventional case, the static dual gradient case is quite simple to understand. It is generally when the system turns into a dynamic one it becomes a bit more challenging. Suddenly the system contains fluids with varying properties interacting, pumps, hoses, chokes, geometry issues, temperature and pressure effects all working together. All the dual gradient concepts that are reviewed in this thesis, are using various methods of circulating the cuttings from seabed to surface. All of which differ from the conventional method, which use the riser as a flow path from wellbore to surface.

Looking into the different dual gradient principles, one of major concerns faced by all the providing companies was how their systems would operate during a predefined worst case scenario? None wanted to be in the centre of major incident, especially after the Macondo accident in the GoM. Would the simulations/ models be accurate enough? Would some or all operational procedures and parameters have to be revised? How extensive would training of personal be? To what degree could existing vessels and equipment be used, or would it require development of new technology? Where can the technology be used? Cost versus benefit? Overall, many aspects that needed to be assessed before the technology could be sustainable. The work through this thesis will try and reflect on some of these problems. What is about this “old” concept that makes it so interesting for many oil companies today?

Currently, there is an on-going race to be the first provider of fully integrated deep water dual gradient solutions. There exists a variety of DGD concepts being developed by different companies, some of which require purpose built vessels. Others however look into the possibility of making “light” dual gradient systems by means of upgrading existing vessels to be able to be classified as a “proper” DG drilling technology.

4.1.2 DGD Challenges

Besides the obvious technological challenges faced by most of the concepts, most of the dual gradient developers also need to address a series of regulatory and operational problems with their technologies, before getting the all clear label. Among the most predominant are:

- Track record
- U-tubing phenomenon
- Well control and lack of standards

4.1.2.1 Track record

Besides RMR, most of the dual gradient concepts described in this thesis are lacking operational experience. Resulting in operators being reluctant to be the one taking the first step and fully integrating this technology in their portfolio. Keeping in mind that most new technologies are bound to face a series of "child deceases" before 100% operability can be achieved. Based upon initial testing in the early 2000's, many of the companies deemed it high risk and high cost to operate the mentioned dual gradient systems. The risk of running the operational cost through the roof may simply have scared many potential users.

Lately however, the demand for deep water technology has increased significantly, influencing the operators to closely collaborate with each other. This has resulted in large scale industry projects, sharing knowledge, cost and risk across company boundaries, across countries and even continents. Sharing the risk and cost between multiple interested parties, seem to provide the extra push the industry need. With time these efforts are expected to generate sufficient possibilities and confidence, which may enable DGD technology to be used on a larger number of wells.

4.1.2.2 U-Tubing Phenomenon

One of the major concerns with the dual gradient concepts is how to account for the U-tube effect, which occur due to a pressure imbalance of the system. Conventionally the hydrostatic of the inside and the outside is more or less the same which creates a balance in bottom hole pressures. The U-tube problematic is not however only reserved for dual gradient concepts, but may also cause some irregularities during conventional operations, for example when pumping a heavy plug.
Displayed in figure 4-2 is a simplified static dual gradient system, showing before and after circulation is stopped. What is further evident from looking at the before figure is that the hydrostatic of the inside will be greater than the outside. This inherent pressure imbalance together with the knowledge that fluids will flow from high to low pressure, it is apparent that this system if left unattended will try and level out the differences. The result being the inside mud level will decrease until the pressure balance at the bottom between the outside and inside, once more is restored. The decrease in mud level is often referred to as the free fall rate and is affected by several factors, such as: Mud weight, viscosity, water depth/height of marine riser, well depth, drill string diameter, nozzle size and other restrictions.

As a mitigating measure, most dual gradient concepts deploy anti u-tube valve in the bottom of the drill string. It will be able to be operated with a small differential pressure, which means it will close as soon as the pump is stopped and open almost immediately after pump pressure is regained. The u-tube phenomenon, when the rig pumps are shut down, can act to mask one of the most important kick indicators, flowing well with pumps off. Distinguising between a kick and the u-tube is difficult, but not impossible. There has however been a lot of work completed with the u-tube phenomenon, some say it is possible to fingerprint, effectively reducing the need for installing a troublesome valve down hole, while other think the fingerprinting will take too long, due to normalization time of up towards 5-10 minutes depending on the factors mentioned above.[24]

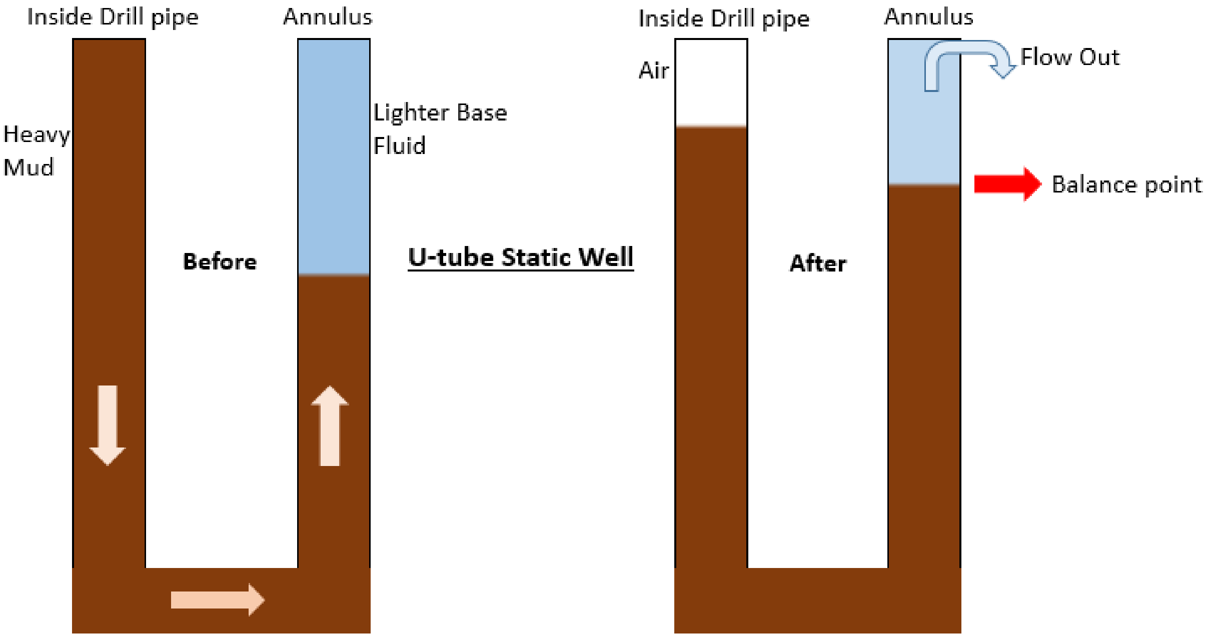

Figure 4-2: U-Tubing phenomenon for a static well.

It is generally agreed that the effects of u-tubing is increasing with length of riser section and water column, especially if the setup is similar to that of Figure 4-2. Further increasing the benefits of introducing an anti u-tube valve to the end of the drill string.

4.1.2.3 Well control

As for DGD concepts described in this thesis, most of the kick indicators are both as applicable and accurate, or more so than conventional riser drilling. An increase in annulus flow can readily be detected sooner and more accurately amongst other, by careful monitoring inlet pressures, pump power and performance, choke pressures, etc.

Since DGD specific technology has been used on a very limited number of wells. It still are some unanswered questions with regard to how the systems will operate during a actuall well control scenario. Conceptual studies and simulations are obvious steps toward better understanding this process and how to deal with it, but even these have their own limits. Before fully implementing DGD, large scale lab or pilot test seem to be the only way to fully test the controlability and operability of these systems. As of now, barriers and procedures will have to be specially shaped for every operation. Additionally, getting new procedures approved by the regulatory agencies has proven a time consuming process. [25]

4.2 Dual Gradient Technologies

There exist a large amount of dual gradient concepts, some are still being designed, while others are partially or fully finished. Ways of approaching DGD today is based upon three fundamentally different methods, dilution method, seabed pumping and mid-riser pumping. Here are some of the most developed technologies available in the market today.

- AGR’s Riserless Mud Recovery System and Chevron’s Subsea Mudlift System having seabed pumping as their main approach.
- AGR’s EC-Drill & CMP, being a pumped riser application.
- Transocean’s Continuous Annular Pressure Management (CAPM) based upon dilution method, by continuously injecting gas or lighter fluids into the riser, reducing the hydrostatic pressure at the mud line. Due to large uncertainties with respect to well control, the CAPM will not be further described during the work of this thesis.

4.3 RMR –Riserless Mud Recovery

AGR’s RMR system is a closed loop system developed for safely and economical drilling of top hole sections. The RMR enable the drilling mud and cuttings to be returned from the seabed back to the rig, which enable the well to be drilled with an engineered mud system that is better suited for the job. RMR provide the following advantages compared to the conventional “pump and dump” technique used offshore today:

- Increased well control before BOP/riser is installed
- Enable the use of engineered fluids
- Improved wellbore stability
- Reduce discharge to sea
- Deeper casing strings, resulting in elimination of casing strings
- Enable cuttings sample and analysis
- Avoid building an uneven seabed for wellhead/ template structure.
- Increased volume control: loss & gain
- Mud cost savings

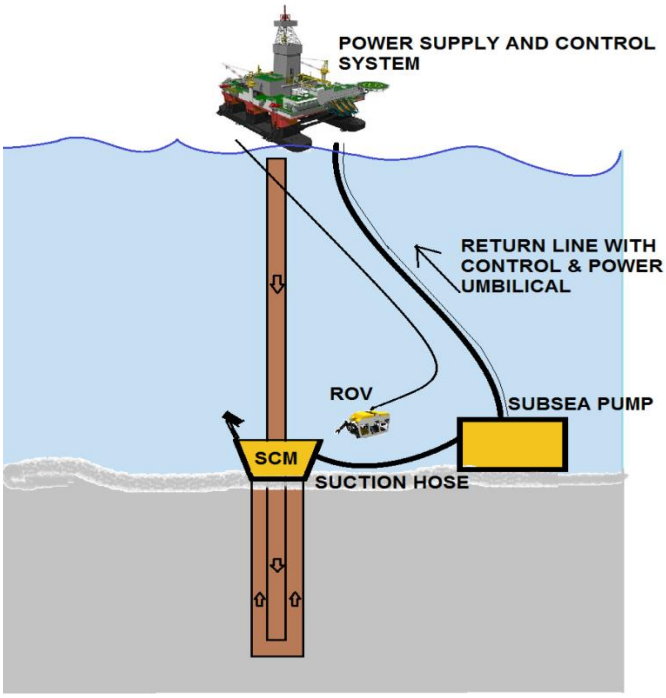

Figure 4-3: Displaying a simplified overview of the RMR layout

4.3.1 RMR System

The main components making up the RMR system are displayed in figure 4-3, and consist of:

- Suction and centralizing module (SCM)
- Suction hose & return line
- Subsea pump module (SPM)
- Topside power supply

The SCM is run and installed over the wellbore. It is the vessel containing the free moving mud cap, while at the same time being fully open to the surrounding sea. Ways of controlling the mud level and to keep the mud from overflowing is a level gauge and camera providing a live feed. From the SCM the returns is directed through a suction return hose which connects the well to the pump module, that is capable of pumping high viscous fluids containing a high percentage of solids.

The pump is powered by an electrical umbilical from surface, which will provide sufficient power to transport the return fluid to surface. Having the power source on surface is beneficial in case of repairs. Equally beneficial for the environment, we find that regulating the pump electrically makes the system more efficient. By continuously monitoring the pump performance and rpm, the pump can be used as an early warning sign of influx. Since the RMR system is a “closed” system, the volumes in should be more or less equal to volumes out. Which means an imbalance, could indicate lost circulation or influx. Pit gain is monitored as for conventional operations. The system has so far been deployed in a pre- BOP installation phases. [26]

Hydraulically the RMR system consists of a fixed pressure at the mud line, due to the static weight of water. This effectively makes a system consisting of three parts, two static and one frictional. During circulation, the bottom hole pressure can be calculated accordingly:

$$P_{BHP} = (\rho_1 H_1 + \rho_2 H_2)g + P_f \text{ , ………………………………………………………………………………… (Eq 4.1)}$$

ρ_1: sea water density
ρ_2: down hole mud density
H_1: Sea depth
H_2: height (TVD) of drill fluid column in the annulus
g: gravitational constant
P_f: annulus frictional pressure drop

All of the hydraulic pressure equations going to be described in this chapter is fairly similar, note however how reference points vary.

4.3.2 RMR track record

While continuously improving their technology, AGR with its RMR system is looking to gain a solid foothold in the industry as a market leader in providing riser less/dual gradient technology. Looking at the track record that AGR have, with implementation of the RMR system on more than 500 wells, it is safe to say that the industry has become aware of the possibilities the RMR technology may create.

Although RMR so far has found its application in the pre-BOP segment, AGR is trying to use some of the knowledge and technology that were developed during the RMR design and operational phase, to design a system that can be used on post-BOP installation and/or deep water applications. Some of which will be further discussed later in this thesis.

4.4 SMD- Subsea Mudlift Drilling

The SMD joint industry project was initiated in the late 1990's and is being classified as one of the biggest single technology investments in the offshore industry to date. The technology development took 5 years, before finally a positive field test was completed back in 2001. However, due to high implementation costs and low oil prices at the time, this post- BOP dual gradient technology was put on the shelf for some years, with the stamp "not viable in today's market". Since then however, the market has seen an upturn in both oil price and increased demand for drilling vessels, with special attention on deep water capability, which meant that the technology was reintroduced to current markets.

During the years that the technology was side-lined, it gave the original developers time to work out some of the challenges associated with the original project. In 2012/13, years of developing the SMD system culminated into the first dual gradient capable drilling vessel being deployed in the GoM. Spearheading the technology, Chevron, has made a 5 year commitment with Pacific Drilling, to install a full DG package on one of their drill ships, Santa Anna. This will provide valuable information weather this technology and its procedures will manage to live up to the goals set by Chevron, when it comes to efficiency and cost.

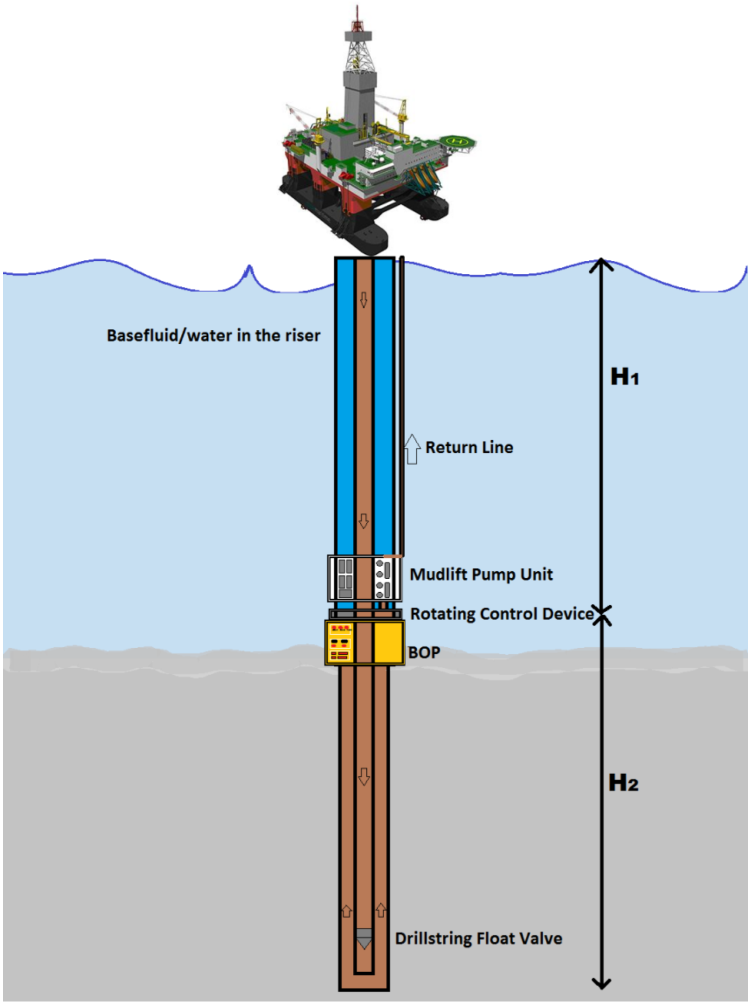

Figure 4-4: Simplified SMD system.

4.4.1 SMD system

The main components making up the SMD system are displayed in Figure 4, and consist of:

- Topside Power unit
- Mud lift pump unit (MLP)
- Drill string Float valve
- Rotating control device (RCD)
- Return line and control umbilical
- Solids Processing Unit (SPU)
- Riser dump joint

The SMD system is based upon directing the flow through a series of subsea devices installed on the riser, just above the BOP. The uppermost being a rotating control device, which acts as a mechanical barrier between the riser blanket fluid and the annulus mud. It is normally designed to operate with a very low differential pressure, but can operate with a maximum of 69 bar differential. The RCD divert the flow from the annulus through the SPU, which ensures that the cuttings going into the mud lift pump, are sufficiently small enough to not represent any threat to the operational integrity of the unit or the return lines.

The MLP is the heart of the SMD system. It provides sufficient force to pump the cutting laden fluid to surface. A special feature of the MLP is that it is entirely powered by water. Topside we find 6 pumps, 3 for pumping mud down the drill string, and 3 pumping water down to the diaphragm chambers in the MLP, enabling continuously pumping of mud. Having the power unit at surface provides many benefits, such as accessibility and maintainability. The “power” fluid is water, which in the event of a leak will not pose any danger to the environment. It is also possible to vent the power conduit lines to sea, which in some cases may be required. Having 3 pumps, provide auxiliary in case of failure of one or more pumps. [27]

To be able to drill post- BOP and still use dual gradient technology, the SMD exploit the fact that it is a closed pressurized system. This will like MPD, provide an accurate and precise control of the wellbore parameters. The SMD operate with the riser filled with a base fluid or water system that is meant to simulate the pressure profile through the water. This attribute of having a riser fully filled with water/base fluid, will during circulation, generate a bottom hole pressure according to the following equation:

$$P_{BHP} = (\rho_1 H_1 + \rho_2 H_2)g + P_{choke} + P_f \text{ , ……………………………………………………………….. (Eq 4.2)}$$

ρ_1: base fluid/water density
ρ_2: mud density
H_1: height of the base fluid column, typically from rotary to control device.
H_2: height (TVD) of drill fluid column, typically from rotary control device to bottom.
g: gravitational constant
P_{choke}: backpressure created with a subsea choke
P_f: annulus frictional pressure drop

During conventional operations, once the BOP is installed, the mud in the riser will start to influence the pressure profile through the well which in some cases can develop into various complications, such as well instability and well control issues. These problems boil down to the enormous amount of mud volumes required to fill the riser. Generally, if assuming a 21 ¼” OD riser with an ID 19 ½” and no drill pipe inside, the volume of mud per 100m of riser will be 19,25 m^3 ≈160bbl. For a 2000 m long riser, this equates to relatively large volumes.

It is generally agreed that major part of the riser volume does not provide any benefit for the active drilling process. One of the game changing features of the SMD system, comprise in actually replacing the mud inside the riser with water or a base fluid with water like properties. This will have the effect on the reservoir as if the drilling vessel was located at seabed. During conventional operations, there exists a pressure imbalance between the inside and outside of the riser at seabed, especially when using heavy drilling fluids. The SMD effectively zeroes out this imbalance. On the return side, the specially developed pump prevents the hydrostatic of the return lines to inflict a backpressure to the system. [28]

4.5 EC-Drill and CMP

AGR has recently developed a new way of effectively managing the wellbore pressure profile throughout the drilling phase of a well. The EC-Drill can in many ways be described as a dual gradient "light" concept, not using any rotating control devices or otherwise closed pressurized systems. The principle behind the EC- Drill is based upon having a floating hydrostatic mud column in the riser. Controlling down hole pressures is mainly done by adjusting the height of the fluid in the riser:

$$P_{BHP} = (\rho_1 H_1 + \rho_2 H_2)g + P_f \text{ , } \ldots\ldots \text{(Eq 4.3)}$$

ρ_1: base fluid/water density
ρ_2: down hole mud density
H_1: Length of the base fluid column
H_2: height (TVD) of drill fluid column
g: gravitational constant
P_f: annulus frictional pressure drop

Primary means of controlling wellbore pressures will be to regulate the height of the mud level in the riser. Weighting up drilling fluid might however be necessary at some point through an operation, but on a less regular basis, which save time through not doing time costly mixing and displacement operations, which over the duration of a well can account for adequate portions of the overall productive time. Unlike the RMR system which is deployed in the pre-BOP phase, the EC-Drill is expected to have its area of implementation in the post-BOP phase, effectively making AGR capable of delivering dual gradient drilling solutions for completing wells from start to finish.
The differences between EC-Drill and CMP has previously been described, their area of implementation are likely to be in shallow and deep water respectively.

After the EC-Drill & CMP test are completed and the working boundaries of the system are defined. The EC-Drill & CMP is expected to provide the following benefits to the drilling operation:

- Improve safety
- To some degree restore riser margin
- Early influx/loss detection (figure 4-8)
- Reduce size of influx/ losses
- Better fit between wellbore pressure vs. natural formation pressure profile
- Faster adjustment of wellbore pressure, ECD control.
- Increase kick margin
- Drilling longer sections, reduce the need for intermediate casing strings.
- Overall drilling time reduced
- Mitigate losses, during conventional operations and cementing operations

Further discussion on where, how and when the EC-Drill & CMP will prove most advantageous will be discussed later.

4.5.1 EC-Drill and CMP System Setup

Although this thesis is not meant to be a technical report, it might be useful to develop a better understanding of the main system components of the EC-Drill or CMP system (Figure 4-5), which consist of the following:

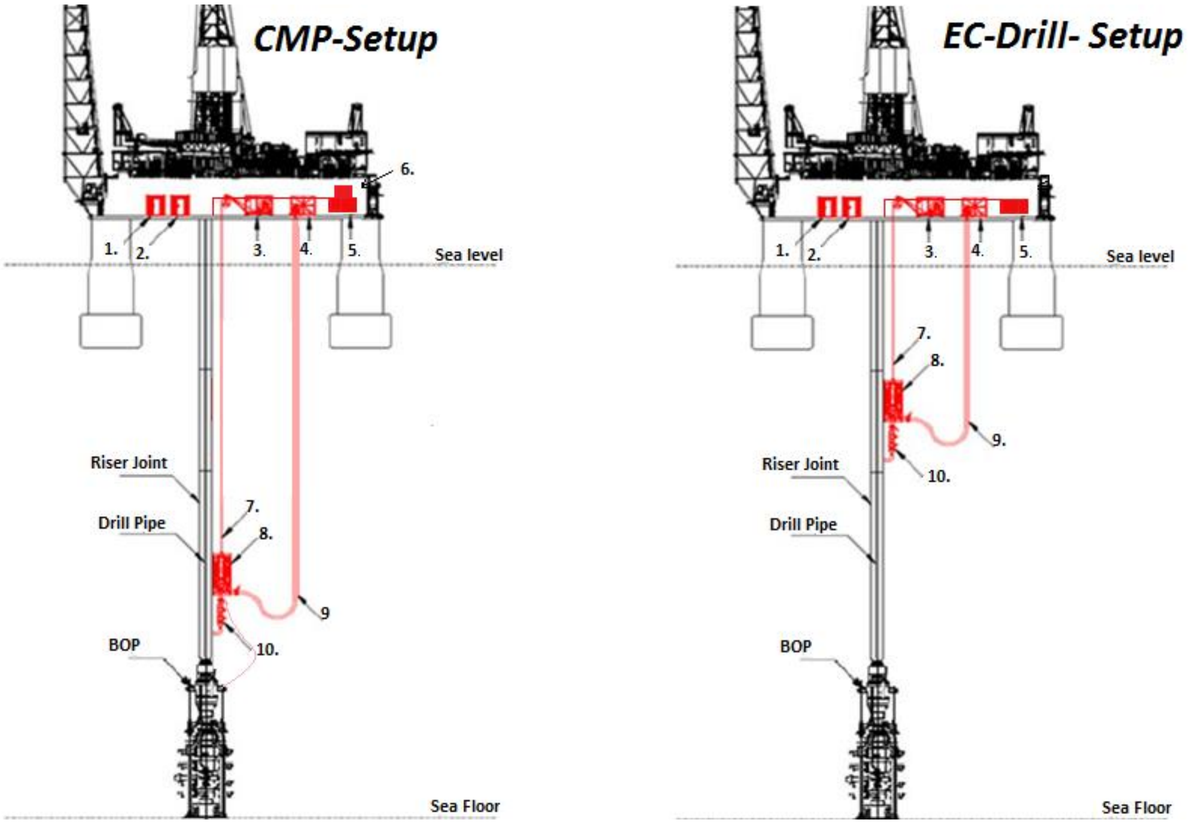

Figure 4.5 : Schematic setup of the EC-Drill [[29]]

Topside Equipment:

1. **Office and tools container**, holding the DGD controls and monitor interfaces as well as most electrical components connecting the EC-Drill system to the rig sensor and control equipment.

2. **Control container**, houses the equipment enabling sufficient power supply to the subsea pump module, SPM.

3. **Winch with umbilical** is transferring power and signals to and from the SPM.

4. **Hose handling platform and hang off point**, enables safe and efficient deployment of the mud return lines.

5. **Top fill pump with flow meter**. Due to the risk of having a possible explosive atmosphere in the riser, the idea of using a top fill pump to fill the empty riser with a blanket fluid was developed. Monitoring the overflow of fluid, may act as a secondary indicator for influx. Additionally, having a top fill pump would greatly reduce the time it would require to

turn the system back into a conventional setup, which seems to better suit the regulatory agencies. The major differences this partial EC-Drill concept would inflict on the operation will be further discussed later in this chapter.

6. **(CMP Specific) Choke skid and gas separation equipment,** is required for the CMP version due to possibility of circulating the kick fluid through the pump. To control the gas expansion up the mud return lines, a topside choke skid is used. If the rig is not already outfitted with a gas handling facility enabling safe and effective separation of kick fluid, this should be in place.

7. **Control and monitoring system**, is the computer system that monitors and control the SPM, ensuring that desired fluid return rates and that the selected riser mud level is achieved. By monitoring the riser pressures, the program will either automatically or manually adjust the speed of the subsea motors, allowing a constant level to be maintained.

Subsea Equipment:

8. **Subsea pump module**, SPM, is the heart of the EC-Drill system and is a 3 stage vertically mounted motor that will be electrically powered from surface. The main purpose of the pump is to give the return fluid the required force to flow up through the external conduit back to surface. The pump is fundamentally the same setup that have been used on the RMR system, and have recorded good operability in its many operations.

   Furthermore the pump contains all the necessary valves, sensors and control modules required to regulate the mud level interphase in the riser. To save time, the pump module and return hose will be run together with the BOP and LMRP on the marine riser.

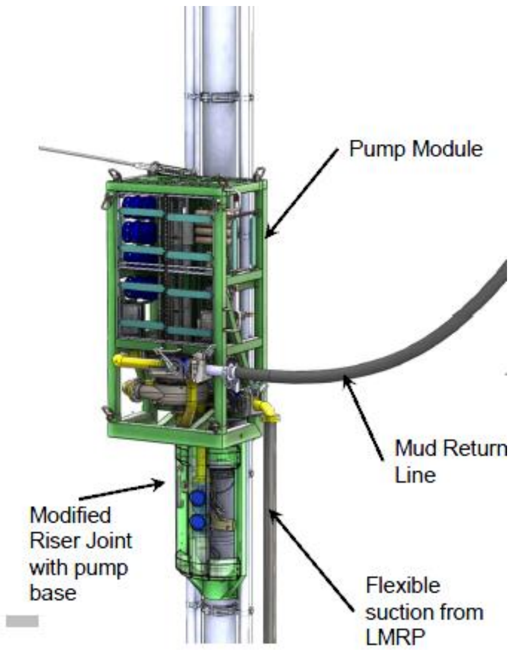

Figure 4-6: Pump module on Modified riser joing.[30]

While compressors work for high gas fractions, pumps have a limiting range of work when the gas fraction increase above a certain size. The CMP pump module is capable of handling 10% gas, fractions beyond this typically impose challenges on the overall pump performance.

9. **Mud return Line,** is typically a flexible return hose that is the flow conduit for transporting drilling mud and cuttings back to surface. In relation to this, the pressure rating of the flexible return line has created some concerns, especially with regards to the CMP well control procedures, which involves the possibility of circulating out small to medium kicks through the pump and up the mud return line. Expansion of gas is controlled through a topside choke.

10. **Modified Riser Joint.** Since rotary control devices so far is not planned implemented, the modified riser joint acts as the tie in point to the riser. It contains isolation valves and sensors that may be operated by, or communicating with the control system via the subsea pump module and umbilical. The riser joint act as an outlet and provide easy connection and hang-off capabilities for the subsea pump-module.

    Current systems do not enable a physical way to effectively measure the actual mud level in the riser. Having two pressure sensors, will enable the operator to read the actual outlet pressure. Furthermore by taking the difference in pressure (ΔP) between the sensors it is possible to calculate the average density between the two points which will provide a real time feed of what the density at the outlet is at all times, in addition, real time mud logging data from surface should be used. The pressure sensors are able to detect changes in the range of +/- 0,005 bar. Sensors are furthermore installed in pairs, for redundancy.

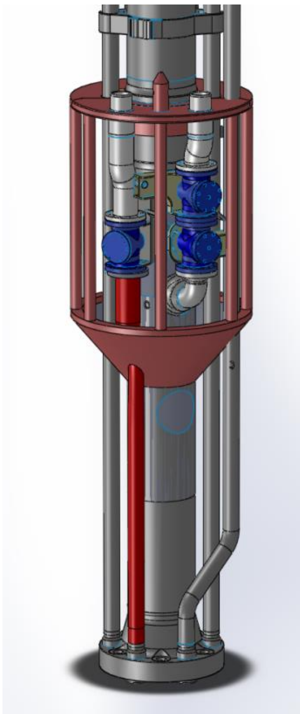

Figure 4-7: Modified riser joint without the pump attached.[AGR]

    For the CMP setup the modified riser joint will typically be run as the third marine riser joint over the LRMP. To save time, the riser joint with subsequent equipment will be run as a part of well control package on top of the wellhead, whereas the EC-Drill will be run on the riser at a later time. Further isolating the subsea pump module, by means of a regulation valves found on the modified riser joint, means both systems may quickly be transformed back to conventional.

11. **Anti U-tube valve**. (Not seen in figure). Earlier the significance of having a u-tubing valve as a part of the dual gradient setup were discussed. For the EC-Drill and CMP set up installing a anti u-tube valve seems to provide more advantages than it does disadvantages. There has however been some sceptesism with respect to initially installing the valve, due to risk of failure, and time associated with retriveal and re-

installation. Some say that correct fingerprinting techniques might eliminate the need for the valve in the first place. [29]

System setup may vary somewhat from that stated above, due to functional requirements set by the various operators as well as individual rig specification. This should however provide a generic example on how an EC-Drill & CMP set up may look like.

4.5.2 Well Control

One of the major concerns with any new drilling technology is in its ability to readily detect and implement control action, effectively reducing the risk of having uncontrolled well incidents. Additionally, making sure proper barriers are in place and fully operative is crucial for the success of any drilling operation. The following section will describe some fundamental terms as well as the major differences between conventional well control and EC-Drill & CMP.

