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Abstract

In the future, oil and gas companies will carry out more drilling operations in demanding environments such as deep water, depleted reservoirs, extended reach wells and high-pressure high-temperature wells. These drilling operations require high accuracy and caution because they have a narrow pressure window. These wells are more prone to lost circulation, formation influx and packing. As a result, non-productive time will increase while creating a dangerous situation for the platform and people, if the events are not handled properly.

Traditional data transmission from down-hole during drilling has a low bandwidth and a high time delay, making real-time data use impractical. As a result, the state of the well is mostly determined by surface measurements and the driller's knowledge and expertise.

Newer and improved drilling technologies such as wired drill pipe telemetry that provides wired communication with downhole tools, making the real-time measurements available during most of the drilling operation. New technology opens up for new opportunities, but it often comes with a steep price tag.

Managed Pressure Drilling (MPD) is a technology that mitigates many of these conventional drilling challenges, by accurately manipulate the annular friction pressure profile throughout the wellbore.

In this bachelor thesis, simulations are done in OpenLab using surface backpressure and wired pipe to maintain a constant bottom hole pressure (CBHP), to quantify the accuracy in both methods. The results are then discussed up against the cost, to determine if the additional cost of wired pipe is worth the investment.

Preface

This bachelor thesis was written during the spring of 2022 as a compulsory part of the study program leading to a Bachelor of Science degree in Petroleum Technology at the University of Stavanger. This thesis work has allowed me to explore the importance of using managed pressure drilling in general and study influencing factors when using downhole measurements versus surface backpressure to keep the bottomhole constant.

This thesis has been very educational, and I will benefit from it in the future.

I would like to thank my supervisor at the University of Stavanger, Jan Einar Gravdal, who has been extremely cooperative and helpful from the very beginning of my thesis. I am extremely thankful for his advice and his time devoted to this work.

Yvonne Nevland

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List of Abbreviation

BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blow Out Preventer
CBHP	Constant Bottom Hole Pressure
DGD	Dual Gradient Drilling
ECD	Equivalent Circulating Density
EM	Electromagnetic Telemetry
ERD	Extended Reach Drilling
HCV	Hydrostatic Control Valve
HPHT	High-Pressure High-Temperature
HSE	Health Safety and Environment
LWD	Logging While Drilling
MPD	Managed Pressure Drilling
MWD	Measurements While Drilling
NPT	Non Productive Time
NRV	Non-Return Valve
OBD	Overbalanced Drilling
PCD	Pressure Control Device
PMCD	Pressurized Mud Cap Drilling
RCD	Rotating Control Device
ROP	Rate of Penetration
RSS	Rotary Steerable System
UBD	Underbalanced Drilling
WDP	Wired Drill Pipe

1 Introduction

The oil business has been an adventure for Norway since the first discovery of oil on the Norwegian Continental Shelf. Hundreds of wells have been drilled and completed successfully, with a huge profit.

During the 1980s and 1990s, issues began to arise. Drilling all these wells have resulted in depleted – and damaged – formations. The reservoirs are practically depleted (from the perspective of present technologies), and the well planning requires more thought, and drilling procedures are more complicated.

It is very relevant to drill more and longer wells in depleted reservoirs on the Norwegian shelf, to utilize the existing infrastructure. Production and injection have caused changes in formation pressures, and because of the pressure fluctuations, the operational pressure window is narrower.

New technology is necessary to achieve an economic profit in today's drilling operations in demanding environments. Managed Pressure Drilling (MPD) is a good solution to these conventional challenges.

The primary reason for choosing to drill a well in MPD mode is because there is a narrow pressure window. A narrow pressure window refers to narrow pressure margins between the pore and fracture pressure. Fracture pressure is the pressure that will cause fracture of the formation and pore pressure is the pressure within the pores of a formation. MPD allows to precisely manipulate the annular friction pressure profile during operations, hence well control events such as kicks and lost circulation can be avoided. A kick is flow of formation fluids into the wellbore during operations (Petrowiki, 2015) and lost circulation is when drilling fluid fluctuates into the surrounding formation (Petrowiki, 2017).

