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Drilling of Deep-set Carbonates Using Pressurized Mud Cap Drilling

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Abstract

A majority of the “easy” fields have already been developed, while demand for oil and gas continues to increase rapidly. Reservoirs in deep-set carbonates contains a large amount of the worlds remaining hydrocarbons and could pose as a solution for supplying the future demand. However, extracting these hydrocarbons has proven to be a daunting task. Carbonate formations are often severely fractured and karstified, leading to large or even total losses during drilling. As these fractures and “caves” are also the main target for gas, kicks and blow-outs are a constant threat.

In this master thesis a variant of Managed Pressure Drilling (MPD), Pressurized Mud Cap Drilling (PMCD), has been reviewed. PMCD uses a static mud cap in the annulus to provide adequate downhole pressure, while a cheap sacrificial fluid is pumped down the drillstring to remove cuttings and transport it into the formation. A literature study was done in order to compare PMCD against other existing techniques, specifically conventional drilling and Constant Bottom Hole Pressure, another MPD variant. Working along side the losses have enabled PMCD to safely drill to Total Depth in these reservoirs, while reducing most of the Non-Productive Time and having an overall cheaper operation. Where other techniques are relying on time consuming and costly Lost Circulation Material, cement or other means of plugging the formation, PMCD works at its optimal.

A static model was made to more clearly show the physics behind PMCD and to be able to simulate an operation through a gas bearing total loss ”cave” in a deep-set carbonate environment. Its procedures and advantages became clear, though the model and reservoir environment was rather simplistic. After an evaluation, the results were that PMCD lacks versatility and is not yet fully accepted by the industry, but that it offers the best solution for drilling of deep-set carbonates. The main conclusion is that in these reservoir, PMCD should as a minimum be used as a contingency in exploration wells.

Sammendrag

Et flertall av de "enkle" feltene er allerede utviklet mens etterspørselen etter olje og gass fortsetter å øke raskt. Reservoarer i dyptliggende karbonater inneholder en stor mengde av verdens gjenværende hydrokarboner og kan være en løsning for å møte fremtidens etterspørsel. Men å nå disse hydrokarbonene har vist seg å være en krevende oppgave. Karbonat formasjoner er ofte kraftig oppsprukket og full av huler som fører til høye eller totalt tap under boring. Ettersom disse sprekkene og hulene er også hovedmålet for gass, er brønnspark og utblåsninger en konstant trussel.

I denne masteroppgaven er en variant av Managed Pressure Drilling (MPD), Pressurized Mud Cap Drilling (PMCD), blitt gjennomgått. PMCD benytter en statisk slamplugg i ringrommet for å gi tilstrekkelig trykk nede i borehullet, mens en billig offer væske blir pumpet ned borestrengen, tar med seg borekaks og dumpes inn i formasjonen. En litteraturstudie ble utført for å sammenligne PMCD mot andre eksisterende teknikker, spesielt konvensjonell boring og Constant Bottom Hole Pressure, en annen MPD variant. Å arbeide sammen med tapene har tillatt PMCD å bore trygt til total dybde i disse reservoarene, samtidlig som uproduktiv tid er redusert og til en lavere pris generelt. Der andre teknikker er avhengig av tidkrevende og kostbar tapt sirkulasjon materiale, sement eller andre midler for å plugge formasjonen, fungerer PMCD på sitt optimale.

En statisk modell ble laget for å tydeligere vise fysikken bak PMCD og for å være i stand til å simulere en operasjon gjennom en gassbærende totale tap "hule" i et dyptliggende karbonat-miljø. Dens prosedyrer og fordeler ble klarere, selv om modellen og reservoar miljø et var ganske forenklede. Etter en evaluering var resultatet at PMCD mangler allsidighet og at den ennå ikke er helt akseptert av bransjen, men at det tilbyr den beste løsningen for boring av dyptliggende karbonater. Konklusjonen er at i disse reservoarene så bør PMCD som et minimum være i beredskap i letebrønner.

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Chapter 1

Introduction

Consumption of oil and gas has increased a lot the last decades and continues to accelerate. It is essential to explore new and occasionally challenging reservoir in order to supply this demand. Carbonate reservoirs contains a large amount of the worlds remaining hydrocarbons, but tapping this valuable resource have proven to be quite a struggle. Carbonates can have highly varying properties within a small section. Fractures and vugs are a common phenomena when drilling through this type of formation, resulting in a small difference between the formations pore and fracture pressure, i.e. a narrow drilling window. Many wells have been confronted with total losses, meaning no returns. In addition to combating losses, these fracture/caves are also the main target for gas and represent a continuous risk of kicks and blowouts.

Conventional drilling of these zones have shown to be challenging as staying within the boundaries in the narrow drilling window requires a precise pressure control that is just not conventionally feasible. In a total loss scenario, the collective procedure has been to pump down Lost Circulation Material (LCM), cement or other means of sealing of the leaky zones, while bullheading down the annulus to counteract a potential kick. Most wells have been successfully drilled to Total Depth (TD), but only after days or weeks of Non-Productive Time (NPT) and at a high cost.

Newer techniques on the market provide a better way of dealing with these extreme zones. Managed Pressure Drilling (MPD) was recognized at the start of this millennium and aims to drill the un-drillable. Constant Bottom Hole Pressure (CBHP) is one of the variants of MPD, often referred to as regular MPD. By using a closed-circulation system and control of a back-pressure, CBHP is able to quickly adjust the annulus pressure profile and stay within narrow boundaries. With equipment for fast detection of kicks and change in flow rate, fluid loss is minimized and small influx can be circulated out. This will provide a higher safety upon encountering total losses, but CBHP is depended on conventional methods (LCM etc.) to mitigate it.

Pressurized Mud Cap Drilling (PMCD) is another variant of MPD. This technique is as unconventional as it gets and is actually dependent on total losses to be applicable. A static mud cap is placed in the annulus to maintain adequate downhole pressures, while cheap sacrificial fluid is pumped down the drillstring. The seawater carries with it cuttings from drilling and transports it inside the formation, without any return to the surface. Kicks are efficiently bullheaded back into the formation. Non-Productive Time (NPT) from combating losses is drastically reduced, in addition to having better well control and lowering the cost of operation.

1.1 Objective and Approach

The objective of this thesis is to investigate the challenges with drilling of carbonates, particularly deep-set carbonate reservoirs and the most common techniques used for drilling them. PMCD is the main focus and is to be compared against both conventional drilling and CBHP. In addition to a literature study, the objective is to make a simple model for PMCD, implement it in MATLAB and simulate an operation through a gas filled total loss zone. This simulation will be used to verify the findings of the literature study and to better understand its procedures. PMCDs advantages and disadvantages are to be discussed and evaluated.

Chapter 2

Deep-set Carbonates

Carbonates are a type sedimentary rock, mainly formed in a marine setting. It is named after its main minerals, either calcium carbonate (limestone) or magnesium carbonate (dolomite), which is precipitated or dissolved from the groundwater under the right conditions.These minerals form the cement, binding together lithic fragments and dead organisms (Schlumberger, 2014a).

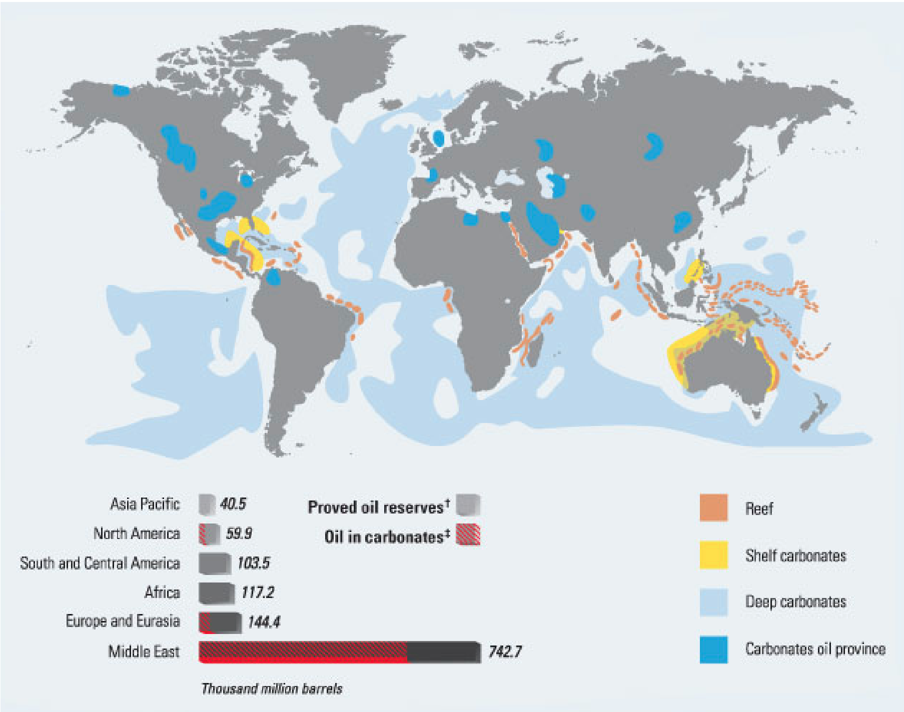

Figure 2.1: Worldwide overview of carbonate reservoirs (Schlumberger, 2014b)

Carbonates are typically good source rocks due to the large amount of organic compound, but they may also pose as a potential reservoir rock. Actually, "it is estimated that more than 60% of the world's oil and 40% of the world's gas reserves are held in carbonate reservoirs (Schlumberger, 2014b)."

Figure 2.1 shows the huge potential of deep-set carbonates. In fact, the worlds largest oil field Ghawar, located onshore in Saudi Arabia, is found in carbonate reservoir rocks. This chapter will look at the challenges with tapping this valuable reserve and how it is done conventionally.

2.1 Drilling Challenges

Drilling through a carbonate structure can present several challenges, especially in a reservoir zone with hydrocarbons. Carbonates might be soft or hard, ductile or brittle and they can easily be dissolved, often causing them to be severely fractured and vugular. These fractures can range from microscopic fissures to kilometer long swarms and may be corridors with permeability of a thousand times greater or more than the surrounding rock matrix. The vugs, also called karst-caves, can be seen within a surface structure in *Figure* 2.2. Karst-caves are underground cave-like structures caused by erosion, varying in size from 1cm to big caves. It is these fractures and vugs that are the main target for gas in deep-set carbonates (Schlumberger, 2014b).

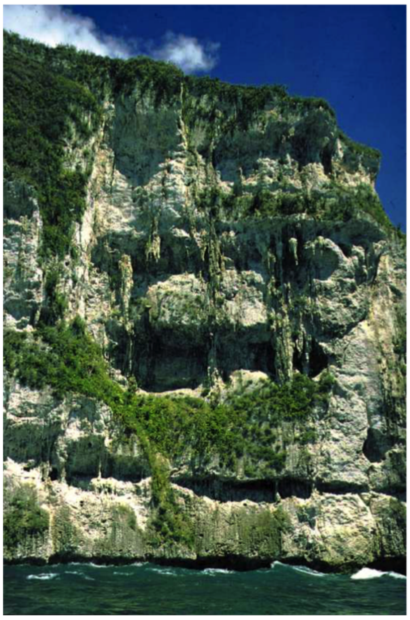

Figure 2.2: Karst caves at surface (Svein Hovland, 2013)

Well planning is an important aspect ahead of any drilling operation, even more so with suspicion of the aforementioned features being present. Their presence causes large changes within small sections, making the reservoir difficult to characterize. A certain amount of information about the reservoir will exist for production wells, while for exploratory wells, there are normally large uncertainties surrounding the geology and pressure regimes. From the information that is known, a drilling window is made based on estimations of the formations pore and fracture pressures. It may be accurate to assume that in a severely fractured and/or vugular zone, the fracture pressure is almost similar to the pore pressure of the carbonate formation, resulting in a non-existing drilling window[1]. Staying within the pre-determined pressure boundaries are the most important factor for maintaining a high degree of well control. Failure to do so can have serious consequences:

- Lost Circulation
- Kicks

2.1.1 Lost Circulation

Lost circulation is caused by fractures and vugs in the formation. They might exist naturally or caused by the mud weight gradient exceeding the fracture pressure gradient, fracturing the formation. Loss of drilling fluid is expensive and can result in loss of well control. The potentially large network of fractures and vugs in carbonates

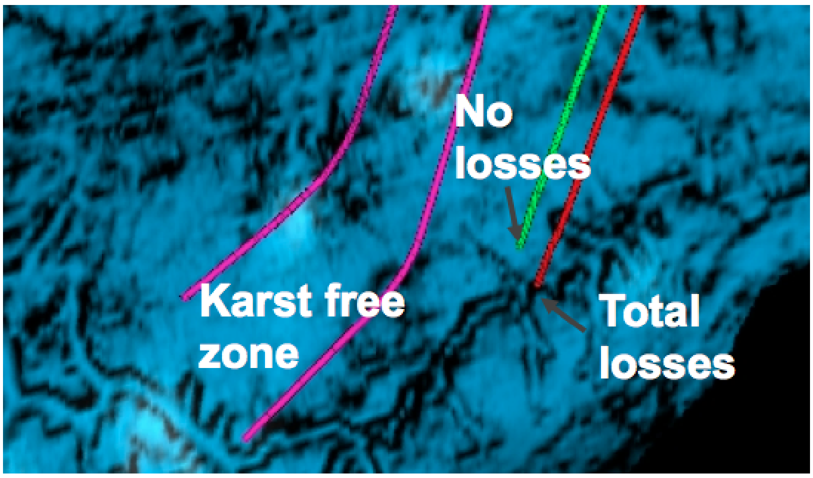

Figure 2.3: Imaging karst and risk mitigation (Svein Hovland, 2013)

[1]John-Morten Godhavn, personal communication (E-mail) 20.03.14

could lead to total losses, meaning that there will be no return of drilling fluid in the well. Shell has drilled several wells into carbonate structures in offshore Sarawak and reports that total losses occurred in one out of every six wells (Terwogt et al., 2005). In *Figure* 2.3, it is clearly shown how small boundary there is between drilling with no losses and total losses.

The amount of fluid that is lost is determined from the Productivity Index (PI) of the formation and by the difference between fracture pressure and Bottom Hole Pressure (BHP)[1]. PI has the unit $^{lpm}/_{bar}$.

$$Rate_{loss} = PI \times (BHP - P_{frac}) \tag{2.1}$$

In deep-set carbonates, a high PI can be expected, giving large losses even at minimal overbalance and in static condition. The biggest concern is that fluid level in the annulus starts to drop and BHP decreases, also losing pressure communication. As these fractures are also the main target for gas, well control becomes an real issue. Formation fluid can start to flow from another loss zone if well pressures get too low, meaning that lost circulation can actually lead to a kick. This is called an induced kick.

2.1.2 Kicks

Kick is an influx of formation fluid and is a result of the mud weight gradient deceeding the formation pore pressure gradient. Similar to lost circulation, the amount of influx is determined from the PI of the formation:

$$Rate_{influx} = PI \times (P_{pore} - BHP) \tag{2.2}$$

When a kick enters the well it has the same pressure as the formation it came from. If the well is shut in, the kick will rise without expanding and with the same pressure. Otherwise, the kick will expand as it rises and its pressure decreases. The kick will continue to take up more and more space in the fluid column, decreasing BHP and inviting further influx. If the kick is not safely circulated out or bullheaded back into the formation, the worst case scenario is a blow-out.

In deep-set carbonates, both regular and induced kicked can occur, though in highly fractured and vugular parts, a more likely scenario is an induced kick due to the severity of the losses.

[1] John-Morten Godhavn, personal communication (E-mail) 20.03.14

2.1.3 Other Drilling Related Issues

In addition to lost circulation and kicks, other known issues associated with drilling through fractured and/or karstified carbonates (Rojas et al., 2013):

- Poor hole cleaning
- Low Rate Of Penetration (ROP)
- High vibration
- Stuck pipe

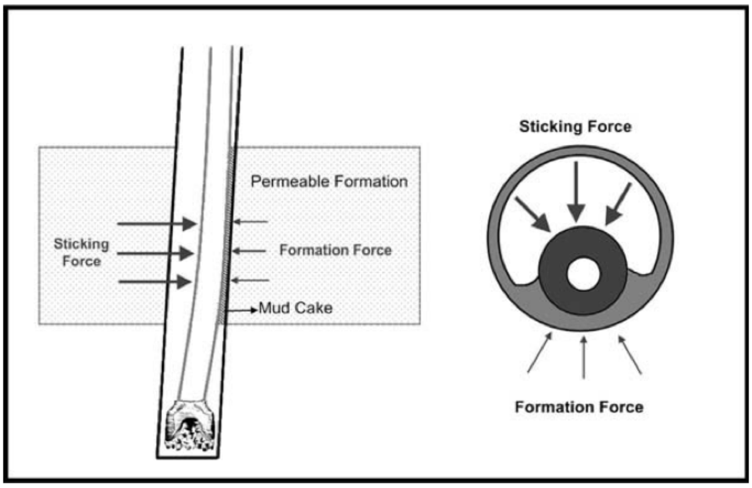

Figure 2.4: Differential sticking (Bill Rehm et al., 2008)

Stuck pipe is mainly due to rock fragments plugging the well or from differential sticking. Differential sticking is a result of overbalance in a porous formation, leading to the drillstring being pushed against against the wellbore. If a thick mud cake is present, the pipe might get stuck like in *Figure* 2.4. Differential sticking and lost circulation are the largest contributors to pressure related NPT.

Existing or induced fractures and/or vugs can result in an over-gauge hole. Over-gauge hole will have a poor effect on hole cleaning and vibration. Cuttings might accumulate around the BHA and cause it to be stuck, worsened by presence of losses and large overbalance. The bit may wiggle around, affecting steering capability and vibrating the drillstring. ROP will be kept low to produce less cuttings and reduce vibration, but also due to carbonates often hard nature. Penetrating a vug can result in the drillstring dropping, damaging the bit and sensitive equipment in the BHA.

In addition, existing or induced fractures and/or vugs can lead to cement being lost to the formation and fail in sealing of the reservoir. According to (Standard Online AS, 2013), there should be at least 200m Measured Depth (MD) of cement above the point of influx.

2.2 Conventional Drilling in Carbonates

The conventional way of drilling for hydrocarbons have more or less been the same for decades. Changes that have been made through the years are on equipment and regulations. The principle is to stay within a predetermined drilling window explained earlier, typically 50 bar difference between pore- and fracture pressure for conventional drilling [1]. Conventional drilling uses an open-to-atmosphere system that is filled with mud at a specific density to provide adequate downhole pressures:

$$Mudweight = \frac{BHP_{static}}{g \times TVD} \tag{2.3}$$

where TVD is the True Vertical Depth of the point in question. During drilling, mud is pumped down the drillstring, cooling the bit and carrying with it cuttings up the annulus. As a result of this circulation, the well pressure increases due to Annular Friction Pressure (AFP). *Figure* 2.6 shows the difference between the static and dynamic pressure profile.

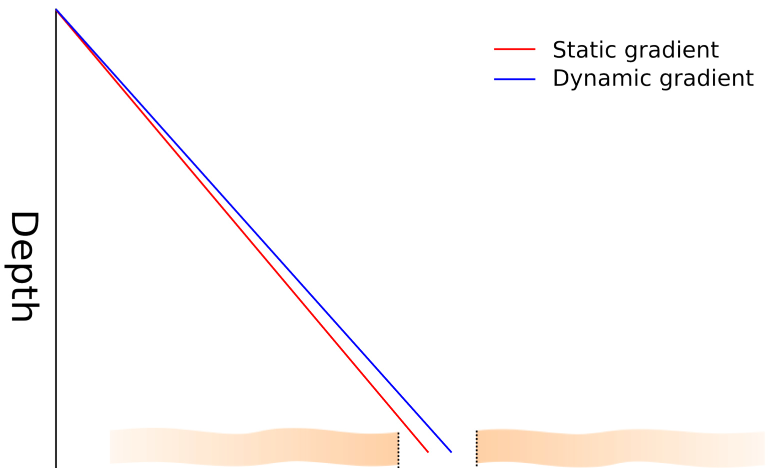

Figure 2.5: Static and dynamic pressure profile with conventional drilling

AFP is caused by frictional forces from moving the column of mud along the annulus. In order to move the fluid, the mud pump must deliver a pressure to overcome these forces and well pressure increases. Knowing the exact contribution of AFP may not

[1] John-Morten Godhavn, personal communication (E-mail) 20.03.14

be possible, but it can be approximated. A new term is born to incorporate the effect of circulation, Equivalent Circulating Density (ECD):

$$ECD = mudweight + \frac{AFP}{g \times MD} \tag{2.4}$$

where Measured Depth (MD) is the total length of the well. BHP during circulation will the be:

$$BHP_{dynamic} = P_{mud,ann} + \triangle P_{ann} \tag{2.5}$$

where $\triangle P_{ann}$ is the friction pressure loss contribution in the annulus. The mud is designed so that it provides a pressure higher than the pore pressure to avoid kicks during static conditions, but not so high that losses occur or that it fractures the formation during circulation. The aim is a gradient that allows drilling to planned depth. Unless problems occur, mud weight is the determining factor on how long a section can be drilled. Once at planned depth, casing is run down and cemented in place. This procedure is repeated for every section, adding more weight materials as they go to cope with the increasing formation pressures, until TD is reached.

Understood from this procedure, changing mud weight is the primary way of controlling the pressure profile. This process requires a lot of time as the total volume in both the drillstring and annulus are quite large. There is also an option of adjusting the flow rate through the well or changing the viscosity of the mud. This will increase or decrease the contribution from AFP, but is normally not practiced due to the poor effect it has on cuttings transport and hole cleaning.

2.2.1 Handling Losses and Kicks

Encountering fractured carbonates with conventional drilling can in many cases be difficult and time-consuming. The perhaps fluctuating formation pressures will take time to compensate for when the main way of adjusting downhole pressure is by changing mud weight. Having an adaptive pressure control would be beneficial. Still, several precautions can be taken (Petrowiki, 2014):

- Maintaining proper mud weight
- Minimizing AFP losses during drilling and tripping in
- Adequate hole cleaning

Another important factor is to set casing as close to the reservoir zone as possible, this will help minimize the area where problems can occur. Carbonate stingers can make it difficult to determine the top of carbonates formation. At the last casing shoe, it is important to perform a Formation Integrity Test (FIT) to make sure that the formation has sufficient integrity, that it can withstand a kick and that the cement is properly sealing off the overburden. If, despite the previous precautions, lost circulation still occurs in the reservoir, the normal procedure is to slow down the circulation rate and add LCM. LCM consists of fibrous, flaky and/or granular material that is added to the drilling fluid and will help retard the losses to the formation by plugging it (Schlumberger, 2014a).

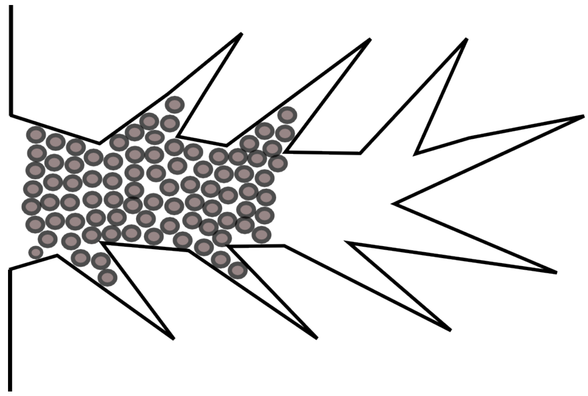

Figure 2.6: LCM penetrating and plugging the fractures

Other means of sealing of the formation can be by performing a gunk squeeze or cement squeeze. Squeeze meaning forced into a zone. Gunk squeeze can be a Bentonite Diesel Oil (BDO) mixture. Interaction with water downhole will cause it to thicken and create a sticky or hard material that can either seal of parts of the well or be forced into the formation, sealing of the leaky zone. Cement squeeze is pumped into the formation under pressure, where it hardens, in an attempt to isolate the fractures and vugs. If these fail, mud weight is reduced to better resemble formation pressures. In most cases, a combination of reducing mud weight and pumping down LCM will succeed in allowing drilling to continue. The drawback with this method is that it requires a lot of time and could result in the well going over budget. It can also reduce reservoir productivity and cause the pipe to get stuck if not all materials are forced into the formation.

Conventional procedure for handling kicks is mainly done using either the Driller's Method or the Engineer's Method. The Engineer's Method is the most common as it safer and quicker. When a kick is noticed, the well is shut in while recording casing and pump pressure.

A kick will be more noticeable in Water-Based Mud compared to Oil-Based Mud (OBM). Gas can conceal itself within the OBM and make it more difficult to discover. Main ways of detecting a kick (Petrowiki):

- Flow rate increase
- Pit volume increase
- Flowing well with pumps off
- String weight change

Heavier mud is pumped down the drillstring and the kick is circulated out while keeping a close eye on the casing and pump pressure. The well must stay in overbalance to prevent further influx, but not so high that pressures can damage equipment. A choke lets fluid out to maintain adequate casing pressure. Once the kick is circulated out and the well is filled with new mud, operations can continue. The basics behind this process can be seen in *Figure* 2.7. Notice how a kick will increase the well and surface pressure, specifically Shut-In Drill Pipe Pressure (SIDPP) and Shut-In Casing Pressure (SICP).

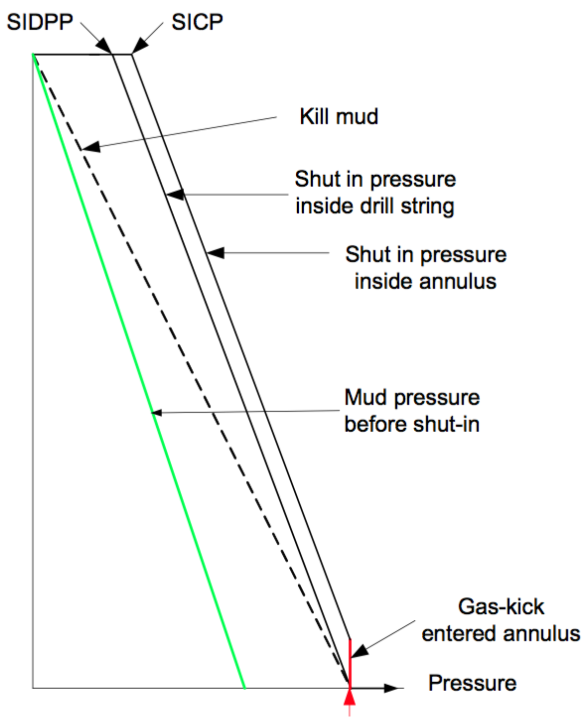

Figure 2.7: Pressures during Engineer's Method (Pål Skalle, 2012)

With the Drillers Method, the kick is first circulated out using the existing mud. This will make the casing pressure higher as no heavier mud is being pumped simultaneously to balance the formation pressure while circulating out the kick. The two-step process also takes more time.

Adressing the drilling related issues in *Section* 2.1.3, adequate hole cleaning is maintained by having a fluid with sufficient cuttings carrying capabilities, maintaining a proper flow rate, and periodically pumping down a high viscosity pill. Vibration due to wiggling of the bit can be reduced by using a downhole motor and centralizers on the drillstring. Differential sticking can be decreased by having as low overbalance as allowed and using mud that does not create mud cake that is too thick. ROP will be higher if the above factors are improved, also depending on the hardness of the formation. The issue with cement can be solved by making a plug (gunk squeeze etc) over the loss zone, if possible, and cementing above this. Using a production liner, cement is pumped from the top and on the outside of the liner, sealing off the point of influx within requirements.

Total Losses

The real challenge starts when PI increases to the point of total losses and mud level starts dropping. "Cement and various formulations of LCM are typically used to cure the losses, but usually with short-term effect, resulting in more cement being required and further delays (Muir, 2006)." Carbonate fractures and cavities can be quite large and require so huge quantities that it has little effect over a short period of time. If the reduction of mud weight and/or setting a well plug is unsuccessful, then the fluid column in the annulus could start dropping and BHP decreases. Kick is now an imminent threat. There is also no guarantee that there will be only one zone of this magnitude, several zones will further complicate the already dangerous situation.