4.5.2.1 Kick, what is it?

A kick is defined as flow of formation fluids into the wellbore during drilling operations. The kick fluid can be any formation fluid, saltwater, liquid or gases. The kick typically occurs due to a pressure imbalance between the wellbore and the formation. The condition of lower wellbore pressure is typically caused by the pressure in the wellbore being less than that of the formation pore pressure, resulting in flow from high to low pressure. The predominant causes that may result in a kick are:

- High pressure zones
- Pore pressure uncertainty
- Low mud weight due to operator failure or system failure
- Swabbing due to tripping or heave effects (EC-Drill & CMP not affected by heave)
- Imbalance caused by lost circulation, due to drilling into weak zones, caves/karst, or pressure surges.
- Insufficient hole fill while tripping out

It is generally agreed that early kick detection is imperative for safe handling of a kick. If a kick goes undetected and the influx is not properly stopped, in a worst case scenario, the kick turns into a blowout. Common warning signs that a kick is taking place might include the following[31]:

- Drilling break, increased rate of penetration.(flow check the well)
- Increasing flow rate
- Pit volume increase
- Decrease in circulation pressure and an increase in pump speed on the surface pumps.
- Flowing well with pumps off
- Increase in string weight
- Increase in rotary torque, drag and fill

4.5.2.2 Factors affecting kick severity

Several factors exist that may affect the severity of a kick. Among the most predominant are the geo-mechanical properties of the formations, generally referring to rock properties like porosity and permeability. Firstly rock porosity gives the relationship of available pore volume within a given rock volume. This quantifies the rocks ability for storing hydrocarbon, fluids or gases. Secondly the permeability describes the connectivity between these pores, a property that is predominant in allowing fluid to flow. A formation with high porosity and/or high permeability, coupled with a negative differential pressure greatly increases the risk of having a large kick.

4.5.2.3 EC-Drill well control versus Conventional Kick detection

The primary means of detecting wellbore influxes for conventional drilling operations has been to observe abnormal flow or increase of mud volumes in the pits. Procedures have then been to stop pumps and perform a flow check, and if positive shut in the well. For the EC-Drill and CMP however the well control is taken one step further in trying to provide fast detection and subsequently fast response. In a situation where minutes may differentiate between having a small, medium or a large influx. Fast detection followed by correct well control procedures are paramount for the success of any drilling operation.

To distinguish between the time a kick can be detected conventionally versus EC-Drill, SINTEF completed a simulation with these generic data[32]:

- Size of influx, 10 bbl
- Rate of influx, 3 bbl/min
- Initial circulation rate, 3200 l/min
- Kick circulation rate, 1500 l/min
- Detection based on pit gain, detectable limit is set to equal 2m^3 (12,5bbl)
- Detection based on the EC-Drill pump power or rpm, set to 10% increase in power or 0,5 Hz (0,01 relative rpm) frequency change for rpm

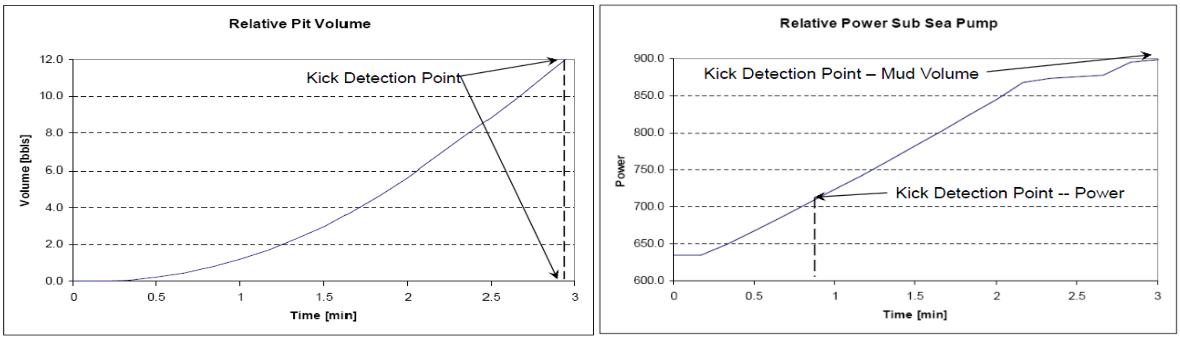

Figure 4-8: Detection time of influx by conventional methods against that of using the pump power/rpm for the EC-Drill system.

As the graphs show, the time it takes to detect a kick using the EC-Drill method is clearly reduced compared to conventional. The enabling factor of using rpm or pump power as a detection method, is made possible by setting the outlet pressure and/or subsea pump rate to be constant. The effect an influx will have on the system as it rises through the annulus is to increase the mud level in the riser. As a consequence, the pumps will have to work harder to try and maintain the constant riser base pressure, generated by the now increasing levels of mud in the riser. Test completed at SINTEF show that faster identification of influx by means of monitoring pump rpm and power variations are possible, and may result in a reduction of up to 75% or more in influx volumes, compared to conventional detection methods.

Additionally, the EC-Drill control system recieve signals from the pressure sensors installed on the riser. The accuray of the sensors are in the range of ± 0,005 bar, and will facilitate in accurately determining mud level changes, which a kick will result in.

More importantly, the tests at SINTEF were simulations, the EC-Drill has yet to prove it self during a wellcontrol incident. The purpose of the Troll Pilot, is to mimic a kick using various amounts of nitrogen gas, to see to what degree the system actually can handle a well control incident. This will help define the working boundaries of the system and will perhaps shed light on areas of improvement.

4.5.2.4 Well control procedures

Developing a new system and subsequently new procedures is in the interest to the developers for safety reasons, by trying to make procedures as similar or close to conventional kill procedures as possible. This would significantly reduce uncertainty throughout the crew to when, where and what order the procedures will have to be performed in, significantly reducing the risk of something going wrong as well as reducing the time spent from initial detection, to regaining control.

In the situation where an influx is suspected, factors concerning kick size, intensity, incremental pressure requirements to control flowing zone, formation fracture pressure, weather etc., are all important factors that the team will have to agree upon before making an educated decision as how to handle that influx. It should also be determined if the unbalance is caused by an actual kick or just a ballooning formation. This is made possible by a technique called Fingerprinting.

4.5.2.5 Fingerprinting

Fingerprinting is rig and well specific and involves the process of accurately measuring and documenting real time changes in surface mud volumes and in down hole pressures when specific operations take place. Fingerprinting procedures are not used throughout the entire well, and are more commonly used in formations that have a risk of hydrocarbon influx. In these cases, operations including, tripping in and out, turning pumps on/off, setting slips, altering mud properties etc.
The value of fingerprinting lies within its ability to differentiating the expected, namely what “could” or “should” happen, from what actually “did happen” under a given set of conditions.

The overall objective of fingerprinting is to be able to quickly and correctly identify an actual influx by comparing real time data to the previous “Fingerprinted” data. The data recorded during a given operation becomes the “expected behaviour” or “the Fingerprint” for the next time the same operation is performed. Good communication between the driller, the mud logger and the engineer responsible for the system (EC-Drill and CMP) is essential. Due to the inherent difference, where EC-Drill rely on conventional kill procedures, there will be more focus put on the specialized kill method of the CMP setup. By using fingerprinting techniques and specially developed decision trees for the CMP, it should be possible to distinguish between a ballooning formation and a real influx.

4.5.2.6 Kick Circulation

When a kick has been detected, and confirmed as such, the decision to control the influx via the CMP method or the Drillers Method versus Bullheading will be critical and will be based largely on the most current conditions, (largely kick size and intensity.) The Drillers Method has in the past been used to assist in keeping the drill string free when circulating out a kick from a rubble or gouge zone and in geologic pressure regression situations as the well experiences a lower pump shut down period. Similarly in a CMP dual gradient situation the pumps are not taken off-line thereby some mitigation is achieved in regards to keeping the drill string free.

The following decision tree is intended to assist in selecting the best option for handling the well control event. If possible, all attempts should be made to circulate out the influx using the CMP method at a reduced pump rate through the CMP pump and up the mud return line. If this is not possible then bullheading should be considered. If bullheading is not an option then conversion to a single gradient fluid and conventional well control should be examined.

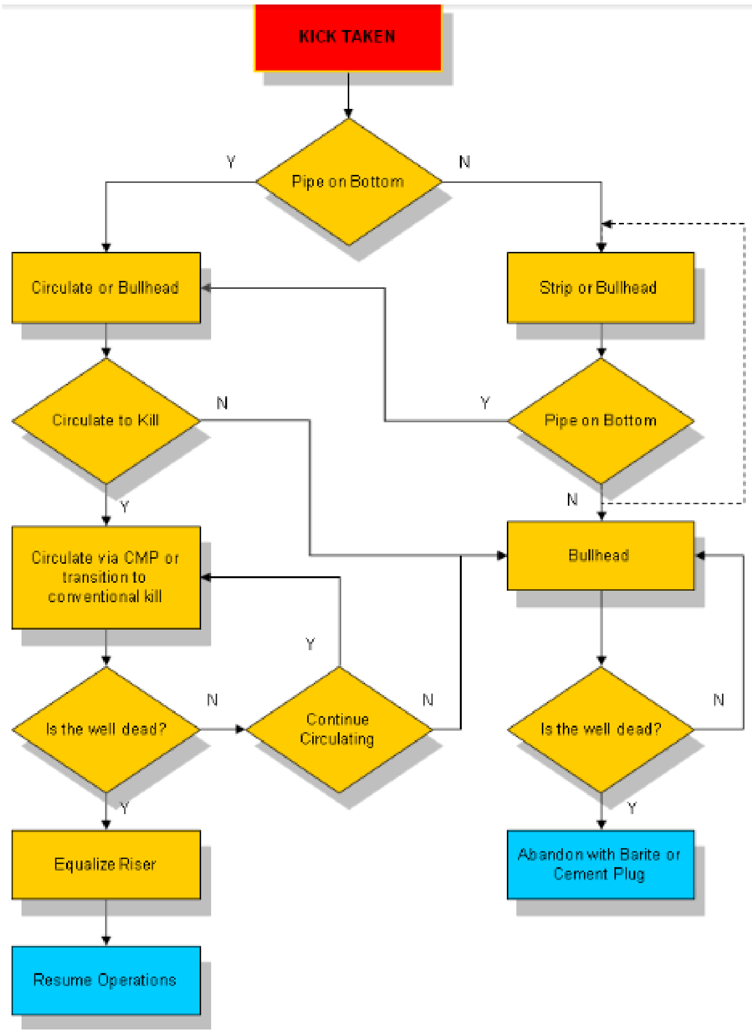

Figure 4-9: Decision CMP kill sheet.[33]

Whereas the EC-Drill will rely on conventional means of circulating the kick out of the wellbore, the CMP primary means of circulating out a kick will be through the subsea pump and up the mud return lines, seen in figure 4.10. This way problems associated with choke line friction during conventional kill procedures is minimized. The return line is in this case working in the same way as a choke line would for a conventional kill operation, only with a much bigger inner diameter, effectively reducing the line friction compared to the regular choke line. Limiting factors for the CMP kill method may however be in the pressure rating requirements to be able to safely circulate a kick fluid through the return line, which typically is around 50 bar (flexible pipe). Effectively limiting the full range of what the system is capable of handling.
Furthermore, controlling the rates and gas expansion throughout the mud return lines, a surface choke will be used to control the pressures. The operation of the choke will affect the subsea pump, so to optimize the kill procedures a control system has been developed that will ensure optimum controllability of the return fluid.

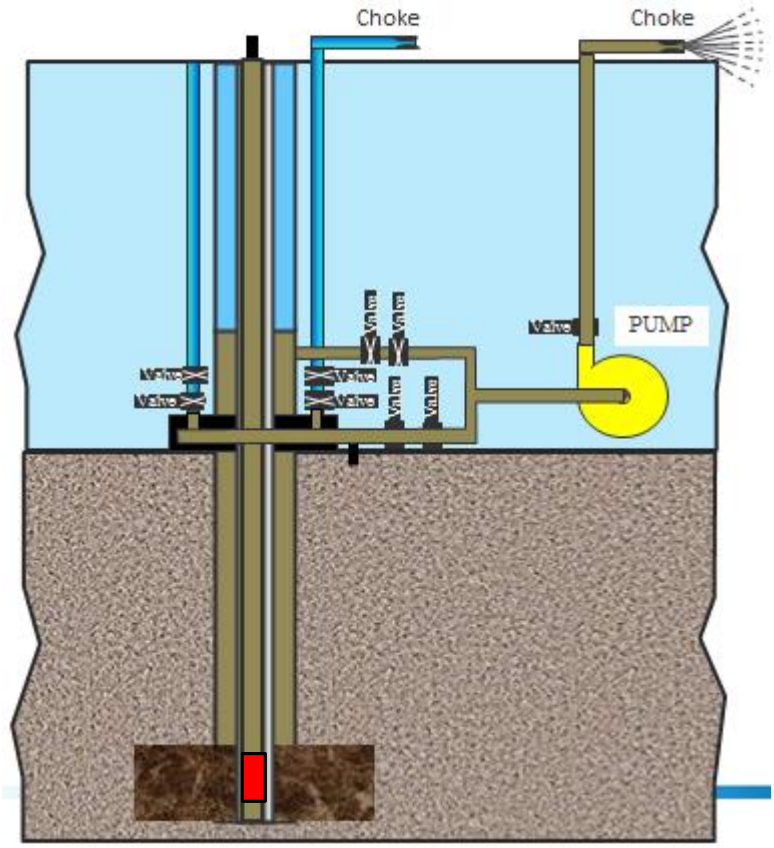

Figure 4-10: Generic schematic of the BOP, kill and choke line, subsea pump and mud return line with choke.[33]

Furthermore, a large set of new procedures were created to try and capture most thinkable eventualities, such as swabbed kicks, drilling with and without anti U-tube valve, running casing and CMP failure etc. Describing these in a detailed level is however outside the scope of this thesis.

4.5.2.7 Well control Barriers

To prevent a kick from developing into a surface blowout, the well is designed with a series of barrier elements that together creates a barrier meant to prevent or reduce the consequence of a well control incident. These elements are often divided into two groups.

- Primary elements
- Secondary elements

Primary elements are the first barrier preventing a kick from developing, for conventional and managed pressure drilling applications the weighted mud typically represents the primary barrier element. Should the primary element fail to prevent the influx from occurring, it is down to the secondary barrier elements to further prevent the situation from escalating out of control. Secondary barrier elements typically consist of a series of fixed “devices”, such as BOP, casing, the cement behind the casing, the wellhead and high pressured riser (if installed). Due to a large number of operations, each having specific requirements that need to be followed, the reader is referred to the NORSOK-D010, where more in depth information is available for various operations.
“The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are as far as possible intended to replace oil company specifications and serve as references in the authorities’ regulations”. [34]

This document effectively benchmarks the lower regulatory requirements that the operators have to comply with. Additionally, most companies have their own regulatory framework and guidelines on top of what the NORSOK dictates. One important consideration is that the current revision does not cover into the areas of managed pressure drilling operations (MPD and DGD). It is however expected that the revised document will describe these too.

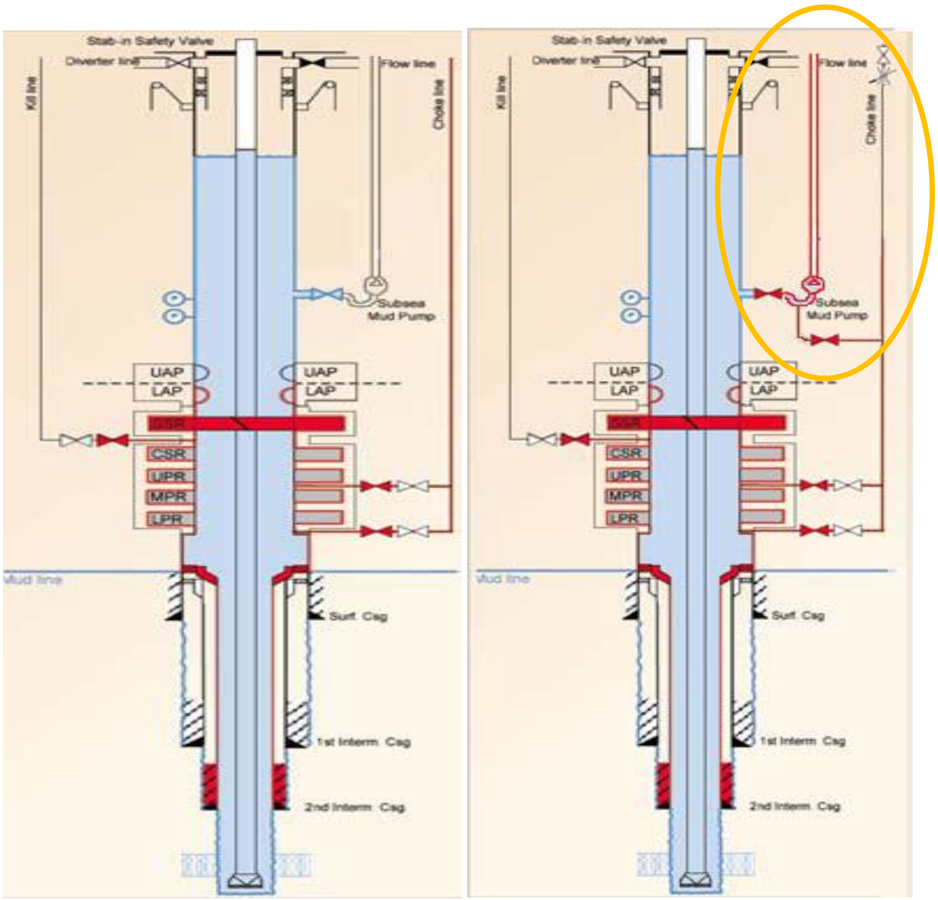

Figure 4-11: Schematic barrier diagram showing primary barrier (blue) and secondary (red). Yellow circle marks the added secondary barriers. [AGR]

The figure above display how an EC-Drill barrier diagram varies from that of CMP set up. Since the CMP will be capable of circulating a kick fluid through the pump and the mud return line, modification to the barrier diagram is required. The CMP may readily rely on the following[35]:

- Primary Barrier elements:
  1. Drilling fluid (common)
  2. Riser pressure sensor (level control)
  3. Drilling riser
  4. BOP Body (common)
  5. HP wellhead (common)
  6. Casing (common)
  7. Casing seal assembly (common)
  8. Cement behind casing (common)

- Secondary Barrier elements:

  1. Casing & Cement
  2. Casing seal assembly
  3. HP wellhead
  4. SS BOP body & element
  5. Choke line and choke line valves

6. Kill line and Kill line valves

In addition, marked by the yellow circle in figure 4-11, the following equipment will furthermore contribute to the secondary barrier elements:

7. AGR Riser isolation Valve
8. AGR Choke line valves
9. AGR Pressure sensors
10. AGR Pump
11. AGR Mud return line
12. AGR Topside choke skid
13. AGR Control system (controlling pump and back pressure during circulating of kick).

4.5.2.8 Kick Margin

As important as detecting and controlling the kick in the first place, the kick safety margin is a important parameter to understand when drilling wells, more precisely is the difference between the pressure needed to control the well and the pressure that breaks down the formation at the last casing shoe. Comparing the kick margin for the CMP and the convnetional system, over the same well interval, the CMP will typically generate a much higher margin:

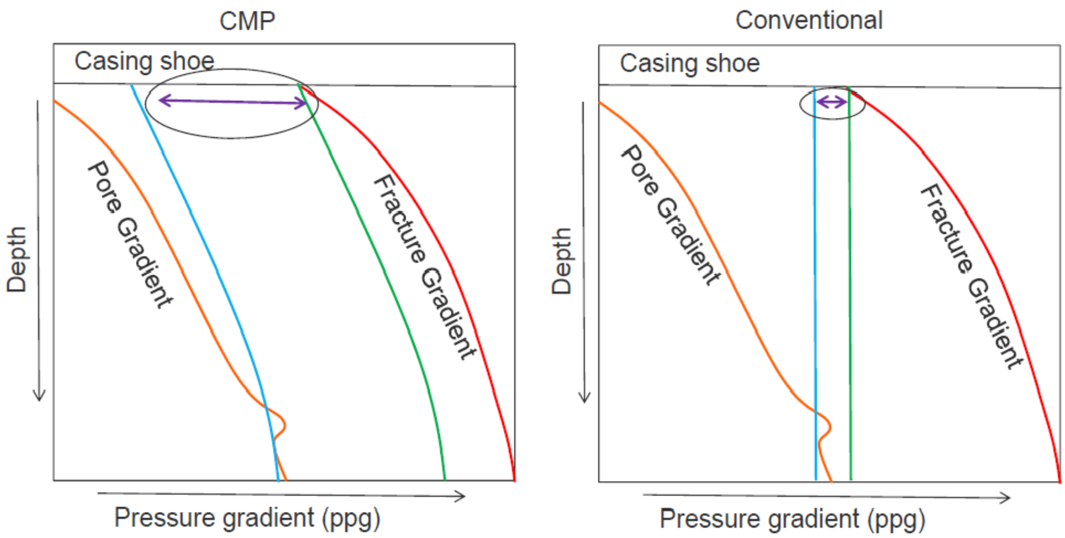

Figure 4-11: Kick margin for the CMP vs conventional.[30]

However accepting this as normal procedure, may eliminate the main reason for using EC-Drill in the first place, namely to increase the length of each section intervals, and being able to set the casing shoes deeper than with conventional operations. As the well sections grow in length however the consequence of dual gradient seems to be an actual reduction of kick margin, comparing the initial case with the latter. This is due to the fact that pressures normally increase with depth, narrowing the marginal window where the well is under control, without fracturing the formation at the shoe.

4.5.2.9 Riser margin

Defined as the pressure differential between the hydrostatic of the inside mud column and the outside water column. The riser margin represents an important parameter in maintaining the primary barrier, and should therefore be incorporated as a part of the drilling safety margin. On closing the BOP and LMRP during a disconnect, the hydrostatic of the mud on the inside of the riser will be replaced with the hydrostatic of the water. This means that it is increasingly harder to maintain riser margin as the water depth increases.

In cases where unanticipated disconnect occur, drilling without riser margin may result in dramatic reduction in the BHP, which again increases the risk of taking a kick, due to already loss of primary fluid barrier. In cases like this, the well head and the BOP now represent the last barrier against having an uncontrolled blow out to the environment.

As one of the main advantages with the EC-Drill, lies in its ability to circulate high density mud through the wellbore. By operating with a mud level just around or above the lower mud level limit (set at 100m above seafloor) it is to a large degree possible to maintain the primary fluid barrier at all stages of operations, even during an emergency disconnect. The chances of maintaining riser margin is however larger for the full EC-Drill concept than for the partial, the reason for this lies in the inherent need of typically relying on a higher mud weight for the full EC-Drill concept compared to the partial.

4.6 Partial versus Full- EC-Drill or CMP

Concerns about possibly having an explosive atmosphere in the riser, together with well control issues, prompted the development of a Partial EC-Drill and CMP concept, evolving around using a top fill pump to regulate the level of a blanket fluid above the floating mud cap. By replacing the gas/air in the open riser section with a blanket fluid, the risk of having an explosive atmosphere was solved. Having a fully filled riser is furthermore beneficial in the way it does not generate unnecessary large collapse pressures, due to high differential between the inside and outside of the riser. Additionally, avoid having dry slip joints (expansion joint on the riser) and significantly reduce the risk of overheating of the same joints.

4.6.1 Level of regulation

Introducing a second fluid into the riser section, it is clear that it would contribute to the overall pressure profile of the well. As the following generic example will show, fully accepting the blanket fluid concept as the primary method may be faulty in the way it generates unnecessary controllability problems. The following figure show a setup that may be defined as the deep water version of the EC-Drill system, the CMP system, having the outlet at the lower half of the riser. The name EC-Drill and CMP may sometimes be used interchangeably, not to be confused, the systems are more similar than they are different.

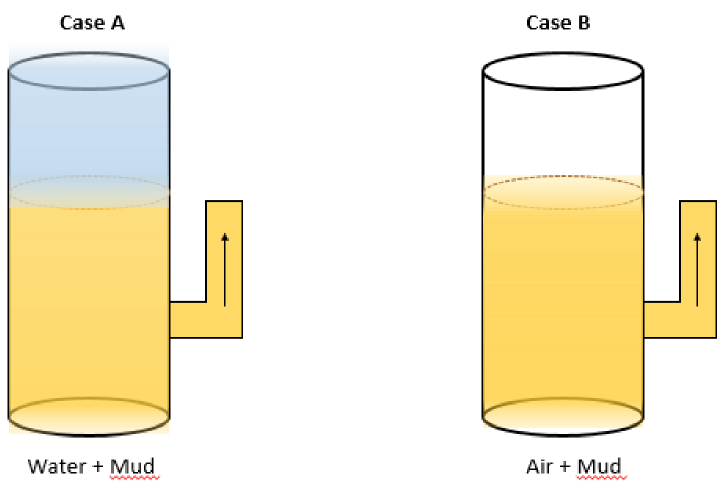

Figure 4-12: Partial vs Full CMP setup.

	Case A= Partial CMP		Case B= Full CMP	
	Before	After	Before	After
Mud density (fixed) [s.g]	1,5	1,5	1,5	1,5
Water density (fixed) [s.g]	1	1	0	0
Riser length (fixed) [m]	800	800	800	800
Height of mud in riser (variable) [m]	200	410	600	670
Height of water in riser (variable) [m]	600	390	0	0
TD (fixed) [m]	3000	3000	3000	3000
Approximate BHP [bar] (hydrostatic)	412	422	412	422
Difference in mud height [m]	= 410-200 = 210		= 670-600 = 70	

Table 4-1: Generic data for example. Friction is neglected.

The table of calculations shows how much the level of mud needs to be regulated to generate a 10 bar pressure increase at the bottom of a 3000 meter well. What separates the two cases is that one has two liquids in the riser, mud at the bottom and water filling the rest of the riser volume (case A), while the second case only has mud in the riser (case B), with no water on top. For case A, the mud and water is immiscible and therefore do not mix. Friction is neglected for both cases, and mud and water density are constant, available riser volume are fixed and remains the same for both cases. Before and after, subsequently refers to the initial and final state, before and after the mud level has been adjusted.

Although greatly simplified, the results clearly show, the required adjustment of the mud level in case A is much higher than for case B for the same pressure increment, even though the overall mud level in case B initially is higher than in case A. Furthermore, if assuming constant flow rate into riser, the time it would take to adjust the mud level in case A is 3 times greater compared to case B. For operations like ECD management, stopping/starting circulation to make a connection or fast increase of mud level to prevent further influx, the time spent to adjust the riser mud level may be outside the abilities of the subsea pump. In a perfect world the mud level could be adjusted in a second or two, which would make all required variations to bottom hole pressures fast and accurate. In real life however there will be a time delay experienced between initial and final state, this is perhaps one of the biggest challenges with the EC-Drill and CMP system with special emphasize on the Partial concept.

4.6.1.1 Level of regulation: Slim riser

Introducing topics like slim riser design, which in effect is removing riser volumes that are not used for supporting hydraulic parameters or cuttings transport. According to Eq 6.11, by subsequently reducing the riser flow area, the rate at which it is possible to adjust the level of mud is greatly increased. As an example: By reducing the ID of the riser from conventional 19 ½" (inches) to 18" ID, with a 5 ½" drill pipe inside, the rate at which it is possible to regulate the mud level in the riser is 1,5 times faster for the slim riser case. Today the riser is more or less standardized; meaning modifications might have to be done to rig or riser handling equipment to facilitate safe handling. Additionally having a smaller riser might create connectivity problems with existing BOP set up or running of large OD tools into the wellbore.

4.6.2 Range of Operability

Stating the importance of regulatory abilities, one should not forget the most important however. The main benefits with any DGD technologies, as the EC-Drill and CMP, readily lies in its ability to create the pressure curves that seem to better fit the natural pressure profiles of most formations. Like earlier described the EC-Drill and CMP mostly rely on adjusting the mud level to influence the bottom hole pressure, maintaining mud weight adjustment to an absolute minimum. As the next example will show, introducing Partial EC-Drill or CMP, has reduced the range of which the bottom hole pressures readily can be adjusted through mud level adjustments.

Conventionally, the mud has to be weighted up and circulated into the well, an operation which takes time; with the EC-Drill or CMP system this time can be greatly reduced. The resulting max/ min pressures are defined according to the upper and lower mud level limit, and are for this example set at 1000 m (full riser) and 100 m above the seabed. The 100 meter lower mark is set minimum mud level limit/ safety margin that will ensure full returns at all time. Data required for the calculations are displayed in table 2.

	Partial CMP		Full CMP	
	Before	**After**	**Before**	**After**
Mud density (fixed) [s.g]	**1.8**	**1.8**	**1.8**	**1.8**
Water density (fixed) [s.g]	**1**	**1**	**0**	**0**
Riser length (fixed) [m]	**1000**	**1000**	**1000**	**1000**
Height of mud in riser (variable) [m]	**100**	**1000**	**100**	**1000**
Height of water in riser (variable) [m]	**900**	**0**	**0**	**0**
TD (fixed) [m]	**3000**	**3000**	**3000**	**3000**
Approximate BHP [bar]	**459.108**	**529.74**	**370.818**	**529.74**
Δ Pressure bottom hole [bar]	**70.632**		**158.922**	

Table 4-2: Generic data for example 2. Friction is neglected.

As the calculation and the following figure will show, the Full EC-Drill or CMP has a much wider range of pressures to operate within (blue line), compared to the partial concept. It is this feature together with the regulatory benefits shown in the previous example that makes the full EC-Drill concept more versatile than the partial system. The "after" case for both concepts readily show how the pressures vary when the riser is filled all the way up with mud, and is turned back to a conventional system,

represented by the vertical lines in figure 4-13. Furthermore, the partial lines represent cases where the mud level is being increased to now fill 50% of the riser. Maintaining a constant mud weight, the light blue and black lines represent the range of which pressures can be adjusted by only regulating the level of mud. Both examples are static cases where friction has been neglected.
If the goal of using the EC-Drill system is to generate beneficial pressure profiles, the effect seems to be decreasing with wellbore length or mud column length.

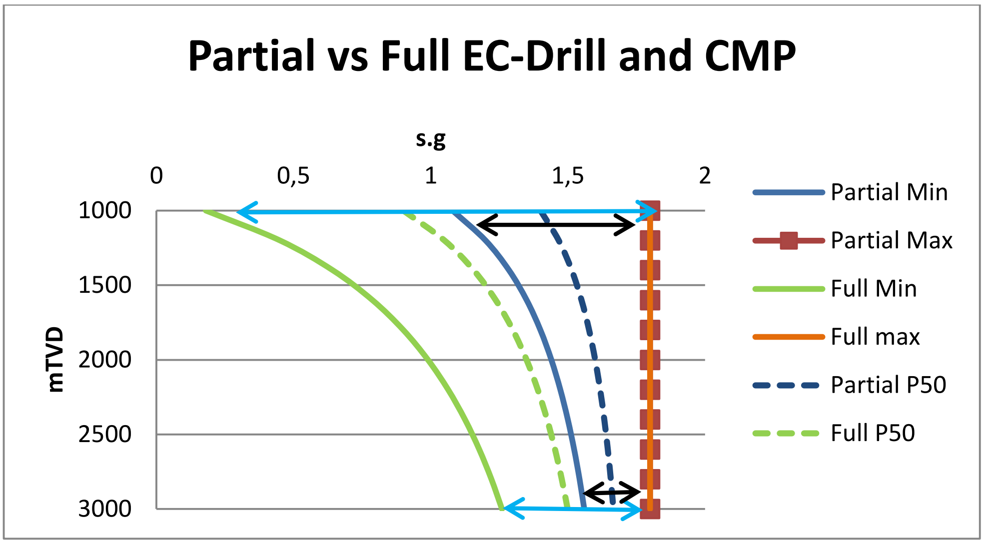

Figure 4-13: Pressure vs Depth: Partial and Full EC-Drill & CMP concept.