The previously described Engineer's Method uses heavier mud to regain control of the well, in a total loss situation this would only contribute to increase the losses. At this point, the most common practice has been to shut in the well and continuously circulate down the drillstring with LCM or cement until control is regained, while bullheading to counteract a potential kick. To understand how much time this could require, an operator in a field in Qatar stated: "The large volume cement squeeze operations were time consuming and resulted in 2 to 4 weeks of non-productive time (Niznik et al., 2009)."

Chapter 3

Managed Pressure Drilling (MPD)

> *"MPD, as a discipline or drilling technique, is the result of the high costs of nonproductive time caused by the close proximity between pore pressure and fracture pressure."*

- Bill Rehm et al. (2008) -

MPD is a technique that have mostly been used in recent years, but it is not a new technology. Several "Abnormal Pressure" symposiums that were presented at the Louisiana State University between 1967 and 1972, contained many of the ideas that MPD are based on. Looking back, there are also records of drilling operations that have later on been referred to as a clear case of MPD. Still, it was not till around 2003 that MPD was identified and given a name (Bill Rehm et al., 2008; Johan Ech-Olsen et al., 2012).

International Association of Drilling Contractors now defines MPD as (IADC, 2014):

"An adaptive drilling process used to precisely control the annual pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process."

This chapter will describe how MPD distinguishes itself from other existing methods and explain the four main variants of MPD, along with advantages and disadvantages. The most common variant, CBHP, will be compared to conventional drilling in fractured and/or karstified carbonates.

3.1 Introduction to MPD

MPD is one of the three main drilling techniques that exist today:

- Under-Balanced Drilling (UBD)
- MPD
- Conventional drilling

The difference between them can be seen in *Figure* 3.1 . Conventional drilling has an open-to-atmosphere circulation system and uses overbalanced operations to prevent any influx from entering the well. This is most common way of drilling and has been so for decades. UBD uses the same equipment as MPD and both a closed-circulation system, but they must not be viewed as similar techniques. The difference is the principle which they are based on, UBD is designed for operations below both formation pore- and fracture pressure while continuously managing a influx. MPD on the other hand, aims to avoid influx by being slightly overbalanced. More precise control of downhole pressures compared to conventional drilling, enables drilling with a well pressure close to pore pressure, safely.

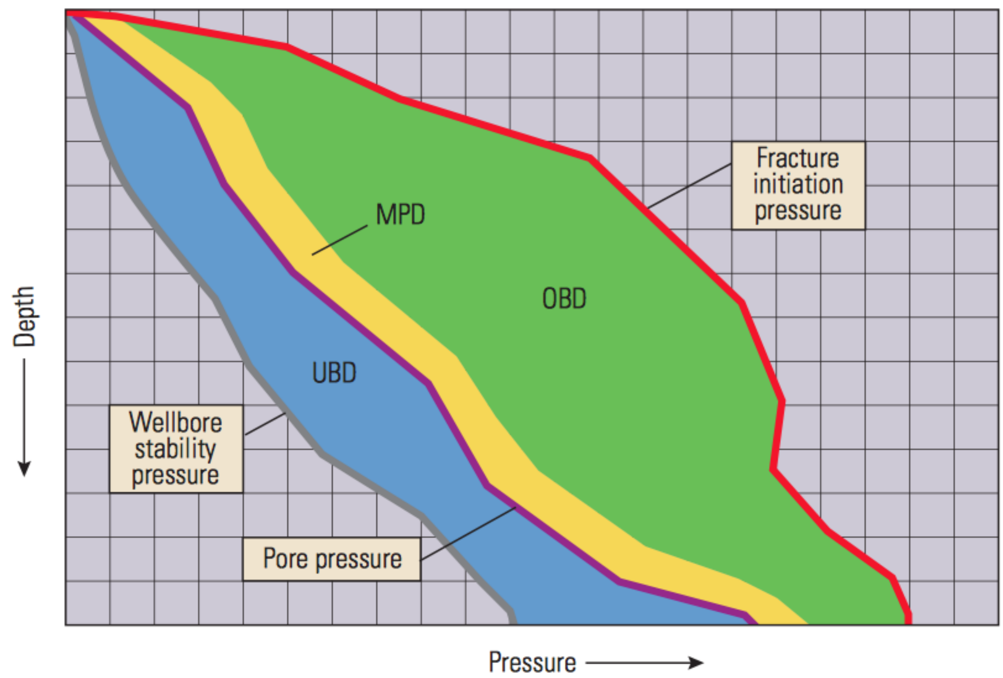

Figure 3.1: Operating area for the different drilling techniques (IADC, 2010)

An overview and explanation of the equipment that is used in MPD operations can be found in Appendix A. With the use of the specialized equipment, MPD is an adaptive drilling process that can avoid or at least reduce many of the drawbacks with conventional drilling. *Figure* 3.2 shows a normal MPD setup, where red symbolizes the additional tools that comes with MPD compared to conventional. The closed-circulation system is made possible by the rotating seal, also called Rotating Control Device (RCD). Mud return is directed through a choke with an adjustable closure element, exerting a back-pressure down the well. The closure element will increase or decrease the back-pressure by narrowing or widening the flow path. This gives a precise control of the pressure profile. A choke is MPDs primary way of ascertaining the downhole pressure environment limits and will effectively have the same result as changing mud weight, only much faster. The Back-Pressure Pump (BPP) is optional, but can be useful during connections, or when for other reasons the well flow has to be stopped.

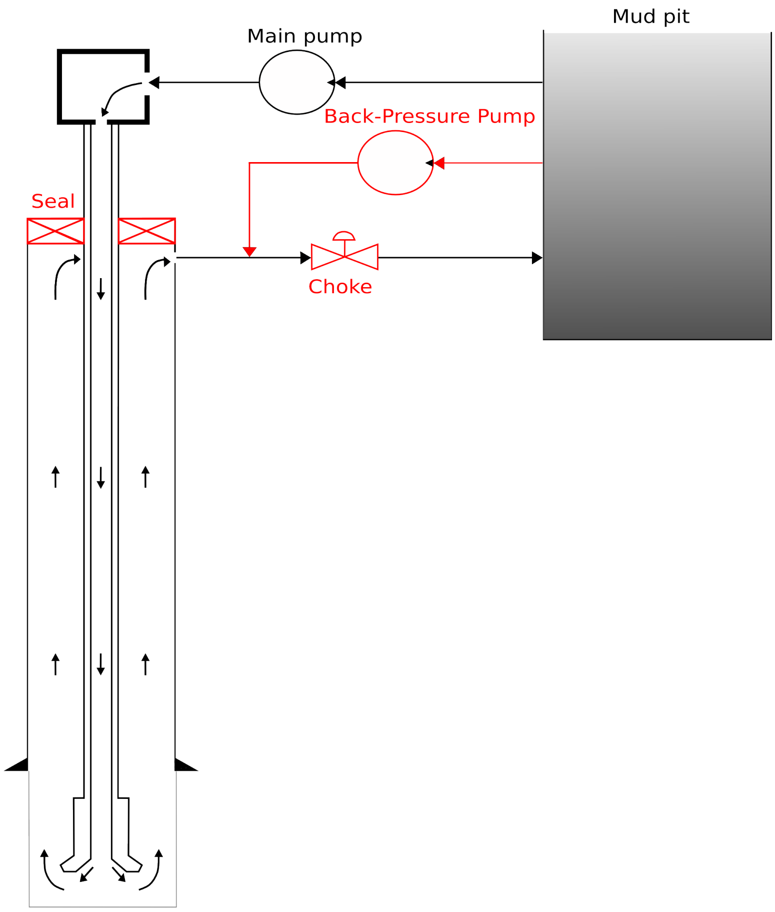

Figure 3.2: Simple schematic overview of MPD and its basic equipment

3.2 MPD - Variants

MPD is now a well established method and a variety of different variants exist to suit several needs. They all use basically the same standard equipment, but their procedure is different. MPD can be used in two basic approaches:

- Reactive: The well is drilled conventionally with MPD equipment installed and ready to take over when nessecary. In this case the precise control is not fully utilized, though it is safer and more efficient than it would be using only conventional.
- Proactive: MPD equipment is rigged up and used from start, adapting to well conditions as drilling progresses.

The four main variants of MPD are Constant Bottom Hole Pressure, Dual Gradient, Pressurized Mud Cap Drilling and HSE. These will be introduced in this section.

3.2.1 Constant Bottom-Hole Pressure (CBHP)

This variant is the most commonly used and as the name predicts, the aim is to maintain a CBHP, with or without circulation in the well. *Figure* 3.3 shows how MPD handles this AFP, as compared to the conventional technique in *Figure* 2.6.

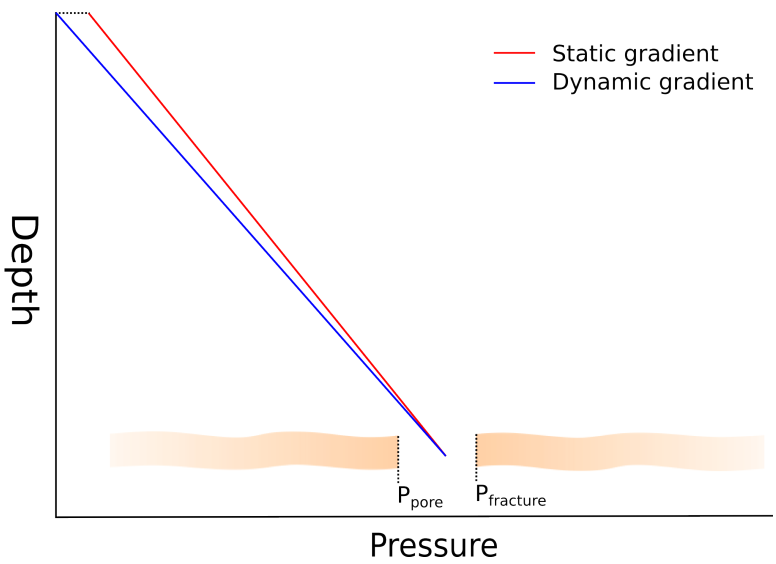

Figure 3.3: Static and dynamic pressure profile with CBHP

In a well with a narrow drilling window, the mud weight alone might bring the BHP close to the formations fracture pressure. With the contribution of AFP, the formation might fracture and lead to loss of well control. Lowering the mud weight could result in underbalance during stops of circulation. Downhole pressure for CBHP:

$$BHP_{ann} = P_c + P_{mud,ann} + \triangle P_{ann} \tag{3.1}$$

where P_c is the back-pressure. CBHP solves this by using lower density mud and compensating by choking the flow, exerting a back-pressure. As circulation starts and flow rate increases, back-pressure is lowered so that the BHP is kept as constant as possible at all times. It will also be able to maintain this pressure during a connection of drillpipes by using the back-pressure pump when the well flow is stopped. Adjusting the choke will also make it possible to quickly compensate for any changes in formation pressures, as long as the mud gradient stays within the drilling window further up the well (Bill Rehm et al., 2008).

3.2.2 Dual Gradient (DG)

Dual Gradient (DG) has, as its name suggest, two mud gradients in the well. This can be done in two ways, either by having a lower level of mud in the riser or without a riser at all. In a riserless case, the overlaying fluid will be the surrounding seawater. The pressure profile can be seen in *Figure* 3.4

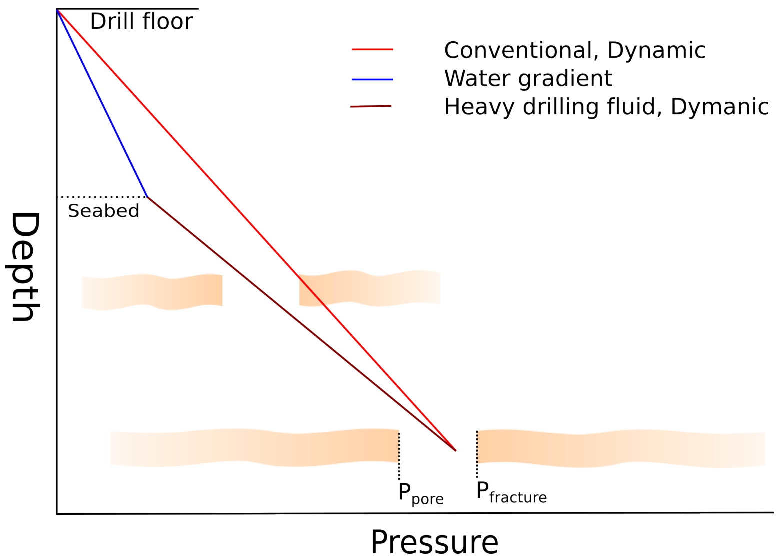

Figure 3.4: Static profile with riserless Dual Gradient

With a riser installed, a light fluid is placed above the mud level. Return mud does not travel through the riser, but instead through a hose and up to the rig by the use of a Subsea Mud Pump (SMP). SMP adjusts the level of mud in the riser by accelerating or decelerating fluid returns, consequently adjusting well pressures.

Conventionally, there is a single mud gradient in the entire well, from the drill floor to the bottom of the hole. This may provide desired BHP at the bit, but further up local well pressure can become close to the formations fracture pressure and restrict the section length. As there are now two fluids in the well and the upper is light, drilling fluid has to be heavier than conventional in order to achieve the same BHP as with one mud gradient. This heavier fluid tends to replicate the formations pressure gradient better in parts of the wells. Downhole pressure for DG:

$$BHP_{ann} = P_c + P_{light} + P_{mud,ann} + \triangle P_{ann} + \triangle P_{hose} \tag{3.2}$$

where P_{light} is the pressure contribution from the light overlaying fluid and $\triangle P_{hose}$ increase in pressure due to friction in the return hose.

3.2.3 Pressurized Mud Cap Drilling (PMCD)

This variant of MPD will be presented in detail in the next chapter, as it is the main focus of this thesis and specifically developed for drilling through fractured and karstified formations.

PMCD is a technique of unconventional nature. Conventionally, the objective is to drill to target without any fluid loss or influx as this can compromise well control. Explained in the *Chapter* 2.1, heavily fractured and karstified carbonates can cause lost circulation, occasionally total losses. PMCD has an interesting way of dealing with this type of situation, instead of fighting it, it rather encourages losses and uses it to its advantage. The technique is often called “drilling blind”, as there are no returns to surface. When total losses occur, a mud cap, Light Annular Mud (LAM), is injected below the RCD through a hose and replaces the previous mud. Sacrificial Fluid (SAC) is pumped down the drillstring and starts filling up the fractured and/or vugular formation. The mud cap will mostly be static and is made so that it balances the pore pressure at top of the fractured zone while holding a specific Surface Back-Pressure (SBP). This SBP, along with pump pressure, is used for information on well condition. Drilling can now continue while SAC and cuttings will flow into the formation. *Figure* 3.5 shows the pressure profile for PMCD.

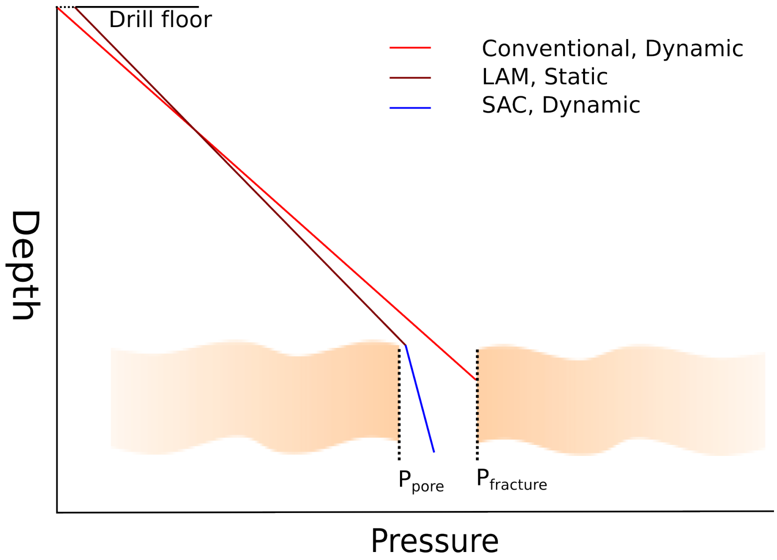

Figure 3.5: Static pressure profile with PMCD

If a kick should occur, it will be noticed as an increase in the SBP, and more LAM is bullheaded down the annulus until the surface pressure is back at initial value. Downhole pressure for PMCD:

$$BHP_{ann} = SBP + P_{LAM} + P_{SAC} + \triangle P_{ann} + \triangle P_{frac} \tag{3.3}$$

where P_{LAM} and P_{SAC} is the hydrostatic pressure from the column of LAM and SAC in the annulus, respectively. As there are no returns to surface, a choke is not used with this variant (Bill Rehm et al., 2008).

3.2.4 HSE MPD or Returns Flow Control (RFC)

The basic principle of this method is not to control annular pressure, but to safely divert any influx up the choke manifold. Other flow lines will be closed, keeping hydrocarbon release away from the drill floor. There is no need for closing the Blow-Out Preventer (BOP) as RCD provides a annulus sealing mechanism. The choke manifold will circulated hydrocarbons out of the hole in a controlled manner. (Darmawan et al., 2011)

3.3 Advantages of MPD

MPD's primary objective and advantage is to safely reduce the drilling cost due to NPT. According to Weatherford's sources, as seen in *Figure* 3.6, around 42 % of all NPT are caused by pressure related issues.

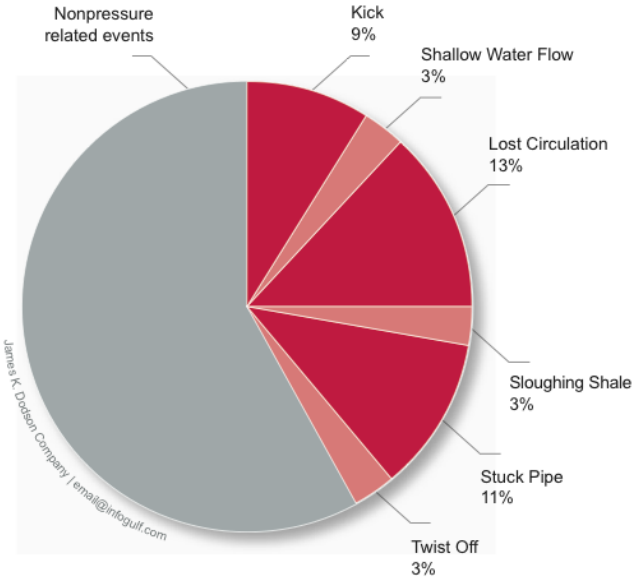

Figure 3.6: Percentage overview of causes of NPT (Weatherford, 2010)

Remedial work is time-consuming and costly, being able to adapt and avoid situations before they occur would be beneficial. Thorough planning is essential to every successful operation. All possible dangers that may be encountered should be foreseen, along with a plan on how to remedy the situation.

International Association of Drilling Contractors provides further explanation of MPD (IADC, 2014):

- *"MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.*
- *MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.*
- *MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects."*

3.3.1 CBHP in Carbonates

CBHP is regarded as *regular MPD* and offers a solution to many of the drawbacks with conventional drilling, making it a good candidate for drilling through a carbonate formation (PMCD will be focused on in *Chapter* 4). Looking back at *Chapter* 2.1, some of the issues with drilling through fractured and/or karstified carbonates are:

- Lost Circulation
- Kicks
- Hole Cleaning and Stuck Pipe
- Low ROP

A MPD operation can be conducted with lower overbalance than conventional, referring to *Figure* 3.1, thus minimizing the risk of lost circulation. MPDs ability to adjust the choke position on the return flow, quickly increasing or decreasing a back-pressure, will allow drilling in a narrower pressure window (down to 5 bar [1]). *Figure* 3.7 pictures a CBHP operation through a fractured sandstone formation, clearly showing how MPDs precise control gives it the ability to adapt to sudden changes and stay within close boundaries. LCM or similar remedial materials are pumped down in the event that lost circulation still occurs, e.g. in zones with high PI.

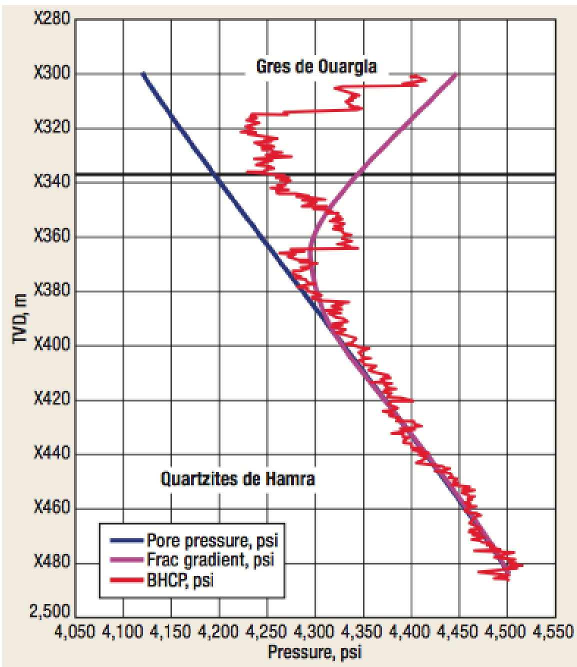

Figure 3.7: CBHP in highly fractured, gas-bearing sandstone reservoir (Kartobi et al., 2011)

[1] John-Morten Godhavn, personal communication (E-mail) 20.03.14

If the event of a kick, MPD has optional equipment for Early Kick Detection (EKD). Higher back-pressure is exerted, preventing further influx. The closed-circulation system will also prevent gas from erupting on the drill floor. Small kicks can safely and quickly be circulated out, while adjusting the choke to compensating for the increasing surface pressure and expanding gas.

The lower overbalance will have a positive effect on several of the challenges covered in *Section* 2.1.3:

- Hole cleaning: Diminishes the hold-down effect on cuttings, reducing the accumulating around the BHA and the risk of stuck pipe
- Differentially stuck pipe: Less overbalance will decrease the force that pushes the drillstring against the formation
- ROP: Less overbalance will increase ROP

These advantages are still not sufficient in drilling to TD during a total loss scenario, such as the case for a highly fractured and/or karstified carbonate reservoir. Large kicks and losses will have to be dealt with using conventional methods from *Section* 2.2.1. The difference compared to conventional, is that with MPD equipment installed, reaction time is lowered while maintaining a higher level of well control (Godhavn, 2012).

Additional Benefits With MPD

In addition to providing a better solution for drilling of carbonates, MPD has other attributes that could be useful in drilling cheaper wells and in more difficult conditions.

- Extended casing points: Wells with a narrow drilling window can present a challenge in reaching the reservoir with adequate casing size. DG uses a higher fluid gradient in the annulus that tends to match the formation better, enabling, longer sections, reduced amount of casing points, and so-called Extended Reach Drilling (ERD).
- Deep water: DG provides a “simple” way of drilling riserless by use of a SMP and returns through a hose. This will remove the need for a heavy riser in deep water and potentially open for the use of a cheaper, lower specification rig.

3.3.2 Disadvantages

MPD has proven itself to be a reliable technique, though as with everything else, there are drawbacks:

- Expensive: MPD requires more equipment and specialized personnel, increasing the already high cost of operation. The wells can be drilled with either reactive or pro-active MPD. Should it not be used at all, the well will become more expensive. If it is used on the other hand, it can actually save money.
- Unconventional: The industry does a lot of research into developing new methods, but getting an operator to use the new technology can be a challenging. Rigs might have to be modified, crew has to be taught the new system and operation procedures. Stepping into the unknown and going away from the working and well established techniques may be intimidating.
- More equipment needed, potentially complicating the operation.
- MPD is highly automated and it might be dangerous to trust a system too much.

A breach in the closed-circulation system which MPD is dependent on, could be catastrophic. At Gullfaks C, a Statoil operated rig in block 34/10 in the northern part of the Norwegian North Sea, had a serious incident while using MPD back in 2010. A hole occurred in the 13 ⅜" casing during final circulation and hole cleaning after reaching TD. The 13 ⅜" casing was a common well barrier element and therefore both required well barriers where lost. Loss of back-pressure lead to influx from the exposed reservoir and gas emission on the rig. In this case they where lucky as solids or cuttings packed of the well at the 9 ⅝" liner shoe and limited further influx. Still, almost two months where spent gaining back control of the well and re-establishing required well barriers. (COA INV, 2010)

Chapter 4

Pressurized Mud Cap Drilling

This chapter continues from *Section* 3.2.3, going further into detail around the entire process. PMCD is variant of MPD, though it grew out of practical experience with Mud Cap Drilling (MCD). MCD is designed for combating large losses during drilling of fractured formations and when conventional practices are no longer sufficient, safe, or economical. Floating Mud Cap Drilling (FMCD) is the well-established and simple version of MCD. The difference is that FMCD does not use a closed-circulation system. Fluctuations in formation pressure could lead to the mud cap being forced out at surface or lost to the formation. PMCD was developed later on in order to avoid the disadvantages with FMCD. The result were reduced cost and risk, while maintaining a higher level of safety (Urselmann et al., 1999).

PMCD is defined by International Association of Drilling Contractors (IADC, 2014):

"A variation of Managed Pressurized Drilling (MPD), that involves drilling with no returns to surface and where an annulus fluid column, assisted by surface pressure (made possible with the use of an RCD), is maintained above a formation that is capable of accepting fluid and cuttings."

This chapter will explain how it is determined if the formation is suitable for PMCD and the transition between going from MPD over to PMCD mode. Further on, it will be explained how a PMCD operation is conducted from start to finish, along with field results from real wells in Asia.

4.1 PMCD in Carbonates

Extensive planning is an important part of any drilling operation, though it might be difficult to foresee all potential scenarios. In sub-salt formations and exploration wells, there are large uncertainties surrounding the geology and pressure regimes. Therefore, it is important to have equipment and materials ready so that it is possible to instantly react to any incidents that may occur. For PMCD to be applicable, MPD equipment will have to be available on the rig. Normally, reaching TD is non-negotiable, PMCD as contingency could potentially save an entire well and therefore have a large financial benefit. *Figure* 4.1 shows an example of a decision tree when drilling through fractured formation. Notice how PMCD is the last available option.

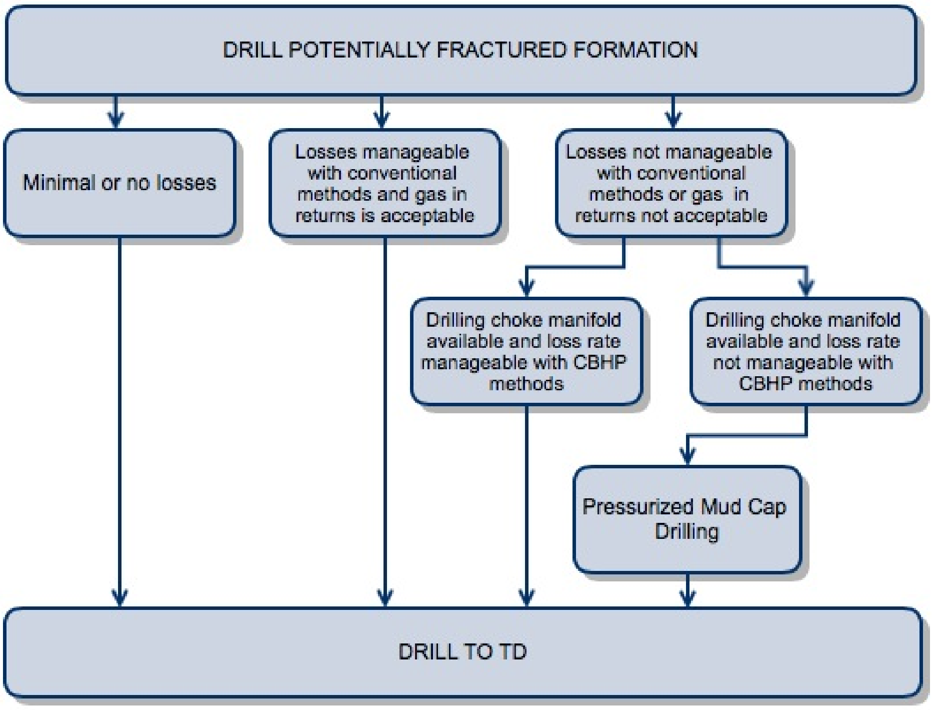

Figure 4.1: Decision tree in a loss scenario (Rehm et al., 2013)

4.1.1 Testing the Formation

PMCD, unlike other techniques, can not be used everywhere. For it to be applicable there has to be a high rate of lost circulation present in the well. The normal procedure is to start of by drilling conventionally or in CBHP mode if there is any indications of a narrow drilling window. Drilling proceeds until a zone of acceptable losses are encountered.

An injectivity test is performed in order to confirm that the zone is suitable for PMCD. Conventional mud is pumped down the drillstring at increasing rate until expected drilling rate is achieved. Surface pressures are closely observed, if this rises prohibitively high at any point during the test, PMCD can not be used in this zone. Static and dynamic fluid loss rates are determined, dynamic fluid loss should be slightly higher for PMCD to be applicable. During stops of circulation, an annular pump is turned on to prevent fluid level from falling (Rojas et al., 2013).

4.1.2 Going from MPD to PMCD

Once a zone with adequate losses is confirmed, the well is ready to be converted to PMCD. If the well is drilled conventionally at first, MPD equipment will have to be installed ahead of the conversion. *Figure* 4.2 exemplifies a simple PMCD setup with the required equipment, both for platform and subsea wells.

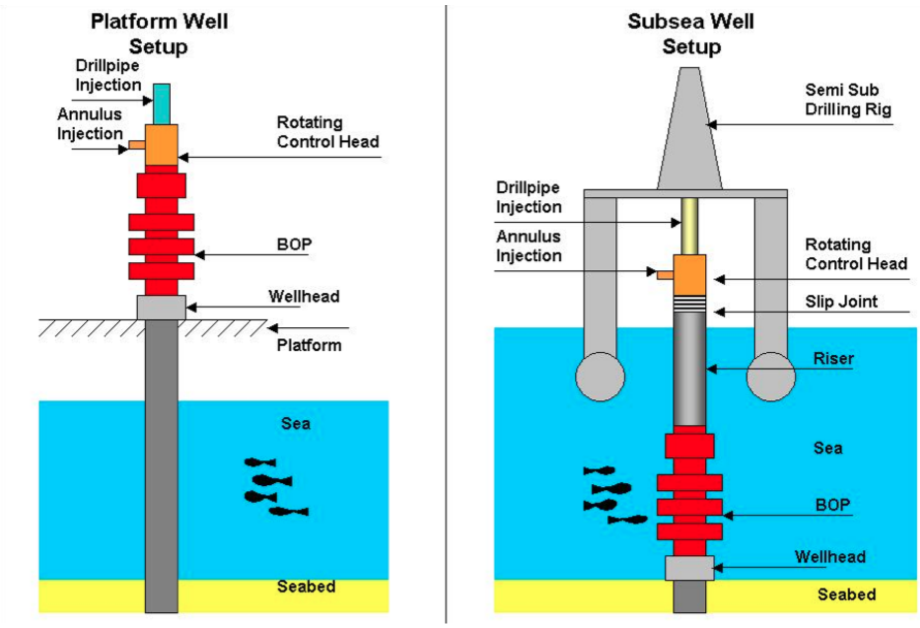

Figure 4.2: Simple overview of a PMCD setup (Terwogt et al., 2005)

The upper BOP annular is closed in and the pressure below the BOP is recorded using the kill line. *Figure* 4.2 shows only the annulus injection line, but there will be several, including a kill line that gives the opportunity of injection below a closed BOP. *Appendix* B shows a more detailed setup of a PMCD subsea well. The kill line is pre-filled with a fluid of know density. Combing this recorded pressure along with the hydrostatic pressure from the mud, will give a fairly accurate estimate of pore pressure at the top of the fractured zone. The mud cap, also called LAM, is now calculated to balance this pressure, while holding a specific SBP, usually 150 psi or around 10 bar.

$$\rho_{LAM} = \rho_{pore,topfrac} - \frac{SBP_{desired}}{g \times h_{topfrac}} \tag{4.1}$$

This means that the mud cap is deliberately made underbalanced, SBP will make up the difference and ensures that the annulus is at all times filled with LAM. Annulus is displaced with the new LAM while observing dynamic pressure and static pressure once the bullheading is stopped, comparing this with the earlier set value (10bar). The remainig step is to start pumping SAC fluid to replace the old mud in the drillstring. SAC fluid is circulated at drilling rate, while recording dynamic pressures, weight and determining parameters for further drilling. *Figure* 4.3 shows the basic principle of PMCD.

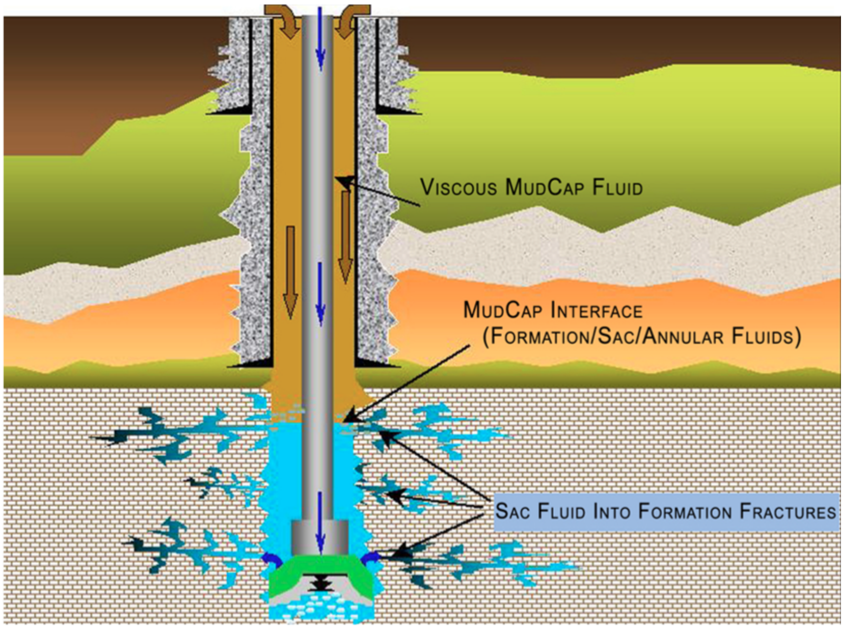

Figure 4.3: Basic principle of PMCD (Durkee et al., 2012)

To be able to drill with several flow rates and still having information on well conditions, these parameters should be tested over a wide range of flow rates. The bit is lowered and drilling in PMCD mode can commence. As an option to filling the entire annulus with LAM, the old mud can be used below the BOP and a light fluid above, giving the same pressure as with a single gradient (Rojas et al., 2013).

4.1.3 Drilling Procedure

After the well is converted to PMCD, operation progresses as “normal”, but in a so-called blind mode. No returns to surface, SAC fluid and cuttings are all dumped into fractures and vugs in the formation. As a result of this circulation, SBP will become slightly higher than the initial 10 bar due to friction pressure loss from SAC fluid sliding along the annulus and penetrating the fractures below the static mud cap (Bill Rehm et al., 2008).

During drilling, kicks can be expected due to the well and formation pressure being practically equal. A kick will be noticed as an increase in SBP as the kick displaces LAM and result in a further underbalance from the mud cap. Look at the end of this subsection for a complete list on how to determine conditions in the well. Ahead of drilling, a predetermined Maximum Surface Back-Pressure (MSBP) is set. This value will depend on how often the operator wants to bullhead and on the operating range of the equipment. SBP should not exceed 50% of the RCDs maximum operating pressure (Steve Nas, 2009).

Once SBP reaches this value, the procedure is to bullhead LAM down the annulus and force the kick back into the formation. *Appendix* D shows a detailed explanation of this kick and bullheading cycle, also for a liquid bearing formation. The minimum rate of bullheading is determined from having to overcome the gas migration:

$$V_{gm} = \frac{\triangle SBP}{\rho_{LAM} \times g} \tag{4.2}$$

$$q_{bullhead} = SF \times V_{gm} \times (ID_{hole}^2 - OD_{dp}^2) \tag{4.3}$$

where V_{gm} is the gas migration and SF is a safety factor($\sim 1.5 - 2$). Bullheading continues until the SBP is again at its desired value. This procedure is repeated until reaching TD. Bullheading practices tends to vary from operator to operator, some prefer to continuously pump small volumes down the annulus as drilling progresses and extra large volumes at specific intervals.

Throughout the operation it is important to keep a close eye on torque & drag, SBP, pump pressure, and hook height, as these will give a good indication on well conditions. Torque & drag are valuable in observing good hole cleaning practices. Velocity of the SAC fluid, seawater, is the only variable that controls hole cleaning. Performing regular sweeps with high viscosity pills is crucial as seawater has poor lifting capability. Note that several total loss zones can make it difficult to establish a stable column of SAC fluid. Increasing pump rate can be an option for better hole cleaning and to ascertain a stable fluid column. Several total loss zones will most likely not cause any major safety concerns in PMCD mode.

Hook height will give a fast indication on new fractures and vugs, resulting in the drillstring dropping. Readings of pump pressure and SBP are the two main factors for a safe operation. Should they become high, meaning losses are decreasing, the well will have to revert back to either conventional or CBHP (Rojas et al., 2013).

SBP	**Pump Pressure**	**Probable cause**	**Suggested action**
Decreases	Decreases	Increased loss rate, either due to the formation cleaning up or a low pressured zone is encountered	Continue drilling if other factors are not a problem
Increases	Stays the same	Gas migration up the annulus	Bullhead down the annulus until SBP at its previous value
Increases	Increases	Formation plugging or a higher pressured zone is encountered	Switch back to either conventional or CBHP should the losses become too low
Stays the same	Decreases	Drillstring washout	Find washout and mend the pipe
Stays the same	Increases	Drillstring is being plugged	Continue unless pump pressure get too high

Table 4.1: Reading of pressures to predict well conditions in PMCD mode

4.1.4 Tripping

Tripping in this type of situation is not an easy task, as heavy losses will most likely continue even in static conditions. Actually, according to the Operator's policy, tripping out the BHA is not allowed while experiencing total losses (Rojas et al., 2013). In PMCD mode though, it can be done safely if all barriers are in place and adequate measures are taken. The reason for tripping out is normally to change BHA, bit, or when reaching TD. First step to any tripping operation is to stop drilling and ensure proper hole cleaning, in this case done by pumping down a high viscosity pill and circulating SAC fluid. During this process, the drillstring is pulled slowly upwards until the bit is at least above the top of the last loss zone. LAM is then pumped down the drillstring and the entire well is displaced with LAM to maintain adequate pressure and to be able to bullhead during tripping. Strip out of hole while pumping enough LAM to counter-act displacement of steel, lost circulation and gas migration. Once full length of the BHA is inside the riser, close annular preventer in the BOP, bleed of the pressure in the riser and remove the RCD element. Injecting point is switched from below the RCD to below the BOP. BHA is now free to be stripped out and LAM is injected as required to prevent gas migration.

If tripping out was done in order replace the BHA, running a replacement is done in the exactly the same way, just in reverse. The well should not be left in this condition for a long period of time, so BHA should be ready and run back in as quick as possible. In the event that there is not enough space between the RCD and BOP to fit the entire BHA, there are two common solutions:

- Downhole Isolation Valve (DIV)
- Bullheading for an extended period of time, ahead of tripping

DIV is a full-bore, surface-controlled flapper-type valve, installed in the previous set casing. This will seal of the open hole section and enable safe removal of equipment. DIV can also be used in an emergency as a way of sealing of potential kicks from reaching surface.

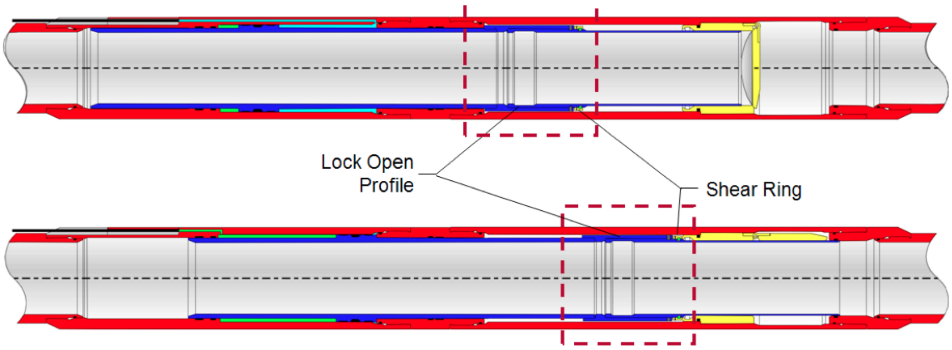

Figure 4.4: Downhole Isolation Valve in the previous set casing (Sasongko et al., 2011)

Bullheading for an extended period of time will push the gas further into the formation, increasing the time it takes before it enters the well. Tests have been done in order to time how long the gas will stay away, depending on how long it is bullheaded, but the results were different on every try. Still, it showed that it is possible to create a sufficient time frame (Rojas et al., 2013).

4.2 Post-drilling Activities

"When drilling in fractured and vugular carbonates, once PMCD mode is initiated, drilling operations will almost never revert to conventional mode (Toralde et al., 2010a)." Unlike with conventional and other MPD variants, the losses are not sealed off and the well will most likely continue to experience severe losses and occasional kicks until it is completed. In order to keep the well stable, fluid has to be almost continuously pumped down and the well kept on a closed circulation system to be able to control the pressure profile.

This will greatly effect several of the operation that is performed after drilling to TD and can cause problem with finishing the well within requirements. This section will look at techniques that have been developed to solve the previously described challenges.

4.2.1 Logging

Running logging tools, normally done by wireline, is difficult in the case of PMCD. The wireline is much thinner than a drillpipe and the RCD will not be able to seal around it. Wireline logging and snubbing adapters exist, but these do not provide the option of maintaining similar pressure control. As the well still experience losses and fluid is being pumped down, there is a chance that the logging tool might get damaged by erosional forces and possibly differentially stuck against the formation. Logging equipment is expensive and contain radioactive sources, it is not the equipment you would want to lose in a well. For this reason, Logging While Drilling (LWD) which could have been a viable solution, is generally no longer used. Due to these issues, logging is often run after the hole has been cased and the formation sealed off.

Another solution, described in (Toralde et al., 2010a), could meet the objectives of logging in PMCD mode. "This involves the utilization of a purpose built drillpipe-conveyed logging system designed for bad hole conditions that does not use wireline, known as the well shuttle, in conjunction with an RCD and a DIV (Toralde et al., 2010a)." The well shuttle can be run down, protected inside the drillstring while circulation is being maintained on the descent. Seen in *Figure* 4.5, the well shuttle is deployed once at TD. Centralizers keeps it centered in the hole. The string will ascend to surface while circulating and rotating as needed, acquiring data in memory mode.

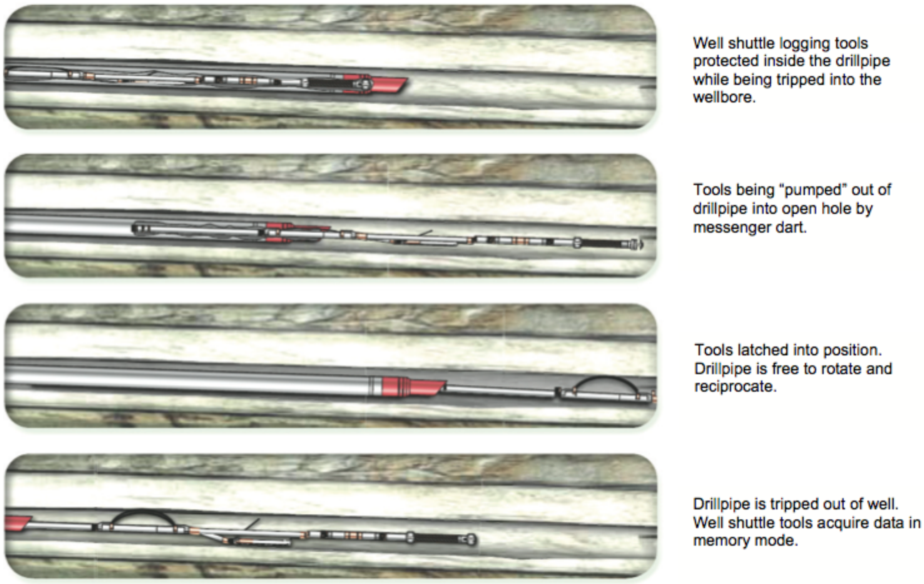

Figure 4.5: Overview of the well shuttle procedure (Toralde et al., 2010a)

4.2.2 Running Liner and Completion

The main factor that complicates the operation of running down liner and completion is the fact that they are too big to pass through the RCD. This means that there will be no closed circulation system and less information on well conditions. The existing solutions to this is that off tripping, bullheading for extended period of time or by using a DIV. Equipment is run down while pumping fluid in both the annulus and inside the liner or completion. Other methods that have been tried and partly successful:

- Top kill of the well
- Pumping down gunk plugs, LCM etc.

Top killing is pumping down heavyweight and viscous mud, hoping that it will create a plug. At TD, the liner will be cemented in place. Cementing a section with total losses present can be difficult and considered an exercise in futility. Therefore several wells in Asia have been cemented above and below the fractured zone, using packers and/or gunk plug in the annulus. Similar procedure is explained in *Section* 2.2.1, along with the requirement of 200m MD cement above the point of influx.

After the liner has been cemented in place and further necessary equipment is installed, completion is tripped down and packers are activated. The loss zone is permanently sealed off and the production can begin (Toralde et al., 2010b).

4.3 Previous Experience in Deep-set Carbonates

4.3.1 Qatar

"Qatar's North Field is located in the Arabian Gulf and is the world's largest non-associated gas field (Niznik et al., 2009)." The geology is mostly consisting of carbonates with interbedded shale, claystone, anhydrite and sandstone, gas bearing in the reservoir. Carbonates in this area are known to be fractured and karstified, especially in the lower sections. Large losses are almost always encountered in the upper sections, though generally easily controlled. The lower sections on the other hand, tend to result in losses of a magnitude that deems conventional methods insufficient.

A six-well drilling campaign was planned in a highly faulted area of the field. Normal procedures to control the extreme losses in these wells were LCM, cement squeeze and FMCD. LCM and cement squeeze shown to be both expensive and not so effective in the most damaged carbonates, failing to plug the formation and reduce losses. FMCD was only attempted in shorter sections due to the risk of mechanically sticking the drillstring from cuttings fallout. The operator was also worried that the mud cap would be forced out or lost to the formation during pressure fluctuations. Only bullheading large volumes of cement (500bbl) proved to reduce or stop losses. The drawback with this bullheading was the resulting NPT, varying from 2-4 weeks.

A new six-well drilling campaign was announced, this time with RCD as a contingency should MCD should be necessary. Three wells were of higher risk than the others and the rule of thumb was that losses of 100 bbl/hr were manageable. Lost circulation occurred as expected in the so-called Arab zone and 12 1/4" section of the well.

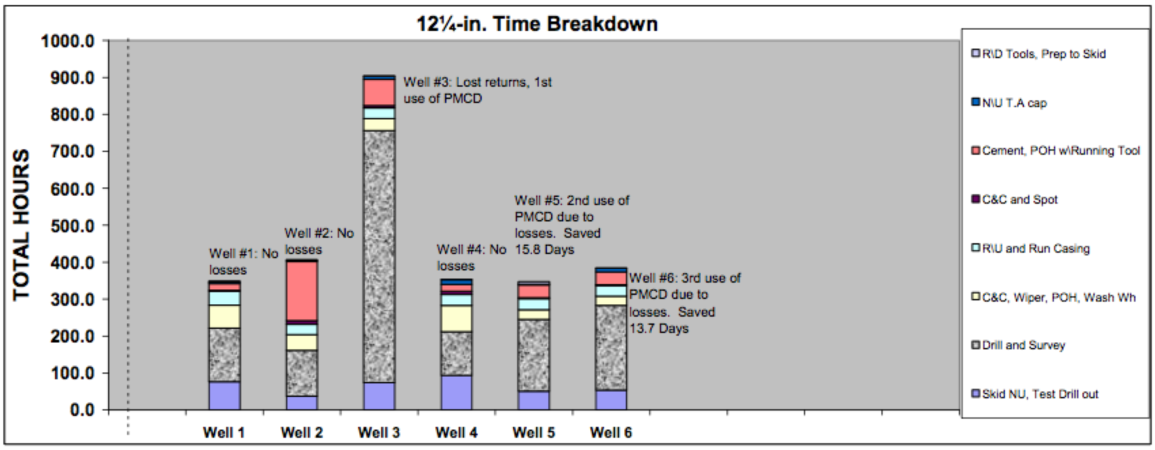

Figure 4.6: Time Breakdown of the 12 1/4" sections (Niznik et al., 2009)

The last section in well # 3 was planned from 5523ft MD to 11 492ft, expecting losses at +/- 7500ft MPD. Losses were met at 7028ft MD and the operator was not successful in curing the losses with the procedures mentioned earlier. The entire well was then filled with seawater and prepared for PMCD. Due to the pore pressure being so low in this zone, only 1087 $^{kg}/_{m^3}$, seawater was used in both the drillstring and in the annulus. To aid clearing of the annulus, seawater was continuously pumped down the annulus with a rate of 1 bbl/min, in addition to 25 bbl of low viscosity fluid pumped down every 30 ft drilled. Torque and drag was closely monitored to check if there was an efficient cuttings transport to the formation.

The well was drilled to TD (11 492 ft MD) using this PMCD procedure, averaging a ROP of around 50 ft/hr. Before running liner and cementing it in place, 25 bbl of 1438 $^{kg}/_{m^3}$ mud were pumped down the annulus to make sure that there would be no flow from the formation. Liner was run without any issues. The cement operation was performed in two stages. First step was a normal operation with 30% excess cement and the secondary performed as a top liner squeeze job with 100% excess cement. Top liner cement squeeze means that cement was pumped from above and down on the outside of the liner. Initially, seawater filled this area to create a underbalance and avoid too much cement from penetrating the formation. Non of the cement jobs had any returns.

The first well was a real success and procedures were implemented on the remaining wells and the operator was able to reach otherwise inaccessible reserves, while saving a total of 30 rig days (Niznik et al., 2009).

4.3.2 Indonesia Onshore

The next well is located in Indonesia, specifically the Soka field in onshore South Sumatra. The reservoir is made up of highly fractured carbonates in the Baturaja formation and has caused severe losses and kicks during drilling. In one well, the Soka 2006-1, the last section was planned to a TD of 3831ft, but had to be stopped at 3331 ft due to total losses with following kicks. After several attempts to regain control, the well was plugged and abandoned until a better solution was in place.

After being suspended for two years, it was decided that PMCD would be the appropriate approach for re-entering of Soka 2006-1. Another well in the area, Soka 2006-6, was planned using the same technique. The losses would here would not be as drastic, so it was decided that this well was to be drilled first and use this as training for the more difficult Soka 2006-1. The operation was a success and provided a strong foundation for the problem-well that followed. To make tripping easier and safer, a DIV was installed in the previous set casing.

Drilling out the two cement plugs that had been put there for plugging purposes started of Soka 2006-1. Total losses immediately followed and PMCD mode was initiated. Freshwater was used for drilling and pumped down at a rate of 950 lpm. Viscous mud was continuously pumped down the annulus at a rate of 320-400 lpm, with an additional 10 bbl high viscosity pill pumped down before each connection. A specific mud weight was not mentioned in the paper, but a SBP of 5,5-10 bars and a Stand Pipe Pressure (SPP) between 220-248 bars were maintained during drilling. ROP averaged around 12-24 m/hr until it gradually dropped due to wear on the bit. The basement rock was penetrated and the well reached TD.

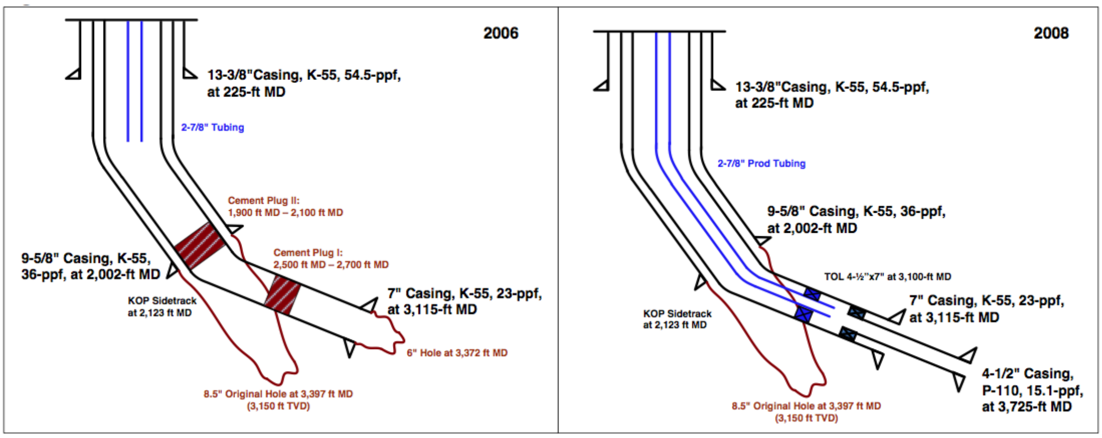

Figure 4.7: Well Schematic for Soka 2006-1 (Runtuwene et al., 2009)

LCM was pumped down in an attempt to plug the loss zone before tripping out, but failed several times. BDO injection finally succeeded in plugging the casing and stopping any gas migration, confirmed by no surface pressure in the annulus. The string was extracted and the liner run down while reaming and washing. Total losses were again encountered at a depth of 3330ft and PMCD mode had to be initiated once more. Gas migration was stopped by bullheading and the liner was run to TD, installed, and successfully cemented in place. The is no mention of the cement job in the paper.

During the entire operation there were no NPT and the section only took 19 hours to drill, compared to one and a half month spent on trying to control the well with conventional methods (Runtuwene et al., 2009).

4.3.3 Indonesia Offshore

The Ujung Pangkah field is located offshore East Java and is estimated to contain 450 bcf (billion cubic feet), overlaying 450 million barrels of oil. The operator, Hess, announced in 2005 that 40 wells were planned for the development of this field, which in found within a carbonate formation. The gas wells showed signs of losses in the lower Kujung formation, the wells 8-1/2" section, due to possible naturally occurring fractures. For this reason all the wells were planned with MPD as contingency, though MPD was not used on all wells. Focus will be on one of the wells, UPA-01/ST1.

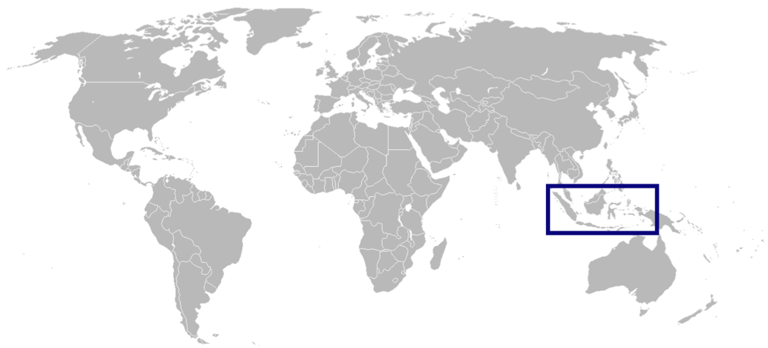

Figure 4.8: Location of the Ujung Pangkah field (Nas et al., 2009)

Subsequent to drilling of a pilot hole, UPA-01, the plan was to plug back and drill a sidestep, UPA-01/ST1. Sudden and total losses were met at 6877ft, along with continuous migration of gas in the annulus. Periodically bullheading were performed while pumping down large volumes of LCM, three gunk pills, and a drilliable cement plug in an attempt to stop the losses. The BOP developed significant wear and it was decided to mobilize MPD equipment and personnel.

40 barrels of high viscosity fluid were pumped down the annulus and 15 barrels in the drillstring. After bullheading seawater, washing, and reaming of the open hole, drilling in PMCD mode was possible and the last 55ft were drilled, reaching TD at 6932ft. Large volumes of seawater was bullheaded during the operation to counteract the gas migration and to finally enable tripping of the string. This last section was planned as a open hole, meaning no liner and cementing operation. A casing scraper run of the previous casing were performed successfully. After again bullheading large volumes of viscous mud, the completion was run down and a packer set in the previous 9 5/8" casing . The packer was pressure tested and MPD equipment was rigged down the following day.