Had the well continued to grow in length, the curves would approach vertical, seemingly losing the continued benefits of dual gradient. For limiting sections like the one shown in the figure, the full benefit of dual gradient may be realized. The two previous examples have to some degree provided the impression that the Partial and Full EC-Drill or CMP concepts vary greatly. For most cases however, there will exist a combination of mud weight and mud level that enable the creation of gradient lines that are similar for both setups.

In chapter 6 examples in Matlab will further shed some light on the common operability challenges faced by the EC-Drill & CMP systems.

5 Case study: EC-Drill & CMP Application areas

It is expected that the CMP technology will excel in areas where use of conventional means are not effective or other ways impracticable. Each well is different and should be treated as so, which makes the task of making a "baking recipe" of operations and areas where the technology may prove beneficial extremely challenging. In a hectic rig market where time is money and safety has become the number one priority for most operators, it is hard to see how this relatively new and unproven technology may compete against conventional systems, which for the better part of half a century have been the way to drill wells. On analysing a large number of wells spanning the globe, the result will to some degree provide some guidance into what kind of terrain the EC-Drill & CMP technology is expected to prove most successful.

NB: This chapter is not designed to further comment or critique already completed wells, reports or conclusions being made from others, but rather showcase to what extend and possibilities the author believe the EC-Drill & CMP technology may generate.

5.1 BG-Group Offshore Locations

To investigate areas which DGD technologies may prove beneficial, one does not have to look further than any offshore market in the world, no matter how small. To help narrow the search, BG-Group provided well data from offshore locations from areas where they operate.

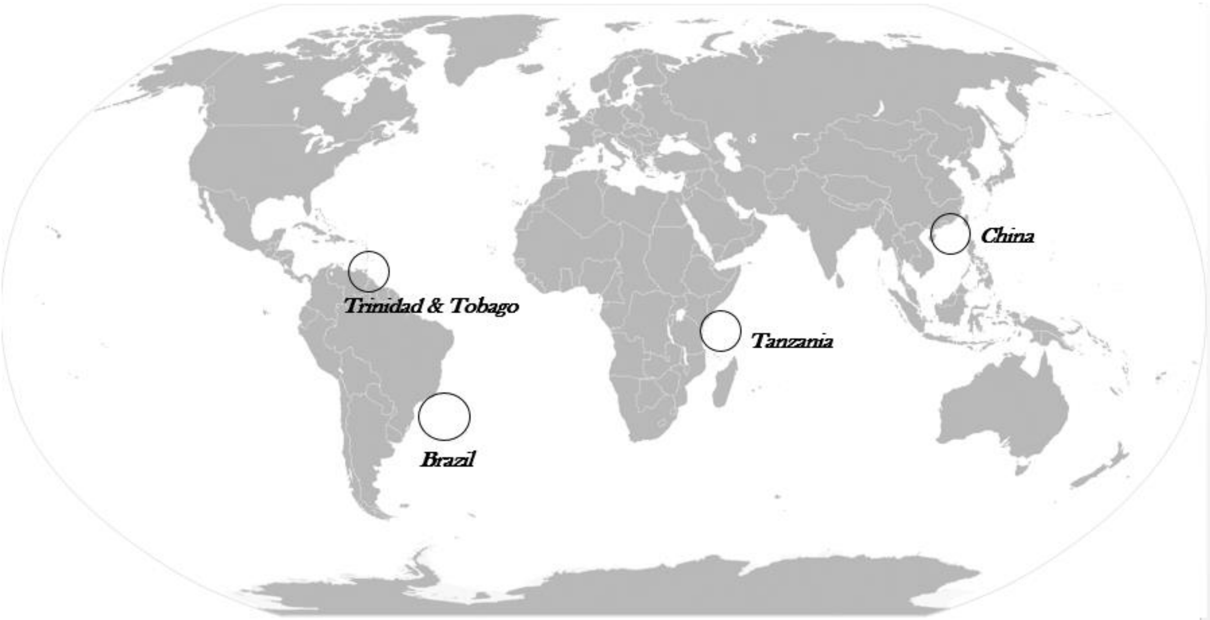

Figure 5-1: Analysed offshore locations. [36]

In a reactive market like the oil and gas industry, these locations may change very quickly and should only act as a reference. Furthermore, the actual properties of the formation should be more important than any specific location name, as the result of the following analysis will show.

5.2 Area of Analysis

Extracting the relevant data from drilling programs and well reports is fairly straight forward. However applying the correct decision criteria when analysing if any DGD technology will prove beneficial during any level of the drilling, is the challenging part. Offshore operations are like a complex puzzle, requiring that all the small parts fit together to increase the chances of success. In doing so, there are certain aspects that one should be looking for when planning or evaluating already drilled objectives with respect to using dual gradient drilling, here are some of the most predominant:

- Operational window (PP/FG)
- Water depth and hazards
- Dynamic or static losses
- Duration and contractual terms
- Type of well

5.2.1 Operational Window

Defined as the upper and lower wellbore pressure limit, the operational window is one of the most, if not the most important parameter to know when drilling wells. Staying above the pore and collapse pressure at one point, whilst at the same time staying below the fracture pressure may in some situations prove challenging. In chapter 1.3 narrow operational windows were defined as a deep water problem, which is not entirely true. Drilling wells in shallow waters may generate similar problems with narrow pressure margins.

On hydrocarbon producing fields, it is furthermore not uncommon to meet formations that experience abrupt pressure changes, either as a consequence of sustained pressure support such as water or gas injection, or natural pressure depletion as the reservoir is produced. Generating artificial pressure anomalies, as previously described are a common occurrence in most fields that have been producing for some time (somewhat reduced in reservoirs that experience natural subsidence, like Ekofisk on the NCS).

Most of the wells analysed during this thesis were however exploration and early development wells, which is before onset of such depleted or over pressured formations have had the time to develop. Not forgetting that there are also natural reasons for over pressured or depleted formations, such as pressure being trapped with uplifting formations.
Looking from a NCS perspective, these types of formations should not however be left out of the analysis, due to the fact that dual gradient technologies are expected to remedy some of the bigger challenges associated with depleted or over pressured formations, which for instance is the purpose of the pilot test at Troll.

Furthermore the operational window to a large degree helps define where and how many casing strings need to be set to provide adequate wellbore stability throughout the duration of the well. Earlier the problems surrounding narrow operational windows were discussed, and it is expected that EC-Drill in some cases may generate a pressure profile that better fit the natural pressure profile of the formations, than what is achievable with conventional means.

Pinpointing whether any of the wells had troubles maintaining proper hydraulic control, well control incidents is often a good indicator of this then determining if this was due to wrongful anticipation of pore pressures or failure to correctly apply the required drilling parameters, or both.

5.2.2 Water depth and Shallow Hazards

Until riser and BOP is installed and proper barriers can be maintained, pressure related shallow hazards pose a big threat to any drilling operations. By using technologies like RMR, the full benefit of using engineered mud may be realized. For conventional operations, if called upon, heavier mud may be used to circulate; this mud will however be lost to the ocean. Whether or not it is possible to balance the cost of the lost mud against the cost of having an RMR setup and mud returned to rig is outside the scope of this thesis. It is however believed that drilling top-hole sections in a batch, by using the RMR set up or conventionally, will save valuable rig time regarding rig up/down, faster drilling due to know lithology's and pressures, knowledge of shallow hazards, etc.

Compared to a conventional system, the EC-Drill has an additional parameter that can be changed to obtain the desired pressure in the wellbore, namely the riser mud level. Adding to this, the conventional way has been to adjust the mud weight in steps to reach the target bottom hole pressures. The EC-Drill & CMP try to maintain a minimum of adjustments to the mud weight, which fundamentally leaves the mud level in the riser as the defining variable that can be changed. As the examples later will show, introducing a safety lower mud level limit on top of an initially short riser section, will impair the range of which the EC-Drills are capable of adjusting the mud level. For later reference, the analysed Trinidad and Tobago wells are shallow water cases, while rest can be defined as deep water wells.

5.2.3 Dynamic and static losses

Losses and gains from formation remain one of the biggest challenges when drilling wells today. In a perfect world, what went into the well would come out of the well. Unfortunately it is not like this, static and dynamic losses are a regular part of any operation, and may be hard to control. Cases where losses of fluid only occur while circulation takes place are called dynamic losses; cases where fluid is lost when circulation is not taking place are called static losses. Ways of remedying losses may for both dynamic and static cases be to lower the mud weight. Remedial work such as pumping lost circulation pills, with particles of varying size and composition, may fully or partially solve the problem. Additionally, reasons for dynamic losses may be excessive flow rate, which may require lowering of this to eliminate further losses.

Operations such as cementing are typically prone to excessive lost circulation due to the fact that cement properties normally require the use of higher viscous, density spacers and fluids compared to drilling mud. In cases where excessive losses are seen during regular operations, pumping cement is almost certain to make these losses increase. Worst case might be that the cement due to loss of liquid part, set up too soon, not being strong enough to provide a proper annulus seal or weak bonding capabilities with the casing.

Additionally, wells that at some point or another have had to commence with kill procedures are more likely to experience major losses when continuing drilling. This is typically due to pressure fluctuations throughout the wellbore, shutting-in pressures, heavy kill mud, excessive flow rates, etc.

5.2.4 Duration and contractual terms

Operations on the NCS are unique in the fact that they tend to take somewhat longer than similar wells elsewhere around the world. The reasons for why wells typically take longer to drill in Norway might be many, among the most predominant reasons are, safety regulation and requirements, mechanical pipe handling, operational procedures, environmental requirements, offshore personnel work schedules and rights, waiting on weather, contractor and operator experience, etc.

Duration and cost of a drilling campaign is often closely linked together, which means that the additional cost associated with having extra equipment, offshore personnel and increased power consumption, will have to benefit the operation in a substantial way to create a net positive effect. As the cost of implementing the EC-Drill or CMP so far is unknown, the cost which will strongly depend on contractual terms, long/ short term agreements, technology rights or privileges, rig integration, etc. Due to the relatively unproven track record of the EC-Drill, comparing the cost of conventional operation against the EC-Drill might thus be hard to accurately quantify.

Worth mentioning, long term contracts tend to generate lower average cost per well than single standalone developments. It is therefore likely that at some point, the technology will be part of an extended drilling campaign, not unlike Chevron with its SMD system that was earlier described.

5.2.5 Type of well

Closely linked with the dynamic and static losses, defining what type of well, vertical, horizontal or somewhere in between are crucial in defining system constraints. For long reach or horizontal wells the contribution from the friction may introduce operability challenges while circulating the well.

Additionally, defining if a well is an exploration well with higher uncertainty and limited pressure and lithology data, or a development well where predictions are likely more certain and accurate information is available. Considering exploration wells one might have to take into account its design quickly changing wellbore parameters, due to high uncertainty in pressure or formation properties. This favours the use of systems like for example dual gradient or MPD systems, which are designed to quickly detect controllability issues and implement control action.

Equally valid for development wells, however keeping in mind as a field development progresses, better and more accurate information should greatly reduce formation related uncertainties. Often reducing the need for a system that is highly adaptable to large changes within a small timeframe. Or on the contrary, specific knowledge about the formation may provide beneficial in a way that it is possible to create better drilling programs, procedures and parameters, resulting in adequate time and cost saving benefits. Like with MPD, the EC-Drill could be used reactively, merely being a contingency if needed.

5.3 Introduction to cases

To best define the environment where the EC-Drill concepts are expected to excel, specific wells from the available data sets have been selected. Putting operability concerns aside, it turns out, that the two EC-Drill concepts, due to respective pressure gradient, might prove beneficial in slightly different environments.

In chapter 5.2, the areas of analysis were discussed. The next part will, to some degree, try to use what was earlier described and implement with real cases. Due to sensitivity of data, the wells will not be described by name or in too great detail; limiting description of data to the most essential for the cases at hand.

5.3.1 Case A: EC-Drill Operational window

The following PP/FG plot represents data from a deep water well in Tanzania. The well was drilled conventionally, the green line representing the actual mud weight used.

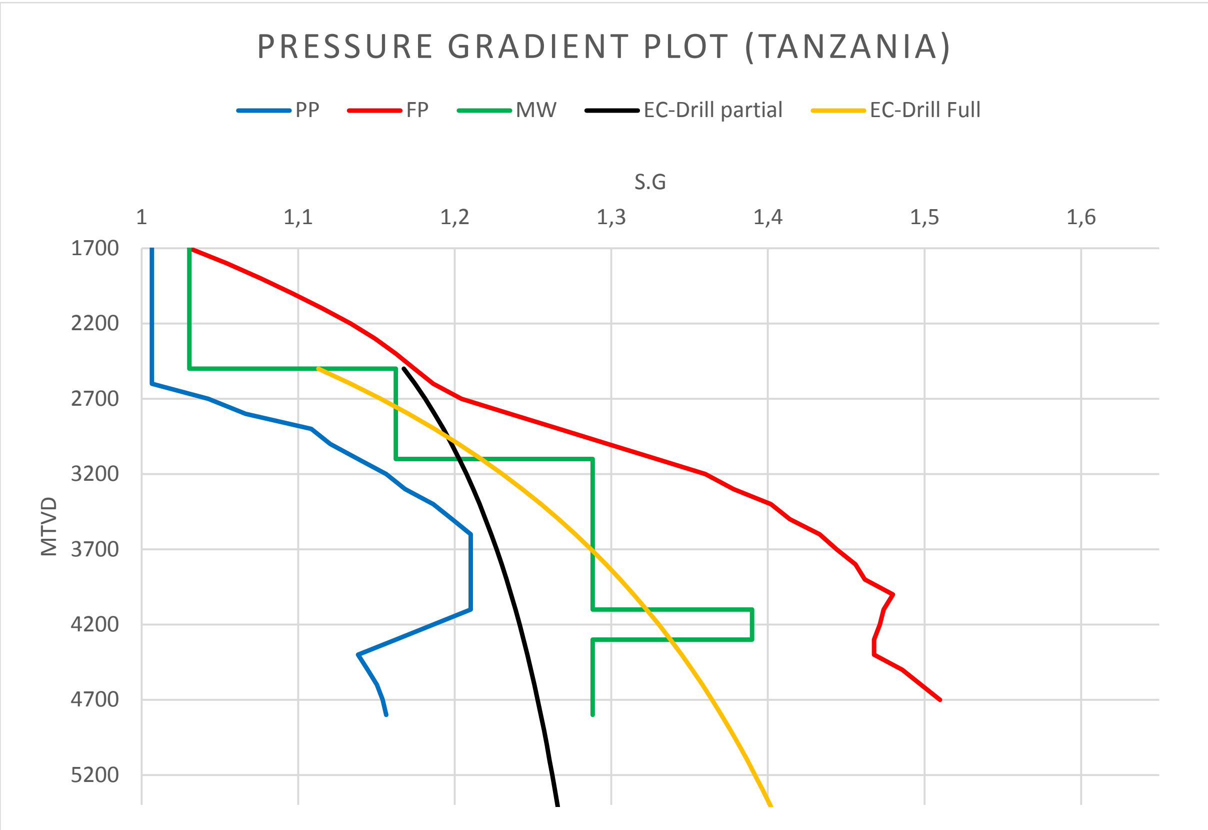

Figure 5-2: The PP/FG-plot from a well in Tanzania. Water depth is 1664 m.

The red and blue line represent the upper and lower operational boundaries of fracture and pore pressure respectively. The black line represents the pressure gradient for the partial EC-Drill concept, while the orange represents the full EC-Drill wellbore pressure gradient. This example is meant to show how this well may have been drilled using EC-Drill & CMP concepts, additionally how sometimes the partial system impose certain controllability issues compared to the full concept.

Easily seen from the pressure plot, this well due to a pressure ramp up has a relatively narrow operational window spanning from seabed, until it opens up at around 3400 meter TVD. The selected gradient lines only represent one of multiple combinations. If it in real life would be possible to drill from surface casing shoe to TD without having to resort to changing mud weight, mud level or set casings is hard to say. Decisions should be based upon drilling safety margins, kick tolerance, lithology, casing and well design. What in theory looks possible may not always transfer to real life. Let us just for the sake of the argument say it was possible. The input data for the dual gradient curves are:

Concept	***Mud weight [s.g]***	***Blanket fluid density [s.g]***	***Height to mud cap (seabed-mud) [m]***	***Sea depth [m]***	***Riser margin***
Partial EC-Drill	1,35	1,00	100, rest is filled with blanket fluid	1664	No
Full EC-Drill	1,65	0	875	1664	Yes

Table 5-1: Data behind the partial and full EC-Drill concepts.

It is clear from looking at Figure 5-2, that the full EC-drill gradient line generates a much better fit through the well than the partial. It is however very unlikely that the partial concept leave enough room allowing for circulation or kick margin to be maintained. For controllability reasons, the mud level in the riser should never drop below the 100 meter mark (seabed- mud cap). Which means that the partial EC-Drill concept, besides really small adjustments have lost all its ability to safely adjust bottom hole pressure. In other words, an increase in mud weight or mud level would shift the curve outward and to the right exceeding the formation strength.

On the other side, lowering of the mud level is impossible due to the mud being at the lowest level already. Further reduction of the mud weight will greatly increase the risk of having the wellbore pressure going below the pore pressure margin at around 3600m. A combination of increasing mud level and decreasing the mud weight would only result in making the pressure gradient line more vertical, or closer to that of conventional mud gradient.

Using the partial EC-Drill and maintaining the current surface casing setting depth, it would be impossible to drill the entire narrow window without having to set a liner or casing, failing to fully take advantage of the dual gradient concept. For the full EC-Drill concept however (yellow curve), it seems it is possible to adjust the mud level and mud weigh up and down, which leaves more room for safely navigating through the narrow window. For this particular well it seems that using the full EC-Drill may prove the safest and best way of drilling the well, further realizing more of the advantages with dual gradient.

There is however a different option, both EC-Drill & CMP (full and partial) concepts could be purely used for safety reasons, although perhaps not the most economical option. Maintaining the conventional casing program, drilling dual gradient through each section will provide a better fit through the operational window than what could be achieved using conventional setup. Using the

EC-Drill will greatly increase the chance of maintaining full riser margin, additionally reducing the risk of exceeding the operational limits, pore and fracture pressure respectively, as the following figure will show.

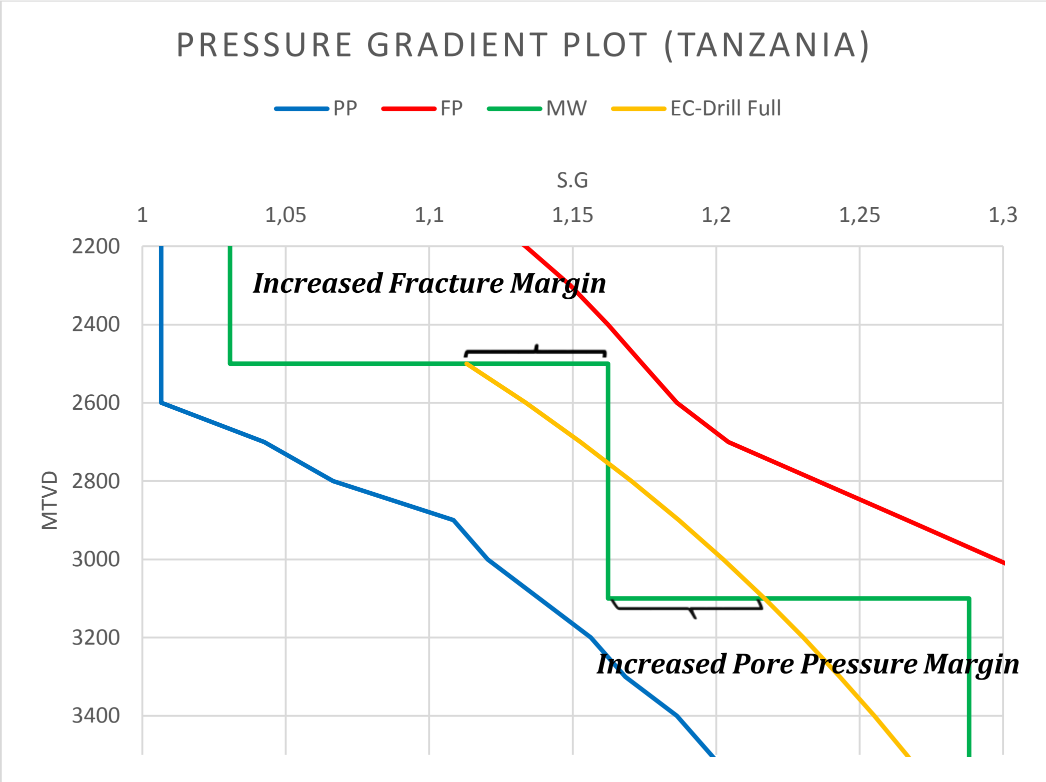

Figure 5-3: Increase pore and fracture pressure margins is one of the major benefits with EC-Drill.

Besides the small issues described, the well in case A seemed be completed without major drawbacks. Which in other terms means that using the EC-Drill for this well may generate cost and time benefits by reducing the number of casing strings, reducing cementing jobs and significantly reducing the risk of exceeding the pressure limits of the well.

5.3.1.1 Extreme Operational Window

The full benefits of the EC-Drills capabilities are expected to be realized in wells that are experiencing even narrower drilling windows, over longer intervals, than what was seen in case A. Strangely enough most examples evolving un-drillable wells always seem to include wells from GoM, wells that seem to experience narrow windows from the very first meter of well through the last, with pore and fracture gradients similar to that of figure 5-4.

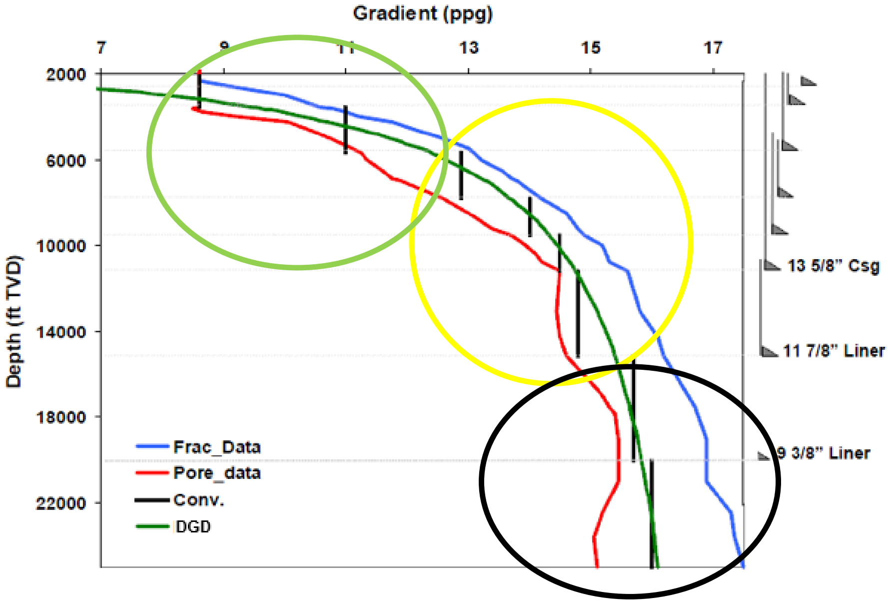

Figure 5-4: Gulf of Mexico well, showing an extreme case of narrow operational window. [35]

For cases like these, it may seem like using the EC-Drill or other dual gradient technologies might very well be the enabling factor that allows the well to be completed within a reasonable time, cost and with a hole that the production engineer can use. This example is however meant to showcase the adaptable nature of the DGD concepts, keeping in mind that most cases are not as extreme as this. Due to the fact that the EC-Drill & CMP would have to be run at a post-BOP stage, the use for the technology may fundamentally be limited to intermediate sections marked by the yellow circle. The pre-BOP phase, marked by a green circle, may be drilled conventionally or using RMR technology. When it comes to the final stage, marked by the black circle, using the EC-Drill will more or less generate similar gradient lines as conventional. Consequently using the EC-Drill & CMP for these sections should strictly be limited to its ability to readily lower mud levels during cementing and/ or improved kick detection capabilities. In other words, the last section is not initially planned to be drilled by the EC-Drill system, however if contractual terms state that the cost for the system will be the same regardless if the EC-Drill is used or not, it might as well be put to good use.

5.3.2 Case B: Dynamic and static losses

For most wells, reasons for loosing fluid to the formation may be many, but the fact still remains the same, lost circulation represent a common occurrence in most if not all drilling operation. It typically develops into a problem when losses grow into a substantial size, either making it hard to accurately account for the wellbore fluid balance, conditioning of existing mud or refilling of lost mud may in many cases halt drilling progress. As the following example will show, a well drilled in Tanzania experienced some major losses at two very different locations in the well, marked with yellow circles. At around 4000 meters the losses became such a big problem that a contingency liner had to be run to prevent further losses. To facilitate cementing of the liner, a low weight base fluid was pumped into the annulus that would sufficiently lower the hydrostatic pressure, enabling the correct cementing parameters to be maintained, maintaining static and dynamic losses to a minimum.

Starting at around 5000 mTVD, an unanticipated abrupt decrease in fracture pressure resulted in using a mud weight that was close to the formation fracture pressure. This resulted in excessive static and dynamic losses. First a large number of lost circulation pills were pumped to try and cure the losses, without significant success. To further eliminate the losses, the mud weight had to be decreased.

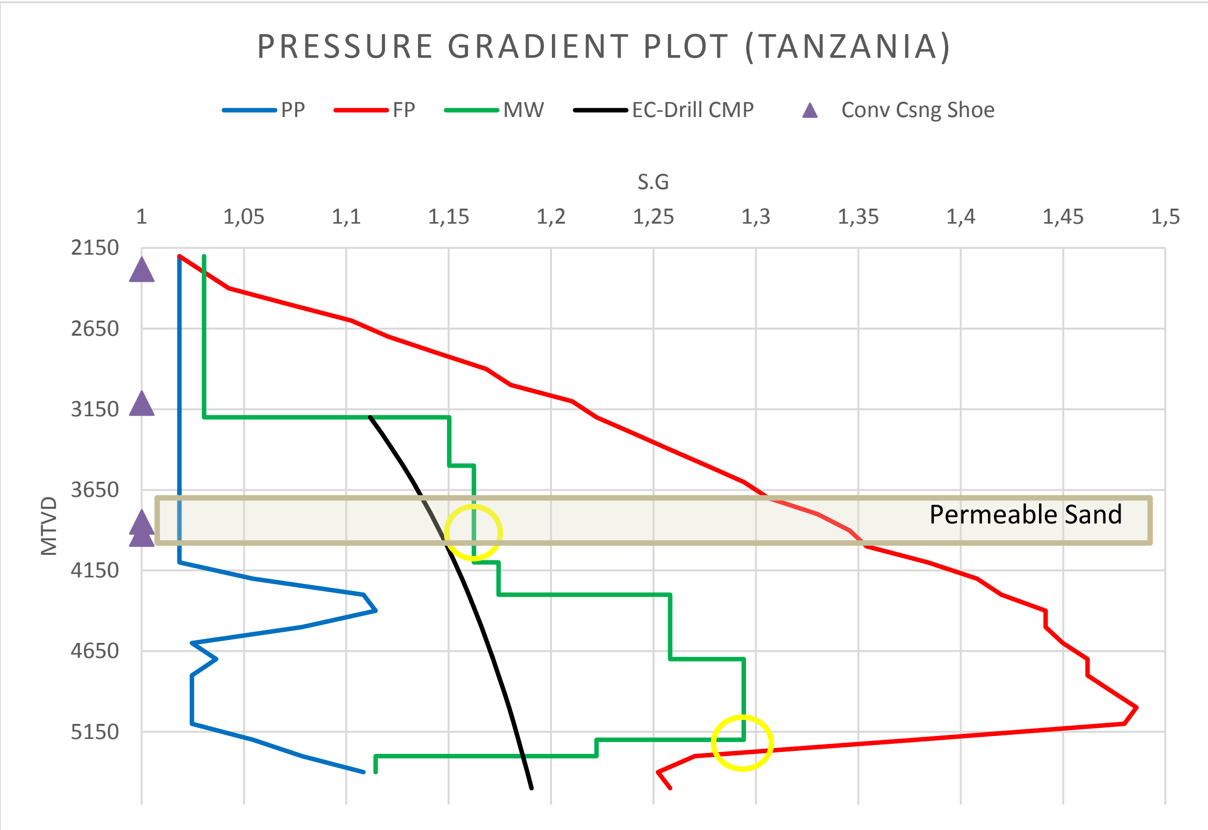

Figure 5-5: PP/FG curve- Tanzania. Water depth 2185 m.

The partial EC-Drill line in Figure 5-5, is generated by using a 1,3 s.g mud and a mud level at 100 meter above seabed, the rest of the riser is filled with water. What is interesting to see about this well was that losses are not only experienced in parts with close proximity to the fracture pressure gradient as one normally would expect, seemingly the upper most circle is more or less centralized in the operational window, with sufficient margin to both the pore and fracture pressure. To try explain why losses were experienced here, one might have to review the lithological data to find a better answer. As it turns out the zone was a highly permeable sand formation, resulting in losses while circulating. Due to an anticipated pore pressure ramp up, the previous casing had to be set in a permeable sand formation, resulting in continued losses as the last part of the sand was drilled. On completion of that section, to further limit losses, a contingency liner had to be run.

Introducing the EC-Drill or CMP system to this well, with its quick loss detection capabilities, may have resulted in the overall losses being kept to a minimum, or subsequently removing them all

together. Additionally, there would be a high probability of saving a liner or casing string. Drilling through the permeable sand zone with the EC-Drill may have reduced the losses to a level deemed acceptable, effectively saving to run and cement the contingency liner.
It is however safe to say, if the pore pressure ramp up and decreasing fracture pressure had been correctly anticipated, the mud program might have been slightly different than what was actually chosen. Readily, using the EC-Drill to generate similar curves described in figure 5-5 would have reduced the overall drilling time, through increased ROP made possible by reducing the wellbore pressure compared to what was achieved by conventional means. Additionally, by reducing the wellbore pressure, and subsequently the differential pressure between the well and the formation, the risk of differentially sticking the pipe is also reduced. And perhaps more importantly the major losses experienced in the lower section may have been avoided all together.

5.3.3 Case C: Water Depth and Shallow Hazards

As stated earlier, the EC-Drill has fundamentally been developed for post-BOP drilling operations. This fact leaves the top hole sections to be drilled conventionally or by using other specialized technologies like RMR. The benefits of using RMR have previously been described. The following example is from a development well in Trinidad & Tobago; the well was drilled conventionally and completed without any large problems. It might therefore be hard to justify that things could have been done differently. As the following figure will show, drilling of the top hole section using RMR, may facilitate setting the surface casing deeper, subsequently saving one casing string and cement job. Further introducing two novel options on how to complete the next section.