"The estimated contract value tendered by the MPD service company for equipment and services for the wells in Ujung Pangkah amounted to less then USD 2 million. The money lost to non-performance time in a single well where MPD equipment was not installed beforehand was therefore more than enough to pay for MPD services for all the planned wells almost twice over. The UPA-01 well has proved to be the most productive well drilled in the field to date (Nas et al., 2009)."

4.3.4 Lessons Learned

Initial testing of a new technique and procedure will almost always be inefficient. Existing field experiences are studied, along with trial and error in the actual drilling operation. The operators in the previous described cases, have all drilled several wells after the once that were presented, every time learning new ways. Less time is spent on rigging, more efficient use of bullheading, hole cleaning materials and so forth. The PMCD operation alone decreased rig days, adding a further reduction in materials used will lower the cost of operation considerably. Along the way, observations were done and lessons were learned for future use (Nas et al., 2009; Runtuwene et al., 2009; Niznik et al., 2009):

- Install MPD equipment from the beginning of the zone were losses are expected. By doing this, the operator of the well in *Section* 4.3.3 was able to cut the transition time from 18 days to less than an hour.
- Seawater improves ROP and reduces hold down effect on cuttings, making hole cleaning easier. Frequent wiper trips and testing out several SAC flow rates performed successful in achieving desired cuttings transport. Keep a close eye on torque and drag as it is a good indicator on the efficiency of the hole cleaning.
- Use high viscosity pills of lower density. This will reduce the cost and cause less damage to the formation
- Bullheading for several hour in advance of RCD removal is an effective procedure for running or pulling out equipment.
- From Qatar: Cementing in two steps will in most cases result in a better cement job.
- Use at least two float valves to prevent flow up the drillstring, so-called U-tube effect.
- Mitigating vibration is critical for maximizing bit life.
- Correct alignment of the RCD will reduce wear on the sealing elements.
- The difference between drilling with return and without return, can be as low as 12 $^{kg}/_{m^3}$ to 36 $^{kg}/_{m^3}$ in mud density
- Have large quantities of lubricants and sealing materials ready on the rig, in case sudden losses
- Have pre-job meetings and a properly trained, "can do" crew on the rig.

Chapter 5

Modelling PMCD

> *"Mathematical models give more precise statements of the nature than models formulated in words, and they make quantitative predictions (simulations) possible. Mathematical models can be used to describe, to explain and to interpret physical systems."*
>
> - Pål Skalle, Professor NTNU -

In drilling, hydraulic models are used to predict the pressure profile. Hydraulic relates to a liquid moving in a confined space under pressure. Using downhole and topside measurements for online calibration, these models can provide an accurate overview of the downhole environments and be adjusted for maximum well control. In MPD, the main way of changing the pressure profile is by control of a choke, exerting a back-pressure. The measurements will be used to determine the choke position and provide precise control of downhole pressures.

This chapter will describe a simple, yet intelligent MPD model called the Kaasa Model. The model is primarily used for the CBHP variant of MPD. Available models have shown to be more advanced then necessary. Based on valid assumptions and simplifications, the Kaasa model have proven to be just as accurate in predicting downhole pressure as compared to the more advanced. The Kaasa model will be explained and simplified. This will be used used as a foundation for making a simple, static model for PMCD. The objective with these models are to implement and simulate them in an interactive environment in *Chapter* 6 and simulate a operation through a gas bearing total loss zone in a carbonate reservoir.

5.1 Hydraulic Model CBHP

Recalling IADCs definition of MPD, the main objective is to ascertain the downhole pressure environment limits by accurately controlling the annular pressure profile during drilling. To achieve this, MPD uses a closed-circulation system with a choke manifold on the return line, restricting the flow and creating a back-pressure down the annulus. Downhole pressure equations from *Section* 2.2 and *Section* 3.2.1:

Conventional:

$$BHP_{ann} = P_{mud,ann} + \triangle P_{ann}$$

MPD:

$$BHP_{ann} = P_c + P_{mud,ann} + \triangle P_{ann}$$

Comparing the two different techniques, it is possible to see that the only difference is P_c. This is what makes MPD special and the term can quickly be increased or decreased by adjusting the choke position. Depending on the situation, MPD can have a mud weight gradient below, equal to or above the pore pressures gradient, compensating with P_c to have a pressure profile that is in the range of what is required.

$$q_c = z_c k_c \sqrt{\frac{P_c}{\rho_{ann}}} \tag{5.1}$$

Equation 5.1 is the equation for flow through a choke. The setting point of the choke position, z_c, is the determining factor that enables the precise control. With a constant q_c, a lower value of z_c will make a more narrow flow path and increase flow velocity, providing a higher P_c. The actual choke position is calculated from a hydraulic model. A hydraulic model is an essential part in an automated MPD control system and its objective is " to estimate the downhole pressure and provide a choke pressure set-point to the MPD control system in real-time (Kaasa et al., 2011)."

Any deviations in flow or density will quickly be noticed by the Coriolis flowmeter and the hydraulic model is adjusted accordingly to maintaining desired pressure profile. Information about the new required back-pressure is sent to the pressure control module that calculates a new choke position. This is the Automatic Control System that is explained in *Appendix* A and an overview is depicted in *Figure* 5.1. (Godhavn, 2012)

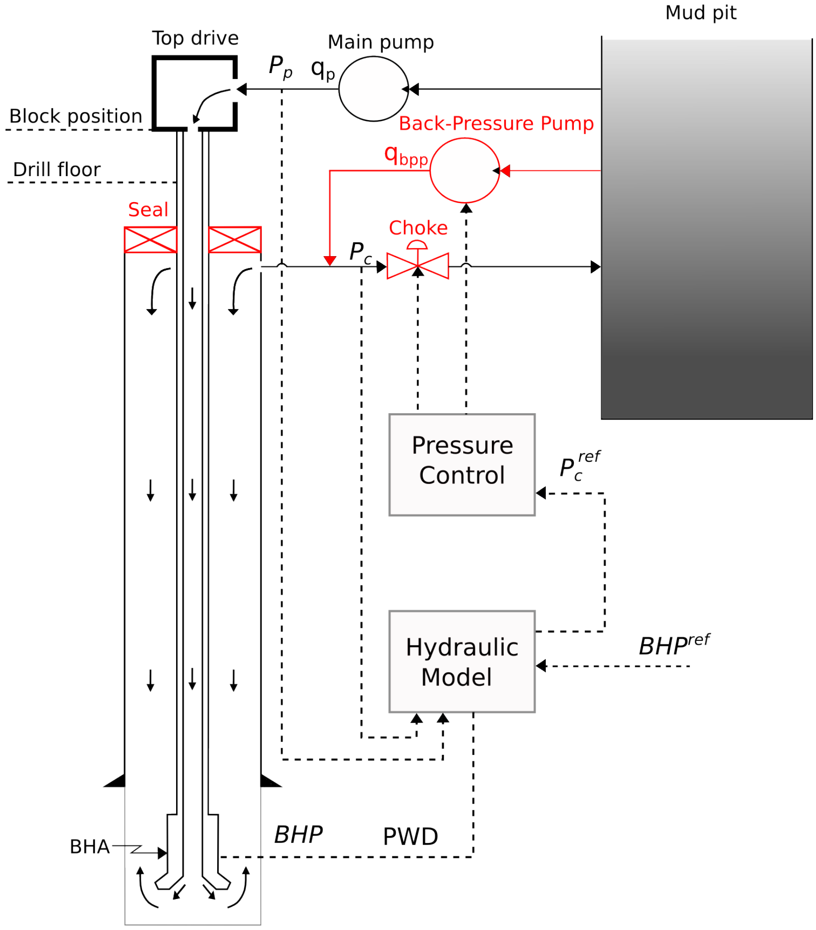

Figure 5.1: Automatically controlled MPD. Based on (Kaasa et al., 2011)

5.1.1 Simplifying the Hydraulic Model

The process may sound fairly easy, but is in fact rather advanced. Well environments are complex and are continuously changing. Therefore the models are often made similar, highly complex, in an effort to capture every aspect of the fluid hydraulics. This requires expert knowledge to set up, calibrate and operate, meaning that complexity could in many cases be the limiting factor for the hydraulic model to achieve accuracy in its estimations.

Parameters are both uncertain and slowly changing, requiring continuous calibration based on topside measurements and at the bit. Without measurements along the well, calibrations are insufficient in providing an accurate model. Focusing on the dominant hydraulics of the system and removing any unnecessary parameters, could provide the industry with a simpler and just as accurate model (Kaasa et al., 2011).

5.1.2 The Kaasa Model

The Kaasa model, presented in (Kaasa et al., 2011), describes a simple hydraulic model for an intelligent estimation of downhole pressure. It is demonstrated that by using topside measurements, Pressure While Drilling (PWD) equipment in the BHA and an algorithm for online parameter estimation, the model achieves a similar level of accuracy compared to more advanced models.

The main simplifications that are made in the Kaasa model (Kaasa et al., 2011):

- "Neglect dynamics which is much faster than the bandwidth of the control system. The hydraulic model should not contain high-frequency dynamics which the control system is not able to compensate
- Neglect slow dynamics. Slowly changing properties of a model can usually be handled much more efficiently by feedback from measurements, than to include these effect in the model as dynamics
- Lump together parameters which are not possible to distinguish or calibrate independently from existing measurements"

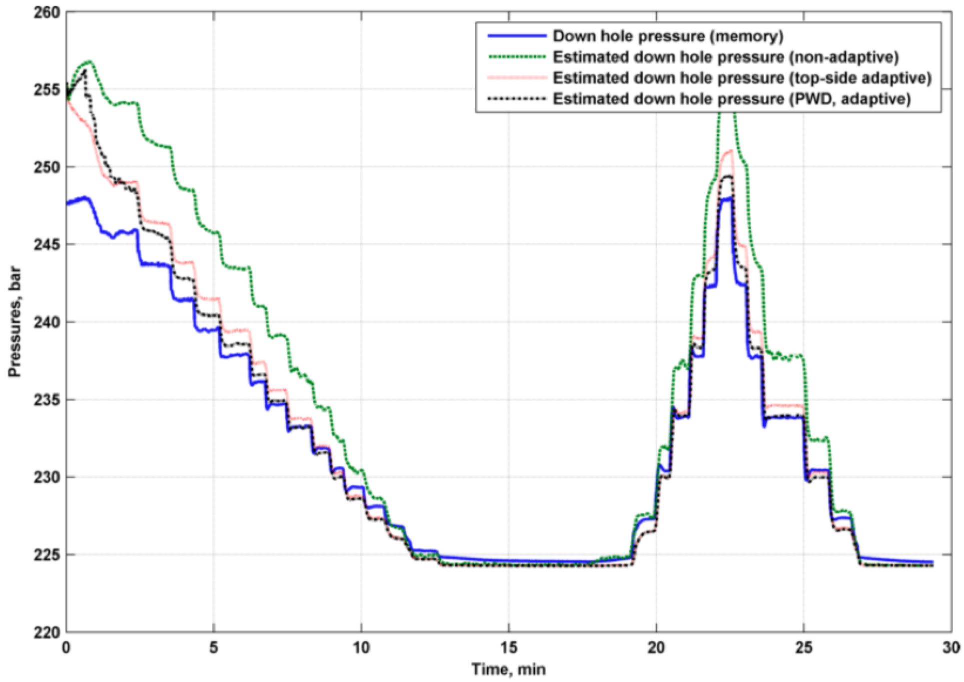

Figure 5.2: Estimations of downhole pressure using different measurements (Kaasa et al., 2011)

The Kaasa Model was tested on a full-scale drilling rig, Ullrigg in Stavanger. This was done in order to test the model and validate that its estimations are accurate. *Figure* 5.2 shows the results of the flow rate experiment. Flow rate is initially 1500 lpm, then zero, back to 1500 lpm and down to zero again. The drillstring was not rotated during the experiment.

The blue shows the actual pressure data, while the three others are based on estimations. Green is based purely on the model with no calibrations from measurements. The red uses calibration from topside measurements, while black uses both topside and PWD for downhole measurements. All three estimated lines starts off with a deviation of around 7 bar, but converges towards memory data within 10 minutes. The last adaptive version, using topside and PWD measurements, is clearly the most accurate and should be the preferred option when using MPD (Kaasa et al., 2011).

The Basics Behind the Model

With the RCD, MPD becomes a closed circulation system and several simplification can be made. Assuming that flow is uniform in the entire length of the annulus and in the drillstring, with no change in density, the system can be split into two separate compartments with different dynamics. This principle is show in *Figure* 5.3

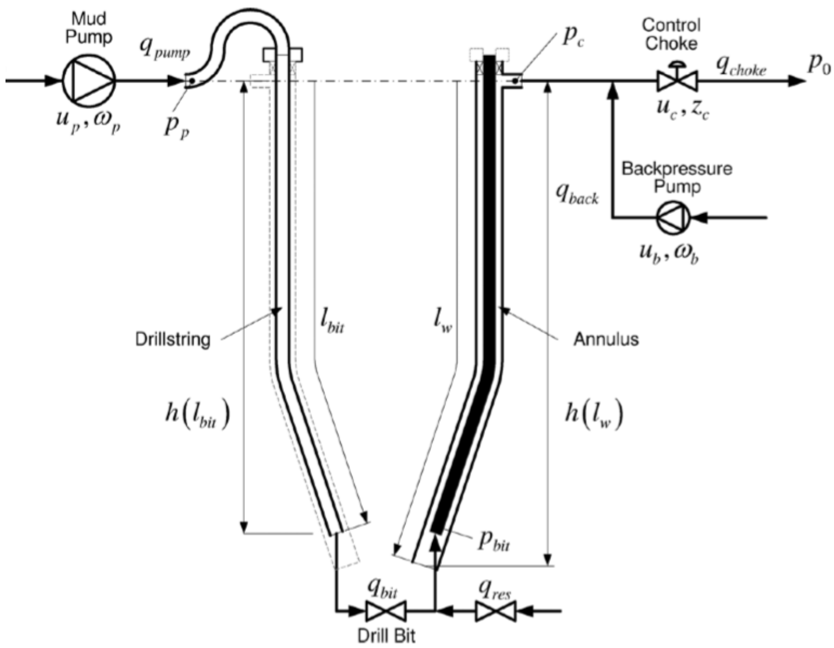

Figure 5.3: Annulus and drillstring compartment (Zhou et al., 2011)

The Kaasa model is based on a several well know and fundamental equations, along with assumptions to simplify these. The full derivation, with the assumptions, is shown in (Kaasa et al., 2011). Five equations are established and used to make up the model.

$$\dot{P_{pump}} = \frac{\beta_{ds}}{V_{ds}}(q_{pump} - q_{bit}) \tag{5.2}$$

$$\dot{P_c} = \frac{\beta_{ann}}{V_{ann}}(q_{pump} + q_{bbp} - q_c - \dot{V_{ann}}) \tag{5.3}$$

$$\dot{q_{bit}} = \frac{1}{M}((P_{pump} - P_c) - \triangle P_{ds+ann} + (\rho_{ds} - \rho_{ann})gh_{TVD}) \tag{5.4}$$

$$BHP_{ann} = P_c + P_{mud,ann} + \triangle P_{ann}$$

$$BHP_{dp} = P_p - \triangle P_{dp} + P_{mud,dp} \tag{5.5}$$

These five equations, along with an estimation algorithm, is enough to capture the dominating hydraulics of MPD. Explained in simple way, the first three equations will account for the changes that occur in the well and adjusts the different terms in the last two equations for downhole pressure estimation. Measurements from PWD are used to correlate and effects from bulk modulus, friction and other factors might be approximated (Kaasa et al., 2011).

5.1.3 Model Used for Simulation

The Kaasa model covers most of the changes that occurs in the flow during an operation. Simulation in *Chapter* 6 will look at MPDs reaction to total losses. Losses will therefore be the only changes that occurs in the system and further simplifications will be made on the model. This will be a static model that is fairly accurate in showing how an MPD operation is conducted in the following simulation chapter.

Effects that have been neglected:

- Compressibility of the fluid
- Change in annulus volume

Focus will be on the annulus side. The following equations are needed to make a model that can be implemented in the interactive environment:

$$q_c = q_b + q_{bpp} - q_{loss} + q_{influx} \tag{5.6}$$

Equation 5.6 will account for the input from the formation and shows the changes that occur in the flow rate through the choke. q_c and a reference back-pressure is then used to determine the choke position:

$$z_c = \frac{q_c}{k_c\sqrt{\frac{P_c}{\rho_a}}}$$

With these two parameters obtained, the actual back-pressure can be calculated and adjustments are made until the back-pressure is at its reference value.

$$P_c = (\frac{q_c}{z_c \times k_c})^2 \times \rho_{ann}$$

Equations for z_c and P_c are manipulated from *Equation* 5.1 on page 40. The last step is to determine the pressure loss from friction along the annulus,$\triangle P_{ann}$. Friction factor is considered constant along the system and is a direct result of flow rate through the specific area, either being drill pipe, bit or annulus.

$$\triangle P_{fric} = Frictionfactor \times q_{flow}^2 \tag{5.7}$$

Equation 5.7 is a simplification of how friction pressure loss is calculated. Friction is effected by more than just the flow rate and normally advanced friction models is used to accurately calculate the contribution. Now that all the parameters have been established, the BHP can be calculated.

$$BHP_{ann} = P_c + P_{mud,ann} + \triangle P_{ann}$$

5.2 Hydraulic Model PMCD

The simplicity of Kaasa's hydraulic model can be transferred to PMCD without a lot of additional assumptions. Before starting the process of making such a model it is important to first understand the technique under static- and dynamic conditions and to determine what are the inputs and what are the outputs in the system.

Input:
- Influx
- Losses

Output:
- Surface Back-Pressure
- Pump pressure

Hole cleaning, plugging of formation, losses and kicks will all affect pressures in the well. For this simplified model, hole cleaning and plugging of the formation will be computed as a change in friction factor. Kicks will be regarded as a continuous stream of gas that takes up more and more space in the mud cap. Logically, the input will determine the output, giving an overview of what is happing down in the well. PMCD is often referred to as "drilling blind" , SBP and P_{pump} are the eyes of the operation and will reflect the downhole conditions.

5.2.1 Static Conditions

Referring to *Figure* 5.4, it is now assumed that the well is filled with LAM down to the fractures and SAC fluid below this. When closing the choke in a closed-circulation system, any pressure exerted below the static mud cap will be held at the RCD. The actual mud cap is made underbalanced and the formation will exert a pressure on the column, creating this SBP.

$$SBP_{static} = P_{pore,topfrac} - P_{LAM} \tag{5.8}$$

Pressure at the surface will start at the specific SBP, similar to regular MPD and the choke, only that it is held at the RCD. This leads to the well pressure being equal to the formation pressure at the top of the fractures.

$$P_{ann,topfrac,static} = SBP + P_{LAM} = P_{pore,topfrac} \tag{5.9}$$

BHP in the annulus under static condition will then simply be a result of *Equation* 5.9 and the height of SAC fluid in the annulus:

$$BHP_{ann,static} = P_{ann,topfrac,static} + P_{SAC} \tag{5.10}$$

Knowing the precise height of SAC fluid may be difficult as total losses occurs in the well. For the specific simulation in *Chapter* 6, it will be assumed that SAC fluid first fills up the void space and then continues to fracture formation, opening further space.

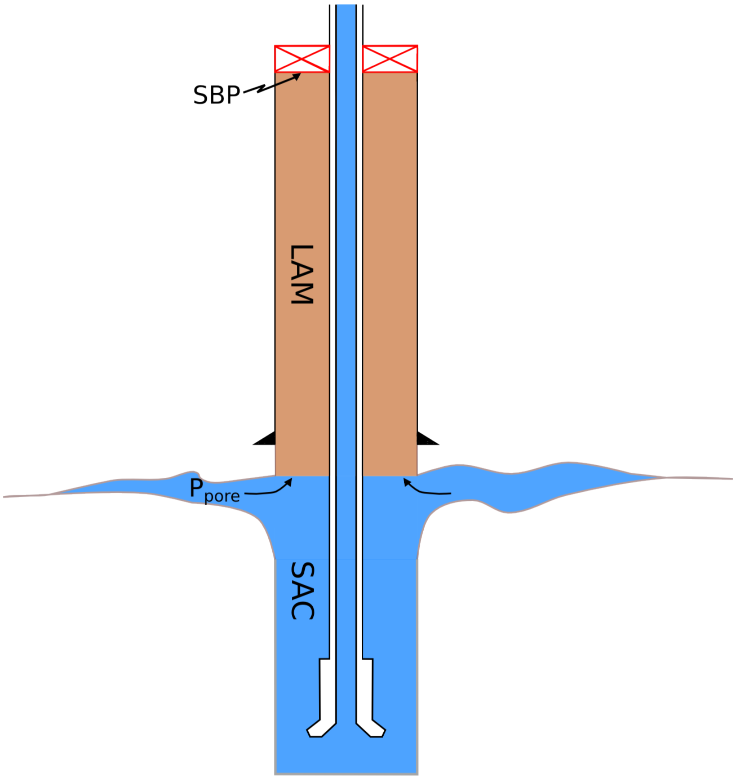

Figure 5.4: PMCD under static conditions

Inside the Drillstring

Fluid inside the drillstring will have a large underbalance relative to the formation. The drillstring is filled with a light SAC fluid and the annulus will exert a pressure on this underbalanced fluid column. Similarly, a back-pressure will be held at the pump (actually at the non-return valve) on surface during static conditions.

$$P_{pump,static} = (\rho_{pore,topfrac} - \rho_{SAC}) \times g \times h_{topfrac} \tag{5.11}$$

This pressure is a result of the differential pressure at the top of the fractured zone, the rest below is seawater in both compartments. BHP inside the drillstring will then be in balance with BHP in the annulus:

$$BHP_{ds,static} = P_{pump} + P_{SAC} \tag{5.12}$$

5.2.2 Dynamic Conditions

The main difference between static and dynamic is the contribution of pressure loss due friction from circulating SAC fluid and periodical bullheading. See *Figure* 5.5. The mud cap (LAM) is regarded as static until bullheading is initiated. To move the fluid down the annulus, the bullhead pump must overcome the static SBP, the rise in pressure due to migration and $\triangle P_{frac,SAC}$, which is the friction pressure loss from moving SAC fluid into the fractures. In addition, it will increase SBP to be able to move LAM along the annulus and into the fractures.

$$P_{pump,bullhead} = SBP_{static} + \triangle P_{migration} + \triangle P_{frac,SAC} + \triangle P_{ann+frac,LAM} \tag{5.13}$$

Pressure from bullheading will be noticed differently throughout the system. SBP will increase with $\triangle P_{bullhead} = \triangle P_{ann+frac,LAM}$, but as $\triangle P_{ann,LAM}$ is gradually lost down the annulus, this will be zero at the top of the fractures. For SAC circulation, the friction contribution will be $\triangle P_{ds}$ and $\triangle P_{frac,SAC}$ when pumping fluid down the drillstring and into the fractures or caves. $\triangle P_{ann,SAC}$ will not contribute much and is neglected. $\triangle P_{frac,SAC}$ will exert a pressure on the mud cap and increase the SBP. Rise in pressure due to migration is reflected as a decrease in P_{LAM}.

$$SBP = P_{pore,topfrac} - P_{LAM} + \triangle P_{frac,SAC} + \triangle P_{bullhead} \tag{5.14}$$

Equations for well pressure at the top of the fractures and below will remain almost the same as in static condition. The only change will be in the hydrostatic pressure of the mud cap and this is accounted for in the SBP. A drop of 2 bar due to gas entering the mud cap, will result in the SBP increasing with 2 bar. $\triangle P_{ann,LAM}$ must be removed as this is not felt below this point during bullheading.

$$P_{ann,topfrac} = SBP + P_{LAM} - \triangle P_{ann,LAM}$$

$$BHP_{ann} = P_{ann,topfrac} + P_{SAC}$$

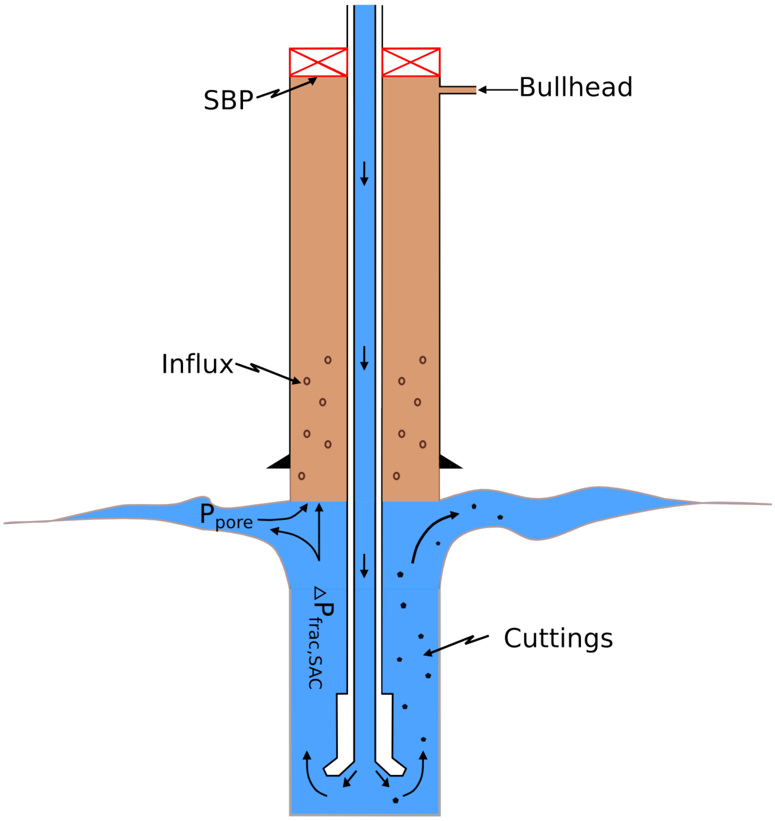

Figure 5.5: PMCD under dynamic conditions

Inside the Drillstring

In dynamic conditions, the main pump that supplies SAC fluid will have to overcome the differential pressure, $P_{pump,static}$ and the loss of pressure due to moving the fluid down the drillstring and into the fractures. During bullheading it must overcome the increase in pressure felt down in the well, $\triangle P_{frac,LAM}$.

$$P_{pump,dynamic} = P_{pump,static} + \triangle P_{ds} + \triangle P_{frac,SAC} + \triangle P_{frac,LAM} \tag{5.15}$$

BHP will, like in static, be the same as in the annulus compartment:

$$BHP_{ds} = P_{pump,dynamic} - \triangle P_{ds} + P_{SAC} \tag{5.16}$$

The right side of *Figure* 5.5 shows how cuttings are forced into the formation. Poor hole cleaning and plugging of fractures will be seen as an increase in $\triangle P_{frac,SAC}$ in this model. Should the formation clean up, it will be seen as a decrease.

5.2.3 Model Used for Simulation

Following the simplistic thinking of the previous model, the only changes that will occur in the system are influx and losses. Above, equations for P_{pump} and SBP will represent the system and determine the output, controlling the model. Influx will migrate into the mud cap and result in further underbalance relative to the formation. Pressure from the formation will now exert an even larger pressure from below. A kick will be noticed as an increase in SBP, while pump pressure remains the same. Assuming that the kick is a continuous stream, taking up more and more space in the LAM, the height of the kick can be calculated by assuming a gas density.

$$h_{influx} = \frac{\triangle SBP - \triangle P_{pump}}{(\rho_{LAM} - \rho_{gas}) \times g} \tag{5.17}$$

The reason for the term $\triangle P_{pump}$ in the equation, is that plugging or cleaning up of the formation (change in $\triangle P_{frac,SAC}$), will be seen as an equal change in both $\triangle P_{pump}$ and $\triangle SBP$. This will be valid in a closed-circulation system where the only change in pump pressure is due friction from penetrating the formation. Removing $\triangle P_{pump}$ will result in only the increase due to migration being accounted for in the influx height estimation. From *Equation* 5.17, the new hydrostatic pressure of the LAM column can be calculated.

$$P_{LAM} = \rho_{LAM} \times g \times (h_{topfrac} - h_{influx}) + \rho_{gas} \times g \times h_{influx} \tag{5.18}$$

By reading SBP and using estimations on height of influx in *Equation* 5.18, downhole pressures can be calculated.

$$P_{ann,topfrac} = SBP + P_{LAM} - \triangle P_{ann,LAM}$$

$$BHP_{ann} = P_{ann,topfrac} + P_{SAC}$$

Chapter 6

Simulation and Results

Simulation is defined as imitating or enactment. For a drilling operation it will be the act of imitating a process by creating a model that is operated over time. Environments may be replicated and the model tested before it is put to use in a real operation. It may also be used for educational purposes and training of personnel.

The static models from the previous chapter and a carbonate reservoir environment will be implemented in a program called MATLAB. This chapter will describe MATLAB and how the models are implemented. The reservoir will be presented and explained, along with a comparison of the pressure profile from the different techniques in the specific drilling window. In an effort to see how total loss zones are handled, a drilling operation is simulated through the reservoir. The operation will start of in CBHP mode before going over to PMCD, also showing the transition. Focus will be on CBHP and PMCD as they are best suited for the difficult environment.

6.1 MATLAB

"MATLAB is a high-level language and interactive environment for numerical computation, visualization, and programming. Using MATLAB, you can analyze data, develop algorithms, and create models and applications. The language, tools, and built-in math functions enable you to explore multiple approaches and reach a solution faster than with spreadsheets or traditional programming languages, such as C/C++ or Java (Mathworks, 2014)."

The static models from *Chapter* 5, along with reservoir data, will be implemented as equations and values in a script. By using iteration, the operations will be simulated over time to replicate a real scenario.

6.1.1 MATLAB Code

The MATLAB code that incorporates the previous models can be found in *Appendix* E. There are two different codes:

- Comparison of techniques in the specific drilling window
- A drilling operation through total loss zones

The first code is meant to show the basic principle behind each technique and an outline of their pressure profile in the drilling window at hand. The second is the drilling operation through the carbonate reservoir that follows.

6.2 Carbonate Reservoir Case

This case was set up by using data from an example, on page 160 in (Bill Rehm et al., 2008), and the drilling window is made to resemble *Figure* 3.7 on page 21 in this thesis. An overview of the well can be seen in *Appendix* C. The main features to notice are the two similar zones of total losses. The fractures contains large amounts of gas and PI in these sections are 1000 $^{lpm}/_{bar}$, meaning that for every 1 bar over fracture pressure, 1000 lpm will be lost to the formation

6.2.1 Well Data

The well in question is drilled as a vertical hole through the carbonate reservoir:

- Previous set casing: 9 ⅝" @ 2700m TVD, ID=0.21m
- Drill pipe: 5 ½", OD=0.14m. Bit OD= 8"
- Drilling fluid rate: 2000 lpm
- Hydrostatic gradient in the overburden: 0.14 $^{bar}/_{m}$
- Top of reservoir: 2750m TVD, $P_{pore,topres}$=385 bar
- Hydrostatic gradient in the reservoir: 0.03 $^{bar}/_{m}$
- First loss zone: 2800m TVD, $P_{pore,1stfrac}$=386.5 bar, PI $>$ 1000 lpm $^{lpm}/_{bar}$
- Second loss zone: 2850m TVD, $P_{pore,2ndfrac}$=388 bar, PI $>$ 1000 lpm $^{lpm}/_{bar}$

6.2.2 Drilling Window

In the overburden, P_{pore} will increase with a hydrostatic gradient of 0.14 $^{bar}/_{m}$. P_{frac} is 30 bar above and parallel to P_{pore}, giving a drilling window of 30 bar above the reservoir. At the top of the reservoir, 2750m (TVD), P_{pore} is 385 bar. The reservoir contains large amounts of gas and P_{pore} will increase with the hydrostatic gradient of the gas, approximately 0.03$^{bar}/_{m}$.

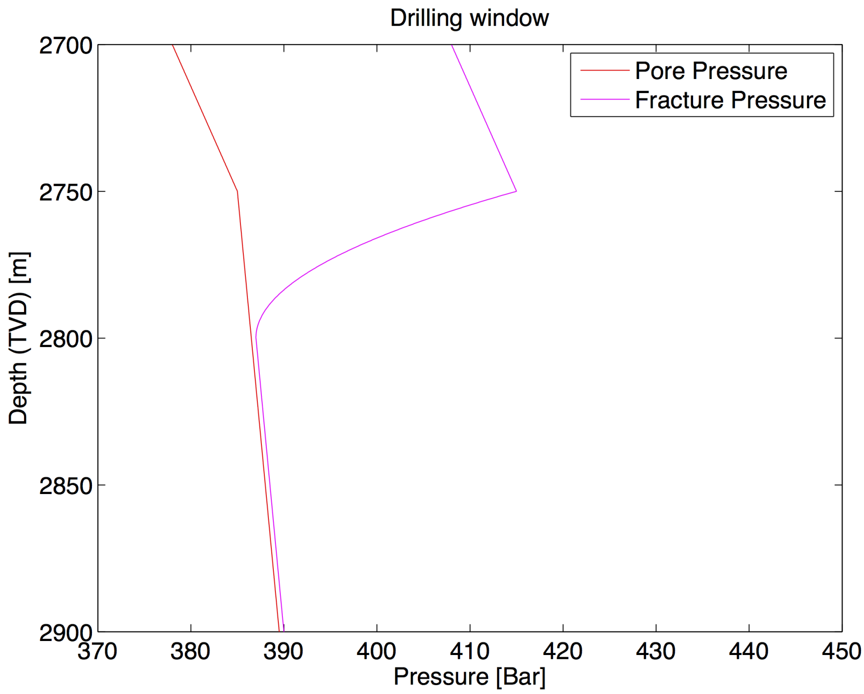

Figure 6.1: The drilling window for the specific well

From this point, P_{frac} decreases towards P_{pore} further down in the reservoir. This will result in the drilling window basically disappearing at 2800m where there are zones with total losses. In a real scenario, there could also be a more sudden change in P_{frac} as these zones are met, meaning that the drilling window would go from 30 bar to 0 bar in merely a few meters. For this case, it is made to resemble *Figure* 3.7 on page 21.

Another large fracture is encountered at 2850m, losses here are similar to that of the fractures/vugs at 2800m. The total losses are caused by a giant set of fractures, behaving like a cave that can take large volumes. Once filled, it will continue to fracture the formation and open more space.

6.3 Pressure Profile in the Specific Drilling Window

6.3.1 Conventional Drilling

Conventional drilling is the oldest and most established drilling method today. It is the preferred option as it is normally the cheapest and the least complex, though it has its drawbacks. Changing mud weight is primary way of controlling the pressure profile, dealing with kicks and losses can be difficult and time consuming. In a reservoir such as this, staying within the drilling window will be virtually impossible for conventional drilling or any of the other techniques. The difference is that CBHP and PMCD has a safer and more efficient way of dealing with the consequences of this, increasing the possibility of reaching TD.

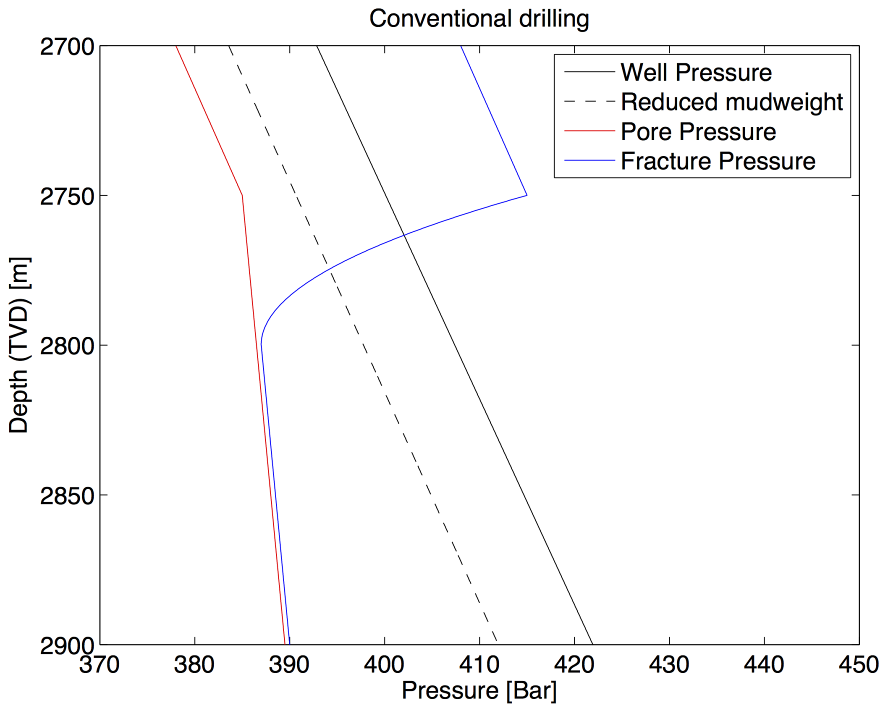

Figure 6.2: Drilling window - conventional drilling

Figure 6.2 shows the conventional pressure profile through the drilling window. The solid black line pictures a normal conventional outline, while the dashed black line how a decrease in mud weight would reduce the overbalance. A reduction in mud weight would bring the pressure profile closer to the pore pressure and reduce losses, but also closer to a potential kick situation and such a large decrease should be avoided.

Still, losses would eventually be met further down in this well. Conventional drilling has the largest overbalance of the three techniques and well control would become an issue. At the point of total losses, there are not much separating procedures in conventional compared to CBHP. LCM or other remedies will have to be pumped down in an effort to stop the losses.

6.3.2 CBHP

CBHP is especially designed for drilling through a narrow drilling window as low as 5 bar. In this carbonate reservoir, the drilling window disappears at 2800m due to the fractured and/or vugular formation.

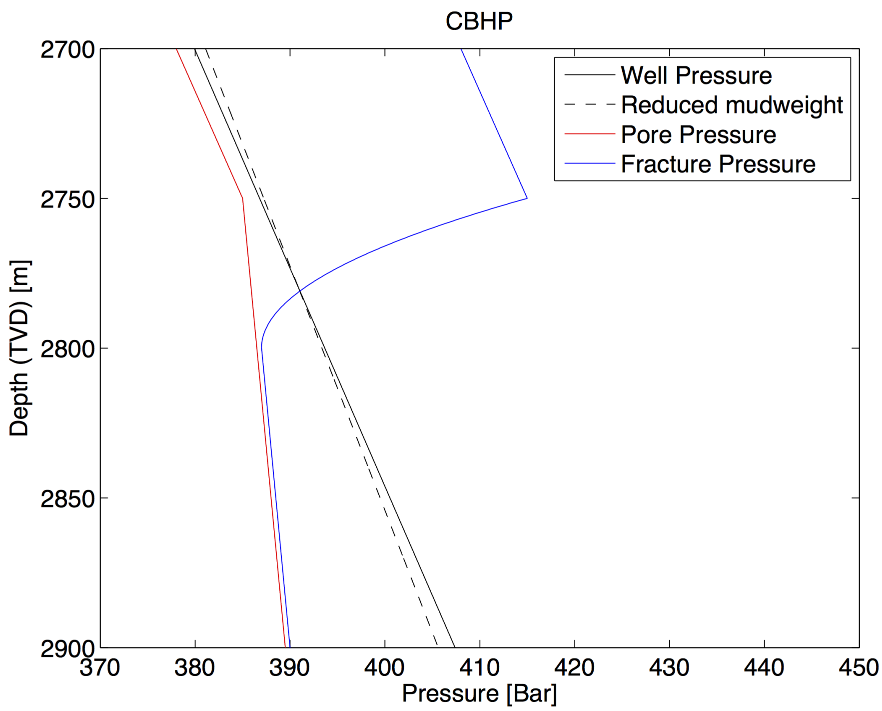

Figure 6.3: Drilling window - CBHP

Figure 6.3 pictures the outline of CBHPs pressure profile through the well. The two different black lines, solid and dashed, effectively shows one of advantages with the MPD technique. The solid line has a back-pressure of 1.5 bar, while the dashed has 42 bar. The latter means that a lower density mud weight can be used in the well, reducing overbalance in the upper sections and providing a slightly lower BHP. CBHP has the second lowest overbalance of the three methods.

Back-pressure can be adjusted as needed to deal with the situations that occurs and to more effectively stay within the drilling window, referring *Figure* 3.7. A drilling operation that encounters total losses in CBHP mode is simulated in *Section* 6.4.

6.3.3 PMCD

PMCD could be described as the unconventional technique. *Figure* 6.4 shows the outline of the pressure profile in the drilling window. The reservoirs hydrostatic gradient is mainly affected by gas and pore pressure will increase slowly with depth. As the column of LAM has a higher hydrostatic gradient, the pressures will decrease faster in the well than in the formation, creating a underbalance above the fractured zone. This should not cause any problems as PMCD offers good control on kicks.

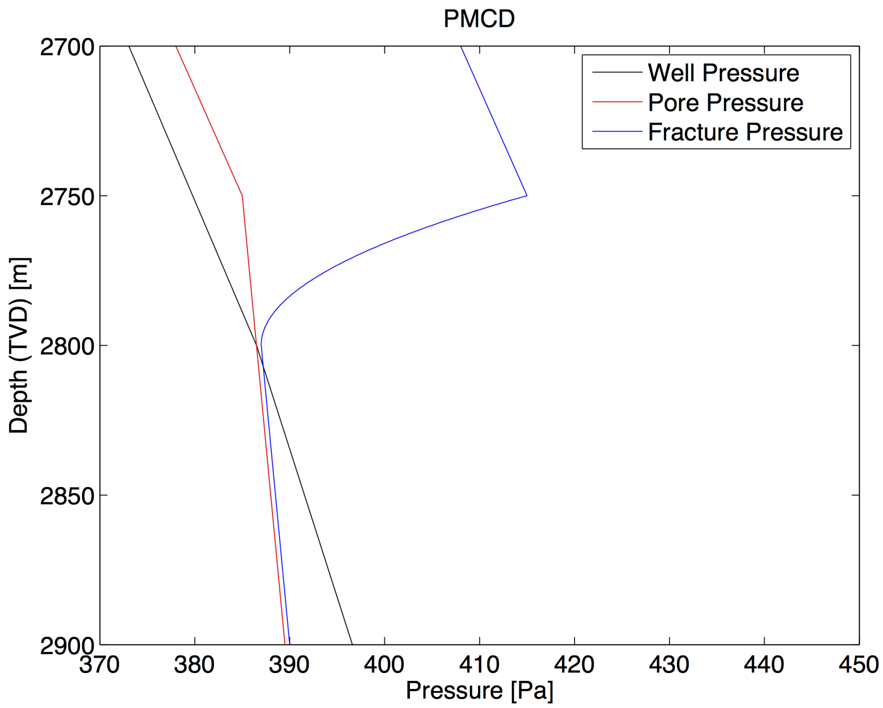

Figure 6.4: Drilling window - PMCD

The LAM (mud cap) will be a static column of fluid down to the point of where total losses occur, top of the fractures (2800m). From this point, seawater fills the well and the hydrostatic gradient will be lower. The change is slightly visible in *Figure* 6.4. Overbalance will be kept low and out of the three techniques, PMCD has the lowest overbalance in the loss zones.

6.4 Simulation of a Drilling Operation Through Total Losses

The primary objective of this simulation is to see how a PMCD operation is conducted and how it handles zones of total losses. The first part of the well will be drilled using CBHP as there are initially no losses, meaning that PMCD is not applicable. The reason for using CBHP and not conventional drilling, which is the most common option, is that CBHP is best suited for the narrow drilling window. CBHP has a safer and faster way of dealing with losses and kicks. Having MPD equipment already installed, will also reduce the time needed to convert to and from PMCD mode. A transition from CBHP and PMCD will be simulated when it is confirmed that the loss zone is sufficiently large that lost circulation will continue for a longer period of time. *Appendix* C shows an overview of the well in question.

For simplicity, it is assumed that the area between the drillstring and the annulus is constant along the entire well path. Compressibility of the fluid is neglected, meaning that pressures will be slightly different from a real scenario. Figures from the simulation contains a time scale on the x-axis, this is not meant to be an accurate estimate of how long the different steps in an operation uses, but rather an approximation.

6.4.1 CBHP Operation

The operation kicks off at 2750m, determined as the top of the carbonate zone. Mud density in the well is 1380 $^{kg}/_{m^3}$ and provides a hydrostatic pressure of 372 bar. Annulus friction pressure loss, $\triangle P_{ann}$, will contribute with roughly 4 bar during circulation and a reference back-pressure is set to 11 bar at the choke. Throughout the operation, the ACS will work towards keeping this back-pressure during circulation. P_{pore} is initially 385 bar while the well pressure is $(372 + 4 + 11)$bar $= 387$ bar, giving an overbalance of 2 bar at this point. Seen in *Figure* 6.3, this is the point where the overbalance will be lowest. To compensate for the lost $\triangle P_{ann}$ during circulation, the ACS will choke the flow further and a higher back-pressure is set to compensate.

Time [Min]	**Event**
10	Total losses occur. No flow through choke and zero back-pressure
11	Choke is closing to prevent annulus fluid from falling
13	Bullhead pump on, bullhead down the annulus for 10 minutes.
24	Bullhead pump off, evaluate for PMCD.

Table 6.1: Time overview of the CBHP operation in the total loss zone

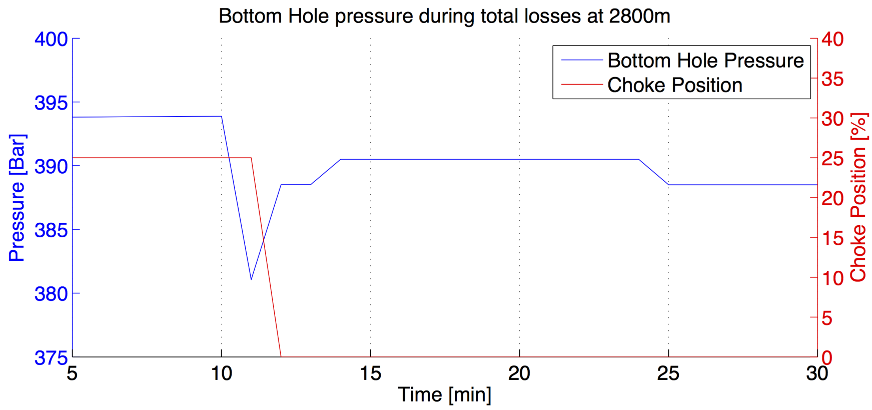

Figure 6.5: CBHP - BHP when encountering a total loss zone

Total losses are met at t=10 min (2800m), resulting a loss in BHP as SBP becomes zero with no flow through the choke. Hook height will indicate the drillstring dropping. Fluid level will start to decrease as PI is rather high, and the response is to stop drilling and close the choke. This will effectively work as putting a finger over a straw filled with water. There is no access to air to replace the water and it will be suspended in the "straw". *Figure* 6.5 & 6.6 shows how BHP and SBP will fall until the choke catches the fluid. The formation will exert a larger and larger pressure on the underbalanced fluid column and this will be held at the RCD, balancing well pressure with P_{pore} at the top of the fractured zone once the choke is completely closed.

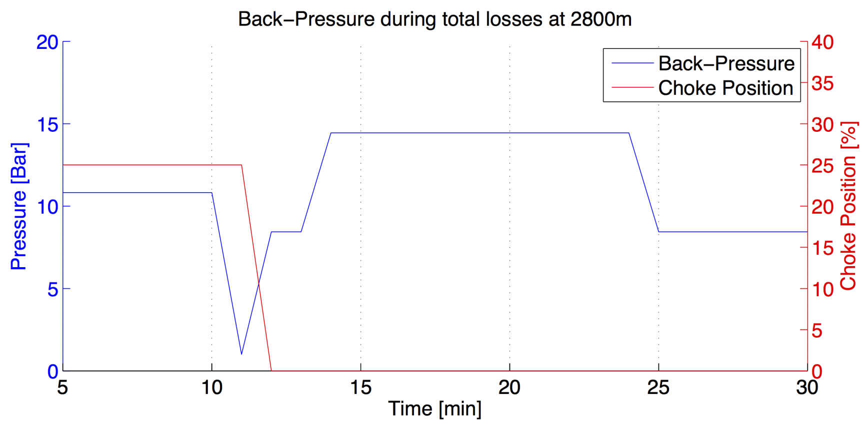

Figure 6.6: CBHP - Back-pressure when encountering total loss zone

The bullhead pump is turned on at t=13min, increasing both BHP and SBP. Slightly more in SBP due to friction from moving mud down the annulus. Bullheading is performed for 10 minutes to check if the fractures/vugs can be filled within a small period of time. Carefully watch for signs that the well again starts to flow, meaning that the vugs are filled, seen as a rise in SBP and P_{pump}. Be ready to open the choke and/or close the BOP should this happen, to regain control. Space out drillstring to avoid closing on a tool joint. From this point there is a limited number of option for dealing with the total losses using CBHP, should the losses continue. The mud is suspended and pressures balanced, but kick is an imminent thread. Kick is under control as long as bullheading continues. Options for further operation with CBHP:

- Pump down LCM, cement or other means of sealing off the fractured zone
- Continue drilling with losses

Trying to stop the losses with these materials can often be an exercise in futility and continue drilling with losses will be expensive. As the formation pressures are rather high, FMCD can not be used and the best option at this point is to convert to PMCD. MPD equipment is already installed and SAC fluid is easily accessible. As the well show now sign flowing, the bullhead pump is turned off at t=24min and the formation is evaluated for PMCD.

6.4.2 Transition from CBHP to PMCD

Referring to the procedure in *Section* 4.1.2, the steps are now to measure the formation pressure at the top of the fractures and from that determine a LAM density that balances this pressure while holding a desired SBP. Procedures for bullheading and mud cap (LAM) must be determined:

- LAM
  - Dilute the old mud and use this in the entire annulus
  - Use the old mud below the BOP and a lighter mud above
- Bullheading
  - Continuously bullhead down the annulus at a low rate during the operation.
  - Bullheading only when SBP reaches a predetermined pressure

For this simulation purpose, the old mud will be diluted and fill the entire annulus. To be able to clearly show how a kick is noticed and handled in a PMCD operation, bullheading will be initiated when SBP reaches a predetermined value, meaning no continuously bullheading during the operation. Weatherford's detailed setup of PMCD can be found in *Appendix* B. Bullheading is performed via the Riser Boost Line.

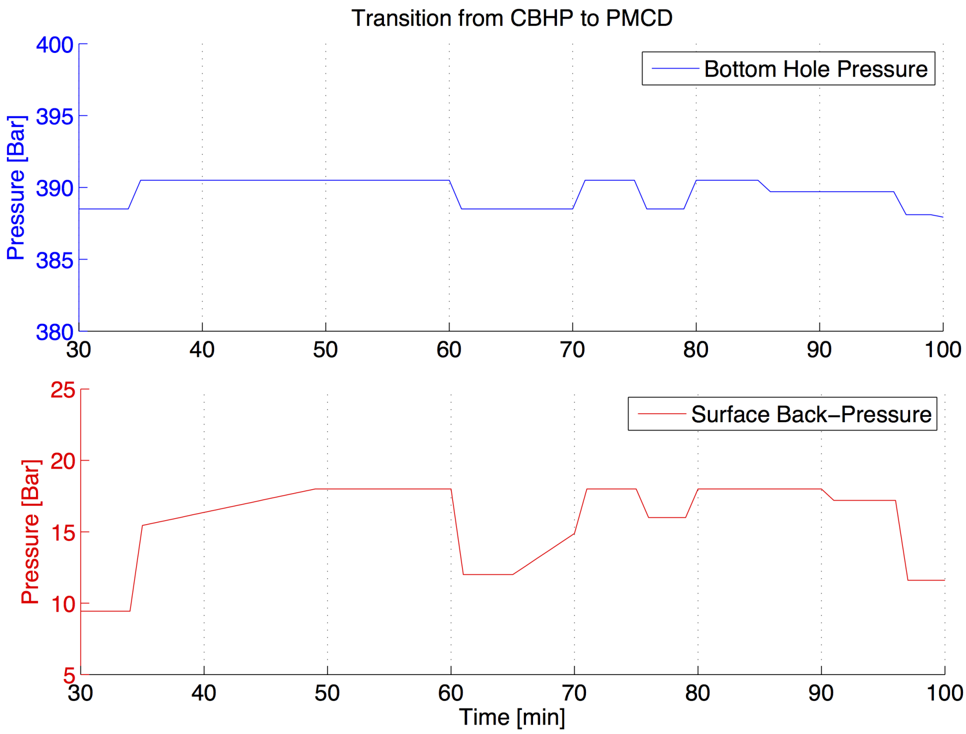

Figure 6.7: Transition from CBHP to PMCD

Time [Min]	Event
30	Bullhead pump off, dilute old mud to make LAM
35	Bullhead pump on, pumping down LAM until stable SBP
60	Bullhead pump off, check stabilizing SBP. Calculate gas migration if a kick enters the well
65	Kick enters the well and migrates upwards
70	Bullhead pump on, forcing the kick back into formation
75	Main pump off, switch from mud to SAC fluid injection in the drillstring
80	Main pump on, pump down SAC. Old mud forced into the formation
85	Drillstring is completely displaced with SAC and friction pressure loss from penetrating the formation is reduced
96	Bullhead pump off, continue drilling PMCD mode

Table 6.2: Time overview of the transition

Here is it assumed that the injectivity test was successful and that PMCD can be used, i.e. total losses. The injectivity test was conducted at several flow rates. BOP is closed and by reading pressure in the kill line and using the hydrostatic pressure of the fluid in the well, P_{pore} is calculated to be 386.5 bar. Desired SBP is set at 10 bar and from that a ρ_{LAM} of approximately 1370 $^{kg}/_{m^3}$ is calculated using *Equation* 4.1 on page 28. Washing and reaming of the hole is performed, this is not seen in *Figure* 6.7. Initially, the main pump is on and the bullhead pump is off, while it is calculated how much seawater is needed to dilute the old mud to a suitable LAM density:

$$\rho_{lam} = \frac{V_{mud} \times \rho_{mud} + V_{seawater} \times \rho_{seawater}}{V_{mud} + V_{seawater}}$$

Rearranged to find the volume of seawater that must be added in the mud pit:

$$V_{seawater} = \frac{V_{mud} \times (\rho_{mud} - \rho_{seawater})}{\rho_{LAM} - \rho_{seawater}} \tag{6.1}$$

Bullhead pump is again turned on and LAM is bullheaded down the annulus at t=35min. The LAM is of less density and will create a larger underbalance, relative to the formation, than with the old mud. *Figure* 6.7 shows how SBP is rising as LAM is pumped down. Notice how there is no change in BHP during this bullheading. As both mud gradient are underbalanced, the difference in hydrostatic pressure is accounted for in the SBP. The only increase seen in BHP is once the bullhead pump is turned on.

The entire annulus is filled with LAM at t=50min and bullheading continues until a stabilizing trend in SBP is established at 18 bar. Once a stabile SBP is confirmed, the bullhead pump is turned off at t=60min to again see a stabilizing trend, this time in static SBP, 12 bar. As the LAM was calculated with a desired SBP of 10 bar, friction contribution from SAC penetrating the fractures is determined to be 2 bar, while 6 bar is required to move the LAM down the annulus and into the fractures.

As expected, a kick enters the well at t=65min, seen as a steady rise in SBP and no change in BHP. From this increase it is possible to calculate a minimum bullhead rate, using *Equation* 4.2 & 4.3 on page 29, that is enough to counteract the gas migration The increase is approximately 0.6 bar per minute, giving a gas migration of:

$$\frac{60000\frac{Pa}{min}}{1370\frac{kg}{m^3} \times 9.81\frac{m}{s^2}} = 4.46\frac{m}{min}$$

$$2 \times 4.46\frac{m}{min} \times (0.21^2 - 0.14^2)m^2 = 0.218\frac{m^3}{min}$$

Minimum bullheading rate to force the kick back into the formation is calculated to be 218 lpm. For this simulation, 1000 lpm will be used to be able to see a more clear difference in pressures during bullheading. Bullhead pump is turned on at t=70min and the kick is forced out of the well.

The main pump must now be turned off in order to switch from mud to SAC fluid injection in the drillstring, as a step towards reducing cost. SAC fluid is mostly seawater which is cheap and widely abundant offshore. It is shut off at t=75min. This will lower BHP and SBP a bit, but bullheading continues to maintain adequate overbalance and to keep influx from entering the well.