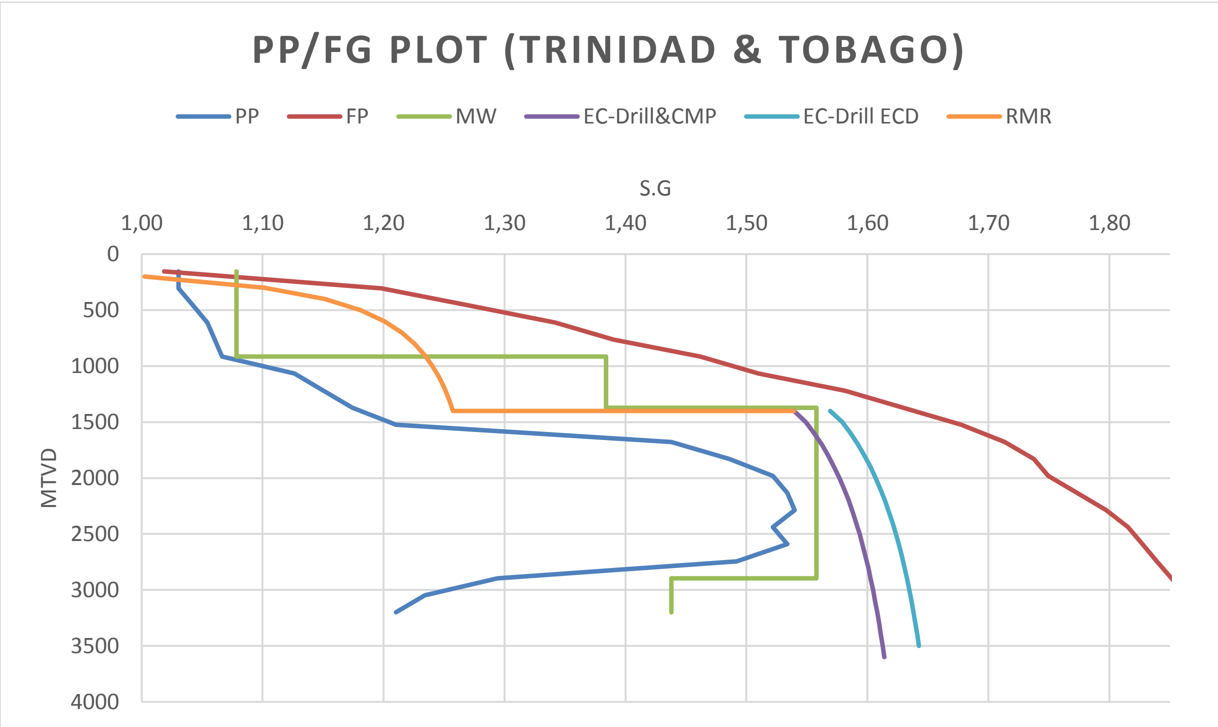

Figure 5-6: PP/FG curve- Development well in Trinidad & Tobago

Keeping in mind that this is a development well, the lithology and formation pressures should be well documented. The next section could be drilled conventionally or with the EC-Drill. Though in general the EC-Drill might provide a better fit between pore and fracture gradients as well as increased safety margins, the cost associated with using the EC-Drill might exceed the benefits. Seemingly the intermediate section was drilled conventionally without major incidents despite of its close proximity to the pore pressure. As this is a development well with a short horizontal section at the TD, using the EC-Drills abilities to control excessive ECD might have been useful. For this specific well however, there is no problems with narrow margins, allowing for high flow rates to be used if need be. Taking all this into conclusion, this well, even though it has some narrow pressure margins, is not a wellbore suited for using the EC-Drill system.

Another feature with this well, unlike most of the other wells analysed in this thesis, is one that is expected to be applicable for similar wells all over the world. Due to relatively shallow water depths and a subsequent short riser, the range at which the EC-Drill may adjust the mud level is somewhat limited. This only facilitates small manipulation of the input variables (mud level adjustments), which prevent the making of highly deviated gradient lines which most dual gradient technologies so strongly rely on. However, as the following example will show, not all jobs rely on large variations in mud level to facilitate its success.

5.3.3.1 EC-Drill Drill BP well in Caspian Sea

Further looking into the available cases history of the EC-Drill, a well completed for BP in the Caspian Sea. The well was drilled from a fixed platform installation with a water level and air gap of 100m and 48m respectively. The well had difficulties drilling to the required casing setting depth, ensuring full integrity for safely drilling the next section. The window of operations was a narrow pore and fracture pressure window of 1,44 and 1,48s.g respectively. Rate of Penetration (ROP) was excessively limited due to build-up of cuttings in the hole as the result of low annular velocity. The increase in equivalent mud weight due to the cuttings load caused losses to the formation. The resulting hydrostatic pressure loss on the high pressure sand caused the fluid (water with dissolved gas) to flow as the margin of overbalance was very small.

By using the EC-Drill system, the driller was able to offset the effect of cuttings loading and frictional pressure loss to keep the wellbore pressure within the pressure window throughout the entire drilling operation. The level of mud in the riser was manipulated in order to achieve the planned Equivalent Circulating Density (ECD) at the bottom of the well. The type of operation described in BP operation show that though operability is greatly reduced, the technology can still be used with great success in the shallow waters. [39]

From this, the following conclusion can be made; as the EC-Drill is strongly dependent on its ability to adjust mud levels up and down, shallow water operations might not take advantage of the full range of benefits that the EC-Drill have to offer, but may still be used with great success, as the BP case earlier described. As conventional drilling operations typically becomes more challenging with increasing water depths, the usefulness of the EC-Drill is expected to increase incrementally. Introducing a long riser, may be challenging with respect to deck space, running, installing and maintaining over time. However putting all this aside and focusing on the drilling part, increasing the riser length basically opens up a window of operability with endless possibilities. Leaving the EC-Drill & CMP system highly adaptable and able to overcome almost any challenges it might face.

As the EC-Drill & CMP is undoubtedly primarily designed to conquer deep water prospects, rightfully doing so, neglecting that major part of the world's offshore wells today and for many years to come, still will be in shallow to medium waters.

5.3.4 Case D: Duration and contractual terms

Earlier the equipment integration process for the Troll pilot was discussed. To briefly sum up that operation, the rig required a dock stay to complete all the required modification. This inherent need for a dock stay might significantly limit the use of the EC-Drill & CMP to single well campaigns. If the rig contractor additionally, shows reluctance toward maintaining the modified equipment as soon as the contract goes to a new operator, either due to deck space and load limitations, or simply that the next operator wants to make modifications of their own, the operator risk having to add additional cost associated with removing the modified equipment. This means, included in the overall price tag, the added cost associated with having to complete one or possibly two dock stays, might simply be too high for any single well campaign.

For extended well campaigns however, the cost associated with the upgrade will spread out over an increasing number of wells. The overall cost will for cases like these, strongly relies on the actual cost of operating the system on a day to day basis, more so than what would be the case for a single well campaign. Contained within the day to day operation, contractual terms like $rate/meter drilled, $rate/day (from arriving on location- leave location), $rate idle (not being used)+ certain fixed $rate (as soon as being used), the contractual terms are limitless and might vary from operator to operator, rig providers and DGD service providers. Even though a highly relevant topic, defining the economic boundaries for the system, further discussion about contractual terms is however outside the scope of this thesis.

Future work will for the system designers evolve around, standardizing, modularizing and further simplifying the equipment and installation process, which at some point will make it possible to install the EC-Drill on location, saving the need for non-productive dock stays. Initially, it was expected that the time initial time lost during installation, testing, retrieval and demobilizing of the equipment might be sufficiently large enough that the EC-Drill will have troubles generating positive advances enabling the operation to "catch up" to the lost time as operation progresses. Adding to this notion, drilling shallow targets typically do not require large number of casing strings to reach TD, which for the EC-Drill is one of the major selling points.

Furthermore, introducing an anti u-tube valve, pressure transmitters, extra pumps, flexible mud return lines, choke, power generators, control lines and control systems, suddenly there is a lot more things that might go wrong. Subsequent failure of any of these may result in time consuming retrieval and repair jobs, additional logistical demands if repair parts are not available.

As the following two figures will show, a well being drilled in the China Sea was completed without major difficulties. From spudding, to finally plugging and abandoning the well, total time spent was 46 days, where 14-15 days were spent drilling, whereas the EC-Drill system only would be eligible to use for about half of that, shown in Figure 5-8. However, defined as a successful operation, completing a well in such a short horizon may leave a very small window of time where the benefits of the EC-Drill system may be realized. Figure 5-7, display how the drilling of the post-BOP phase may otherwise have been completed. As previous examples, the blue and red line, represent the pore and fracture pressure respectively. The green line, represent the mud weight being used, while the purple lines represent the gradient lines of the possible EC-Drill solutions. The conventional and modified casing seats are represented by the orange and grey triangles.

The first thing that is obvious by looking at Figure 5-7, is that there is opportunities for saving an intermediate casing string, furthermore saving a cement job. It is hard to say if the losses at TD could have been cured by reducing the mud level, seemingly it was a high permeable sand formation.

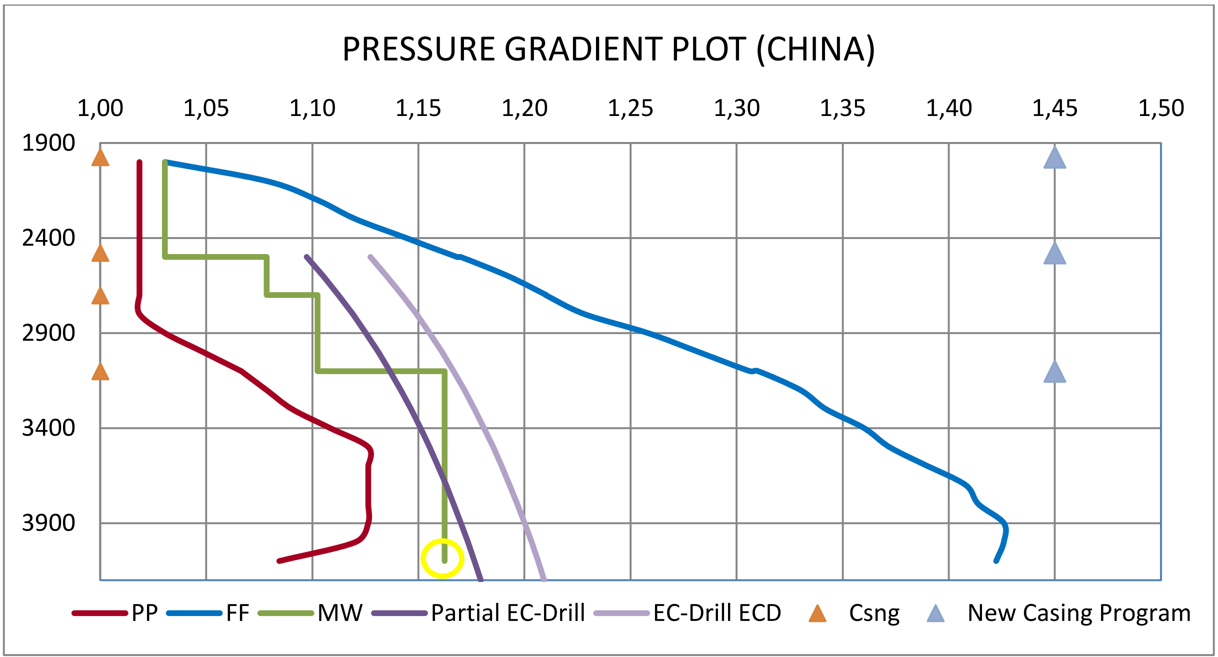

Figure 5-7: PP/FG curve- China Sea. Water depth is 1908m

Mud weight used to generate the EC-Drill curves are 1,3 s.g, with a mud/ water interphase at 250 m above seabed. Yellow circle represent area of lost circulation.

As Figure 5-8 will show, it would be hard to justify the added cost associated with using the EC-Drill system in an operation that was finished almost 14 days ahead of schedule, in an operation without serious drawbacks.

It may however be interesting to see how much time the EC-Drill actually may have saved, if it had been used. Initial running and installation time is somewhat higher for the EC-Drill system compared to the conventional. For this well, the time initially lost is however expected to be gained through not having to run and cement the intermediate casing string. Additionally, times spend on running and cementing of the 11 ¼” liner may be reduced. The red line is purely an imaginary line, created on the notion that the EC-Drill system would perform as good if not better than the conventional drilling system. Further designed to show the reader where the subsequent time reduction may occur. The red line was generated under the assumption that the EC-Drill does not add any unnecessary NPT on-top of what was experienced with the conventional drilling system. Additionally, the ROP of both systems are assumed to be the same. Under these highly idealized conditions, reaching TD using the EC-Drill system, may save drilling time by up and around 3-5 days, compared to the conventional.

It is however expected that until the EC-Drill has increased its track record, and more knowledge about installation, run and de-mobilization times are available, these data only represent expected values.

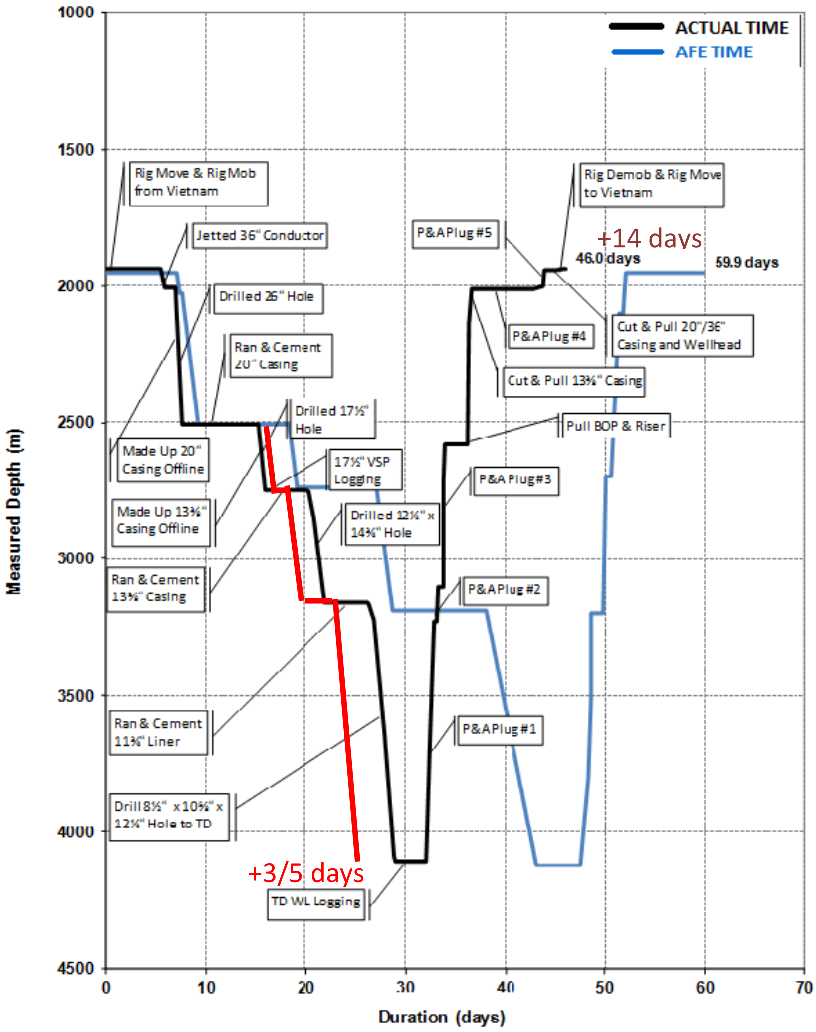

Figure 5-8: Depth vs time curve.

It may however be necessary to challenge the notion that the installation and demobilization time for the EC-Drill system represent a considerable time increment into the overall operational time. As the BP operation in the Caspian Sea resulted in minimal additional online time to prepare and run the system on the riser. The same applied to the de-mob phase of the operation, where retrieving the system only accounted for 1,5 hour additional online time. This number should also only act as a reference, generally it is safe to say that installation and de-mobilization times will vary greatly from rig to rig, fixed or semi-submersible platforms, auxiliary capabilities, crew experience, weather conditions, etc.

5.3.5 Case E: Type of well

In conventional horizontal drilling operation, the friction will be the component of the ECD that increases the most, if not the only, hydrostatic will typically be more or less constant. Cuttings transport in the toe and heel of a horizontal well is a well-known problem area, and is currently the basis for a lot of work and research. However, preventing cuttings from building up at any point along the wellbore, is often achieved with sufficient flow rate, drill string rotation, adjusting drilling rates, pumping high viscous sweeps, adjusting flow rate and/or changing rheological properties of the mud, providing better cuttings transport capabilities.

Most of the wells analysed through this thesis, are to a large degree drilled vertically, except the development wells, which introduced short horizontal sections. Consequently, most of the issues associated with deviated or horizontal drilling were not encountered in any of the wells being analysed. The EC-Drill and CMP is however designed to manage ECD problems in all section in the post-BOP phase, with special focus on wells that may be drilled to a high degree of deviation or horizontal. Furthermore, adjusting the riser mud level will for these wells enable sufficient flow rates to be used, providing sufficient cuttings transport and maintaining operational integrity with respect to pore, collapse and fracture pressure.

Earlier the discussion of what implications using the EC-Drill system would have on drilling operations, and how this to some degree might vary with respect what classification the well is given; exploration or development. For wells with accurately documented pressure regimes, as should be the case for any well, but perhaps more so for a development well than an exploration and wildcat wells, where data might sometimes be based upon educated guesses. This fact may in some cases enable the creation of more accurate drilling programs which might render the EC-Drill system obsolete. Simply by removing some of the uncertainty associated by any drilling operation, conventional drilling methods may in many instances actually be sufficient to complete the well, in a safe and efficient way. Like case B earlier described in chapter 5.3.2, poor anticipation and prediction of formation properties, will in many cases be more detrimental to the operation than the difference between using a conventional setup and DGD systems like the EC-Drill or CMP.

5.4 Discussions

Until the working boundaries of the EC-Drill or CMP system can properly be defined, introducing these system to any drilling operation, development or exploration, should come in light of a in depth evaluation study, where experts from AGR share their experience with the operations planning team. Only then may it be possible to define whether or not the EC-Drill or CMP actually will be able to operate within the constraints of the wellbore, at an affordable price.

Furthermore, including the service provider into the planning phase at an early stage may essentially create possibilities with respect to reducing the overall cost associated with the integration process and running of the EC-Drill system. All of which essentially increases the chances that all parts of the systems are up and running in due time before operations commences. If the service provider is not given adequate time to prepare or manufacture the system components according to specifications, wasting valuable rig time with non-productive fittings and/or repair jobs may in many cases be the result.

Most big projects, exploration and development drilling included, are faced by considerable uncertainty in initial phases of planning. Capturing this uncertainty through time, may significantly increase the likelihood of having to implement small of major changes to the current or initial setup, design or otherwise general specifications. How these changes will influence the cost of that project is hard to accurately quantify. Figure 5-9 on the other hand, is designed to show how the cost of making changes to the initial or current set up may significantly increase the cost of a project. Not surprising, placing last minute orders, or making changes to specific parts or general setup may send the cost through the roof. This is why early involvement from the service provider not only will generate the best setup, but also reduce the risk of exceeding the budget.

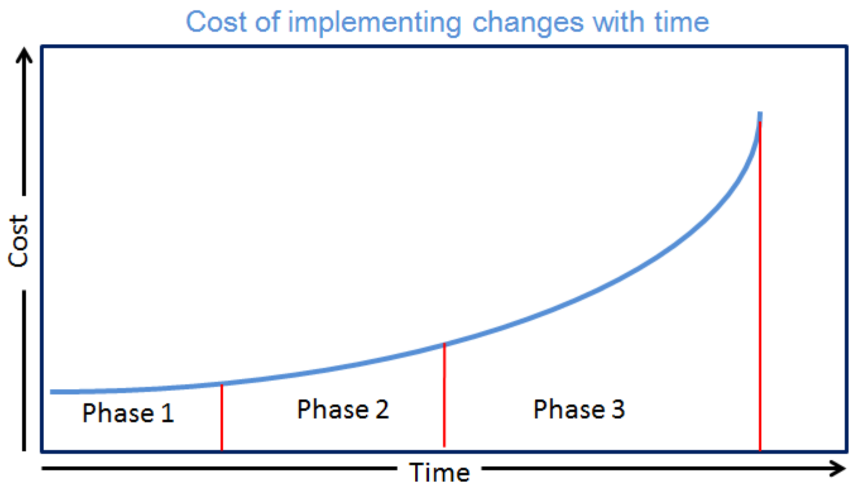

Figure 5-9: Cost of change with time.

Dual gradient technology, and now the EC-Drill & CMP system, has by many said to mainly be used in deep water, narrow margin wells, where excessive use of intermediate casings and liners often are the case. Extending casing seating depth may in many cases reduce excessive use of intermediate casing strings or liners, planned or contingency, effectively reducing the cost and plateau time associated with preparing, running and cementing casing strings. Due to the fact that cement represent a secondary well control barrier, the importance of being able to use cement with desired properties, regardless of limitations to the hydraulics of the well. The fact still remains, many operations, bound by limiting pressure windows, permeable formation, or otherwise restrictive parameters, were forced to pump cement that were known not to be the optimal blend. Due to the extensive variety and nature of cement blends, introducing systems like the EC-Drill might not remove problems associated by cementing altogether, however introducing a novel method of reducing losses during pumping and initial setting of the cement, which in turn will greatly increasing the chances of having a successful cement job.

Until the day when the EC-Drill or some similar system may become a permanent fixture on certain rigs, the EC-Drill technology has so far mainly been introduced to mitigate certain drilling problems, may it be narrow operational window, ECD, excessive losses, kick detection, etc. Which also will be the case in the future. If the EC-Drill system however with time manages to generate a track record as impressive as the RMR system, the use for such a system might be limitless on a global scale. The conventional methods of drilling wells have remained more or less unchanged the last 50 years, introducing new systems like the EC-Drill & CMP might quickly become the way to drill offshore wells, however complex. The adaptable nature of the system, together with the ability to quickly convert back to a conventional setup if required, may greatly benefit most offshore drilling operations.

The question remains, is to what degree the rig contractors, which already have a fleet of drilling vessels capable of drilling conventionally, show willingness towards allocating the substantial resources required to upgrade existing or suitably equipped drilling vessels. Furthermore, there will always be associated a risk by introducing a new and better technology to once portfolio, especially if there already exist a technology that seemingly do the same job, only now this will be outperformed by the new. The same apply for the rig contractors, where the competitiveness of once entire fleet might be depreciated, should new and improved technology enter the market. It is however possible that the new or upgraded rigs, become fully integrated in the fleet without significantly affecting the competitiveness of the other rigs.

Though the analysis completed through this chapter may seem limited in ways, it has to a large degree described areas where drilling with the EC-Drill & CMP setup are expected to exceed the conventional, some more predominant than others. The main reasons should in most cases however be to improve the overall safety, through improved kick detection capabilities and increase chances for staying within the operational pressure margins. Furthermore, as maintaining full riser margin has proven challenging for most deep water wells, placing heavier than conventional mud in the hole, as done with the EC-Drill & CMP, will partially or fully reintroduce this important safety margin to every well, no matter what water depth.

6 EC-Drill & CMP Hydraulic Model

Perhaps the biggest challenge associated with the EC-Drill and CMP technology is how to effectively manage wellbore pressures, or more precisely the BHP. In light of this, a simplified hydraulic model was created, to further show how operability of such a system may be possible. Described in the following chapter, are the system setup, hydraulic model, control boundaries, simulation results, conclusion and final remarks.

There exist a number of various simplified dual gradient models mentioned by the literature, the work completed through this thesis will however be based upon existing models by Breyholtz and Nygaard et al. (2009) and Breyholtz et al. (2011), Kaasa et al. (2012), Øyvind Stamnes, Erlend Mjavatten and Kristian Falk et al. (2012). The Matlab code developed during this thesis, can be found in its entirety in appendix B.

6.1 System Setup

The EC-Drill & CMP system setup is to a large degree described in the previous chapter. Out of the two systems, the following setup may to a large degree be described as the CMP setup, where the pump and its outlet is located at the lower half of the riser. Figure 6-1, show how heavy mud (heavier than what would be used for conventional ops) is pumped down the drill string and into the annulus. By taking the returns through a subsea device, and having a floating mud cap in the riser (located somewhere below sea level), it is possible to realize many of the benefits associated with dual gradient drilling. The drill string will be outfitted with an anti-u tube valve to provide better stability and control, due to the consequently imbalance between the inside and outside of the drill string.

6.1.1 Partial CMP

To avoid the risk of having a possible explosive atmosphere in the riser, a fill line will provide blanket fluid or water to the upper part of the riser. The same fill line may be used to pump drilling mud into the riser just above the subsea pump. The reason for having a fill line connected to the subsea pump is to generate sufficient mud flow into the riser, facilitating the fast mud level adjustments required for regular drilling operations. Perhaps more so, cases such as kick control or making connections, where fast mud level adjustments is essential, the fill line will to a large degree make this possible.

While operating the drilling system, a sensor at surface will ensure that the riser is always full, which means if the level of base fluid/ water starts dropping, which might be the case for mud level decreases, the fill pump will start to backfill the lost volumes. The risk of having to fill the riser from the top while at the same time pumping in drilling mud from the bottom is virtually non-existing, which makes it possible to use the same pump for both operations. For operations where positive (increasing) mud level adjustments are required, the fluid in the top of the riser will start to overflow to the pits, like during conventional operations.

Using water fill in the top of the riser as displayed in figure 6-1, it is clear that the water will contribute to the overall wellbore pressure profile, and has become what earlier was described as a Partial CMP system. The challenges associated with this set up have previously been described on a conceptual level.

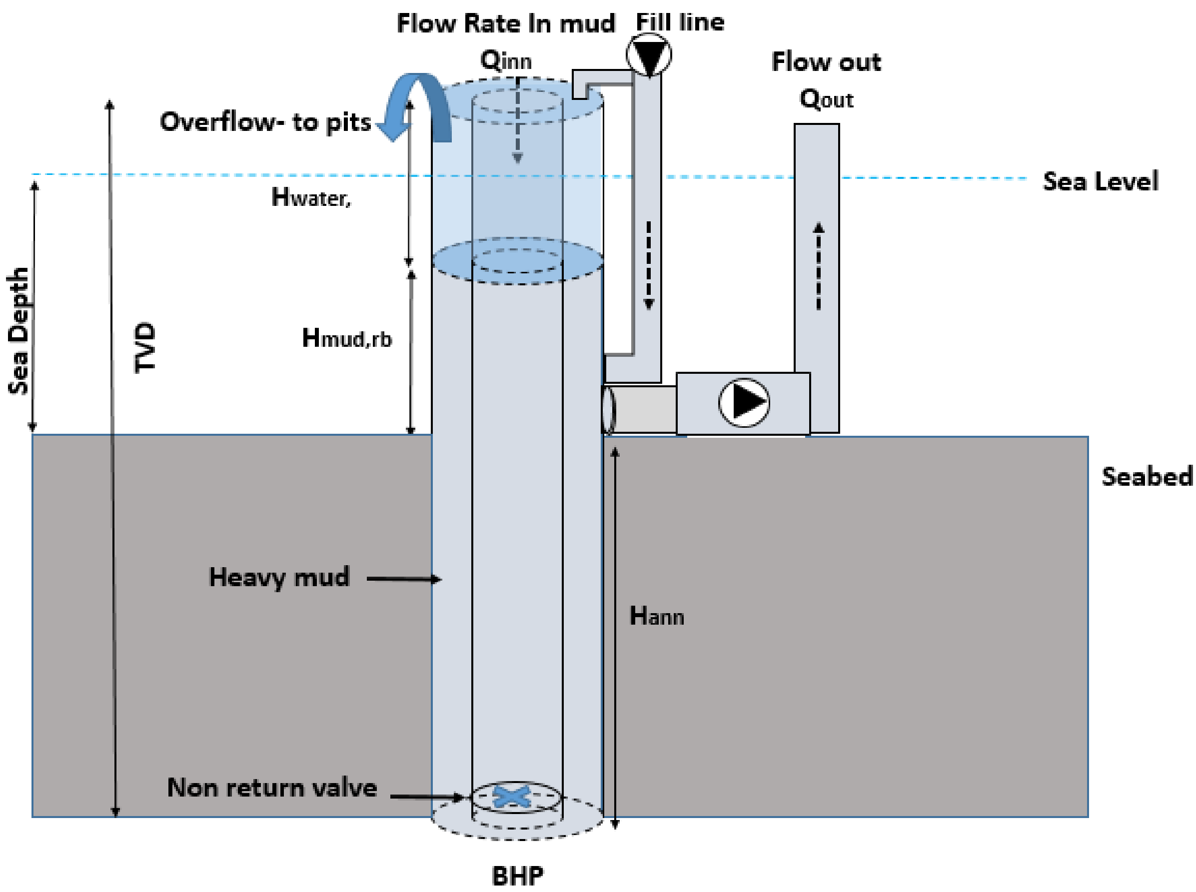

Figure 6-1: Partial CMP flow schematic.

This setup will be used for simulation one and two.

6.1.2 Full CMP setup

The Full CMP setup is basically the same as the Partial, only differing in the fact that it does not rely on a placing any blanket fluid or other liquids to fill the empty space on top of the riser, leaving the mud - gas interphase free to move up and down. A non-explosive gas like nitrogen is pumped into the riser, effectively reducing the risks of introducing any explosive atmosphere at the top of the riser.

The Partial CMP system relies on a fill line connected into the riser pump, providing additional flow rate ensuring fast mud level adjustments. For the Full CMP system, the fill line may be installed in the same manner, however there is the option of filling the mud from surface, by virtually pumping it down on the outside the drill string and let it freefall, filling mud from the top of the riser. The Full CMP setup is shown in figure 6-2 will be used for simulation three through to five.

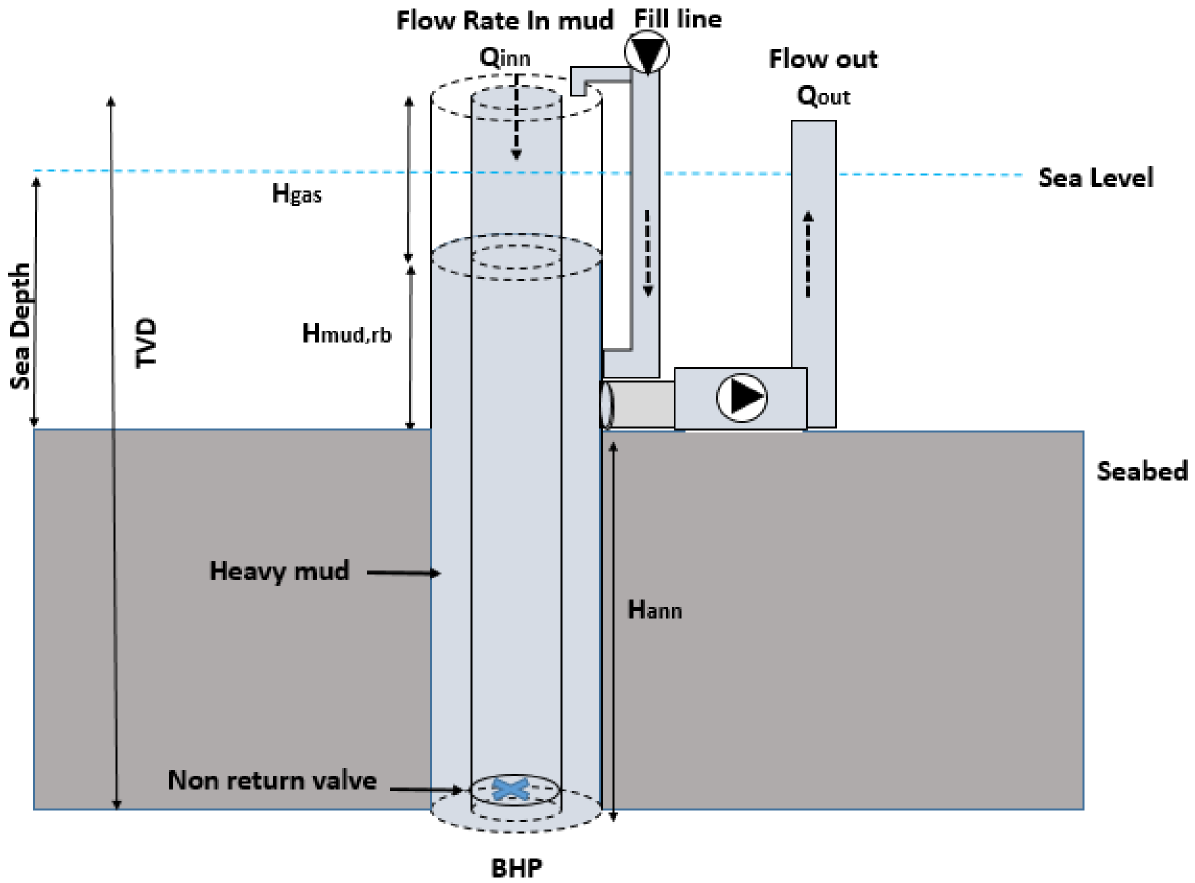

Figure 6-2: Full CMP flow schematic.

Both of the setups being modelled use a vertical well with a slim riser design, the reason for using a slim riser is due to the fact that major parts of the riser volumes do not serve any hydraulic purposes. To generate sufficient riser flow rate, the fill line and slim riser will be used for many of the simulations, however some improvement to general setup may be introduced along the way. The following generic data will however help the reader to better understand the generic setup:

Bottom hole depth TVD	3000m
Total Riser Length	1000m
Length of Annulus	2000m
Pump/Outlet Location below RKB	1000m
Mud Density	1,58 s.g
Water Density	1,00 s.g
Gas density	0 s.g
Annulus Diameter (from TD to seabed)	9 5/8”
Riser Inside Diameter “Slim”	15”
Drill Pipe Outside Diameter	5 ½”

Tabell 6-1: Well specific data.

(Simulation 6 will be completed using a regular riser ID= 18”)

Data otherwise describing the initial conditions of the system may be found in appendix B with the entire Matlab code.

6.2 Types of control and Automation

Manual control has traditionally been the prevailing choice. For the CMP, a manual controllability flowchart may look something like figure 6-3. Sensors are monitoring the control variable (BHP), while the worker is continuously monitoring the real time feed, making the appropriate adjustments to achieve the desired effect or set point of the controlled variable.

The problems with this approach are inherently obvious, introducing MPD and sub categories like DGD, has imposed a set of new challenges with respect to operability and controllability. These concepts often evolve around close monitoring, interpreting and fast adjustment of multiple variables, enabling the operation to stay within the limits of the system. Due to the limiting capabilities for human to reliably handle situations which involve large set of variables, which may result in excessive downtime. Whereas manual control still is the number one way of controlling drilling processes, introducing automated processes has for operations like MPD and now DGD application, enabled the manpower to concentrate on the decisions of higher importance, such as kick circulation, while low order controllability problems are handled by the automated system. Automation has since its first appearance, managed to find its way into most parts of industry all over the world, such as aerospace, traffic control, car manufacturing, refining and chemical industry, etc.

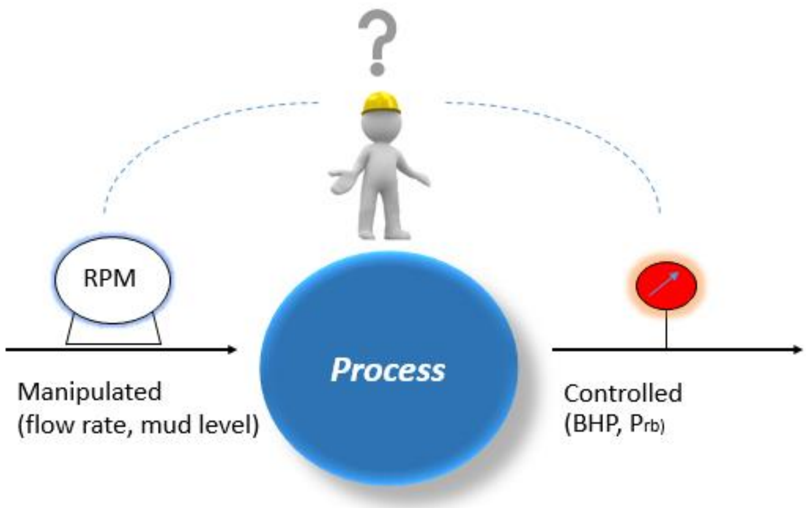

Figure 6-3: Manual Control

With automation the human operator is to a large degree taken out of the loop, the automated flow loop seen in figure 6-4, describes an approach where sensors are installed to monitor the controlled variable. These data are transmitted directly to a feedback control system, where a specialized controller determines the divergence from the desired value and the actual. The controller then calculates a signal reflecting the required change in variable parameters and transmits this signal to a control device (subsea pump, fill pump), which will make appropriate adjustments to the pump output according to the signal strength, resulting in a net negative or positive gain in riser fluid level.

One of the great strengths with this approach is that the system does not need to know in advance the type of disturbances that may affect the process. In fact the system does not need to know the ultimate effect on the control variable or quantitative relationship between the disturbance, which makes the feedback controller perfectly suited for unpredictable and ever changing drilling environment. Automation is basically a method of ensuring that the objective and constraint of a system is fulfilled. The human part of an automated system is in creating the objectives and defining the constraints of the system.[37, 38]

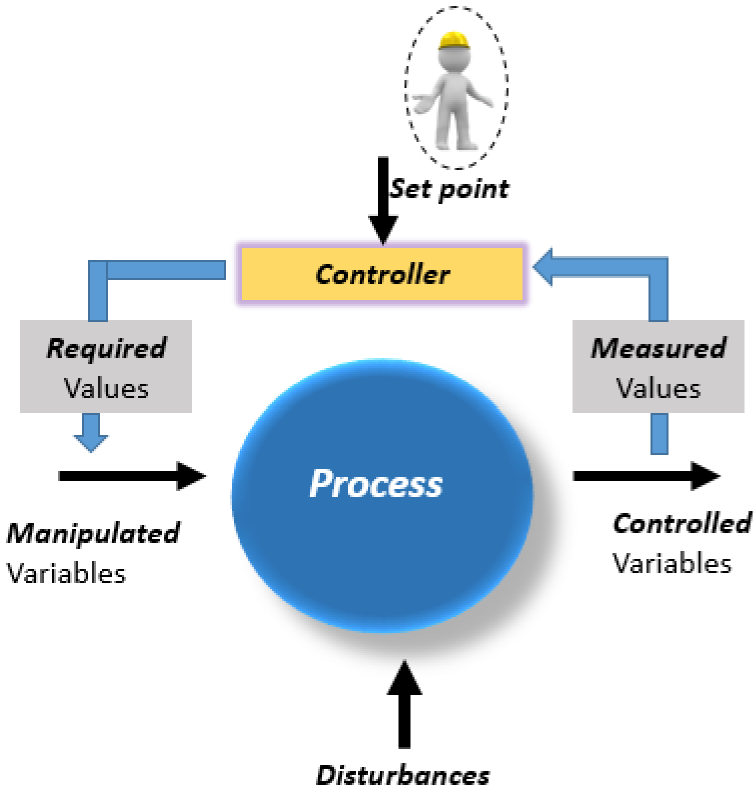

Figure 6-4: General feedback controller widely used for automatic control.

6.2.1 PID Controller

Determining the effectiveness of feedback control is strongly connected with how the system manages to adjust manipulated variables to achieve the desired control variable. This effectiveness is furthermore a direct consequence of what type of controller is used. There are number of standard controllers throughout the industry today, the following are the most popular continuous mode controllers[37]:

- ***Proportional (P):*** This represents the simplest of controllers, where the output is algebraically proportional to the input error signal.
- ***Integral (I):*** Also referred to as Reset control. As the name implies, integration is performed on the input error signal, and the manipulated variable is adjusted at the rate proportional to the error. It can also be thought of a historical count (accumulation) of error. Any positive error will increase the count while a negative will reduce the count. The net count at any time becomes the reset contribution to the manipulated variable.

- ***Derivative (D):*** Also commonly referred to as Rate control. The output of this controller is solely based on the rate of change of the input error signal.

In combination these controllers are referred to as PID, whose sum constitutes the manipulated variable (MV). The proportional, integral, and derivative terms are summed to calculate the output of the PID controller, *u(t)* may readily be written as:

$$u(t) = MV(t) = K_p e(t) + K_i \int_0^t e(\tau) d\tau + K_d \frac{d}{dt}(t) \text{ ,} \quad \text{(Eq 6.1)}$$

where K_p, K_i, K_d, represent the tuning parameters of proportional, integral and derivative gain respectively. Furthermore, *e,* represent the error/difference in measured and desired output (*e= SP-PV*). Whereas *t*, represents the instantaneous time (the present), τ is a variable of integration which account for all the values from time 0 to present time *t.*

The controllers above are rarely used in isolation, one often find two or more in combination.The controller developed for the CMP is a combination of the two first tuning parameters and correctly reffered to as a PI- controller. Without derivative action, a PI-controlled system is less responsive to real (non-noise) and relatively fast alterations in state and so the system will be slower to reach setpoint and slower to respond to perturbations than a well-tuned PID system may be.[39]

6.2.2 Model Constraints

Most drilling operations, conventional, underbalanced or managed pressure including dual gradient drilling operations, employ a series of operational constraints that make each operation unique in its own way. Excluding underbalanced operations, the most critical parameter to control is perhaps ensuring that wellbore pressures at all time, at any point along the wellbore are within the operating pressure window. Defining the upper and lower limit, are formation fracture- and pore or collapse pressure respectively. Choosing the maximum values of the different pressures as the defining boundaries, the following pressure balance can be created:

$$max\left[P_{collapse}(t,z), P_{pore}(t,z)\right) \leq P_{wellbore}(t,z) \leq P_{fracture}(t,z)\right] \text{ ,} \quad \text{(Eq 6.2)}$$

where *t*, represent the time and *z* represent the position along the uncased wellbore interval. Described earlier in this thesis, conventional or managed pressure drilling operations may have problems maintaining a wellbore pressure within this window, Eq 6.2. In the general CMP model presented later, the bottom-hole pressure is the crucial parameter to control, imposing the following output constraint:

$$BHP_{min} \leq BHP \leq BHP_{max} \text{ ,} \quad \text{(Eq 6.3)}$$

Subsequently introducing the following input constraints:

$$Rig\ Pump: Q_{rig,min} \leq Q_{rig} \leq Q_{rig,max} \text{ ,} \quad \text{(Eq 6.4)}$$

$$Subsea\ Pump: Q_{sub,min} \leq Q_{sub} \leq Q_{sub,max} \text{ ,} \quad \text{(Eq 6.5)}$$

$$Topp\ Fill\ Pump: Q_{top,fill,min} \leq Q_{top,fill} \leq Q_{top,fill,max} \text{ ,} \quad \text{(Eq 6.6)}$$

The numeric values of the model constraints are furthermore described in the following table:

Bottom Hole Pressure min/max:	*450±5bar*
Rig Pump rate min/ max:	*0/4000 l/min*
Subsea Pump rate min/max:	*0/4000 l/min*
Top Fill Pump rate min/max:	*0/4000 l/min*

Table 6-2: Model constraints.

6.2.3 Developing a Model

Before models used for control purposes are created, it is to keep in mind that a highly complex model accounting for all variables will be hard to calibrate with actual data and might very well require models of their own to be able to provide interpolated/ extrapolated values. A highly complex model might also greatly increase the time required to adequately finish the calculation. For control purposes this may be a critical fault that might render the model useless within a short time span.

The hydraulic model created in this chapter is a dynamic model, which introduces a PI controller to control the output (BHP), imposed as set of changes to the initial conditions, mainly by manipulating the top fill- and riser pump rate. The volume of the riser and annulus is for the purpose of this thesis fixed (no fluid lost or gained from formation), law of conservation of mass and momentum apply. Furthermore the following assumptions have been made:

- Incompressible fluid
- 1D-flow
- Stationary non rotating drill string
- Constant fluid properties
- Sag is neglected in the mud above the riser outlet.
- Friction above the riser outlet is neglected.
- Pump response time is quick

To simplify the process of making a hydraulic model valid for both CMP setups, partial and full, it might be necessary to split the wellbore into two different control volumes. The first volume that accurately needs to be controlled is the riser volume, extending from the top of riser to the outlet at the riser, denoted riser base. The model created for this thesis is based upon the CMP concept, meaning that the riser control volume will get its contribution from two distinct parts, water and heavy mud for the Partial CMP setup respectively, while gas and heavy mud for the Full CMP setup. Since the riser represents a large flow area, with subsequently reduced flow velocities, the friction is for the purpose of this model neglected for the first control volume, readily making the pressure at riser based possible to be written as:

- Partial CMP

$$P_{rb} = P_0 + (\rho_{mud} h_{mud} + \rho_{base\ fluid}\, h_{base\ fluid})g \text{ , ... (Eq 6.7)}$$

- Full CMP

$$P_{rb} = P_0 + (\rho_{mud} h_{mud} + \rho_{gas} h_{gas})g \text{ , ... (Eq 6.8)}$$

where the P_0 is the atmospheric pressure, the second term represents the static pressure from the heavy mud column, whereas the third term represent the static pressure created from the blanket fluid or the gas.

Knowing the OD of the drill pipe and the ID of the riser and the rate at which the mud is entering or leaving the riser control volume, it is possible to determine at what rate the mud level will increase or decrease. Earlier it was described as a desirable trait to provide fast and accurate mud level adjustment, furthermore the discussion with respect to operability of the Partial and Full CMP system was discussed, where the Full CMP system featured faster mud level adjustments for the same time step then what was achieved by the Partial setup. To further challenge this notion we have to look at the flow balance equation that enables the level adjustment in the first place, assuming zero losses or gains from the formation:

$$Q_{tot,riser} = Q_{in} - Q_{out} \text{ , ... (Eq 6.8)}$$

It is generally agreed that for cases where the following term, Q_{riser} is positive, meaning that more mud is entering the riser than is being pumped out, the result will be an increase in mud level. Whereas a negative value of Q_{riser}, mean that more mud is being pumped out than what enters the riser, resulting in mud level decreasing. A zero flux term will denote a static case, with no change to mud level. To generate the term showing at which the rate the mud level may increase/ decrease we need some additional equations:

$$Q_{riser} = U_{(mud,riser)} A_{(mud,riser)} \text{ , ... (Eq 6.9)}$$

and

$$V_{mud,riser} = A_{(mud,riser)} h_{mud,riser} \text{ , ... (Eq 6.10)}$$

where U is the speed the fluid is entering the riser, V represents the mud volume in the riser, while A represent the riser flow area. After some slight modification it is possible to show how the height of the riser fluid will change as a function of varying pump rates:

$$\dot{h}_{riser} = \frac{Q_{in} - Q_{out}}{A_{ri,ID} - A_{dp,OD}} = \frac{Q_{riser}}{\frac{\pi}{4}(r_{ri,ID}^2 - r_{dp,OD}^2)} \text{ , ... (Eq 6.11)}$$

where $r_{ri,ID}$ and $r_{dp,OD}$ represent the riser ID and drill pipe OD respectively. Further introducing time, it is possible to generate actual mud level adjustments. The equation does not take into account the initial mud level, and will only say something about at what rate it would be possible to adjust the mud level from an initial state to a final state. The rate at which the mud can be adjusted will predominantly determine how quickly operations can be completed, such as; start/stop circulation, tripping, switch back to conventional setup (riser full with mud), the latter that might be the case for certain well control scenarios.

Ideally the rate at which the mud can be adjusted would be infinitesimally high, but due to the limits of most pumps this would be unrealistic to achieve. Additionally, pumps and their output is affected by a short time delay, some more than others, which will result in a further delay down the line. To introduce some simplifications, the pumps in this model is not affected by the delay that normal pumps are affected by- output is provided instantaneously.

Now introducing the second control volume, the wellbore annulus, comprising of the wellbore volume stretching from the bottom of the well up to the subsea arrangement or riser outlet. This control volume is typically of much greater length and the dynamics of the system has to be take into account, having friction contribute to the overall pressure distribution, generating the expression for the bottom hole pressure:

$$BHP = P_{rb} + P_f + \rho g H_{ann} \text{ , } \qquad \text{(Eq 6.12)}$$

where P_{rb} represent the pressure at the riser base, P_f represent the friction while the latter term represent the hydrostatic pressure from the annulus fluid below the subsea pump outlet. [38]

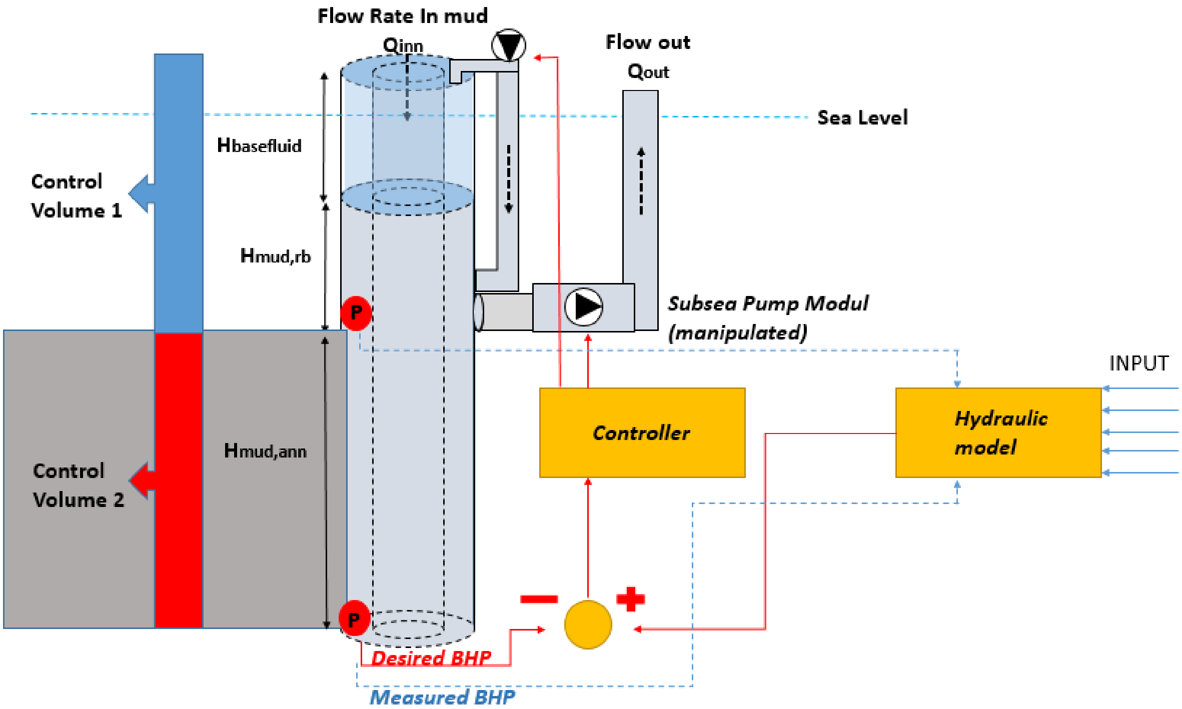

Figure 6-5: Partial CMP flow scheme with PI controller

Figure 6-5, introduce the CMP control system. However by replacing the blanket fluid from the top of the riser with gas, the same controller system applies for the Full CMP system.

6.3 Simulations

The simulations completed in this chapter will illustrate how the mud level in the riser will decrease or increase as the driller adjusts the pump rate topside, or otherwise introducing disturbances to the system. By introducing a PI controller code, the goal of the simulation is to stay within the limits of the system, constant BHP pressure respectively. The bottom hole pressure transmitter is sending data in real time back to surface using wired pipe telemetry. This way, we avoid the time delay associated with conventional mud pulse telemetric systems.

Simulations showing how the system are capable of detecting and handling various influxes have been completed by the SINTEF in Trondheim, with promising results. Therefor simulations with influxes is left outside the work completed here.

6.3.1 Making a connection

Introducing narrow operational drilling windows, either due to natural or otherwise artificial reasons have imposed a set of new challenges with respect to well control. In order to control the bottom hole pressure in conventional drilling one may change the mud weight, which will influence the hydrostatic head, or one can regulate the annular frictional pressure drop by adjusting the pump rate. Problems with this systems lies in the inherent need to stop and start mud pumps during pipe connections or otherwise planned or unplanned events, resulting in pressure fluctuations in the wellbore which can cause problems when drilling in narrow margins between pore pressure and fracture pressure.

To test the CMP's ability to readily control down hole pressures within the predefined limits of the system, examples where the driller through various methods are ramping down the topside mud pump from its initial circulation until circulation is finally stopped.

Completing a so called soft stop where circulation is broken down in steps remain one of the methods that drillers rely on most , especially in wells that are defined as HTHP or otherwise high risk of having influxes. This greatly increases controllability and/or reduce other pressure related problems. However drilling in environments with slim chances of having hydrocarbon influxes, pumps will typically be ramped down much quicker than what is done during a soft stop.

6.4 Simulation Results

The goal of all of the simulations is to see if the controlled variable, the bottom hole pressure could be maintained within the predefined pressure limits. The initial rig pump flow rate of 2500 lpm are chosen for all the simulations through the next sections, this should only act as points of reference, fully knowing that higher or lower rates are frequently used. For the purpose of the simulations this flow rate seem suitable.

6.4.1 Simulation 1: Soft stop- breaking circulation in stages (Partial CMP)

The first simulation revolves around ramping down the rig mud pump in stages, from the initial flow rate of 2500 lpm to 0 lpm, displayed in figure 6-6, the ramp down take 700 seconds in total. The soft stop process, where small plateaus are added to provide the driller more control, additionally facilitate adequate filling of the riser. In real life operations, this might seem excessive, and might very well result in reducing the effective drilling time. However as some of the results described later in this chapter will show, maintaining effective control of the wellbore pressures might prove difficult when shutdown of rig pumps are performed too fast.

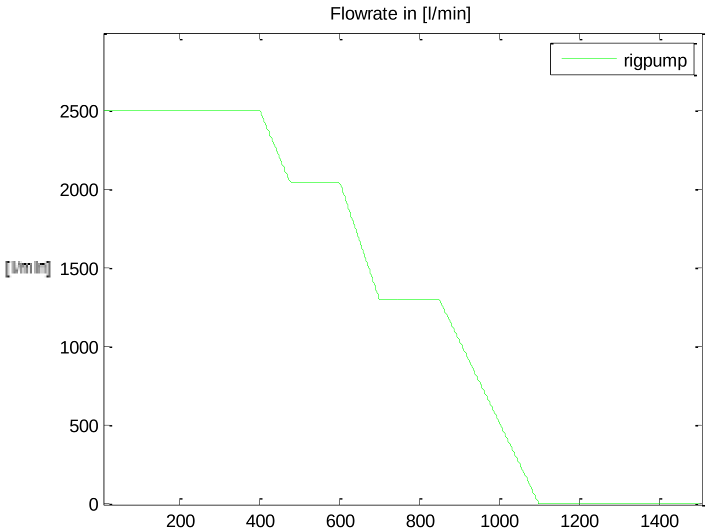

Figure 6-6: Simulation 1- Ramp down of rig pump in stages. X axis is in seconds

Displayed in figure 6-6, the bottom hole pressure is to a large degree maintained within the ±5 bar operational window, earlier set as a system constraint. By introducing plateaus with constant rig pump flow rate, the riser pump and fill line generate sufficient riser mud levels to once more obtain a bottom hole pressure close to the desired value. The plateaus are represented by the red double arrows in figure 6-6. Had these not been introduced, or otherwise continued to maintain a linear ramp down, the bottom hole pressure would have decreased below the 450 ±5 bar window.

There seems to be some initial disturbance which occurs within the first hundred seconds of the simulation, which is believed to happen as a result of not all starting conditions matching 100% across the entire range of parameters, such as a wrongful selection of initial mud level that would match the flow rate. As a result the feedback controller will try and adjust the manipulated variables to reduce the gap between the desired and actual bottom hole pressure. This will in most simulations produce data that looks very strange, the system seems however to stabilize for the time after initial settling. For later references, the first 100 seconds will not be further discussed.

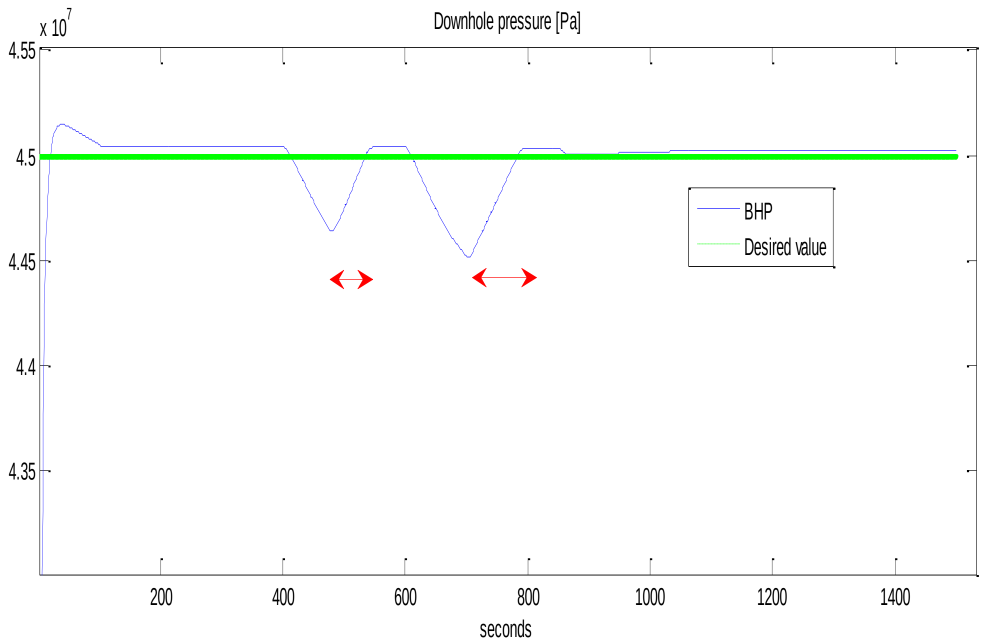

Figure 6-7: Partial CMP- Bottom hole pressure

6.4.1.1 Bottom hole pressure, friction and hydrostatic.

Since the CMP does not rely on any form of back pressure systems, the wellbore pressure get its contribution from the frictional- and hydrostatic pressure respectively. The following graph shows how the frictional and hydrostatic combined make up the equivalent circulating density, ECD.

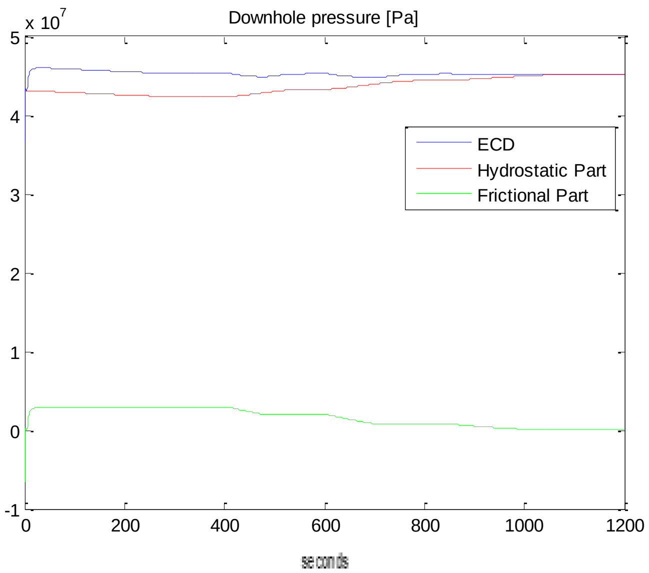

Figure 6-8: Partial CMP-Frictional and hydrostatic component vs time.

As one would expect the frictional pressure decreases in size as the circulation is broken down in steps, before becoming zero at around 1100 seconds. As friction is lost, the purpose of the model is to see if the mud level may be adjusted fast enough to replace the loss in friction. Displayed in figure 6-9, the mud level stabilizes at around 225 meter for the rip pump circulation rate of around 2500 lpm until circulation is being ramped down, which is marked by an abrupt increase in mud level. The constant pump rate plateaus are distinctively recognisable on the figure.

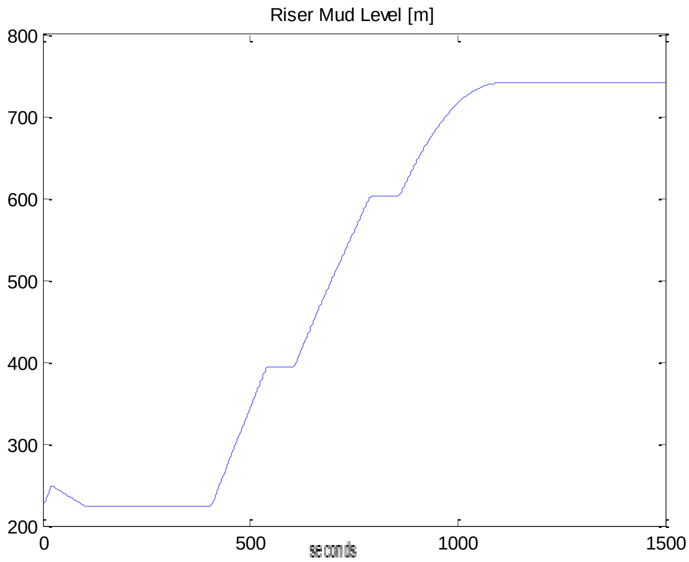

Figure 6-9: Partial CMP- Riser mud level adjustment with time.

Using mud level adjustments to counter the loss of friction, it is clear that the volumes having to moved is very large, around 700 m of water or blanket fluid will have to be displaced by mud to facilitate the generation of bottom hole pressures displayed in figure 6-8. Keeping in mind that this model represent the partial CMP system, with the blanket fluid or water filling the rest of the riser, and not the full CMP system, where gas or air would be the second phase. In conjunction with what was earlier described about the full CMP concept, same pressure manipulation would be possible to complete, using less riser mud level adjustments, which is beneficial for faster and safer operations.