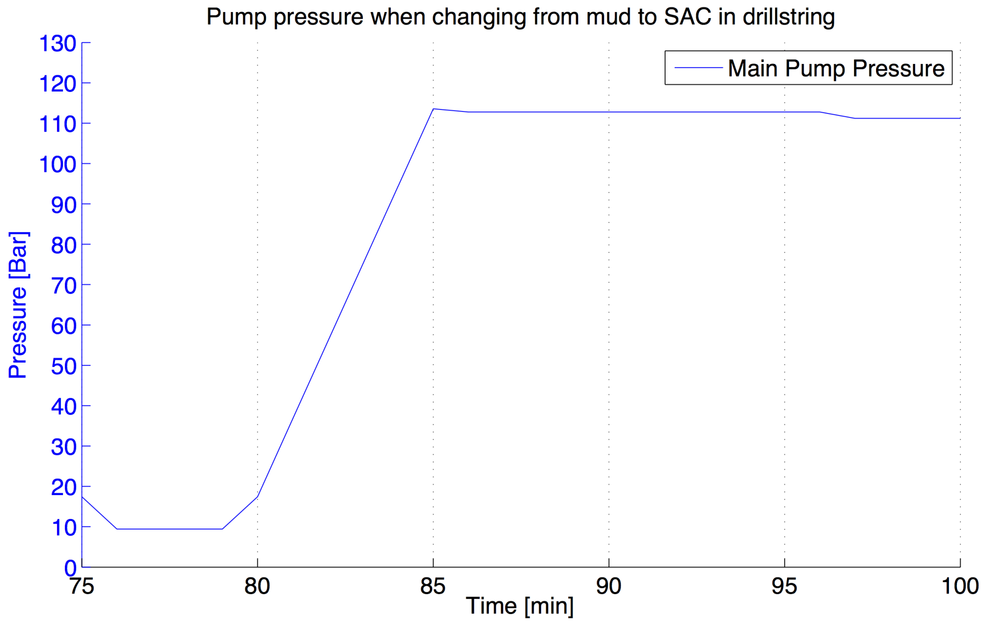

Figure 6.8: Transition from CBHP to PMCD, switching to SAC

SAC fluid is lined up and pumping is initiated at t=80min. *Figure* 6.8 shows how P_{pump} increases drastically. The increase is due to seawater having a lower density than the old mud. The differential pressure relative to the formation will become larger and larger as more seawater fills the drillstring, requiring a higher P_{pump} to balance pressures. A small reduction in P_{pump} is seen as the old mud is completely displaced at t=85min and friction from penetrating the fracture is decreased due to lower density fluid. SAC is now pumped continuously. The bullheading pump is shut off at t=96 min and the well is ready for drilling in PMCD mode.

6.4.3 PMCD Operation

Drilling now progresses in PMCD mode, dealing with kicks as they come. Influx will eventually penetrate the static mud cap, seen as a continuous rise in the SBP, see *Figure* 6.9 and *Table* 6.3. Once the SBP reaches a predetermined level, in this case 20 bar, bullheading is initiated until SBP returns to its original value. The figure shows a small increase in SBP once the bullhead pump is turned on, as expected. Bullhead rate is set from the gas migration calculated earlier. Cement pump is ready at all times to inject kill mud should there be any emergencies.

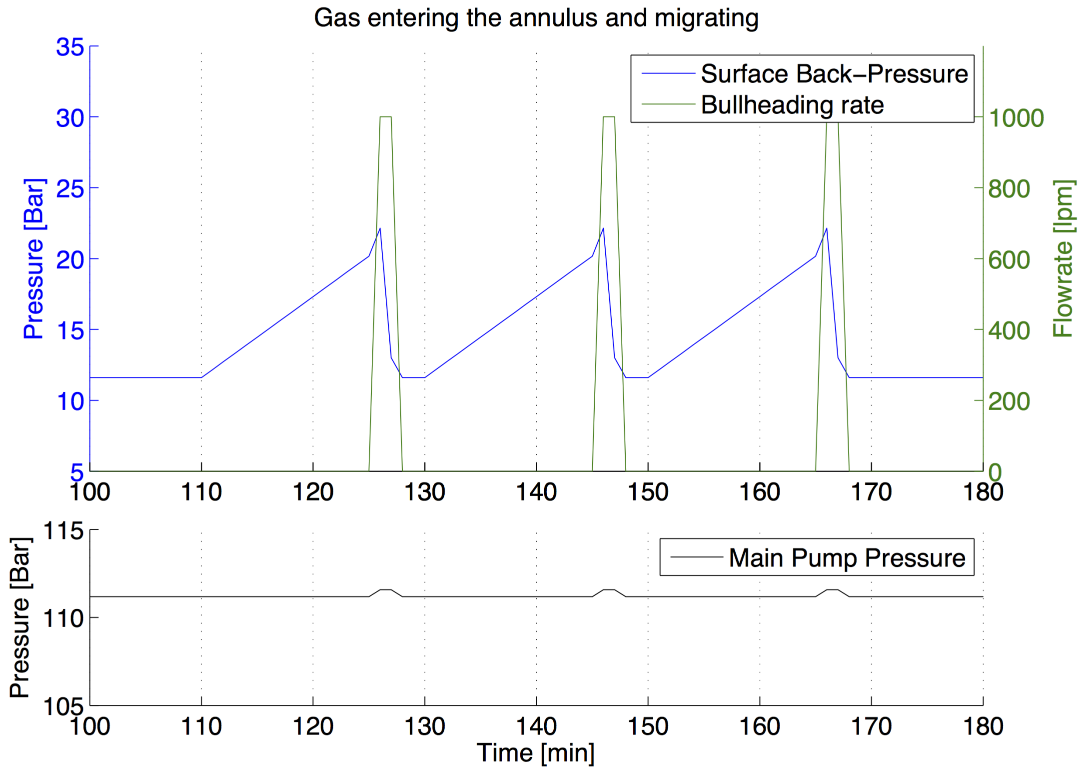

Figure 6.9: PMCD - Kick and bullheading during drilling

Time [Min]	Event
110, 130, 150	Kick enters the well and SBP increases due to increased underbalance
125, 145, 165	Bullhead pump turned on, pumping down LAM and forcing the kick back into the formation. Bullheading for one minute

Table 6.3: Time overview of the kick and bullhead procedure

In *Section* 4.1.3 it is said that the gas migration should not produce a rise in P_{pump}. This is confirmed in the sub plot in *Figure* 6.9. There is no change in P_{pump}, the only difference is when bullheading is initiated and well pressure is increased. Bullheading will increase the BHP with same value as the friction pressure loss from penetrating the fractures with LAM.

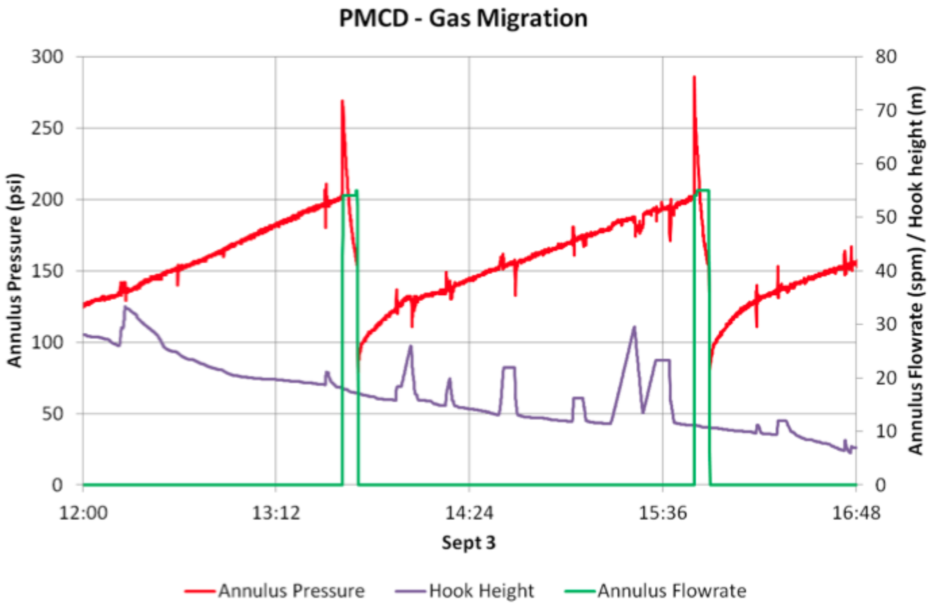

Figure 6.10: Real PMCD operation in a gas bearing reservoir (Rojas et al., 2013)

Figure 6.10 is taken from a real drilling operation in offshore Malaysia, by Petronas. This is a more detailed plot than *Figure* 6.9, but the similarity is pretty clear. The purple line shows how the hook height is lowered during drilling. The spikes in the lines are caused by stops of circulation and the drillstring being pulled up, most likely due to hole cleaning or similar procedures. A more detailed explanation of the kick and bullheading cycles are found in *Appendix* D, also for a liquid bearing formation. These operations are performed until reaching TD, in this case 2900m TVD.

Connection of a New Stand of Drillpipe in PMCD Mode

To reduce the chance of kicks during a connection of drillpipe, the bullheading pump is turned on at t=180min and the gas is pushed as far into the formation as possible. *Figure* 6.11 shows how BHP is increased during bullheading. Bullheading may or may not be continuous throughout the connection, in this case it will as long as there is no circulation of SAC fluid. CCS, from *Appendix* A, is not a required tool with MPD. To ensure proper hole cleaning, a high viscosity pill is pumped down. This event not seen in the figures. When SAC circulation is halted at t=185min, BHP will fall equivalent to the $\triangle P_{frac,SAC}$. *Figure* 6.12 pictures how the SBP rises due to the bullheading ahead of a connection, while falling when SAC circulation is stopped. All pressures return to normal once bullhead pump is off and main pump on, at t=190min.

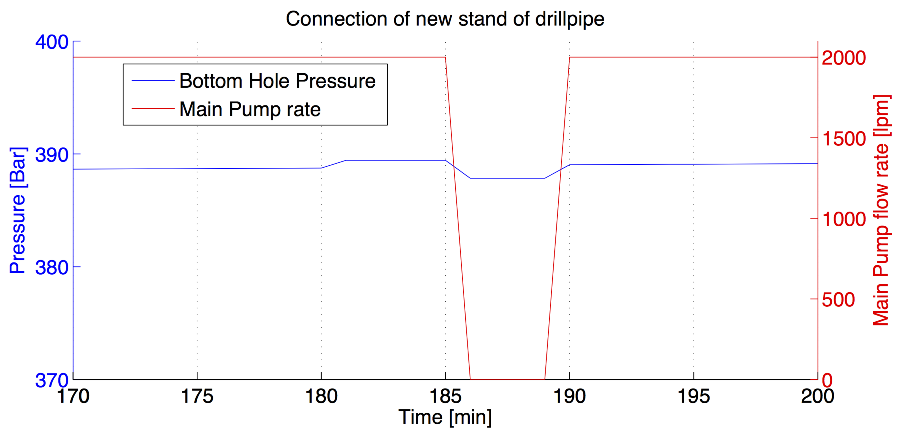

Figure 6.11: PMCD - BHP and flow rate during a connection

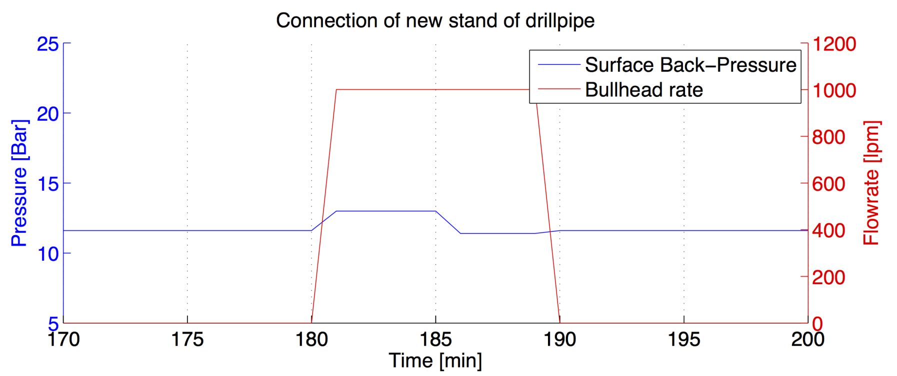

Figure 6.12: PMCD - SBP and bullhead rate during a connection

Time [Min]	Event
180	Bullhead pump on, push gas as far into the formation as possible
185	Main pump off, make up connection. Continue bullheading
190	Main pump on, bullhead pump off. Continue drilling with PMCD

Table 6.4: Time overview of a pipe connection

Plugging and Cleaning up of the Formation

As stated in *Chapter* 4 on page 30, plugging of the formation will be seen as a rise in both P_{pump} and SBP. This is due to an increase in friction during circulation and will change the indicators with the same value. *Figure* 6.13 pictures this situation, at t=200min, the formation is plugging and forcing the pump to deliver a higher pressure in order to continue SAC circulation at the same flow rate. Poor hole cleaning will also be seen as a similar rise in SBP and P_{pump}.

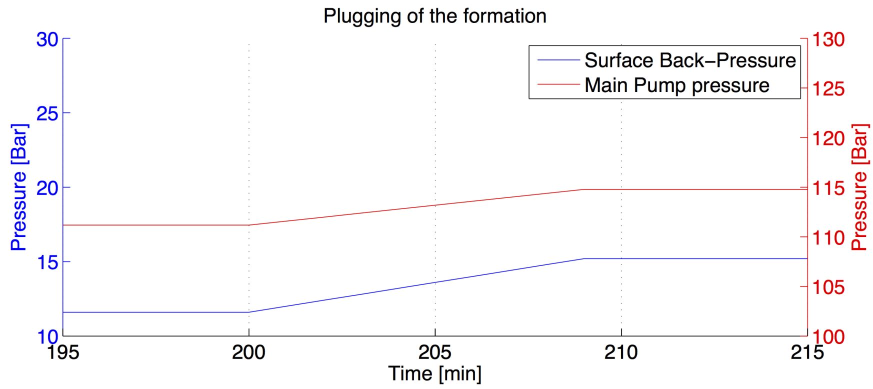

Figure 6.13: PMCD - Increase in pump pressure and SBP during plugging of the formation

When the second loss zone is encountered at 2850m and t=580min, the friction will drop as the new cave is more easily filled. *Figure* 6.14 shows this event. The difference is a decrease in friction factor, similar in both P_{pump} and SBP. This may cause some fluid to fall out of the mud cap, in that case bullheading is initiated.

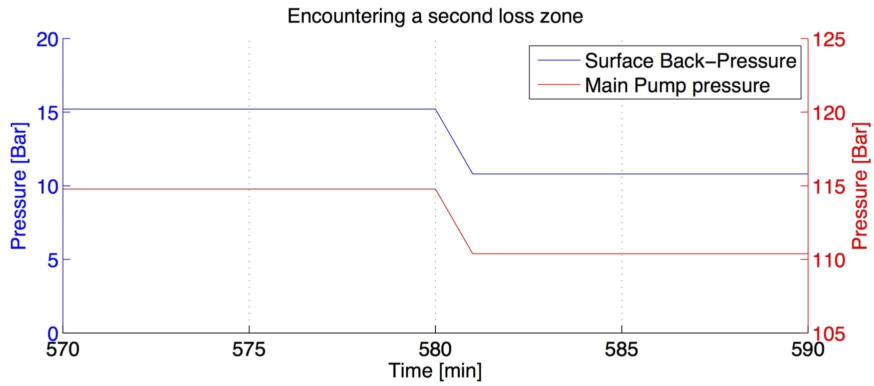

Figure 6.14: PMCD - Lower pump and SBP pressure once a new loss zone is encountered

Chapter 7

Discussion & Evaluation

This chapter will discuss the main challenges with deep-set carbonates and why they are important to investigate. The literature study in this thesis will be used to evaluate the potential of PMCD in the specific environment, in addition to debating the model and simulation to validate the outcome. At the end there will be a general discussion of certain aspect about the thesis that needs to be addressed and recommendation for further work.

7.1 Challenges with Deep-set Carbonates

The main challenge found with drilling of carbonates is lost circulation, often of catastrophic magnitude. The naturally existing fractures and vugs in carbonates can consume large volumes and result in a virtually non-existing drilling window. Deep-set carbonates showed to contain large amounts of gas in addition to the oil. Both normal and induced kicks are commonly occurred, adding further challenges to a drilling operation.

7.1.1 Why is this Important to Investigate?

The reason for investigating deep-set carbonates were due to the vast potential of this sedimentary rock. It is estimated that 60% of the remaining oil and 40% of remaining gas is located within carbonate reservoirs. These formations could hold the solution for keeping up with the worldwide increase in energy demand.

However, the most common techniques, specifically conventional drilling and CBHP, struggles with taming the extreme losses frequently encountered in deep-set carbonates. Conventional drilling operates with large overbalance, working against requirements for safely drilling such reservoirs. The lack of precise control and ability to quickly adapt further complicates an operation. CBHP was developed to address these shortcomings and do it rather well. The drawback is that in a total loss scenario, both are relying on time consuming and costly LCM, cement or other means of plugging the formation to allow further drilling. To be able to overcome these challenges one has to understand the heterogeneous nature of the reservoir. “New tools, techniques, and interpretation methodologies are required to address the specific challenges above to drill and produce these reservoirs optimally (Schlumberger, 2014).” It was therefore of interest to study PMCD.

7.2 Potential of PMCD

Throughout this master thesis, the different methods are explained with advantages and disadvantages along the way. Based on the theoretical knowledge only, PMCD clearly offers a better solution in a total losses scenario. Where conventional drilling and CBHP is relying on time consuming and costly LCM, cement or other means of plugging the formation, PMCD works at its optimal. Fighting losses and kicks has been the main source of NPT in these high-risk zones.

Cost is an important aspect of a drilling operation, especially when considering the amount of wells that are drilled in a single field. Small reductions can have large financial benefits. By excepting losses and working along side it, PMCD is able to mitigate a majority of the previously described NPT. Kicks are efficiently bullheaded back into the formation. With the combination of an underbalanced mud cap and seawater as drilling fluid, PMCD is able to further reduce the cost:

- Low overbalance:
  - Increased ROP, less expensive rig time
  - Better hole cleaning due diminished hold down effect on cuttings
  - Reduced risk of stuck pipe
- Less expensive mud is lost to the formation
- Avoiding costly handling of cuttings, especially with OBM
- Seawater does not reduce reservoir productivity as with LCM etc.

Although cost is crucial, it should not be given priority at the expense of safety. "Drilling of multiple total loss zones conventionally had proven to be highly uneconomic and highly likely to jeopardize safety of the operations (Han Sze et al., 2013)." PMCD is able to use almost all of the equipment and advantages that comes with regular MPD, besides choke and Coriolis flowmeter as there are no returns. The closed-circulation system reduces potentially dangerous emission on the rig, whilst having quick detection of kicks and a low reaction time. In combination with the SBP, irregularities in annulus fluid level are avoided in the event of fluctuations in formation pressure, keeping a more constant BHP. The ability of examining well conditions based on flow and cuttings is lost, though SBP, pump pressure, torque & drag have shown to be sufficient indicators. For this reason it is important to keep the well full at all times to be able to have pressure communication. As a conclusion, PMCD is capable of maintaining a higher level of safety in fractured and karstified carbonates compared to other techniques.

An essential and unique side of PMCD must be addressed; wells cannot be drilled using this technique alone as it is reliant on total losses to function. This is where the disadvantages start. CBHP is normally used a contingency where conventional drilling fails, but will also be operational throughout an entire well. Either of these will have to be used until sufficient losses are met. Then, and only then, will PMCD be applicable. Should the well then again start to flow, it will have to revert back to one of the other two. This scenario could potentially be dangerous if the BOP is not closed or the choke opened. Pressure could build up at the surface and damage crucial equipment, perhaps making a hole in the closed-circulation system. PMCD clearly lacks versatility, though MPD as a whole has great versatility.

Several possible operations will require more planning, specialized personnel, and equipment. Space on the rig can become an issue. The highly automated system used in MPD may also lead to a false sense of security. MPD is said to be expensive, though the author was not successful in finding a price estimate. Given the fact that there is no guarantee of fractures and karst caves being present, operators might take a calculated risk and use only LCM etc. as a contingency. For production wells with existing knowledge about the formation at hand, this might be valid. Though in exploration wells, having large uncertainties, MPD equipment should at least be available on the rig. Reaching TD is non-negotiable in exploration drilling, failure to do so will render the well useless. As there is an increasing need for more hydrocarbons in the world, it is important that deep-set carbonates are explored. Should PMCD be needed in an exploration well, they will gain experience and most likely reach TD in a safer manner. This will make it easier for an operator to use PMCD further and to explore more carbonates. Should it not be needed, they will have gained knowledge about the formation and can take better calculated risk for the production wells.

7.2.1 Field Results

PMCD is not yet fully accepted by the industry, most of the wells found are located in Asia. One can argue that the reason for is that many of the promising deep-set carbonates are found here, but the unconventional nature of PMCD is most likely a part of the equation. Still, the wells presented in *Chapter* 4 showed promising results for PMCD, backing up the theoretical assessment. Every well was initially drilled conventionally before encountering serious losses, some with following gas migration.

In two of the wells, previous experiences lead to the operator having MPD equipment as a contingency. During the entire drilling campaign in Qatar, the operator was able to save 30 rig days on this decision, with no NPT or accidents. In offshore Indonesia, only a few of the wells that were planned encountered losses. On the other hand, the money saved on the ones that did, was more than enough to pay for MPD services on all the wells, twice. In onshore Indonesia, the operator learned about the nature of carbonates the hard way. After weeks and months of NPT, MPD and PMCD was proposed as a solution. The operation was successful and without any accidents or NPT, only using 19 hour to finish the section. In addition to saving hours of NPT, the operators gained a benefit: they got experience with PMCD and is able to reach otherwise inaccessible reservoirs, where others dear not go. New and improved methods evolved along the way, efficiency where improved and all of the operators have continued the use of PMCD in these areas.

A discovery that is worth mentioning, is that all of the experience that is available, are positive experiences. This gives a rather one sided comparison of PMCD and makes it hard to determine its disadvantages.

7.2.2 Post-drilling Activities

A drawback with PMCDs ability to work along side losses is that the post-drilling activities will have to be performed in the same environment. As the zone is not sealed off, running of liner, cementing, logging and completing the well is carried out during total losses. The operations becomes more complicated. Expensive equipment might get stuck or damaged, also making it hard to evaluate a formation in an exploratory well. Trying to stop the losses would diminish PMCDs advantage on NPT. The DIV showed to be effective in reducing these drawbacks, whilst also providing additional safety during a drilling operation. Should a DIV not be installed in the previous casing, extended bullheading over a large period of time is also a good option. As the well shuttle and the unique cementing procedures have performed excellent, post-drilling activities can be done almost as quickly as with conventional. These are good examples on how a collective industry can achieve great things.

7.3 Model and Simulation

The objective of making a model was to more clearly show the physics behind PMCD, its procedures, and to be able to validate the advantages in a "real" scenario. The model was based on the simple, yet highly intelligent Kaasa model and was implemented in MATLAB, performing an operation through a gas bearing "cave" in a deep-set carbonate environment. Founded on experience and valid assumptions, Kaasa was able capture the dominating hydraulics of an MPD. The model also effectively shows some of MPDs benefits, the ability of having better control on well parameters and quickly reacting to changes in the well. For the simulation purpose in this master thesis, it was further simplified into a static model, making it easier to implement in MATLAB and still having enough accuracy to clearly demonstrate an operation. The simulations showed how PMCD will outperform CBHP, and consequently conventional drilling, in fractured and karstified carbonates.

Conventional drilling was not used in the simulation due to the comparison of pressure profiles in the specific drilling window. CBHP provided a lower overbalance and having MPD equipment installed will reduce time spent on a transition to PMCD mode. From the transition, gas migration and friction contribution was calculated. Even though PMCD is conducted in the blind, it was able to identify the most common occurrences in an operation by reading SBP and pump pressure.

Plugging and cleaning up of the formation was clearly recognized. Hole cleaning was also shown as plugging of the formation, a better indicator would have been torque & drag. A connection of pipe was simulated and it was displayed how this can be done safely even with no flow through the drillstring. Kick was seen as a rise in SBP and effectively bullheaded back into the formation once at a predetermined pressure. This simulated kick scenario was compared against a real operation, *Figure* 6.10 on page 64, in a similar environment. They were quite similar, but the graph was more precise. The above occurrences were only showed by themselves in the simulation, in a real scenario they will occur repeatedly and at the same time. *Figure* 6.10 also took into account stops of circulation due to hole cleaning and hook high as the string is run up and down. Even though the simulation could not capture every aspect of an drilling operation, it was accurate in displaying PMCDs procedures and advantages, also validating the outcome of the literature study.

7.3.1 Source of Error

In addition to the simplifications in the Kaasa model, compressibility and change in annulus volume where neglected. The well was assumed to have a constant cross sectional area in the entire annulus and the friction equation was simplified. These are vital in a real operation and would have affected pressures in the simulation. The carbonate environment was self-made by using examples from a book and a graph from a real operation, but may not be accurate in reflect a real environment.

7.4 General Discussion

The techniques that were reviewed in this master thesis are conventional drilling, CBHP, and PMCD, though there were other mentioned along the way. Dual Gradient, HSE, Floating Mud Cap Drilling and Under-Balanced Drilling are all good methods, but were considered to be inferior techniques for deep-set carbonates.

Another aspect that must be addressed is the use of a underbalanced fluid column in CBHP and PMCD. On page 40 it was said that: "MPD can have a mud weight gradient below, equal to or above the pore pressures gradient, compensating with P_c to have a pressure profile that is in the range of what is required." This statement is theoretical, requirements may restrict the use of an underbalanced fluid column. In the event of a riser disconnect, the well must have two barrier. If the fluid column is underbalanced, BOP will be the only remaining barrier. In the case of PMCD, it was said on page 28 that the LAM fills the entire annulus. Considering Riser Margin, the option of using the previous mud below the BOP and lighter fluid above, is better. During a disconnect, a higher mud weight below the BOP would be beneficial regarding requirements and safety.

7.5 Further Work

Due to discoveries made during writing of this thesis and limited by the time frame, further work is recommended:

- Further investigate the disadvantages and negative experience with PMCD.
- Make a dynamic model for PMCD and take into account the change in annulus volume and also the bulk modulus of the fluids. Use data from a real operation for a more authentic simulation. Simulate with torque & drag as it is an excellent indicator on hole cleaning.
- This thesis focused on gas bearing carbonates. Do similar research on PMCD in a liquid bearing carbonate formation.
- Compare drilling of vertical vs. horizontal wells with PMCD.

Chapter 8

Conclusion

In this master thesis PMCD has been reviewed. The potential of and challenges with these reservoirs have been investigated, and PMCD was compared against conventional and CBHP as a way of successfully drilling this valuable resource. Based on the discussion in *Chapter* 7, the following conclusion can be made:

- Theoretically, PMCD offers a better solution for drilling of deep-set carbonates than any other technique. NPT is reduced, cheaper materials are used, and safety is maintained at higher level.
- Previous field experience supports the theoretical conclusion, but lacks negative involvement and gives a rather one sided comparison. The drawback with post-drilling activities have been solved and it is now possible to perform these in almost the same time as with conventional methods.
- PMCD lacks versatility and is not yet fully accepted by the industry, but MPD as a whole has great versatility. MPD and PMCD should as a minimum be used as a contingency in explorations wells to have a higher chance of deep-set carbonate reservoir being developed.
- The model and simulation were effective in showing the physics behind PMCD, its procedures, and validating its advantages even though the model and carbonate environment was highly simplified.
- A dynamic model that includes the change in annulus volume and the fluids bulk modules should be made, along with acquiring data from a real operation to have a more authentic simulation.
- Further investigate drilling of liquid bearing carbonate formation with PMCD. Compare drilling of vertical vs horizontal wells in deep-set carbonates.

Nomenclature

Abbreviation	Definition
AFP	Annulus Friction Pressure
ACS	Automatic Control System
BBL	Barrels
BCF	Billon Cubic Feet
BDO	Bentonite Diesel Oil
BHA	Bottom-Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blow-Out Preventer
BPP	Back-Pressure Pump
CBHP	Constant Bottom-Hole Pressure
CCS	Continuous Circulation System
DG	Dual Gradient
DIV	Downhole Isolation Valve
ECD	Equivalent Circulating Density
ERD	Extended Reach Drilling
FIT	Formation Integrity Test
FMCD	Floating Mud Cap Drilling
IADC	International Association of Drilling Contractor

Abbreviation	Definition
HSE	Health, Safety & Environment
LAM	Light Annular Mud
LWD	Logging While Drilling
LCM	Lost Circulation Material
MCD	Mud Cap Drilling
MD	Measured Depth
MPD	Managed Pressure Drilling
MSBP	Maximum Surface Back-Pressure
NPT	Non-Productive Time
OBM	Oil-Based Mud
PWD	Pressure While Drilling
PMCD	Pressurized Mud Cap Drilling
PI	Productivity Index
ROP	Rate Of Penetration
RFC	Returns Flow Control
RCD	Rotating Control Device
SAC	Sacrificial Fluid
SBP	Surface Back-pressure
SF	Safety Factor, 1.5 - 2
SMP	Subsea Mud Pump
SPP	Stand Pipe Pressure
TD	Target Depth
TVD	True Vertical Depth
UBD	Under-Balanced Drilling
WBM	Water-Based Mud

Symbols

Symbol	Definition
β	Bulk modulus (Pa)
g	9,81 (m/s^2)
h	Depth (m)
ID/OD	Inner diameter & Outer Diamater (m)
k_c	Choke constant
M	Integrated density per cross-section over the flow path
P	Pressure (Pa)
$\dot{P}$	Change pressure over time (Pa)
$\triangle P$	Increase in pressure caused by friction (Pa)
q	Volume flow rate (m^3/s)
$\dot{q}$	Volume flow rate (m^3/s)
ρ	Density (kg/m^3)
V	Volume (m^3)
$\dot{V}$	Change in volume over time (m^3/s)
V_{gm}	Gas Migration Rate (m/min)
z_c	Choke position (%)
Subscript	
$_{ann}$	Annulus
$_{dp}$	Drillpipe
$_{ds}$	Drillstring
$_{c}$	Choke
$_{frac}$	Fracture
$_{topfrac}$	Top of the fractured zone

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Appendices

Appendix A - MPD Equipment

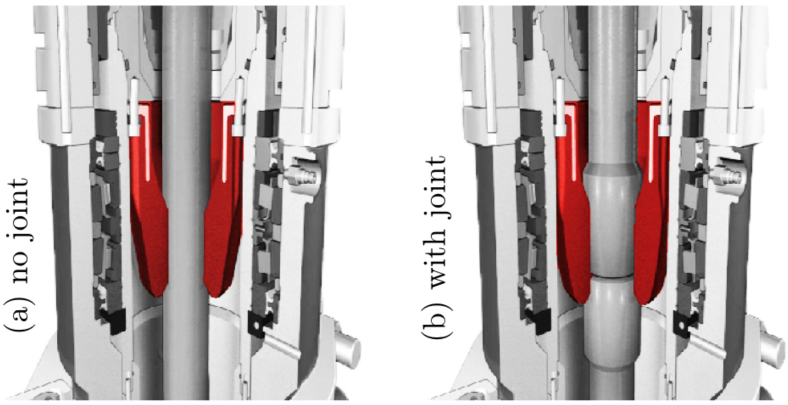
There are a variety of different tools available, some are optional, while others are mandatory. The optional once are dependent on needs, budget, space on the rig etc. As a minimum, to be able create a closed-circulation system, three are mandatory:

- Rotating Control Device
- Non-Return Valves
- Choke

With these three, a closed circulation is achieved and the choke allows control of the pressure profile. The following equipment is based on description from (Bill Rehm et al., 2008; Godhavn, 2012).

Rotating Control Device

The Rotating Control Device (RCD) is one of the most important parts of an MPD operation. Its main objective is to seal off the annulus, providing a closed system during drilling, pipe connections and tripping. Returns are directed from the annulus and through the choke. Due to fatigue, annular preventers in the BOP can not seal the annulus during rotation of the pipe.



(a) no joint

(b) with joint

Figure 8.1: How RCD provides a sealing mechanism (Chrzanowski, 2011)

There are two types of RCD, active and passive, the latter being by far the most common. The difference is how it is actuated, passive is actuated by well pressure and the active by force from a hydraulic ram. Focusing on the passive, it has a packer that is force fit onto the drillstring due to its undersized nature. Further sealing will be provided from the annular pressure exerted from below. The sealing element is connected to a bearing pack that allows it to rotate.

Choke and Back-pressure Pump

A choke manifold is what gives MPD the ability of precisely control of the annual pressure profile throughout the wellbore. It contains a closure element that can be adjusted narrower or wider, depending on desired pressure. Return mud goes through this element and a more narrow flow path will restricting flow and increase back-pressure in the well. A wider flow path will then naturally decrease back-pressure.

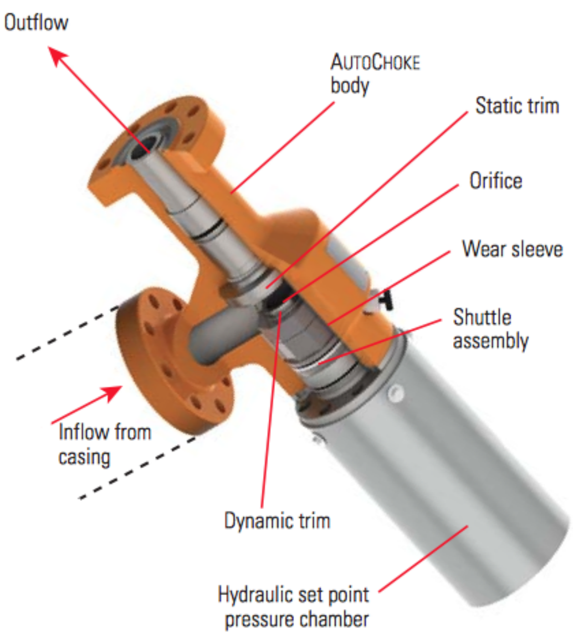


Figure 8.2: Choke manifold (Godhavn, 2012)

There are three categories of choke closure elements that are used with MPD: Shuttles, sliding plates and choke gates. The elements can be automatically or manually adjusted to provide the back-pressure needed to achieve a pressure gradient within the drilling window. In case of repairs or service, there will always be at least two chokes in parallel.

Seen in *Figure* 3.2, the choke can be combined with a BPP that does not divert flow down the well, but instead through the choke only. Back-pressure is dependent on the flow rate going through it, so this will increase the available back-pressure. It also allows for applying a back-pressure during stops of circulation.

Non-Return Valves

At some point during the operation, circulation might be stopped and back-pressure is applied to maintain BHP. To prevent fluid from going up the drillstring, Non-Return Valves are installed inside the pipe. This piece of equipment will allow flow down the pipes, but not upwards. Upwards movement of fluid with cuttings could plug the motor and cause damage inside the Bottom-Hole Assembly (BHA). This is called the U-Tube effect.

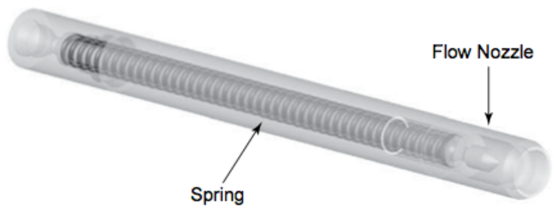


Figure 8.3: Non-Return Valve (Bill Rehm et al., 2008)

Continuous Circulation System

Circulation is important for well stability, hole cleaning, and avoiding kicks. Drilling fluid goes through the top drive, which is connected to the drillstring, and provides circulation in the well. During tripping and connections, circulation is normally stopped. A system has been developed to solve this issue, a Continuos Circulation System (CCS) module is placed on top of the rotary table.

Described shortly, this creates a chamber for the connection by sealing above and below it, while a hose provides mud flow into the compartment and down the string. A seal further up is used to allow pressure equalization in order to add or remove pipe in the chamber.

Coriolis Flowmeter

The Coriolis flowmeter is used for Early Kick Detection (<0,5 bbl) by leading the flow through a U-shaped tube.

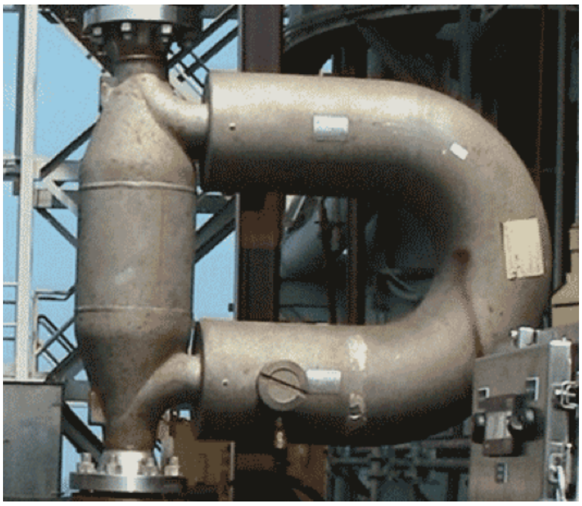


Figure 8.4: The Coriloris Flowmeter (Godhavn, 2012)

The meter measures and calculates:

- Mass flow
- Volumetric flow
- Density
- Temperature

Flow going through the U-tube creates vibration at a certain frequency, difference in frequency between the inlet and outlet is used to calculate the mass flow. An increase in mass will decrease frequency. Any gas in the drilling fluid will be picked up quickly.

ECD Reduction Tool

While circulating a fluid, friction from the drillpipe, BHA, and wellbore will cause an increase in BHP. This can become so high that it is difficult to stay within the pressure window and it must be reduced. An ECD reduction tool is driven by hydraulic force from the circulation fluid inside the drillstring and turns it into mechanical power to help fluid in the annulus upwards. This then decreases the effect of pressure drop from circulation in the annulus.

Automatic Control System

To be able to adapt and respond fast to any changes that might occur, MPD is used with an Automatic Control System (ACS). ACS gives the operator an overview of all parameters in the well and on the rig. The system is driven by the hydraulic model, getting input from:

- Flow rates
- Pressure readings
- Choke position
- Mud density

The ACS will control the Back-Pressure Pump and choke, enabling quick manipulation of the pressure profile.

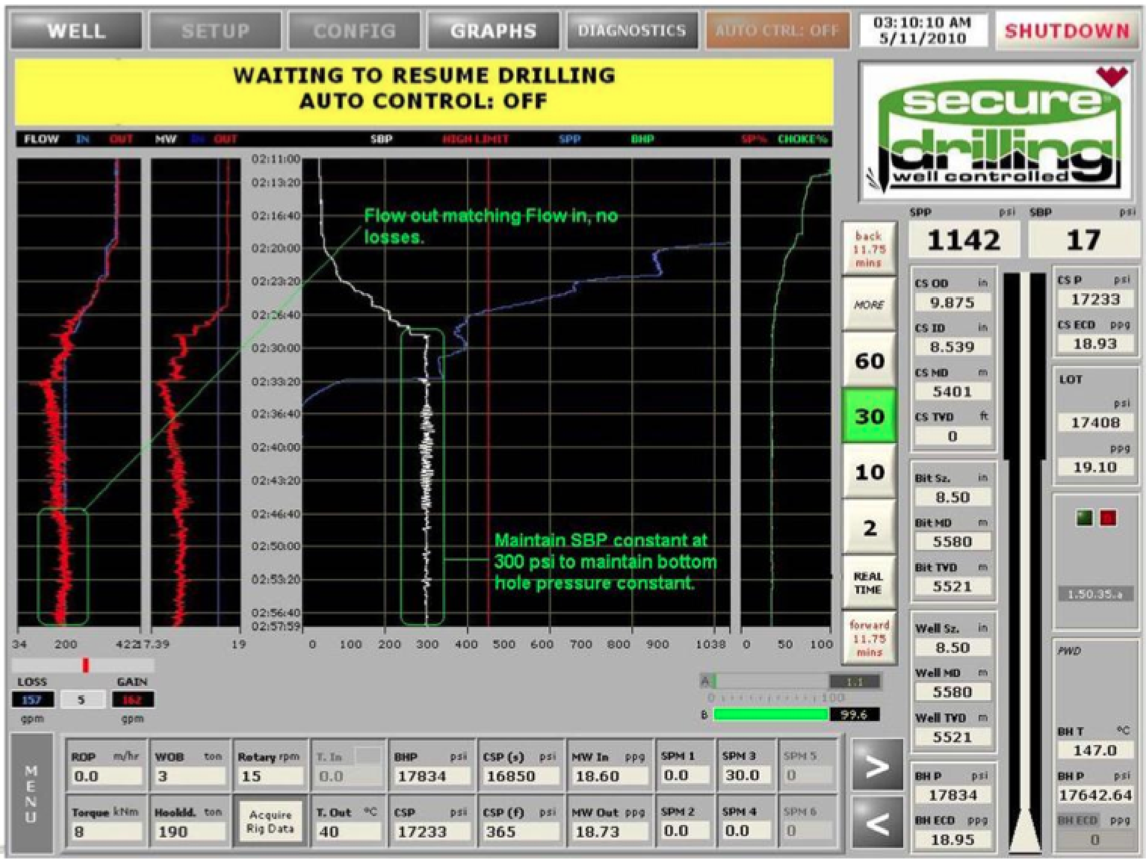


Figure 8.5: ACS during a connection (Godhavn, 2012)

Appendix B - Weatherford - PMCD Setup

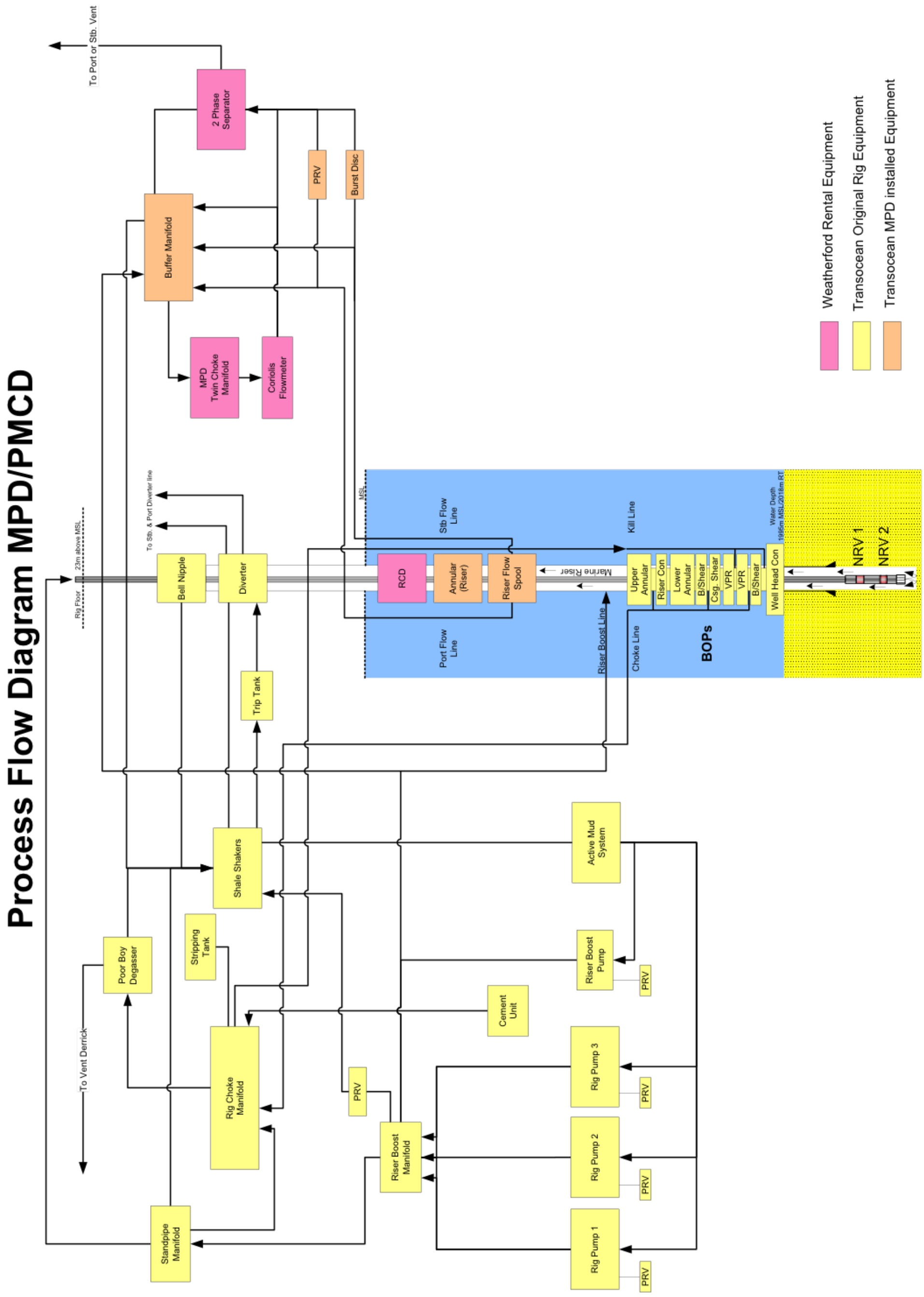


Figure 8.6: Weatherfords MPD/PMCD setup (Robertson, 2013)

Appendix C - Overview of the Simulated Well

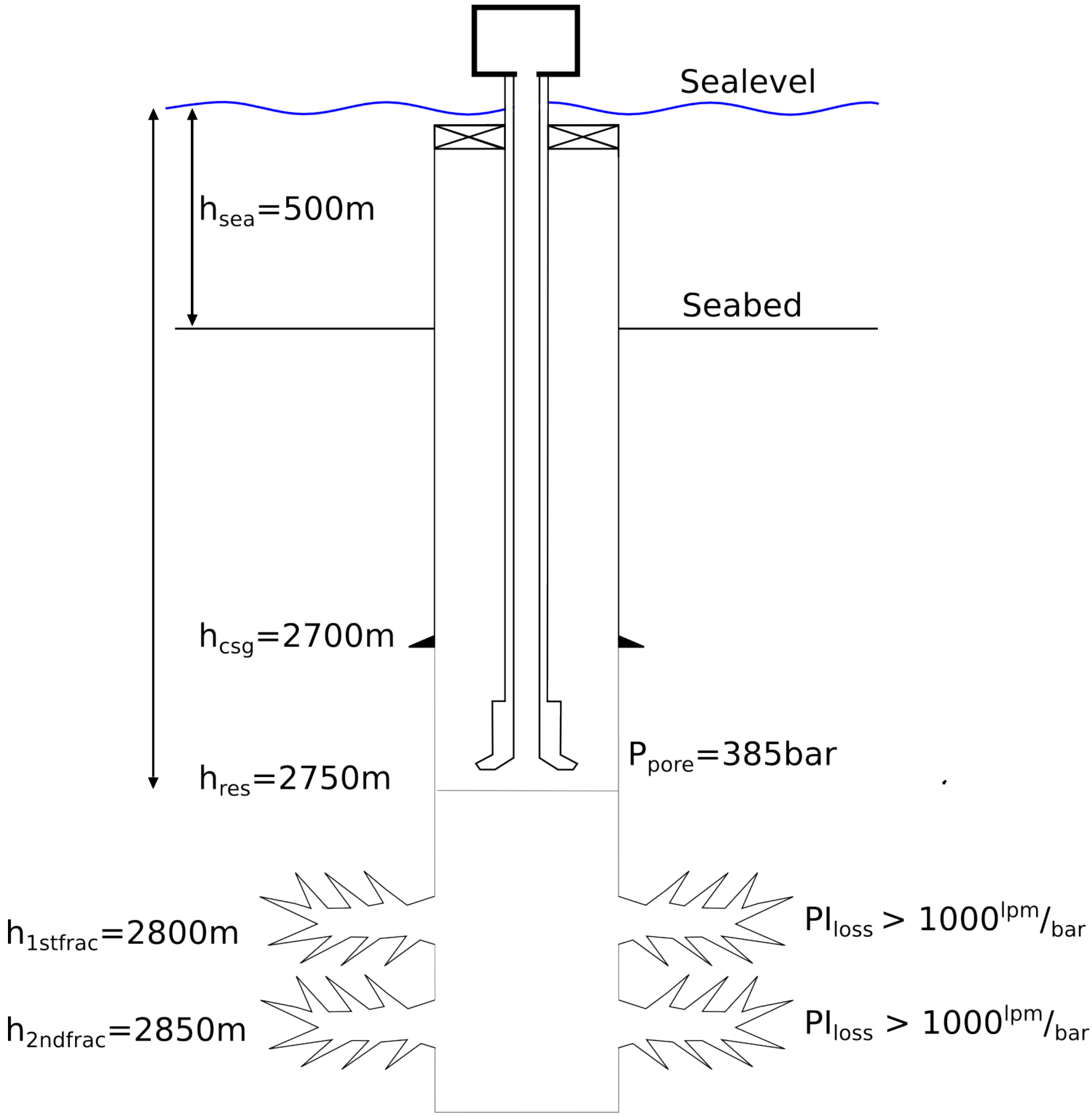


Figure 8.7: Overview of the well

Appendix D - Kick and Bullheading Cycles in PMCD

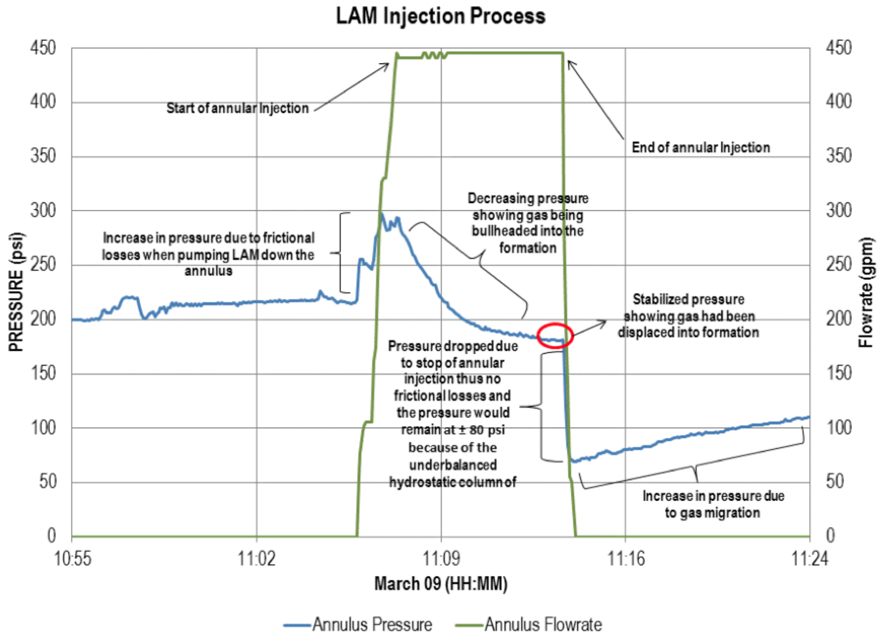


Figure 8.8: Detailed explanation of the kick and bullhead cycle (Rojas et al., 2013)

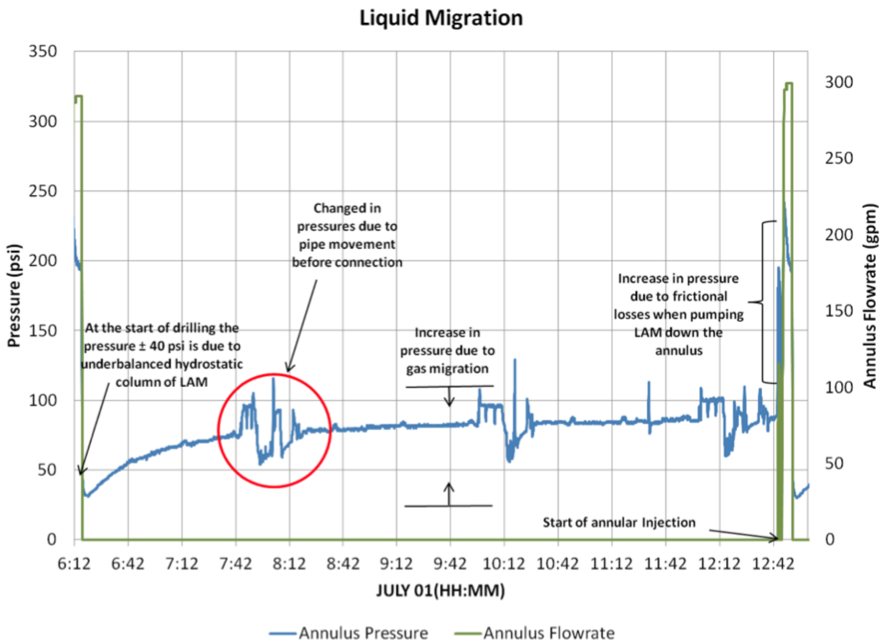


Figure 8.9: Kick and bullhead cycle in liquid bearing carbonates (Rojas et al., 2013)