6.4.1.2 Flow rates

All that has earlier been described through this case in particular has been the result of how the riser- and fill pump rate is operated in connection with the wellbore circulation rate. Earlier described, adjustment of riser mud level is facilitated by an inherent fluid imbalance between what enters and what leaves the riser, resulting in $Q_{tot,riser}$ being negative or positive. Deciding what rate the fluid enters or leaves the riser one looks at the pump rate of the three pumps, rig, fill and riser pump respectively. The riser pump is only designed to pump out of the riser, the rig pump is designed to pump fluid into the riser, however indirectly, the fill pump is specially designed to pump into the riser. The fastest flow rate into the riser is only experienced when the riser pump is fully turned off, while at the same time the rig pump and the fill pump may provide max flow rate of 4000 lpm each. Combining the flow, it is possible to generate the maximum flow rate into the riser, $Q_{tot,riser}$ equal to 8000 lpm. This however represent the maximum output, and will likely never be needed for regular operations.

From figure 6-10, the flow at various system locations are displayed, from this it is possible to see if the mud level will increase (positive $Q_{tot,riser}$) or decrease (negative $Q_{tot,riser}$), by doing the following calculation:

$$Q_{tot,riser} = Q_{rig} + Q_{fill} - Q_{riser} \text{ , } \ldots\ldots \text{(Eq 6.13)}$$

It seems that as the rig pump flow rate decrease, the riser pump responds by fully shutting down, whereas the fill pump give all its output to try and adjust the mud levels fast enough to keep up with the decreasing friction. Without the fill line, the available flow rate for generating mud level adjustments would be represented by the area under the rig pump flow rate, since the riser pump rate would be zero at all times. Additionally, built into the model, the option of introducing losses or influxes to the wellbore. For the purpose of this example however, we assume zero gains or losses, hence Q_{res} is equal to zero.

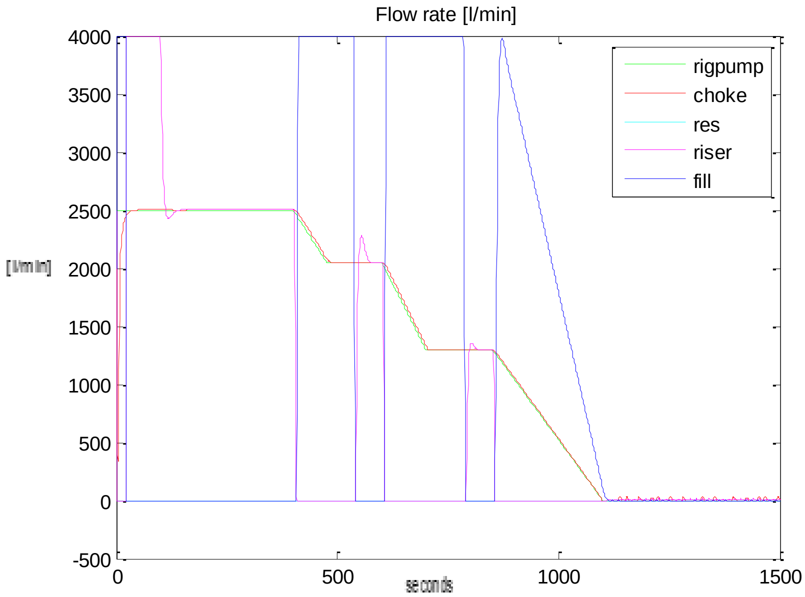

Figure 6-10: Partial CMP- System flow rates

Due to fast controller response, the output of the fill pump is provided almost instantaneously, and is the main reason for the abrupt increase. It may be questionable if this speed may be obtained in such a short period of time, for the sake of the argument, let us say it is possible.

To better understand what happens in figure 6-10, it might be beneficial to correlate with the mud level adjustment in figure 6-9. Every time the subsea pump rate (pink line) is less than that of the rig pump, green line, it will generate a mud level increase, whereas if the pink line is above the green line the overall mud level will decrease. The fill rate will in this case always be positive, which means it can only be used for positive mud level adjustments. The result of all mud level increases, will be that the blanket fluid/ water on top of the mud be displaced, and overflow the riser into the pits. For any negative mud level adjustments, which would be the case for ramping up the rig pumps, the fill pump will fill in the blanket fluid ensuring a continuously filled riser.

6.4.1.3 PI controller

Enabling this system to be autonomous within a high level of accuracy, the feedback controller code, which calculates the difference between the desired reference point (desired BHP) against that of the actual value of BHP. In doing so, the PI controller calculates a signal strength that will be transmitted to the control device, where the strength of the signal refers to how large changes need to be made to the manipulated variable, i.e the subsea pump rate or fill pump, so that the divergence between desired and actual value is reduced.

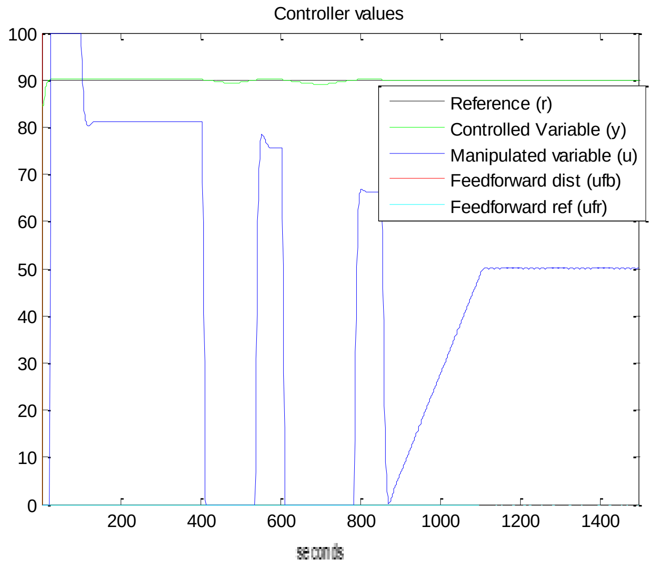

Figure 6-11: Partial CMP-Controller Value vs. time

Displayed in figure 6-11, the subsea pump rate is initially required to deliver 100% of its range to regain control of problem caused by the selection of initial string conditions. For times where the subsea pump is turned off, the manipulated variable is also equal to zero. Since the fill pump is defined as the negative of the riser pump. Its output also controlled through the controller and will experience its max when the manipulated variable is equal to zero, which can be seen for all the peaks and general performance of figure 6-10. Furthermore, this simulation does not introduce any disturbances in the form of lost circulation, influxes or other aspects that might jeopardize the stability of the system. The controlled variable, green line is to a large degree maintained close to the preselected reference point. The blue line represents the controller signal being sent to the riser pump and fill pump respectively.

6.4.2 Simulation 2- Rapid ramp down of the rig pump (Partial CMP)

Described in simulation 1, the flow rate from the topside mud pump was ramped down in controlled steps over a period of 700 seconds. With the help of the PI controller, the system was able to maintain somewhat stable bottom hole pressures. For most operations however, the pumps will be ramped down much faster. To investigate how capable the system is of handling fast adjustments, figure 6-12 shows how a rig pump being ramped down in a linear fashion, over a period of 240 seconds (4 minutes).

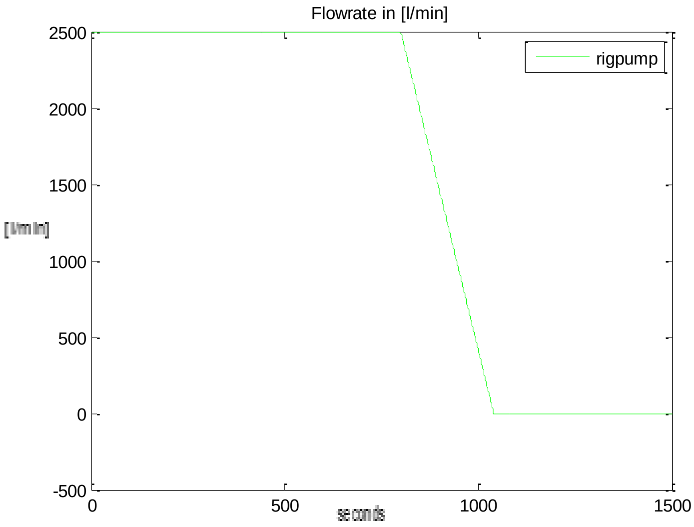

Figure 6-12: Rapid ramp down of mud pumps.

6.4.2.1 Bottom hole pressure, friction and hydrostatic.

As before, the first 100 seconds of the simulation generates a high bottom hole pressure, this is due to the wrongful selection of initial starting values. From around 100 seconds however the pressures are stabilized until the ramp down of the mud pump is initiated after 800 seconds. Due to the rapid decrease in flow rate and hence in friction, it seems the riser pump and the fill pump rate, has difficulties generating the required mud level adjustments, which will maintain a constant bottom hole pressure. This is of course is due to enormous mud volumes that are required to be pumped through a very short time window, given the system constraints.

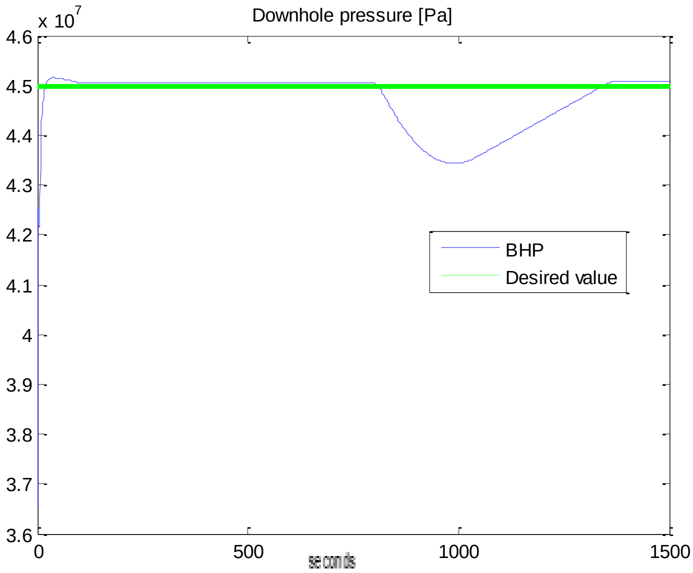

Figure 6-13: Partial CMP- Bottom hole pressure vs. time.

Compared to figure 6-8, figure 6-14 only represents the varying hydraulic parameters, namely the hydrostatic at the riser base and the frictional pressure drop. From this it can clearly be seen how the hydrostatic of the riser increases with decreasing friction, but also that the friction decreases faster with time than what the hydrostatic pressure increases.

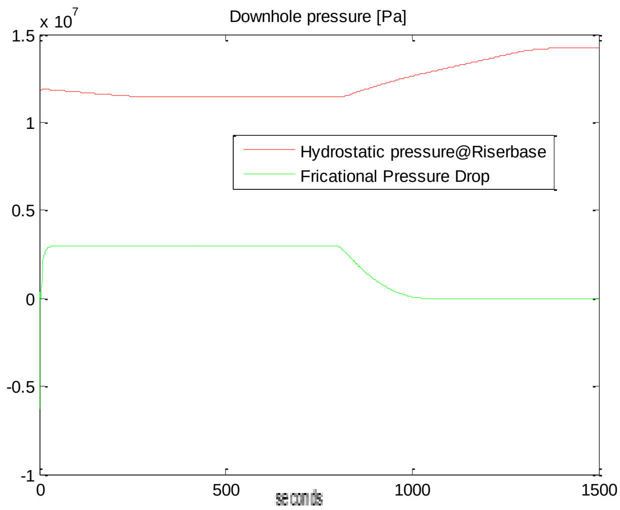

Figure 6-14: Partial CMP-Hydrostatic at riser base and wellbore friction vs. time.

Closely linked with the hydrostatic at the riser base, figure 6-15 display how the floating mud level was adjusted after starting the ramp down sequence. One important thing to notice from the mud level figure is that at 1040 seconds, the rig pump circulation rate had reached zero. Which means that if it had not been for the alternative fill line, providing flow rate into the riser, the mud level would cease to increase, resulting in final bottom hole pressure lower than the desired set point, furthermore all operational flexibility would be lost.

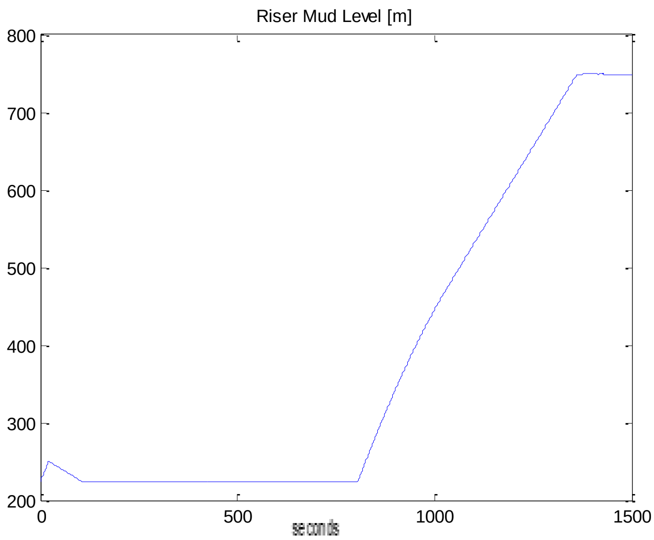

Figure 6-15: Partial CMP- Mud level adjustment vs. time

6.4.1.2 Flow rates

The flow rate of rig pump is stable at 2500 lpm from start of simulation until the 800 seconds mark where a reduction in pump rate is initiated by the driller. To counter this rapid loss of friction, the only way to generate sufficient flow rates into the riser, is by completely shutting down the riser pump, while at the same time ramping up the fill pump to its maximum of 4000 l/min. Comparing figure 6-16 with that of the actual mud level adjustment, it may be seen that the mud level increased rapidly from the point when rig pumps start to ramp down. However when looking at the actual bottom hole pressures, the rapid response in mud level adjustment is still not enough to obtain the desired wellbore pressures, with a minimum pressure of 435 bar which fails to align with the system constraints, which means that the rig pump is being ramped down to fast.

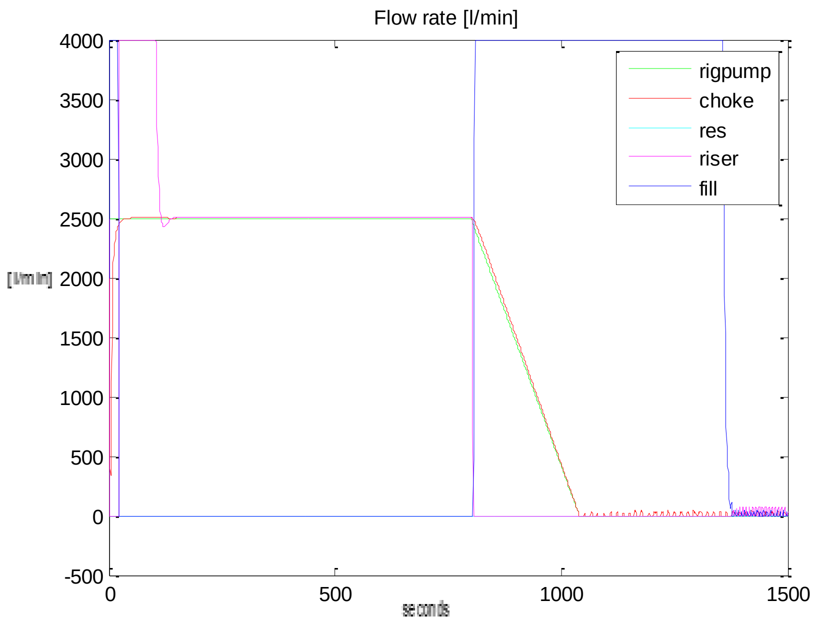

Figure 6-16: Partial CMP- Flow rates.

6.4.2.3 PI controller

Initially the manipulated variable controller is fully active, once more due to the initial values not aligning 100%. However due to the fast response of the controller the controlled and manipulated variable is quickly adjusted within a desirable range. The sudden drop in the manipulated variable basically means that a signal is sent to the subsea pump, to turn off. With zero controller value, the fill pump is designed to provide its full output. As a result the controlled variable does not manage to align with the predesigned reference point.

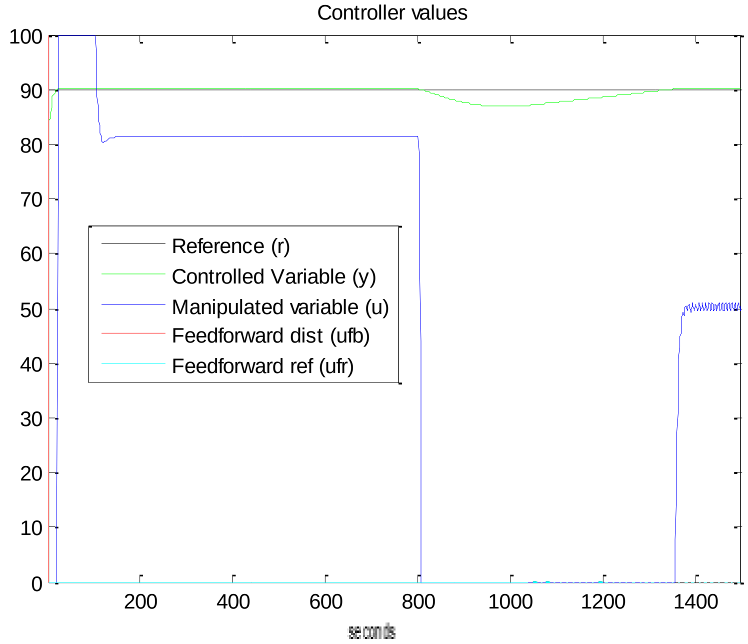

Figure 6-17: Partial CMP- Controller values

6.4.3 Simulation 3- Soft stop- breaking circulation in stages (Full CMP)

The following method of ramping down was first introduced in simulation one, only then the Partial CMP setup was used. The following simulation is designed to show how the two systems, Full and Partial CMP, vary with respect to controlling the bottom hole pressure. Whereas simulation one and two where discussed at a higher abstraction level, the following simulations will to a large degree focus on the areas of interest, neglecting certain mechanics of the model. This way the reader will get a better understanding for what actually seem to be the concern with this system.

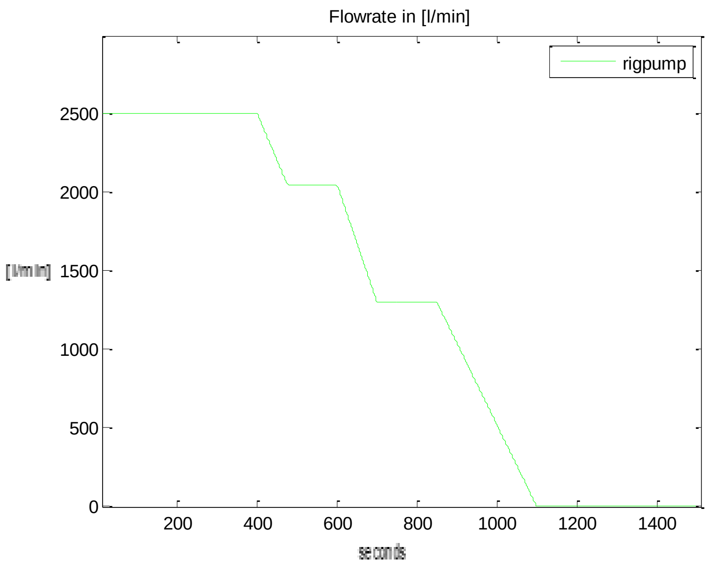

Figure 6-18: Rig pump flow rate.

6.4.3.1 Bottom hole pressure and mud level adjustment.

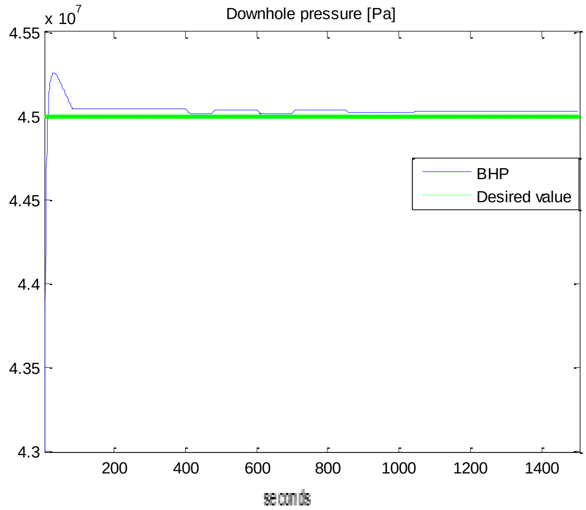

Figure 6-18: Full CMP- Bottom hole pressure.

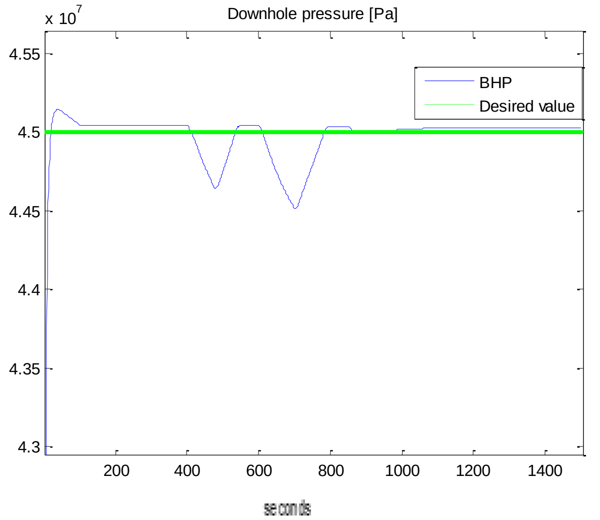

Figure 6-7: Partial CMP- Bottom hole pressure

Comparing the two setups, it seems that it is possible to maintain a more constant BHP using the full CMP concept relatively to the Partial Concept. The reason for this might be better understood when looking at the mud level adjustments that were performed by the individual setups.

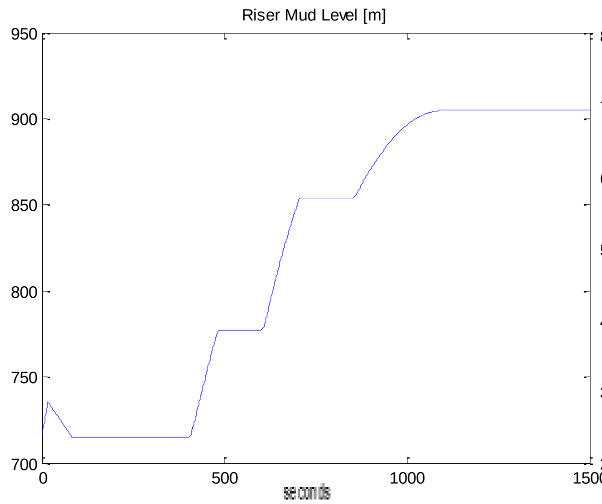

Figure 6-19 Full CMP-Mud level adjustment.

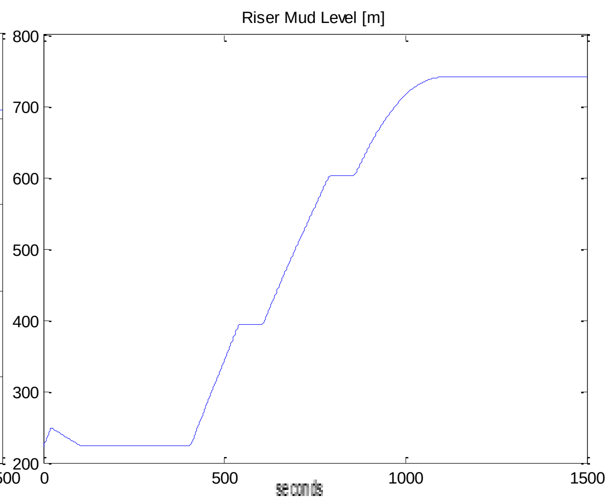

Figure 6-9: Partial CMP-Mud level adjustment

Initially the figures 6-19 and 6-9 may seem similar, it follows the same trend over the same time interval. Separating the two is however the start and stop points at the y-axis. The Full CMP setup clearly requires less mud level adjustments (around 200m) than what is required by the Partial setup (700m). This is predominantly the reason why the BHP in figure 6-18 is more constant throughout the simulation. Easily explained, the pumps on the Full CMP concept have to move less volumes of mud, which makes it possible to operate the system within the limits of the system, without having to ramp the pumps up and down excessively, which in the long run might increase chances for something breaking down.

6.4.4 Simulation 4- Rapid ramp down of the rig pump (Full CMP)

Simulation 3 proved that the Full CMP system was capable of maintaining a fairly constant BHP during a soft stop of the rig pumps, stepwise breaking of circulation. To see if similar control may be achieved during a faster ramp down of the rig pumps, simulation 4 will also be based upon the Full CMP system. The rig pump will be operated in the same manner as simulation 2, figure 6-12.

6.4.4.1 Bottom hole pressure and mud level adjustment.

Using the Full CMP setup, figure 6-20 represents the bottom hole pressures that were generated, whereas figure 6-13 represent the pressures during the same ramp down procedure. The pressure drop experienced with the full CMP seem marginal compared to the Partial CMP. Numerically the BHP drops by around 1 bar, against 15 bars for the Partial CMP. Furthermore, the time from initial disturbance occurs, until regaining control is much greater for the Partial system. Which means that the partial system showed signs of having difficulties generating enough flow into the riser, keeping up with the loss of friction.

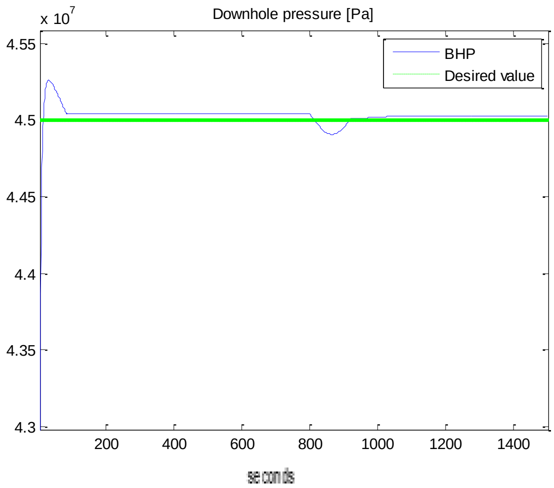

Figure 6-20: Full CMP-Bottom hole Pressure

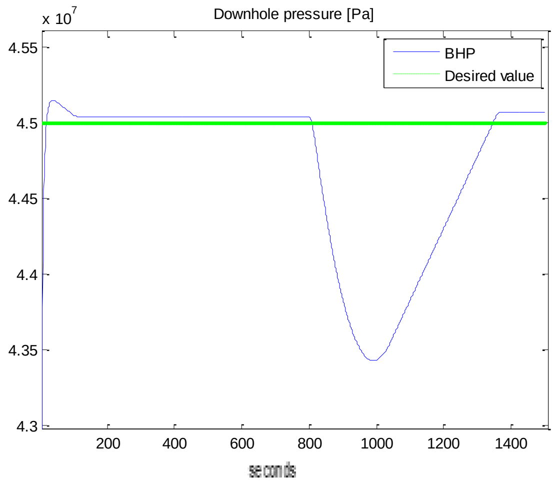

Figure 6-13: Partial CMP- Bottom hole pressure.

The mud level adjustments required for the two setups are distinctively different, in the way that the initial mud level is higher for the Full CMP setup compared to the Partial setup. Additionally, the overall level requirements are greatly reduced with the Full CMP system.

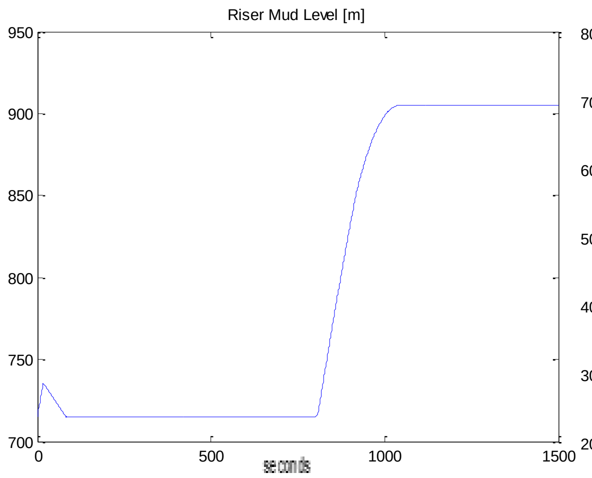

Figure 6-21: Full CMP- Mud level adjustment.

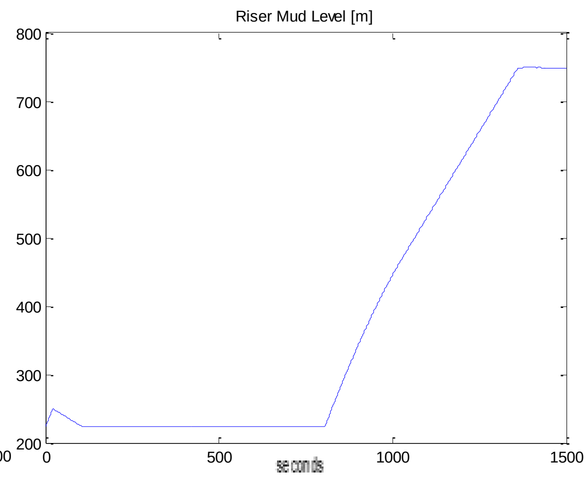

Figure 6-14: Partial CMP-Mud level adjustment

From looking at the BHP in figure 6-20, it is clear that it might even be possible to further reduce the initial ramp down time of 4 minutes, this would however only apply to the Full CMP setup. Seemingly the ramp down time was too fast for the partial CMP, there would be no point in further reducing the ramp down time. The simulation further reducing the ramp down time using the Full CMP is not displayed, but it was further possible to reduce the time by a minute to three minutes, which resulted in the ±5 bar boundary being met.

6.4.5 Simulation 5- Removing the fill line (Full CMP)

As part of the CMP setup described in this thesis, a fill line was introduced to increase the flow rate into the riser, subsequently increasing system response, increasing the chances of maintaining constant pressures through the entire operation. During the third simulation, the full CMP setup seemed highly capable of maintaining close to constant pressures, which generated the question; would it be possible to remove the fill line described in the initial setup all together, and still operate within the limits of the system?

Using the same ramp down method as described for simulation one and three, only this time not taking advantage or otherwise removing the fill pump described in the initial setup (Q_{fill}=0), the following bottom hole pressures was generated.

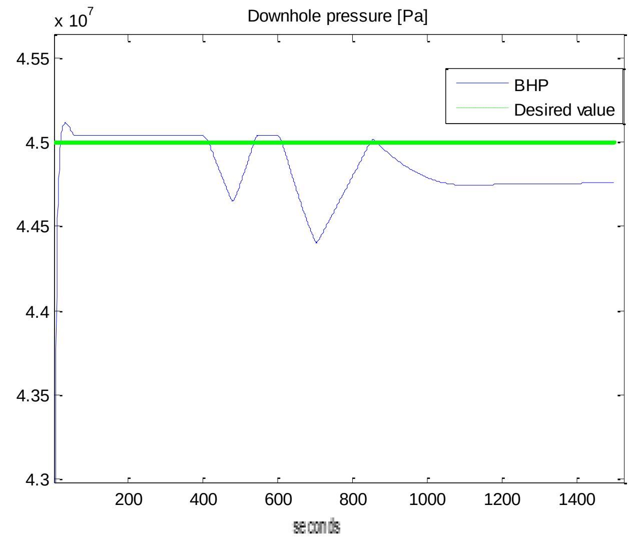

Figure 6-22: Full CMP- BHP without using a fill line.