Appendix E - MATLAB Code

Comparison of Techniques in the Specific Drilling Window

```
%% Comparison of techniques in the specific drilling window%%%%%%%%%%%%%%

%Clearing and closing previous variables and plots
clear all
close all

%Time parameter
maxtime=10000;              %Maximum time (min)
dt=0.001;

%Array initialization
BHP_ann_conv_ar=zeros(maxtime,1);
BHP_ann_CBHP_ar=zeros(maxtime,1);
BHP_ann_PMCD_ar=zeros(maxtime,1);
p_pore_ar=zeros(maxtime,1);
p_frac_ar=zeros(maxtime,1);
depth_ar=zeros(maxtime,1);
BHP_ann_convreduced_ar=zeros(maxtime,1);
BHP_ann_CBHPreduced_ar=zeros(maxtime,1);

%Flow rates
q_p = 2;                    % Flowrate from Pump (m^3/min)
q_b=q_p;                    % Flowrate through Bit m^3/min)

%Reservoir parameter
q_loss=0;                % Initially no losses to the formation
q_res=0;                 % Initially no influx from the formation
p_poregrad_res=0.03e5;   % Pore pressure gradient of the reservoir(Pa/m)
p_poregrad=0.14e5;       % Pore pressure gradient of the overburden(Pa/m)
p_pore_csg=378e5;        % Pore pressure at the previous set csg shoe (Pa)
p_pore_topres=385e5;     % Pore pressure at the top of the reservoir (Pa)
p_pore_1stfrac=386.5e5;  % Pore pressure at the 1st fracture (Pa)
p_pore_2ndfrac=388e5;    % Pore pressure at the 2nd fracture (Pa)

% Well parameters
Fd= 1e5;                % Friction factor of drillstring
Fb = 5e4;               % Friction factor through bit
Fa = 2e5;               % Friction factor of annulus
Ff=1e5;                 % Friction factor penetrating the fractures
rho_m = 1455;           % Density of fluid in the annulus (kg/m^3)
rho_m_reduced=1420;     % Reduced density of fluid in the annulus (kg/m^3)
rho_gas=204;            % Density of gas in formation (kg/m^3)
rho_sac=1030;           % Density of gas in formation (kg/m^3)
rho_CBHP=1400;          % Density of fluid in the annulus (kg/m^3)
rho_CBHP_reduced=1250;  % Reduced density of fluid in the annulus (kg/m^3)
g = 9.81;               % Gravity constant (kgm/s^2)
h_csg=2700;             % Distance drilled (m)
h_topres=2750;          % Depth of reservoir (m)
h_1stfrac=2800;         % Depth of 1st fracture (m)
h_2ndfrac=2850;         % Depth of 2nd fracture (m)
h_TD=2900;              % Depth of Target Depth (m)
OD=0.1;                 % Outer diameter of the drillpipe (m)
ID=0.2;                 % Inner diameter of the annulus (m)

%Choke Parameters for CBHP
z_c=0.6;                % Choke Position
z_c_reduced=0.092;      % Reduced choke position
k_c = 0.375;            % Choke Constant

%Desired Surface_back Pressure for PMCD
SBP_desired=10e5;

% Initial Values
h_drilled=h_csg;
```

```
%% Main Iteration
for time=1:maxtime
%% Drilling operation
h_drilled=h_drilled+0.1;
depth=h_drilled;

%% Drilling window
% Pore Pressures
if (depth>=h_csg) && (depth<h_topres)
   p_pore=p_poregrad*h_drilled;
end

if (depth>=h_topres)
   p_pore=p_pore_topres+p_poregrad_res*(h_drilled-h_topres);
end

% Fracture Pressures
if (depth<h_topres)
   p_frac=p_pore+30e5;
end

if (depth>h_topres) && (depth<h_1stfrac)
   for eulerstep = 1:(1/dt)
   p_frac_dot=(250-h_drilled*5+h_topres*5)*44.9;
   p_frac=p_frac-p_frac_dot*dt;
   end
end
if (depth>=h_1stfrac)
   p_frac=p_pore+5e4;
end

%% Equations for the different methods

%Conventional drilling
p_fric_ann=(Fa*(q_b)^2)*(h_drilled/h_TD);
BHP_ann_conv=rho_m*g*(h_drilled)+p_fric_ann;
BHP_ann_convreduced=rho_m_reduced*g*(h_drilled)+p_fric_ann;

% CBHP
p_fric_ann=Fa*(q_b)^2;
q_c=q_b+q_res-q_loss;
p_c=(((q_c)/(z_c*k_c))^2)*rho_CBHP;
p_c_reduced=(((q_c)/(z_c_reduced*k_c))^2)*rho_CBHP_reduced;


BHP_ann_CBHP=rho_CBHP*g*h_drilled+p_fric_ann+p_c;
BHP_ann_CBHPreduced=rho_CBHP_reduced*g*h_drilled+p_fric_ann+p_c_reduced;


% PMCD
delta_p_frac_sac=Ff*(q_b^2);
rho_lam=((p_pore_1stfrac)/(g*h_1stfrac))-((SBP_desired)/(g*h_1stfrac));
SBP=SBP_desired;


if (depth<=2800)
    BHP_ann_PMCD=rho_lam*g*h_drilled+SBP;
end

if (depth>2800)
    BHP_ann_PMCD=rho_lam*g*h_1stfrac+SBP_desired+rho_sac*g*...
        (h_drilled-h_1stfrac);
end

% Store parameter
BHP_ann_conv_ar(time)=BHP_ann_conv;
BHP_ann_CBHP_ar(time)=BHP_ann_CBHP;
BHP_ann_PMCD_ar(time)=BHP_ann_PMCD;
p_pore_ar(time)=p_pore;
p_frac_ar(time)=p_frac;
depth_ar(time)=depth;
BHP_ann_convreduced_ar(time)=BHP_ann_convreduced;
```

```
BHP_ann_CBHPreduced_ar(time)=BHP_ann_CBHPreduced;
end
%% Figure
% Drilling window
figure;
plot(p_pore_ar*10^-5,depth_ar,'-r',p_frac_ar*10^-5,depth_ar,'-b');
xlim([370 450])
set(gca,'XTick',(370:10:450))
ylim([2700 2900])
set(gca,'YTick',(2700:50:2900))
axis ij
set(gca, 'fontsize', 14);
title('Drilling window');
legend('Pore Pressure','Fracture Pressure');
xlabel('Pressure [Bar]');
ylabel('Depth (TVD) [m]');

% Conventional
figure;
plot(BHP_ann_conv_ar*10^-5,depth_ar,'-k',BHP_ann_convreduced_ar*10^-5,...
    depth_ar,'--k',p_pore_ar*10^-5,depth_ar,'-r',p_frac_ar*10^-5,...
    depth_ar,'-b')
xlim([370 450])
set(gca,'XTick',(370:10:450))
ylim([2700 2900])
set(gca,'YTick',(2700:50:2900))
axis ij
set(gca, 'fontsize', 14);
title('Conventional drilling');
legend('Well Pressure', 'Reduced mudweight','Pore Pressure',...
    'Fracture Pressure');
xlabel('Pressure [Bar]');
ylabel('Depth (TVD) [m]')

% CBHP
figure;
plot(BHP_ann_CBHP_ar*10^-5,depth_ar,'-k',BHP_ann_CBHPreduced_ar*10^-5,...
    depth_ar,'--k',p_pore_ar*10^-5,depth_ar,'-r',p_frac_ar*10^-5,...
    depth_ar,'-b');
xlim([370 450])
set(gca,'XTick',(370:10:450))
ylim([2700 2900])
set(gca,'YTick',(2700:50:2900))
axis ij
set(gca, 'fontsize', 14);
title('CBHP');
legend('Well Pressure','Reduced mudweight','Pore Pressure',...
    'Fracture Pressure');
xlabel('Pressure [Bar]');
ylabel('Depth (TVD) [m]')

% PMCD
figure;
plot(BHP_ann_PMCD_ar*10^-5,depth_ar,'k',p_pore_ar*10^-5,depth_ar,...
    'r',p_frac_ar*10^-5,depth_ar,'b');
xlim([370 450])
set(gca,'XTick',(370:10:450))
ylim([2700 2900])
set(gca,'YTick',(2700:50:2900))
axis ij
set(gca, 'fontsize', 14);
title('PMCD');
legend('Well Pressure','Pore Pressure','Fracture Pressure');
xlabel('Pressure [Pa]');
ylabel('Depth (TVD) [m]')
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
```

A Drilling Operation Through Total Loss Zones

```
%% Encountering total losses  %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

%Clearing and closing previous variables and plots
clear all
close all

% Time parameter
maxtime=1200;                %Maximum time (s)

%Array initialization
BHP_ann_ar=zeros(maxtime,1);
SBP_ar=zeros(maxtime,1);
q_bullhead_ar=zeros(maxtime,1);
z_c_ar=zeros(maxtime,1);
p_c_ar=zeros(maxtime,1);
p_pump_main_ar=zeros(maxtime,1);
q_pump_main_ar=zeros(maxtime,1);

%Flow rates
q_pump_main = 2;         % Flowrate from the main pump (m^3/min)
q_b=q_pump_main;         % Flowrate through Bit (m^3/min)
q_bpp=0.8;               % Flowrate from the Back-Pressure Pump (m^3/min)

%Reservoir parameter
q_loss=0;                % Initially no losses to the formation
q_res=0;                 % Initially no influx from the formation
p_poregrad_res=0.03e5;   % Pore pressure gradient of the reservoir(Pa/m)
p_poregrad=0.14e5;       % Pore pressure gradient of the overburden(Pa/m)
p_pore_csg=378e5;        % Pore pressure at the previous set csg shoe (Pa)
p_pore_topres=385e5;     % Pore pressure at the top of the reservoir (Pa)
p_pore_1stfrac=386.5e5;  % Pore pressure at the 1st fracture (Pa)
p_pore_2ndfrac=388e5;    % Pore pressure at the 2nd fracture (Pa)

% Well parameters
Ff=5e4;                  % Friction factor penetrating the fractures
Fd=1e5;                  % Friction factor of drillstring
Fa=1e5;                  % Friction factor of annulus
Fb=5e4;                  % Friction factor through bit
rho_CBHPmud=1380;        % Density of fluid in the annulus (kg/m^3)
rho_gas=250;             % Density of gas in formation (kg/m^3)
rho_sac=1030;            % Density of SAC fluid (kg/m^3)
g = 9.81;                % Gravity constant (kgm/s^2)
h_csg=2700;              % Depth of last casing (m)
h_topres=2750;           % Depth of reservoir (m)
h_1stfrac=2800;          % Depth of 1st fracture (m)
h_2ndfrac=2850;          % Depth of 2nd fracture (m)
h_TD=2900;               % Depth of Target Depth (m)
OD=0.14;                 % Outer diameter of the drillpipe (m)
ID=0.21;                 % Inner diameter of the annulus (m)
A=(ID^2-OD^2)*(pi/4);    % Horizontal cross sectional area downhole
PI_frac=1000;            % Productivity index of the formation

% Initial Values
h_influx=0;              % No influx at start
q_bullhead=0;            % Bullhead rate (lpm)
h_drilled=2799;          % Start of drilling operation
h_mud=h_topres;          % Mud fills up the entire annulus
p_pump_main_old=0;       % Initially no change in Pump Pressure
delta_SBP=0;             % Initially no change in SBP
h_sacDP=0;               % Initially no SAC fluid in drillpipe
h_lam=0;                 % Initially no LAM in the well
delta_p_migration=0;     % Initially no gas migraton
BHP_ann=rho_CBHPmud*g*h_topres; % Initial Bottom Hole Pressure

% Choke Parameters
z_c= 0.25;               % Initial Choke Position
k_c = 0.4;               % Choke Constant
p_c=5.5e5;               % Initial Choke Pressure

% PMCD
```

```
SBP_desired=10e5;         % Desired Surface Back-Pressure
SF=2;                     % Safety factor when bullheading
h_CBHPmudDP=2799;         % Initial height of mud in the drillstring

 %% CBHP Iteration
for time=1:29

% Continous drilling until a cave is encountered after 500 min (2800m)
h_drilled=h_drilled+0.1;
p_pore=p_pore_topres+p_poregrad_res*(h_drilled-h_topres);

% Fracture pressure of the formation at 2800m
if (time>=10)
    p_frac=p_pore;
end

 %% Scenario
% Total losses encountered
if (time>=11) && (time<12)
    h_drilled=2800;                        % Stop drilling
    h_mud=h_drilled;                       % Height of mud in the annulus
    q_loss=PI_frac*((BHP_ann_CBHP-p_frac)*10^-5); % Loss rate
    q_b=0;                                 % No flow from bit and up
    q_pump_main=2;                         % Still flowing to prevent kick
end

% All fluid pumped down the drillstring is lost to the formation
if (q_loss>2)
    q_loss=2;
end

% Choke closes to prevent fluid from falling
if (time>=12)
    z_c=0;
end

% Bullheading is initated to try and fill the fractures or vugs
if (time>=14)
    q_pump_main=2;
    q_bullhead=2;
    h_drilled=2800;
end

% Bullheading is stopped to change from CBHP to PMCD
if (time>24)
   z_c=0;
   q_bpp=0;
   q_bullhead=0;
   h_drilled=2800;
end

%% Model
% Flow rate through choke
if (time<=10)
q_c=q_b+q_bpp+q_res-q_loss;
end

% No returns when the losses occur
if(time>=11)
    q_c=0;
end

% Friction pressure loss
delta_p_ann=Fa*(q_b)^2;                 % Along annulus, from drillstring
delta_p_frac_CBHP=q_loss*Ff;            % Into fracture, from drillstring
delta_p_bullhead=(Ff+Fa)*(q_bullhead)^2;% Along annulus and into fractures

% Choke pressure
p_c=((q_c/(z_c*k_c))^2)*rho_CBHPmud+delta_p_frac_CBHP+ delta_p_bullhead;

% If the choke is closed, the pressure will be balanced at the top of the
% cave or fractures. Pore pressure exerts a pressure on the mud column
if (z_c==0)
```

```
    p_c=p_pore_1stfrac-(rho_CBHPmud*g*h_mud)+delta_p_frac_CBHP+...
         delta_p_bullhead;
end

% Bottom hole pressure
BHP_ann_CBHP= rho_CBHPmud*g*h_drilled+delta_p_ann+...
    p_c-(Fa*(q_bullhead)^2)+delta_p_frac_CBHP;

%% Store parameters

BHP_ann_ar(time)=BHP_ann_CBHP;
z_c_ar(time)=z_c;
p_c_ar(time)=p_c;

end

%% Transition from CBHP to PMCD iteration

for time=30:99

  % Pore pressure
  p_pore=p_pore_topres+p_poregrad_res*(h_drilled-h_topres);

 % Initially only flow through drillstring. Dilute old mud for bullheading
 if (time>=30) && (time<31)
     q_bullhead=0;
     q_pump_main=2;
 end

%Determine LAM
rho_lam=((p_pore_1stfrac)/(g*h_1stfrac))-((SBP_desired)/(g*h_1stfrac));

%Changing from CBHP mud to LAM for PMCD by bullheading LAM down the
%annulus. Continue until SBP stabilzes.
if (time>=35) && (time<50)
    z_c=0;
    h_mud=h_1stfrac*((49-time)/14);
    h_lam=h_1stfrac*(time-35)/14;
    q_bullhead=2;
end

% Bullheading stops to see a stabilizing trend in SBP
if (time>=61)
   q_bullhead=0;
end

% Kick. Calculate gas migration rate
if (time>=66) && (time<71)
    q_res=q_res+0.1;
end

% Force out the kick by bullheading down the annulus
if (time>=71)
    q_bullhead=2;
    q_res=0;
end

% Switch from mud to SAC injection in drillstring.Continue bullheading
if (time>=76) && (time<77)
   q_pump_main=0;
   q_bullhead=2;
end

% Pumping down SAC and old mud is forced into the formation
if (time>=80) && (time<86)
   q_pump_main=2;
   h_CBHPmudDP=h_1stfrac*((85-time)/5);
   h_sacDP=h_1stfrac*(time-80)/5;
end

% Friction factor drops due to SAC fluid now penetrates the fractures
if (time>=86)
    Ff=4e4;
end

% Stop bullheading and continue drilling in PMCD mode
```

```
 if (time>96)
     q_bullhead=0;
 end

 %% Equations

 % Friction pressure loss
 delta_p_bullhead=(Ff+Fa)*(q_bullhead)^2;% Along annulus and into fractures
 delta_p_frac_sac=Ff*q_pump_main^2;      % Into fractures, from drillstring

 % Pressure on the main pump
 p_pump_main=(p_pore_1stfrac-(rho_CBHPmud*g*h_CBHPmudDP+rho_sac*g*...
     h_sacDP))+Ff*q_bullhead^2+(Ff+Fb+Fd)*q_pump_main^2;

 % Surface Back-Pressure
 SBP=p_pore_1stfrac-(rho_CBHPmud*g*(h_mud-(q_res/A))+...
     (rho_gas*g*(q_res/A))+rho_lam*g*h_lam)+delta_p_bullhead+...
     delta_p_frac_sac;

 % Bottom Hole Pressure
 BHP_ann=rho_lam*g*h_lam+rho_CBHPmud*g*(h_mud-(q_res/A))+...
     SBP-((Fa)*(q_bullhead)^2)+(rho_gas*g*(q_res/A));

 % Store parameters
 BHP_ann_ar(time)=BHP_ann;
 SBP_ar(time)=SBP;
 p_c_ar(time)=p_c;
 p_pump_main_ar(time)=p_pump_main;

 end

 %% PMCD drilling Iteration

 for time=100:maxtime

 %Drilling operation
 h_drilled=h_drilled+0.1;
 q_bullhead=0;
 p_pore=p_pore_topres+p_poregrad_res*(h_drilled-h_topres);

 %Initial values
 SBP_static=10e5;        % SBP due to underbalanced Mud Cap
 SBP_start=12e5;         % Increase due to friction from circulating SAC
 p_pump_main_start=1.117556750000000e7; % Initial pump pressure

 %% Encountering kicks

 % Gas migration up the mud cap
 if (time>110) && (time<=126)
     q_res=0.1;                      % Influx of 100lpm
     delta_p_migration= delta_p_migration+(rho_lam-rho_gas)*g*(q_res/A);
 end

 % Gas migration up the mud cap
 if (time>130) && (time<=146)
     q_res=0.1;                      % Influx of 100lpm
     delta_p_migration= delta_p_migration+(rho_lam-rho_gas)*g*(q_res/A);
 end

 % Gas migration up the mud cap
 if (time>150) && (time<=166)
     q_res=0.1;                      % Influx of 100lpm
     delta_p_migration= delta_p_migration+(rho_lam-rho_gas)*g*(q_res/A);
 end

 % Controller: Bullhead when SBP reaches 20 bar
if (SBP>20e5)
    q_bullhead=1;
end

if (SBP>=21e5)
    q_bullhead=1;
    q_res=0;
    delta_p_migration=0;
end

if (SBP<=13e5)          % Set at this value due to a 4 bar increase when
```

```
    q_bullhead=0;        % bullheading. These will be removed when
end                      % bullheading stops.

%% Connection of drillpipe

 % Stop drilling and bullhead before connection to push gas as far into
 % the formation as possible
 if ( time>180) && (time<=190)
     q_bullhead=1;
     h_drilled=2811;
 end

 % Connection is made, only circulation from bullheading
 if (time>=186) && (time<188)
     q_pump_main=0;
     h_drilled=2811;
 end

 % Connection is done and main pump is turned back on. Bullhead pump off
 if (time>=190)
     q_pump_main=2;
     q_bullhead=0;
 end

 %% Encountering difference in losses

 % Formation plugging, increase in friction factor
 if (time>=201) && (time<210)
     Ff=Ff+1e4;
 end

% Encountering second loss zone at 2850m, decrease in friction factor
if (time>=581)
    Ff=2e4;
end

 %% System

 % Friction pressure loss
 delta_p_fric_bullhead=(Fa*(q_bullhead)^2); % Along annulus
 delta_p_frac_bullhead=(Ff*(q_bullhead)^2); % Into fractures
 delta_p_frac_sac=Ff*(q_pump_main^2);     % Into fractures, from drillstring

 % Required pump pressure for bullheading
 p_pump_bullhead=SBP_static+delta_p_frac_sac+...
     delta_p_migration+delta_p_frac_bullhead+delta_p_fric_bullhead;

 % The pressure increase in SBP due to bulheading
 delta_p_bullhead=(delta_p_fric_bullhead+delta_p_frac_bullhead);

 % Pump pressure
 p_pump_static=p_pore_1stfrac-rho_sac*g*h_1stfrac;
 p_pump_main=p_pump_static+((Fb+Fd+Ff)*q_pump_main^2)+...
     delta_p_frac_bullhead;

 % Surface Back-Pressure
 SBP=SBP_static+delta_p_frac_sac+delta_p_migration+delta_p_bullhead;

 % Difference in surface pressures and pump pressure
 delta_p_pump=p_pump_main-p_pump_main_start;
 delta_SBP=SBP-SBP_start;

%% Model

 % Height of influx
 if (q_bullhead==0) && (q_pump_main==2)
 h_influx=(delta_SBP-delta_p_pump)/...
     ((rho_lam-rho_gas)*g);
 end

 % Hydrostatic pressure from the coloumn of LAM
 p_lam=rho_lam*g*(h_1stfrac-h_influx)+rho_gas*g*h_influx;

 % Well pressure at first fracture
 p_ann_1stfrac=SBP+p_lam-delta_p_fric_bullhead;
```

```
% Bottom Hole Pressure
% (Friction presssure loss from bullheading is lost down the drillstring)
BHP_ann=p_ann_1stfrac+rho_sac*g*(h_drilled-h_1stfrac);

%% Store parameters

BHP_ann_ar(time)=BHP_ann;
SBP_ar(time)=SBP;
q_bullhead_ar(time)=q_bullhead;
p_pump_main_ar(time)=p_pump_main;
q_pump_main_ar(time)=q_pump_main;

end

%% Figures

% CBHP
figure(1);
x=1:maxtime;
[AX,H1,H2]=plotyy(x,p_c_ar*10^-5,x,z_c_ar*100,'plot');
set(get(AX(1), 'YLabel'),'String','Pressure [Bar]','fontsize', 14);
set(H1, 'Color', 'b');
set(H2, 'Color', 'r');
set(AX(1),'XTick',5:5:30)
set(AX(1),'Xlim',[5 30]);
set(AX(1),'YLim',[0 20])
set(AX(1),'YTick',0:5:20)
set(AX(1),'box','off')
set(get(AX(2), 'YLabel'),'color','red','String','Choke Position [%]','fontsize', 14);
set(AX(2),'XTick',5:5:30)
set(AX(2),'Xlim',[5 30]);
set(AX(2),'YLim',[0 40])
set(AX(2),'YTick',0:5:40)
set(AX(2),'YColor','r');
set(gca,'Xgrid','on','box','off')
xlabel('Time [min]','fontsize', 14);
set(AX(1),'fontsize', 14)
set(AX(2),'fontsize', 14)
legend('Back-Pressure','Choke Position');
title('Back-Pressure during total losses at 2800m');

figure(2);
x=1:maxtime;
[AX,H1,H2]=plotyy(x,BHP_ann_ar*10^-5,x,z_c_ar*100,'plot');
set(get(AX(1), 'YLabel'),'String','Pressure [Bar]',...
    'fontsize', 14);
set(H1, 'Color', 'b');
set(H2, 'Color', 'r');
set(AX(1),'XTick',5:5:30)
set(AX(1),'Xlim',[5 30]);
set(AX(1),'YLim',[375 400])
set(AX(1),'YTick',375:5:400)
set(AX(1),'box','off')
set(get(AX(2), 'YLabel'),'Color','red','String','Choke Position [%]','fontsize', 14);
set(AX(2),'XTick',5:5:30)
set(AX(2),'Xlim',[5 30]);
set(AX(2),'YLim',[0 40])
set(AX(2),'YTick',0:5:40)
set(AX(2),'YColor','r');
set(gca,'Xgrid','on','box','off')
xlabel('Time [min]','fontsize', 14);
set(AX(1),'fontsize', 14)
set(AX(2),'fontsize', 14)
legend('Bottom Hole Pressure','Choke Position');
title('Bottom Hole pressure during total losses at 2800m');

%Transition from CBHP to PMCD
figure(3);
plot(1:maxtime,BHP_ann_ar*10^-5,'b');
set(gca,'YTick',380:5:400,'Xgrid', 'on','fontsize', 14,'YColor','b','box','off')
xlim([30 100]); ylim([380 400]);
xlabel('Time [min]');
legend('Bottom Hole Pressure');
ylabel('Pressure [Bar]','Color','blue');
title('Transition from CBHP to PMCD','fontsize', 14);

figure(4);
plot(1:maxtime,SBP_ar*10^-5,'r');
set(gca,'YTick',5:5:25,'Xgrid', 'on','fontsize', 14,'YColor','r','box','off')
xlim([30 100]); ylim([5 25]);
```

```
xlabel('Time [min]');
legend('Back-Pressure');
ylabel('Pressure [Bar]','Color','red');

figure(5);
plot(1:maxtime,p_pump_main_ar*10^-5,'b');
set(gca,'YTick',0:10:130,'Xgrid', 'on','fontsize', 14,'YColor','b','box','off')
xlim([75 100]); ylim([0 130]);
xlabel('Time [min]');
legend('Main Pump Pressure');
ylabel('Pressure [Bar]','Color','blue');
title('Pump pressure when changing from mud to SAC in drillstring');

% PMCD
figure(6);
x=1:maxtime;
[AX]=plotyy(x,SBP_ar*10^-5,x,q_bullhead_ar*1000,'plot');
set(get(AX(1), 'YLabel'),'String','Pressure [Bar]'...
    ,'fontsize', 14);
set(AX(1),'XTick',100:10:180)
set(AX(1),'Xlim',[100 180]);
set(AX(1),'YLim',[5 35])
set(AX(1),'YTick',5:5:35)
set(get(AX(2), 'YLabel'),'String','Flowrate [lpm]'...
    ,'fontsize', 14);
set(gca,'Xgrid','on','box','off')
set(AX(2),'XTick',10:10:180)
set(AX(2),'Xlim',[100 180]);
set(AX(2),'YLim',[0 1200])
set(AX(2),'YTick',0:200:1100)
set(AX(2),'YColor','r');
xlabel('Time [min]','fontsize', 14);
set(AX(1),'fontsize', 14)
set(AX(2),'fontsize', 14)
legend('SBP','Bullheading rate');
title('Gas entering the annulus and migrating');

figure(7);
plot(1:maxtime,p_pump_main_ar*10^-5,'k');
set(gca,'YTick',110:5:115,'Xgrid', 'on','fontsize', 14,'YColor','k','box','off')
xlim([100 180]); ylim([110 115]);
xlabel('Time [min]');
legend('Main Pump Pressure');
ylabel('Pressure [Bar]','color','black');

figure(8);
x=1:maxtime;
[AX,H1,H2]=plotyy(x,SBP_ar*10^-5,x,q_bullhead_ar*1000,'plot');
set(H1, 'Color', 'b');
set(H2, 'Color', 'r');
set(get(AX(1), 'YLabel'),'String','Pressure [Bar]'...
    ,'fontsize', 14);
set(AX(1),'XTick',170:5:200)
set(AX(1),'Xlim',[170 200]);
set(AX(1),'YLim',[5 25])
set(AX(1),'YTick',5:5:25)
set(gca,'Xgrid','on','box','off')
set(get(AX(2), 'YLabel'),'Color','red','String','Flowrate [lpm]'...
    ,'fontsize', 14);
set(AX(2),'XTick',170:5:200)
set(AX(2),'Xlim',[170 200]);
set(AX(2),'YLim',[0 1200])
set(AX(2),'YTick',0:200:1200)
set(AX(2),'YColor','r');
xlabel('Time [min]','fontsize', 14);
set(AX(1),'fontsize', 14)
set(AX(2),'fontsize', 14)
legend('Surface Back-Pressure','Bullhead rate');
title('Connection of new stand of drillpipe');

figure(9);
x=1:maxtime;
[AX,H1,H2]=plotyy(x,BHP_ann_ar*10^-5,x,q_pump_main_ar*1000,'plot');
set(H1, 'Color', 'b');
set(H2, 'Color', 'r');
set(get(AX(1), 'YLabel'),'String','Pressure [Bar]'...
    ,'fontsize', 14);
set(AX(1),'XTick',170:5:200)
set(AX(1),'Xlim',[170 200]);
set(AX(1),'YLim',[370 400])
```

```
set(AX(1),'YTick',370:10:400)
set(gca,'Xgrid','on','box','off')
set(get(AX(2), 'YLabel'),'Color','red','String','Main Pump flow rate [lpm]'...
    ,'fontsize', 14);
set(AX(2),'XTick',170:5:200)
set(AX(2),'Xlim',[170 200]);
set(AX(2),'YLim',[0 2100])
set(AX(2),'YTick',0:500:2100)
set(AX(2),'YColor','r');
xlabel('Time [min]','fontsize', 14);
set(AX(1),'fontsize', 14)
set(AX(2),'fontsize', 14)
legend('Bottom Hole Pressure','Main Pump rate');
title('Connection of new stand of drillpipe');

figure(10);
x=1:maxtime;
[AX,H1,H2]=plotyy(x,SBP_ar*10^-5,x,p_pump_main_ar*10^-5,'plot');
set(H1, 'Color', 'b');
set(H2, 'Color', 'r');
set(get(AX(1), 'YLabel'),'String','Surface Back-Pressure [Bar]'...
    ,'fontsize', 14);
set(AX(1),'XTick',195:5:215)
set(AX(1),'Xlim',[195 215]);
set(AX(1),'YLim',[10 30])
set(AX(1),'YTick',10:5:30)
set(gca,'Xgrid','on','box','off')
set(get(AX(2), 'YLabel'),'Color','red','String','Pressure [Bar]'...
    ,'fontsize', 14);
set(AX(2),'XTick',195:5:215)
set(AX(2),'Xlim',[195 215]);
set(AX(2),'YLim',[100 130])
set(AX(2),'YTick',100:5:130)
set(AX(2),'YColor','r');
xlabel('Time [min]','fontsize', 14);
set(AX(1),'fontsize', 14)
set(AX(2),'fontsize', 14)
legend('Surface Back-Pressure','Main Pump pressure');
title('Plugging of the formation');

figure(11);
x=1:maxtime;
[AX,H1,H2]=plotyy(x,SBP_ar*10^-5,x,p_pump_main_ar*10^-5,'plot');
set(H1, 'Color', 'b');
set(H2, 'Color', 'r');
set(get(AX(1), 'YLabel'),'String','Pressure [Bar]'...
    ,'fontsize', 14);
set(AX(1),'XTick',570:5:590)
set(AX(1),'Xlim',[570 590]);
set(AX(1),'YLim',[0 20])
set(AX(1),'YTick',0:5:20)
set(gca,'Xgrid','on','box','off')
set(get(AX(2), 'YLabel'),'Color','red','String','Pressure [Bar]'...
    ,'fontsize', 14);
set(AX(2),'XTick',570:5:590)
set(AX(2),'Xlim',[570 590]);
set(AX(2),'YLim',[105 125])
set(AX(2),'YTick',105:5:125)
set(AX(2),'YColor','r');
 xlabel('Time [min]','fontsize', 14);
set(AX(1),'fontsize', 14)
set(AX(2),'fontsize', 14)
legend('Surface Back-Pressure','Main Pump pressure');
title('Encountering a second loss zone');
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
```