The BHP barely exceeded the ±5 bar operational boundary that was initially set. If the rate at which rig pump was ramped down could have been slightly reduced, the second dip would not exceed the BHP.

6.4.5.1 Flow rates

Figure 6-23 shows how the only means of adjusting the mud level is achieved by the difference in flow rate between the riser pump and that of the rig pump, assuming zero influx or losses. The riser pump experiences a sudden spike at around 600 seconds, this is due to mud levels once more balancing out the loss of friction. Since the model do not know if this rate will be new rate being further used, or if this is just a temporary level, the riser pump receives a signal from the controller device that it needs to deliver the same rate as which the fluid entering the riser, ensuring balanced rates and maintaining pressures at desired set point.

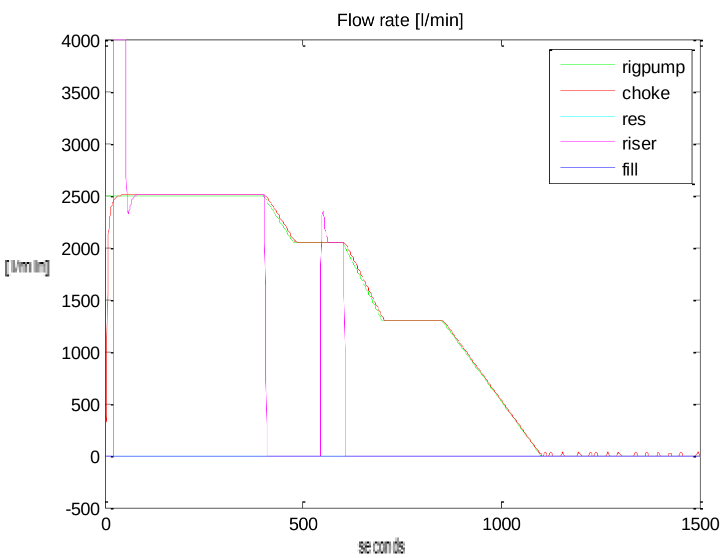

Figure 6-23: Full CMP- Flow rates, no fill.

6.4.5.2 New stop/start procedures

For future references, equipping the model with a special feature designed for optimizing the start/ stop procedures of the rig pump, a system that will introduce an initial underbalance or overbalance to the system. Knowing that all positive or negative adjustments to rig pump circulation, small or big, will generate some changes to the overall bottom hole pressure. Using figure 6-22 as an example, still using 450 ±5 bar as system constraints. As the simulation showed, the lowest value of the BHP was just below 445, at around 700 seconds into the simulation. By means of adjusting the initial mud level to create a positive overbalance of around 4-5 bar, the system becomes more flexible with respect to the lower wellbore pressure limits during ramp down operations. The same could apply for start- up scenarios, only here an underbalance will have to be introduced.

Introducing an initial overbalance equal to 5 bar, the pressures will look something like figure 6-24. The pressure has been adjusted by 5 bar before the initial circulation rate is adjusted, notice how the second dip that previously was outside the pressure window, and now is well within the ±5 bar range. The idea is of being able to press a button in the drillers display, telling the system that a circulation stop lie in the immediate future, and that a correct overbalance, matching the operational limits or current flow rate. Meaning, if the current flow rate is higher, say 3500 lpm, a higher overbalance will be required than what is required for flow rates at 2500 lpm, however the operational limits of pore and fracture pressure respectively should prevent using too low or too high additions.

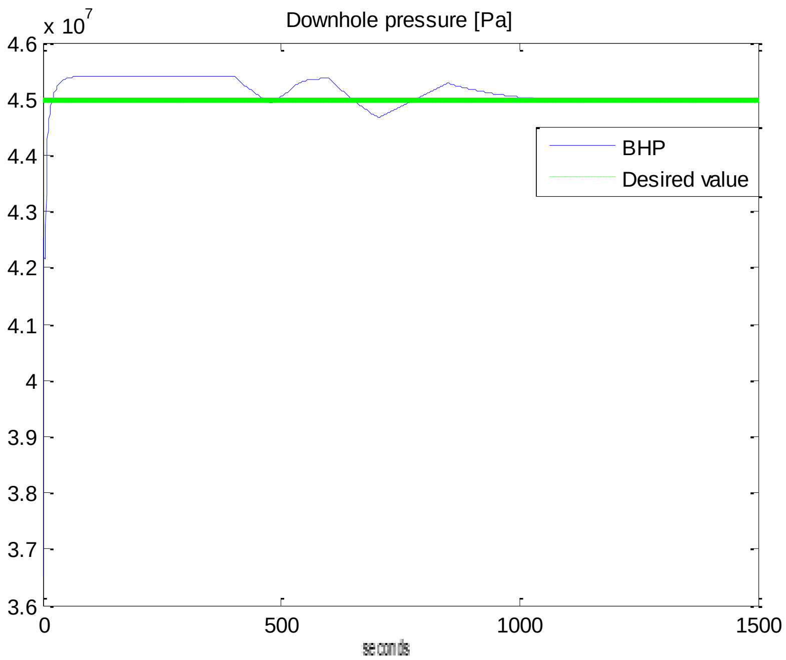

Figure 6-24: Full CMP-Bottom hole pressure + 5 bar overbalance

6.4.6 Simulation 6- Using a regular riser (18" ID) (Full CMP)

All of the previous simulations have used a so called slim riser with an inside diameter of 15 inches, whereas a regular riser typically is 18 inches. Therefore it seems natural to introduce this option, knowing that it is going to increase controllability challenges. For the next simulation, same steps for ramp down as mentioned earlier will be used together with the Full CMP setup for best results.

6.4.6.1 Bottom hole pressures using a fill line

Increasing the riser flow area by introducing a bigger riser is expected to create bigger challenges with respect of controlling the BHP. Displayed in figure 6-25, the full CMP setup seem to a large degree still capable of staying within the ±5 bar limit of the system, however keeping in mind that the ramp down process for this simulation takes 11 minutes to complete, which is sufficient enough to adjust the mud level as the friction is lost. Using this setup would facilitate either faster ramp down, or like before introducing the idea of removing the fill line all together, see 6.4.6.2.

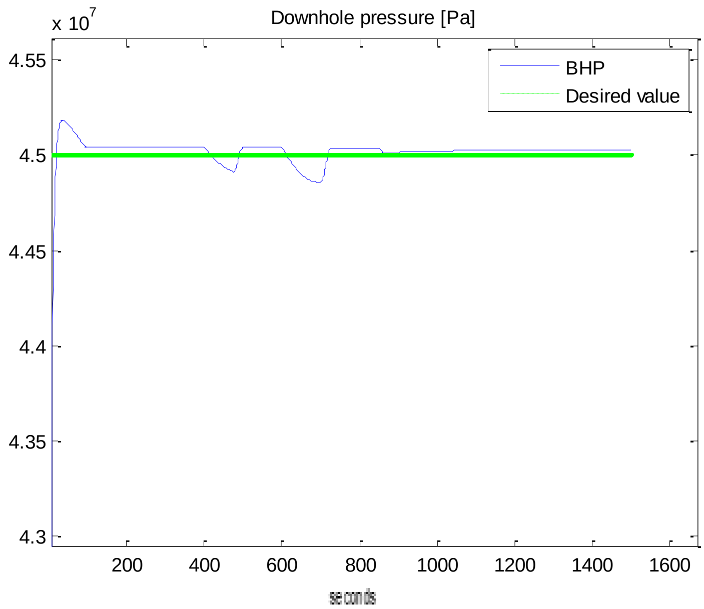

Figure 6-25: Full CMP- BHP (Regular Riser)

6.4.6.2 Bottom hole pressures without fill line

Removing the fill line and introducing large inside diameter riser will generate major problems with respect to maintaining pressures within the predefined boundaries of the system, even when steps for ramp down procedures are taken. The biggest problem with not using the fill line is partially not generating enough flow into the riser, enabling bottom hole pressures to be maintained, but also the fact, as soon as circulation from the rig pumps is stopped, there is further no way of adjusting the mud level if need be, only way of adjusting mud levels is by initiating rig pump circulation again.

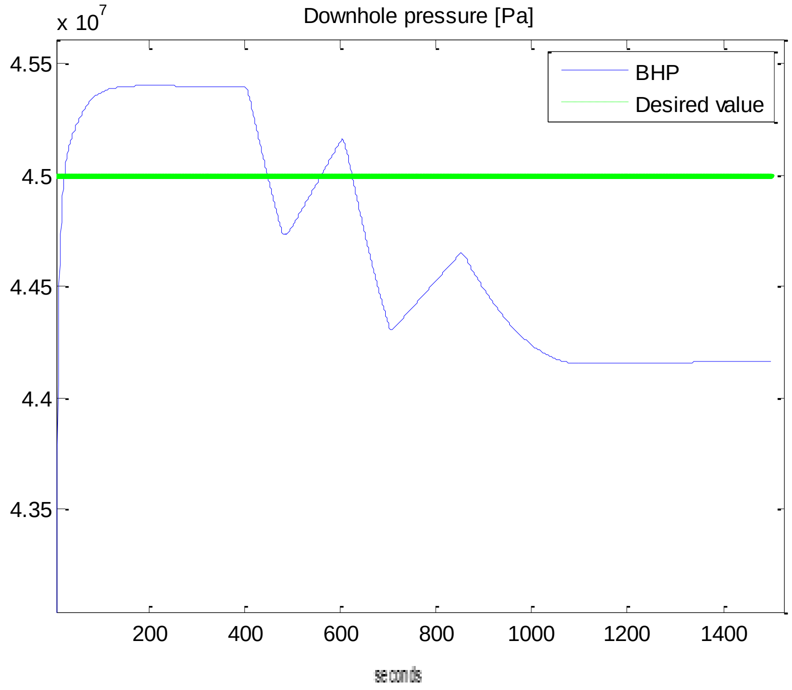

Figure 6-26: Full CMP- BHP (no fill line and regular riser)

6.5 Discussions

Through gradually ramping down the rig pump in simulation one and three, the Partial and Full CMP setup were given sufficient time to recover from the loss of friction, which resulted in wellbore pressures not exceeding the limits set for the system. Controlled ramp downs are to a large degree the industry practice for drilling in high risk environments, and is a way of ensuring that the wellbore has a greater chance of remaining overbalanced and stable.

The second simulation, using the Partial CMP setup, showed that ramping down the circulation too fast may generate challenges with respect to maintaining BHP constant, the volumes that need to be displaced are simply too large with not enough time to do it. Resulting in a drop of 15 bar, which for some wells might be sufficient to generate underbalanced conditions, risking influxes. Not all however is negative, if the simulation was to be compared with that of a conventional drilling system in the same well, where the difference in pressure between a circulating well and a non-circulating well would be around 50 bar. The pressure from the hydrostatic part of a conventional system would be constant, meaning there would be no way of adjusting the hydrostatic as the friction disappears. This means the 15 bar pressure drop experienced during the second simulation is not of great significance, additionally knowing that this number may be greatly reduced by breaking the rig pump circulation down in incremental steps compared to the fast method.

Simulation four and five furthermore tested the range of operability for the Full CMP setup, showing that the Full CMP system is highly adaptable to changes, facilitating even faster ramp down procedures than what was initially introduced. Furthermore, the use of a fill line was questioned, as part of simulation five, new procedures were furthermore incorporated, effectively extending the limits in which the EC-Drill and CMP system may be operated.

By further introducing a regular ID riser, simulation six, shows that by using a fill line it is still possible to maintain a fairly constant bottom hole pressure. However removing the fill line from the setup, may generate controllability issues, even when breaking the circulation in steps.

7 Conclusions and future work

Dual Gradient Drilling technologies have become what MPD was 15 years ago, currently on its way into the world's offshore markets, with special focus on the deep water. Due to recent well control incidents, introducing novel drilling solutions have by some been met with scepticism, others are however praising this leap forward in deep water well control that these dual gradient systems seem to incorporate. The mentioned systems have yet to develop substantial track record, which means that dual gradient technology will continue to be put under a lot of testing and scrutiny ensuring that all parts of the system is working safely and effectively.

For concepts like the EC-Drill and CMP, being able to effectively manage the wellbore pressures is essential to well control and drilling operations, especially when drilling into narrow pore and fracture pressure windows. By means of directly manipulating the rig, riser- and fill pump it is possible to indirectly control the mud level in the riser, subsequently maintaining a stable bottom hole pressure, throughout the entire operation. Changing mud level instead of changing mud weight is also highly effective

The work through this thesis has helped shed light on certain challenging aspects with dual gradient in general, namely u-tubing and well control, which also applies to the EC-Drill and CMP system. By means of automated control processes the human interface will to a large degree be removed from the minute to minute operation, allowing the transfer of human resources to focus on high impact decisions, such as kick and well kill methods.

The work completed through this thesis, with special focus on the EC-Drill and CMP systems have confirmed that most offshore operations may reduce non-productive time experienced during drilling, through increased loss and kick detection capabilities and introducing positive riser and kick safety margins. Furthermore, by means of adjusting the mud level in the riser, it is possible to generate pressure profiles that better fit certain pore- and fracture pressure windows, further reducing excessive use of intermediate casing strings and additionally, reducing problems associated with excessive ECD which greatly increases chances of meeting wellbore objectives.

The current and future success of the EC-Drill or CMP system, is like most other technologies governed by its ability to complete the job, conventional or unconventional, in a safe and effective manner, positively adding to the overall performance. However keeping in mind, no matter how good a concept is, building a solid track record is only achieved if the future demand for the system increases.

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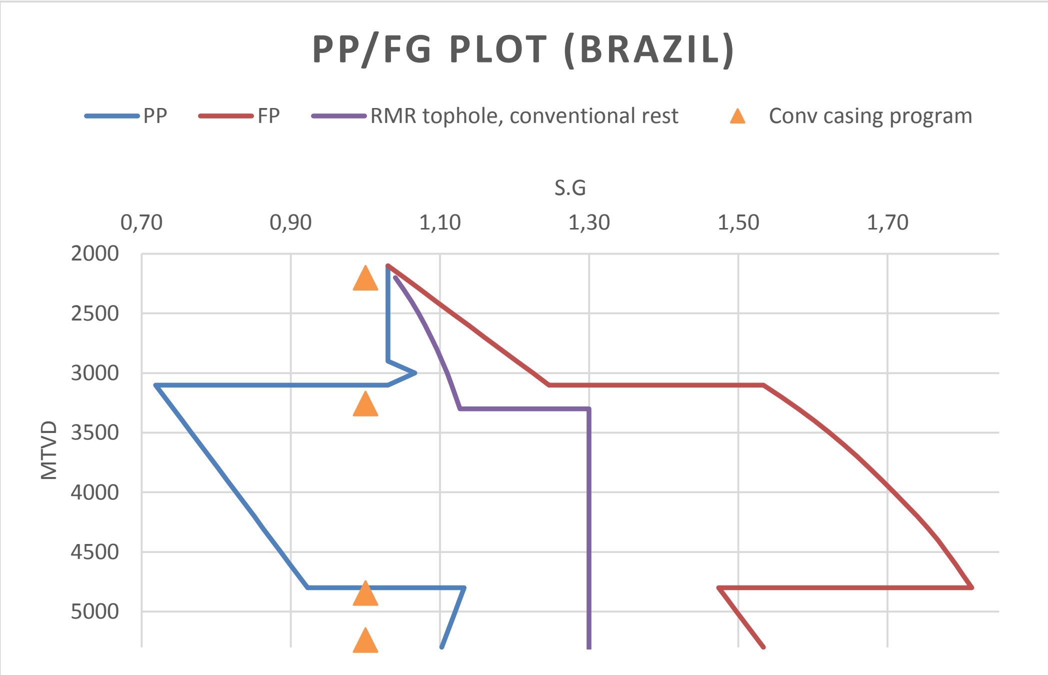
Appendix A

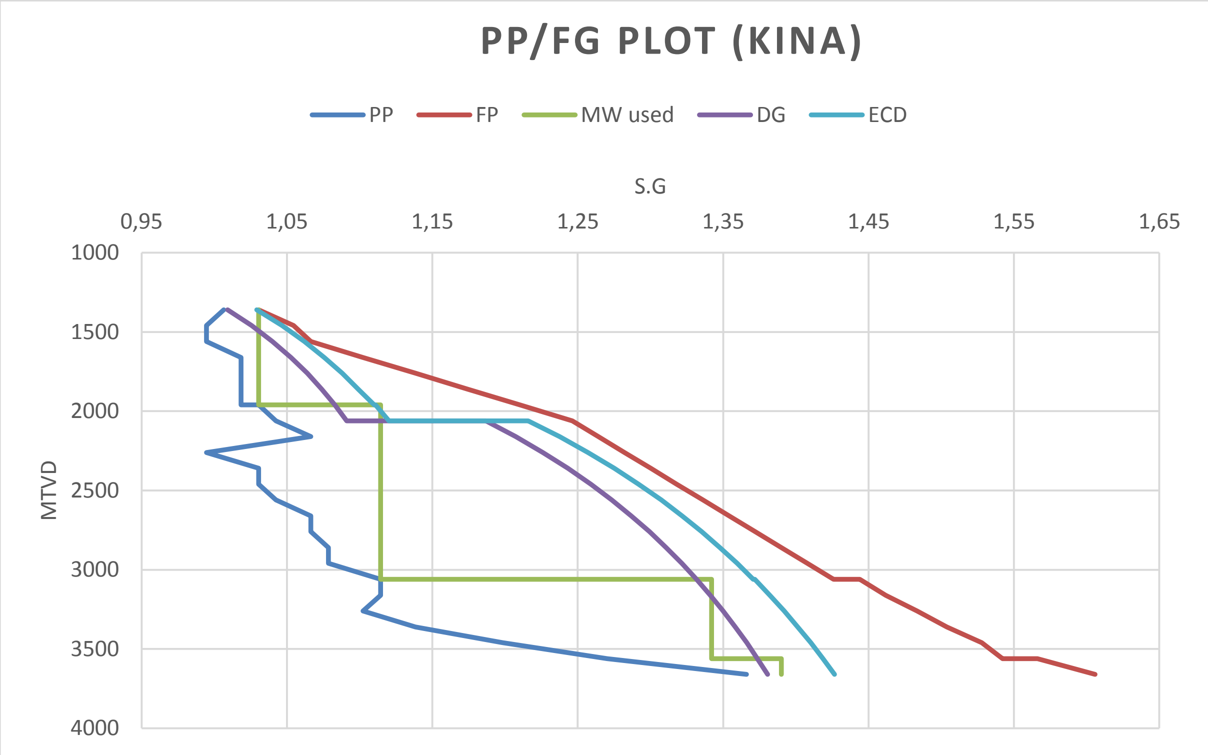
All wells analysed (some more extensively than others) are represented in Appendix A. Selected plots were shown in the analysis, whereas all were used to generate an overall general idea.

Brazil

Due to Portuguese drilling reports and further limiting data, the validity of the PP/FG plot is questionable, therefore has been left out of the analysis.



Kina



PP/FG PLOT (KINA)
PP
FP
MW used
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ECD
S.G
0,95
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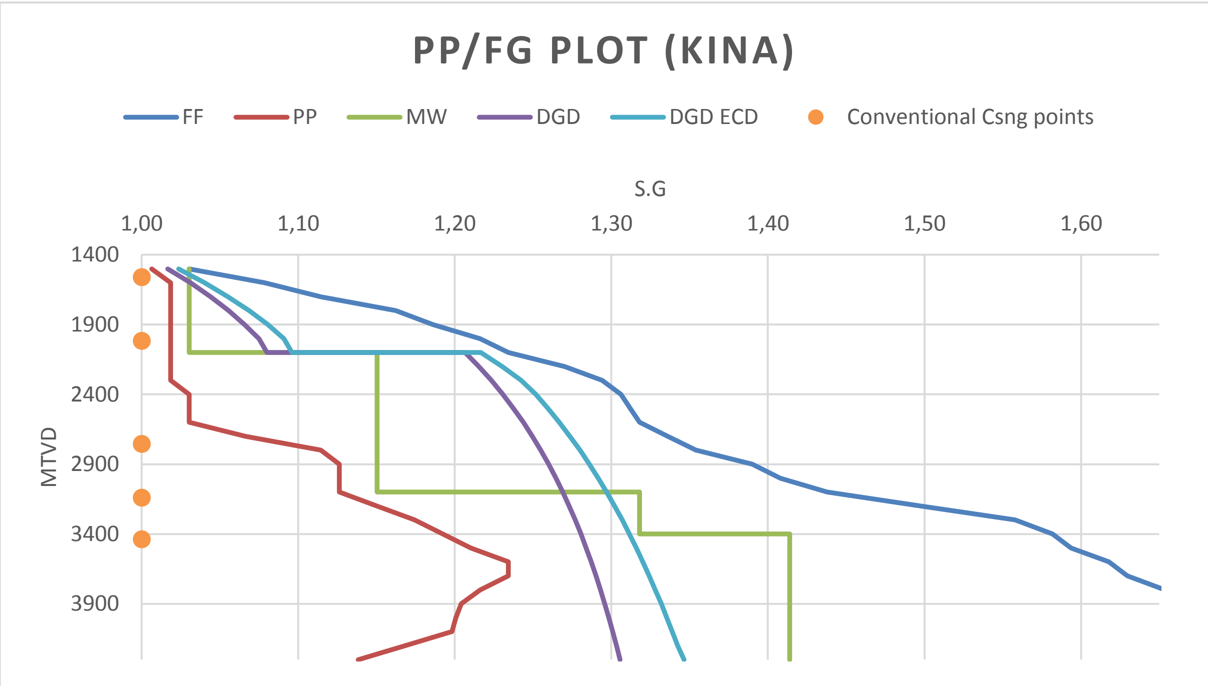

PP/FG PLOT (KINA)
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DGD ECD
Conventional Csng points
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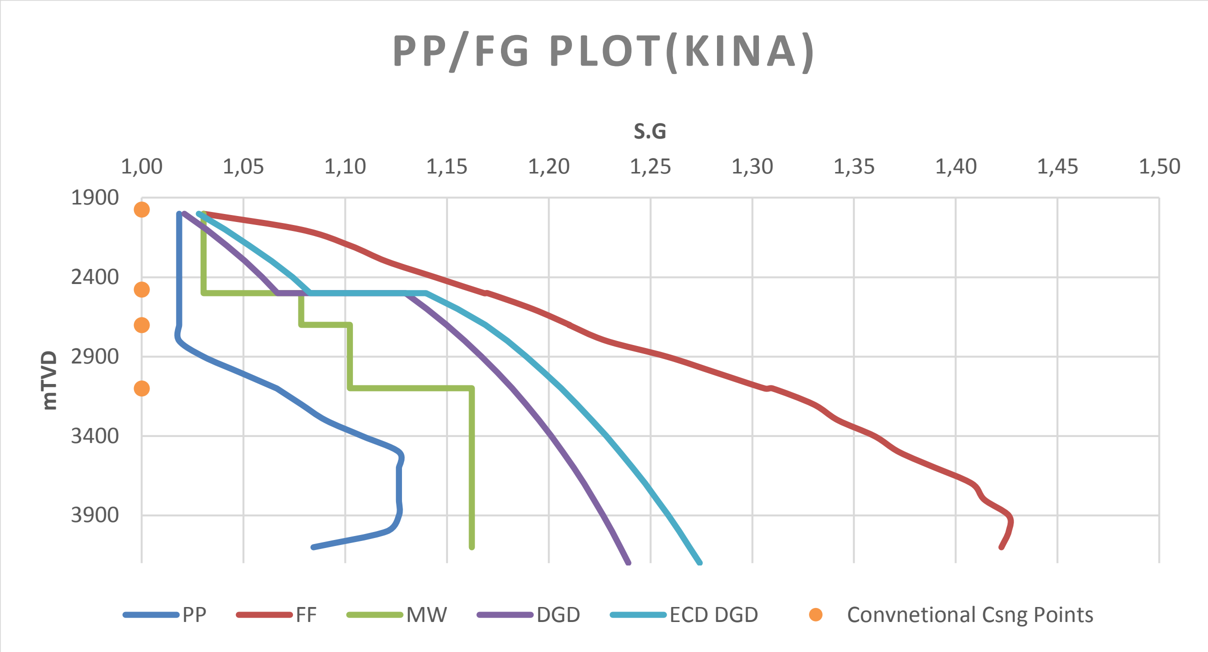
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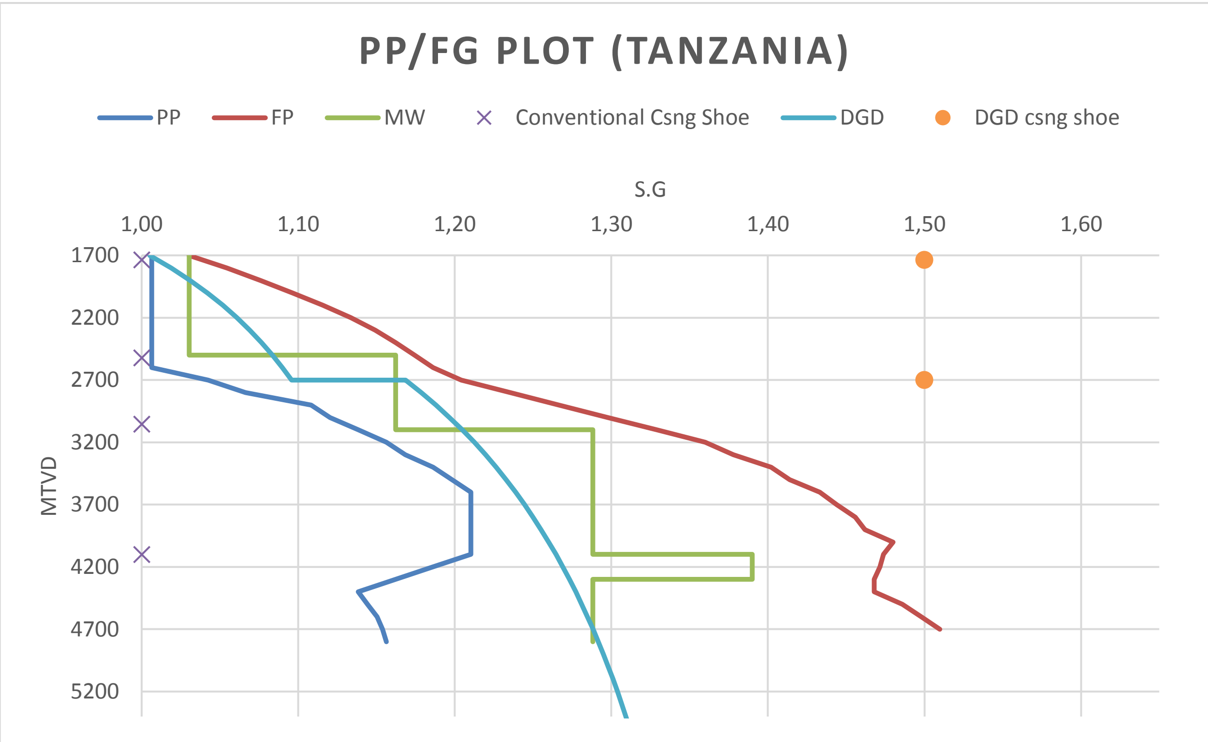
Tanzania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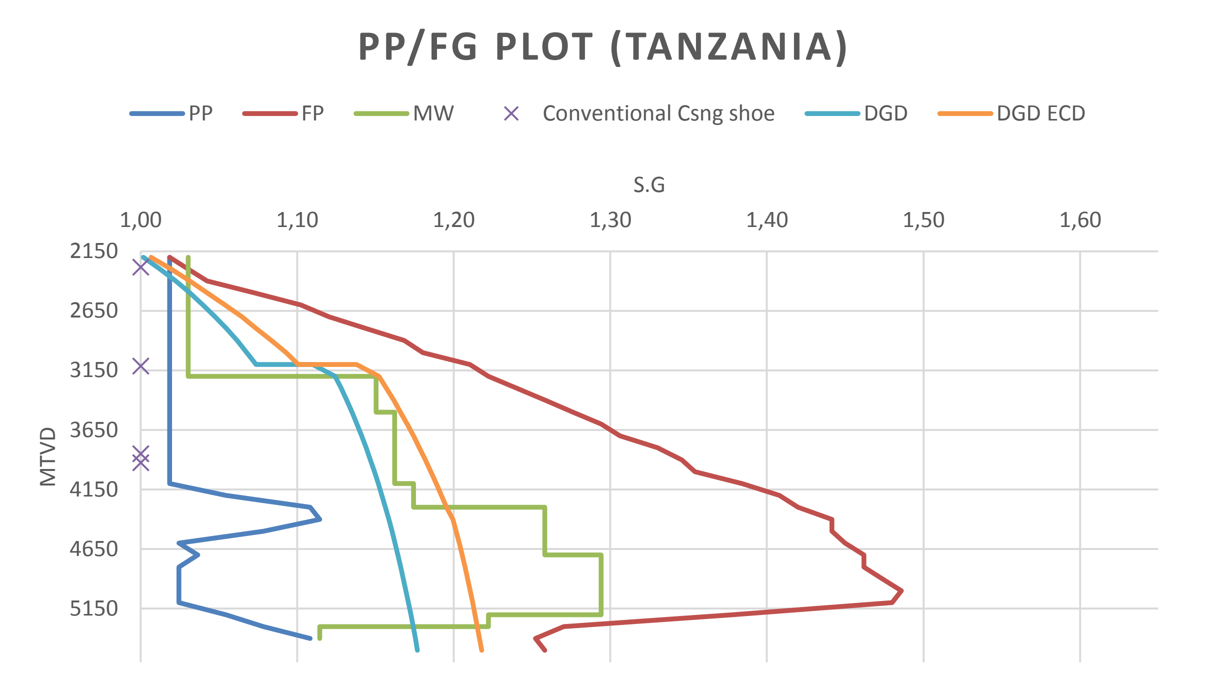
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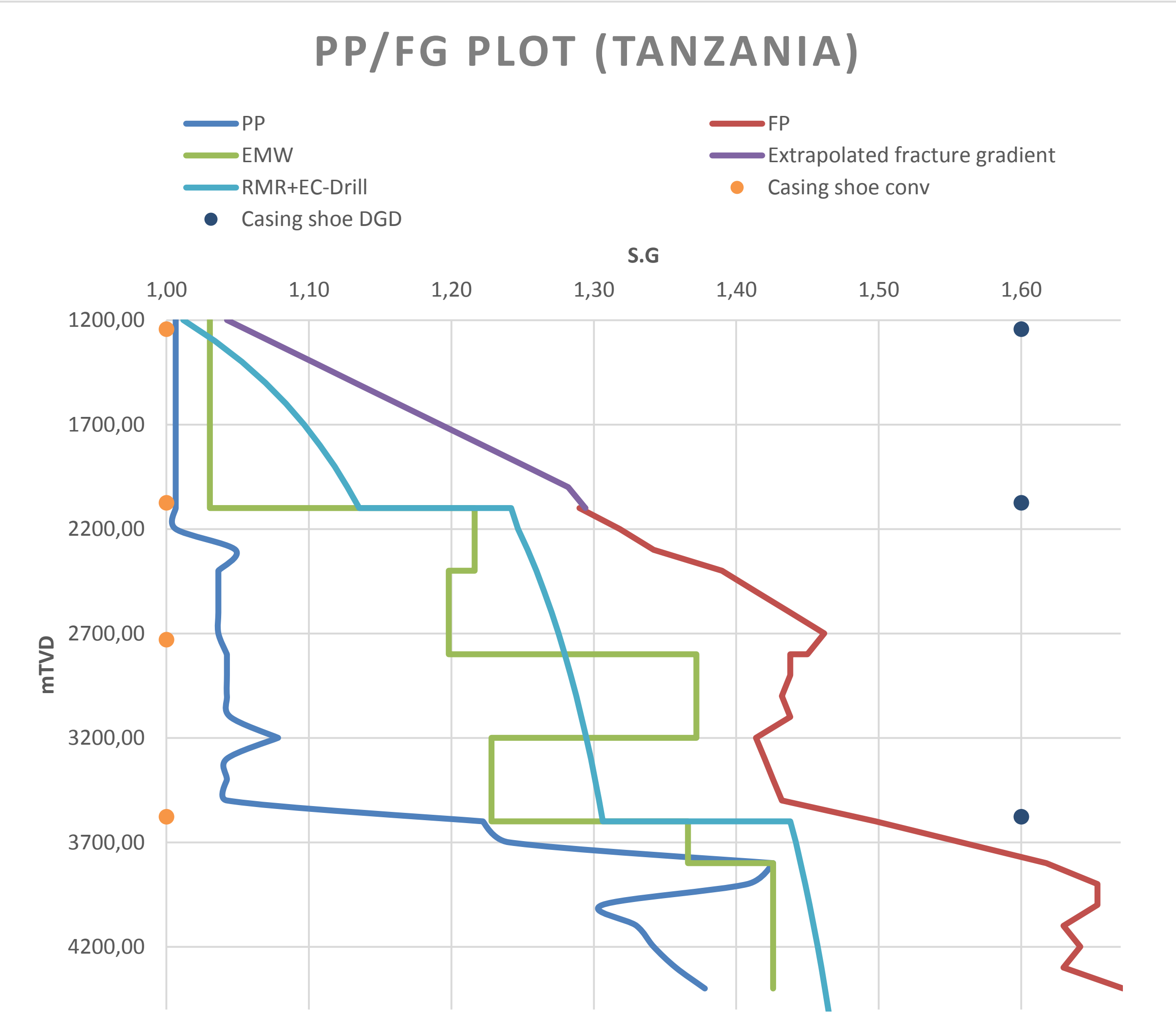
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FP
EMW
Extrapolated fracture gradient
RMR+EC-Drill
Casing shoe conv
Casing shoe DGD
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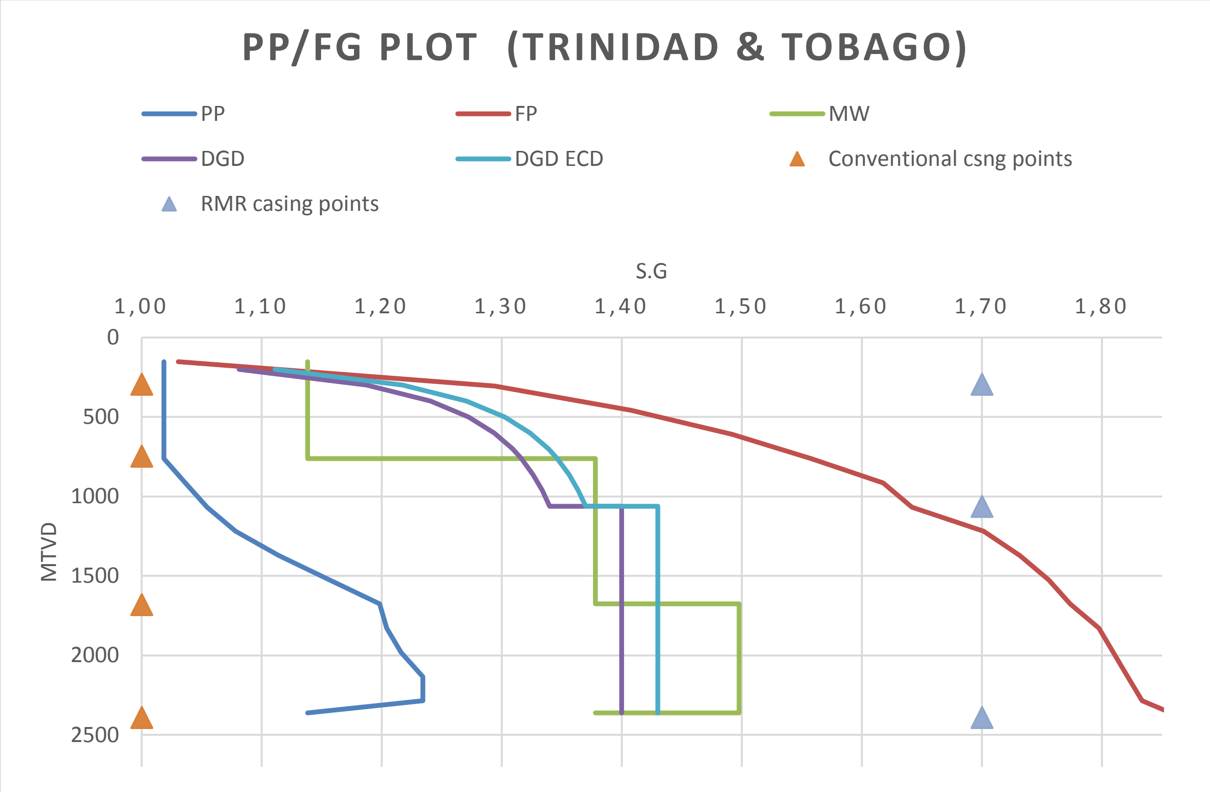
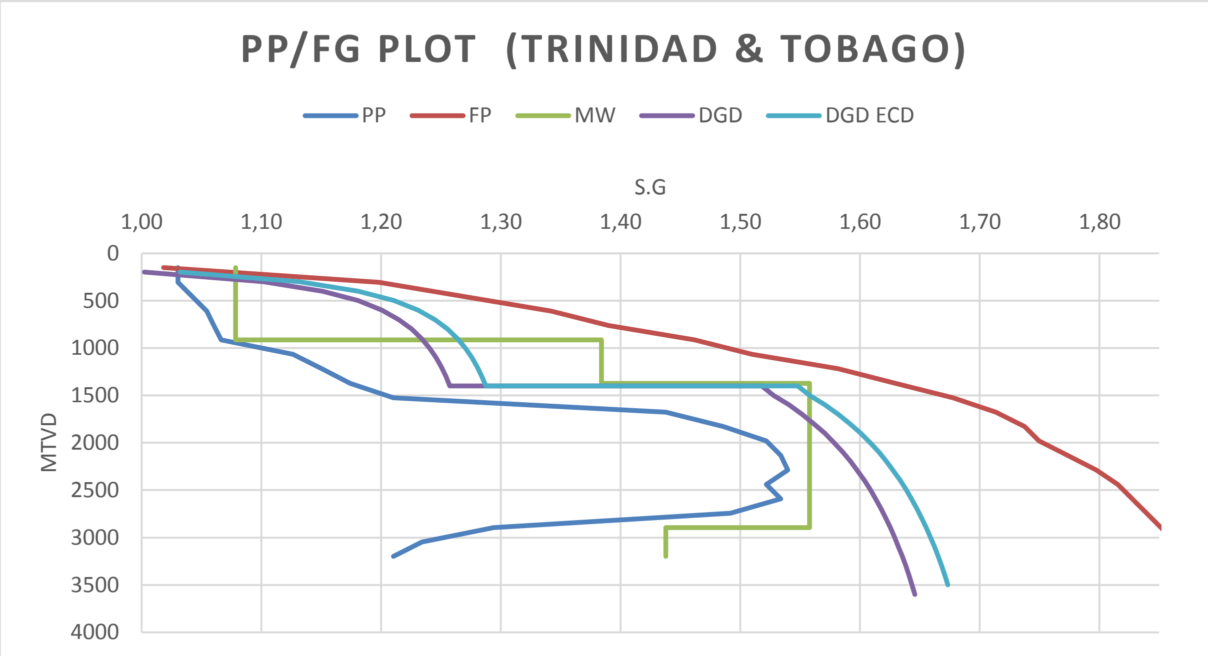
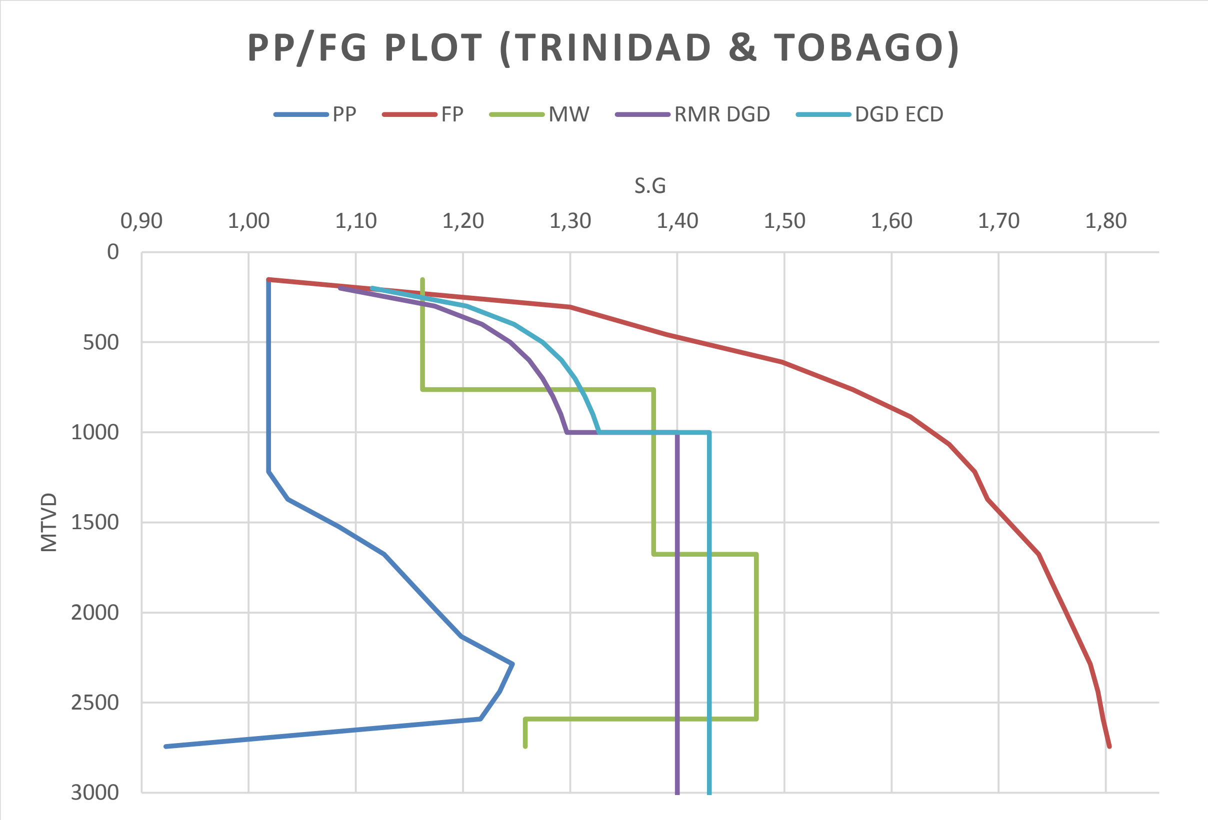
Trinidad and Tobago



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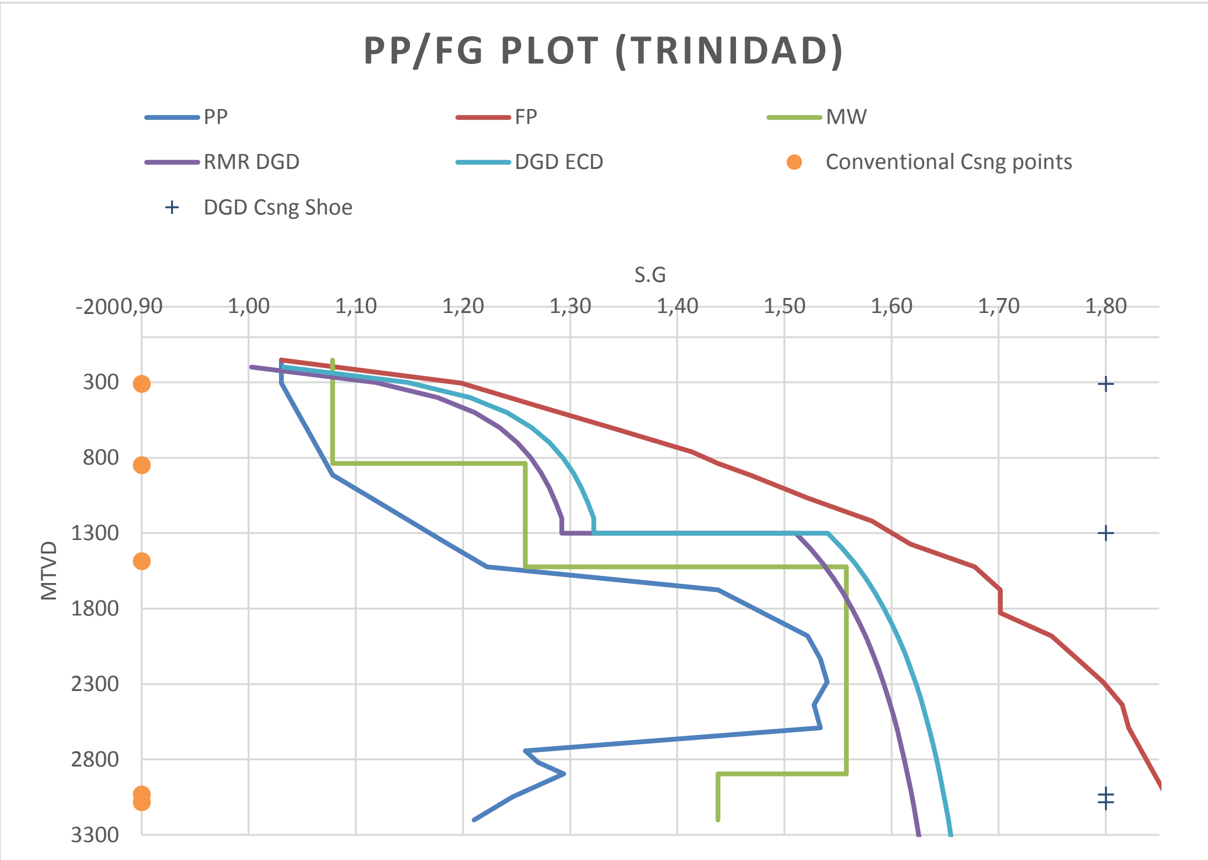
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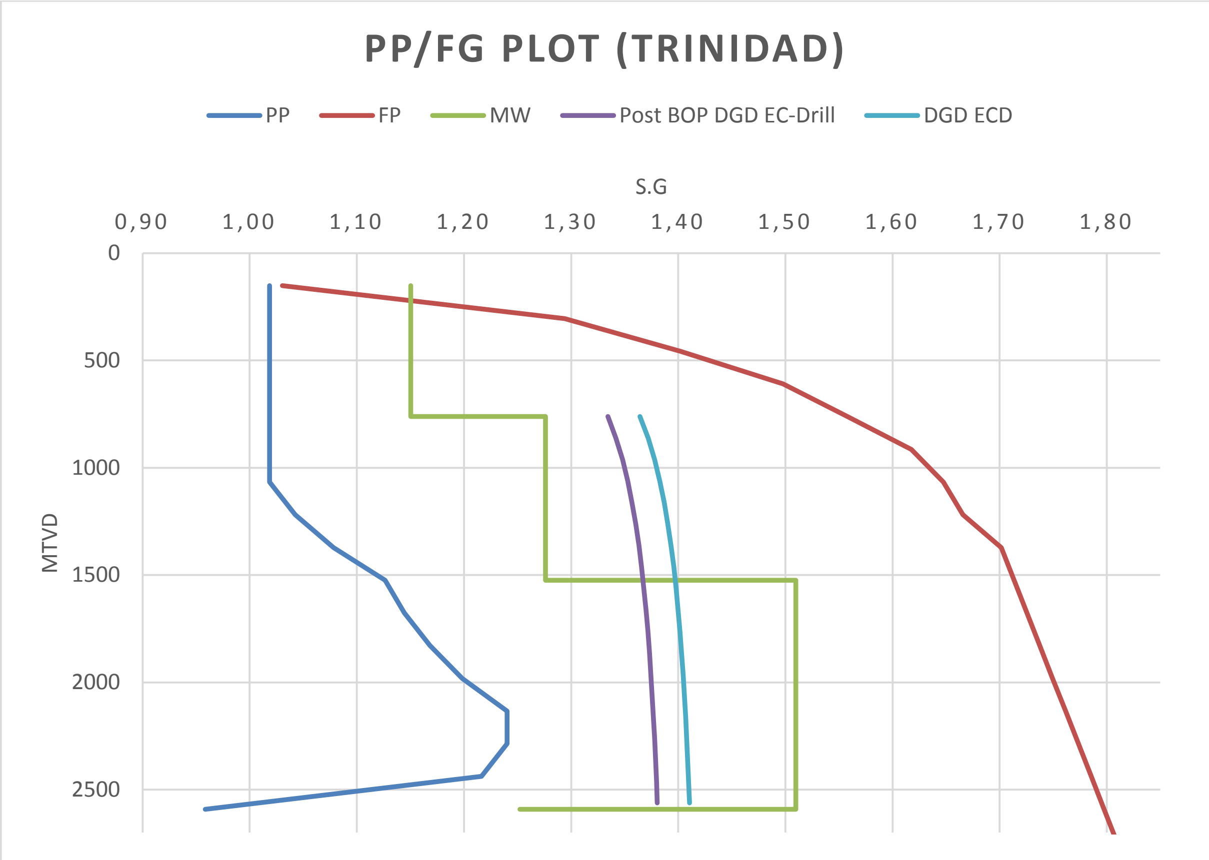
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1,50
1,60
1,70
1,80
MTVD
0
500
1000
1500
2000
2500

Appendix B

```
%% Example of solving the Kaasa model using Euler integration
%
% Differential equations of Kaasa model:
% p_pdot = (beta_d/V_d)*(q_p-q_c)
% q_bdot = 1/M((p_p-p_c)-(Fd+Fb+Fa)*q_b*q_b+(rho_d-rho_a)*g*h)
% p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp-q_c)
% q_c = z_c*k_c*sqrt(p_c/rho_a)
%
% Parameters and initial values
clear all; % deletes all variables
close all; % removes all plot windows

% Constants
maxtime = 1500; % seconds
dt = 0.001; % euler step time
Ts = 0.001;% loop time step

%Operator parameters
q_p = 2500/60000; % 2000 l/min
q_bpp =0/60000;
%q_bpp = 800/60000; % 800 l/min
q_c = q_p + q_bpp; % 2000 l/min
z_c = 1; %fully open choke opening
q_rb = q_c;

% Wellbore parameters
h = 2000;
beta_d =2e9;
beta_a =1e9;
V_d =24; % m3 Volume of 3000 meter DP with 4" ID
V_a = 200; %m3 Volume of  2000m well with 9" ID casing from mudline to TD,
1000m riser with 18" ID
A_a = 0.025; % Annulus ID 9 5/8" with 5 1/2"
A_r = 0.08; % Riser area 18" riser and 5 1/2" OD DP
M = 4.3e8;
Fd = 5e9;
Fb = 1e9;
Fa = 1.7e9;
rho_d = 1580;
rho_a = 1580; % Drillig fluid density
g = 9.81;
k_c = 0.021;
rho_w=  0;%density of air %1000; %density of water


% Define range

p_min=0*10^7; % p_p_m
p_max=5.0*10^7; % p_bhp_m
z_min=0;
z_max=0.20;

qrb_min=-4000/60000;
qrb_max=4000/60000;
q_fill_min=0;
% reservoir parameters
p_pore = 4.3e7;
```

```
p_frac = 4.75e7;
ProdIndex = 0;%(100/60000)/5e5; % 100 l/min at delta p of 5 bar %
'permeability'

%Array initialization
p_p_ar = zeros(maxtime,1);
p_c_ar = zeros(maxtime,1);
p_b_ar = zeros(maxtime,1);
q_b_ar = zeros(maxtime,1);
q_c_ar = zeros(maxtime,1);
q_p_ar = zeros(maxtime,1);
q_bpp_ar = zeros(maxtime,1);
q_res_ar = zeros(maxtime,1);
r_ar = zeros(maxtime,1);
u_ar = zeros(maxtime,1);
y_ar = zeros(maxtime,1);
ufd_ar = zeros(maxtime,1);
h_rb_ar = zeros(maxtime,1);

% Initial values
p_p = 55e5;
p_p_1= 450e5; % Desired referance value
p_c = 10e5;
h_rb = 714;% Full CMP, =221; for Partial CMP: Level between water and
drilling fluid measured from rb pump
h_rb_max= 1000; %Total riser height
q_b = q_p; %2500/60000
p_b = p_p + rho_d*g*h;
p_b1 = p_p + rho_d*g*h;
p_rb = (h_rb_max)-(h_rb_max-h_rb)*g*rho_a+(h_rb_max-h_rb)*rho_w*g;
q_of= 0; %Mud over flow at top of well
q_fill=2000/60000; %water rate at top of well (in/out)
q_riser= 2500/60000;  %%%% Changed this to try and match the initial mud
pump speed eq 2000 L/min, reducing the initial jump that occur
%reference value
p_c_r = 150e5;
p_b_r = 450e5; %Desired Bottom hole pressure

%Initialize controller
e = 0;
u = 0;
ufd = 0;
ufr = 0;
ufb = 0;
y = 0;
r = 0;
Kp = 1000;
Ki = 10;


% Main iteration loop showing how the driller adjust the topside pump rate
for time = 1:maxtime

    p_c_r_last = p_c_r;


%     if (time > 0) && (time <= 200)
%         q_p = q_p +2.5/60000; % ramp up to 2500 l/min
%     end
%
```

```
%
    if (time > 200) && (time <= 400)
        q_p = 2500/60000; % fixed at 2500 l/min
    end
%
%
     if (time > 400) && (time <= 475)

        q_p = q_p - 6/60000; % ramp down to 2250 l/min
    end
    if (time > 475)&& (time <=600)
        q_p = q_p ; %ramp down to 1750 l/min

    end

    if (time > 600)&& (time <=700)
        q_p = q_p - 7.5/60000; %ramp down to 1250 l/min

    end

    if (time > 700)&& (time <=850)
        q_p = q_p;

    end

    if (time > 850) && (time <= 1100)

        q_p = q_p -5.2/60000;

    end
%
%     if (time > 950) && (time <= 1000)
%
%         q_p = q_p -6/60000; %ramp down to 0 l/min
%
%     end
%     %% This section is developed to show various ways of ramping down
%     %%the topside pump, to further show if these might create
controllability
%     %%problems
%     if (time > 300) && (time <= 450)
%
%         q_p = q_p - 10/60000; % ramp down to 2250 l/min
%     end
%      if (time > 500) && (time <= 600)
%
%         q_p = q_p; % ramp down to 2250 l/min
%      end
%      if (time > 650) && (time <= 800)
%
%         q_p = q_p - 6.7/60000; % ramp down to 2250 l/min
%     end
% % % %      Alternative ramp down
%     if (time >300) && (time<=800)
%         q_p= q_p - ((2.55/60000)*10^2)*((time-time+10)/(time));
%     end
% % % %     Alternative ramp down
%     if (time > 300) && (time <= 1300)
%
%         q_p = q_p - 2.5/60000; % Linear ramp down from 2500 l/min to 0
```

```
%
%     end
%     Alternative Ramdown
%    if (time > 0) && (time <= 200)
%
%        q_p = q_p ; % ramp down to 0 l/min
%    end
%
%     if (time > 800) && (time <=980)
%
% %        q_p = q_p - 13.8889/60000; % ramp down to 0 l/min
% %         q_p = q_p - 10.4166667/60000; % ramp down to 0 l/min
%     end
    %Loop that can be used for lost circulation or influx
    %Pore pressure
    q_res = ProdIndex*(p_pore - p_b);

    if q_res < 0
        q_res = 0;
    end

    % Frac pressure
    q_loss = ProdIndex*(p_frac -p_b);
    if q_loss > 0
        q_loss = 0;
    end


    %store parameters
    p_p_ar(time) = p_p;
    p_c_ar(time) = p_c;
    p_c_r_ar(time) = p_c_r;
    p_b_ar(time) = p_b;
    p_b1_ar(time) = p_b1;
    q_b_ar(time) = q_b;
    q_p_ar(time) = q_p;
    q_c_ar(time) = q_c;
    q_bpp_ar(time) = q_bpp;
    q_res_ar(time) = q_res;
    q_rb_ar(time) = q_rb;
    u_ar(time) = u;
    y_ar(time) = y;
    r_ar(time) = r;
    ufd_ar(time) = ufd;
    ufr_ar(time) = ufr;
    h_rb_ar(time) = h_rb;
    q_of_ar(time) = q_of;
    q_fill_ar(time) = q_fill;
    q_riser_ar(time)=q_riser;


    %% Controller code

    % Feed forward from disturbance
    zfr = ((V_a/beta_a)*(p_c_r_last-p_c_r))/(k_c*sqrt(p_c/rho_a));

    zfd = (q_p + q_bpp)/(k_c*sqrt(p_c/rho_a));
```

```
    % scale to percentage
    r = ((p_b_r-p_min)/p_max)*100.0; % reference is p_b1
    y = ((p_b-p_min)/p_max)*100.0; % controlled variable
    u = ((q_rb-qrb_min)/qrb_max)*100.0; % manipulated variable
 %   ufd_last = ufd;
    ufd = ((zfd-z_min)/z_max)*100.0; % feed forward disturbance
    ufr = ((zfr-z_min)/z_max)*100.0; % feed forward disturbance
    %ufb = u ;b1

    % controller code
    last_e = e;
    e=y-r;
%    delta_u=Kp*(e-last_e)+((Kp*Ts)/Ti)*e; % using Kp and Ti
    delta_u=Kp*(e-last_e)+(Ki*Ts)*e; % using Kp and Ki


    ufb=ufb+delta_u; % feedback


    u = ufb; % +ufd+ufr;
%    u = ufb+ufd_last; % +ufd+ufr; with time delay
%    u = ufb+ufd; % +ufd+ufr;
%    u = ufb+ufd+ufr; % +ufd+ufr;

    % limit u
    if u<=0
       u=0;
    end

    if u>100
        u=100;
    end


    %scale to physical values (only z are needed
%     z_c_old = z_c;
%     z_c = z_min + z_max*(u/100.0);
    q_rb_old = q_rb;
    q_rb = qrb_min + (qrb_max-qrb_min)*(u/100.0);




    % Euler integration loop
    for eulerstep = 1:(1/dt)
        p_pdot = (beta_d/V_d)*(q_p-q_b);
        q_bdot = 1/M*((p_p-(p_c+p_rb))-(Fd+Fb+Fa)*q_b*q_b+(rho_d-
rho_a)*g*h);
        p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp+q_loss-q_c);

        if h_rb < h_rb_max
          h_rbdot = (1/A_r)*(q_c-q_rb);
          q_of=0; % mud
          if q_rb<0 % ønsker å øke mud nivå i riser
%             q_fill= -q_rb;
          q_fill = 0;
```

```
%           q_riser=0;
          % compensate q_p with allowable flow reduction
%           q_p = q_p - q_rb;
          q_rb =0;



          else
          q_riser= q_rb;
          q_fill=0;
          end

          else
            h_rbdot = 0;
            q_of = (q_c-q_rb); % overflow of mud
            q_fill=0;
        end

        p_p = p_p + p_pdot*dt;

        if p_p<0
            p_p=0;
        end

        q_b = q_b + q_bdot*dt;
        p_c = p_c + p_cdot*dt;

        if p_c < 0
            p_c= 0 ;
        end
        h_rb = h_rb + h_rbdot*dt;

        q_c = z_c*k_c*sqrt(p_c/rho_a);
        p_rb = rho_a*g*h_rb+ rho_w*g*(h_rb_max-h_rb);
        p_b1  = p_p+rho_d*g*h-(Fd+Fb)*q_b*q_b; % pump pressure
        p_b =p_rb+p_c+rho_a*g*h+Fa*q_b*q_b; % using choke pressure

    end
end

figure;
plot(1:maxtime,p_b_ar,'b',1:maxtime,p_p_1,'--g');
title('Downhole pressure [Pa]');
legend('BHP','Desired value');

figure;
plot(1:maxtime,p_p_ar,'b');
title('Pump pressure [Pa]');

figure;
plot(1:maxtime,p_c_ar,'b',1:maxtime,p_c_r_ar,'k');
legend('Measured','Reference');
title('Choke pressure [Pa]');


figure;
plot(1:maxtime,q_p_ar*60000,'g',...
    1:maxtime,q_c_ar*60000,'r',...
```

```
    1:maxtime,q_res_ar*60000,'c', 1:maxtime,q_riser_ar*60000,'m',...
    1:maxtime,q_fill_ar*60000);
title('Flow rate [l/min]');
legend('rigpump','choke','res','riser','fill');

figure;
plot(1:maxtime,r_ar,'k',1:maxtime,y_ar,'g',1:maxtime,u_ar,'b',1:maxtime,ufd
_ar,'r',1:maxtime,ufr_ar,'c');
legend('Reference (r)','Controlled Variable (y)','Manipulated variable
(u)',...
    'Feedforward dist (ufb)','Feedforward ref (ufr)');
axis([1 maxtime 0 100]);
title('Controller values');

figure;
plot(1:maxtime,h_rb_ar,'b');
title('Riser Mud Level [m]');

figure;
plot(1:maxtime,p_b_ar,'b',1:maxtime,rho_a*g*(h+h_rb_ar)+rho_w*g*(h_rb_max-
h_rb_ar),'r',1:maxtime,p_b_ar-(rho_a*g*(h+h_rb_ar))-rho_w*g*(h_rb_max-
h_rb_ar),'g');
title('Downhole pressure [Pa]');
legend('ECD','Hydrostatic Part','Frictional Part')

figure;
plot(1:maxtime,rho_a*g*(h_rb_ar)+rho_w*g*(h_rb_max-
h_rb_ar),'r',1:maxtime,p_b_ar-rho_a*g*(h_rb_ar)-rho_w*g*(h_rb_max-h_rb_ar)-
rho_a*g*h,'g');
title('Downhole pressure [Pa]');
legend('Hydrostatic pressure@Riserbase','Frication al Pressure Drop')

figure;
plot(1:maxtime,q_p_ar*60000,'g');
title('Flowrate in [l/min]');
legend('rigpump');

figure;
plot(1:maxtime,q_of_ar*60000,'b');
title('Lost overflow [l/min]');
legend('Overflow of drilling fluid');

figure;
plot(1:maxtime,q_fill_ar*60000,'g');
title('Water fill at top [l/min]');
legend('Water fill at top');

figure;
plot(1:maxtime,p_c_ar/1e5,'g');
title('Choke pressure ');
```