Drilling operations are commonly divided into three categories: conventional drilling, underbalanced drilling, and managed pressure drilling (MPD). The pressure windows for the different drilling operations are illustrated in Figure 1.

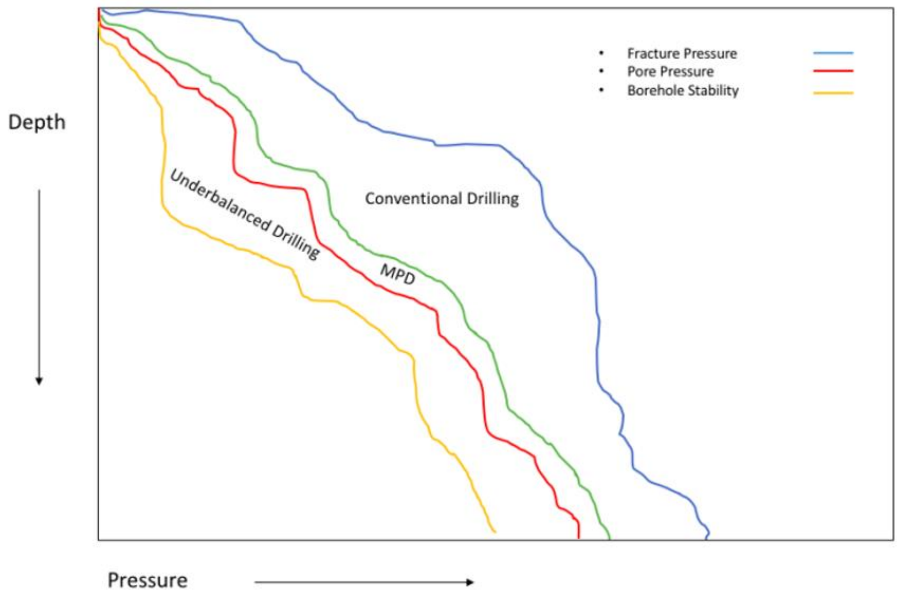

Figure 1 - Pressure window for conventional drilling, underbalanced drilling and MPD (Sommernes & Vik, 2018)

1.1 Motivation

The motivation for writing a thesis on Managed Pressure Drilling and the use of surface backpressure and wired pipe is to quantify their accuracy to maintain a Constant Bottom Hole Pressure.

In the future, more complicated wells will be drilled that require precice regulation of the bottom hole pressure. Then it is important with MPD technology to control the bottom hole pressure within narrow pressure windows. Managing the bottom hole pressure by applying backpressure from the surface is the fastest method, but it may not always be possible to implemented in current drilling operations due to challenging environments.

The drill string is one of the most important parts of the process when drilling a well. The drill string is made up of drill pipes that are joined to form a long steel string. The drill string's goal is to navigate its way through various rock strata and, hopefully, into a hydrocarbon-rich reservoir. The cost and lifespan of a drill string are determined by the quality of steel used and the type of pipe utilized, such as regular or wired pipe.

Drilling fluid characteristics have been a significant factor to regulate the downhole pressure and reaching the target at the lowest possible cost. Oil-based drilling fluids are superior to water-based drilling fluids at reducing friction between the drill string and the casing or hole wall.

1.2 Scope of the Thesis

This bachelor thesis is structured as follows:

- Chapter 1 will give the reader a quick introduction on Managed Pressure Drilling and why it is used.
- Chapter 2 is about conventional drilling and the pressure gradient in static and dynamic conditions.
- Chapter 3 gives a summary of the surface and downhole measurements used to collect data on the wellbore positioning and the well condition. The downhole measurements are based on different types of telemetry.
- Chapter 4 will introduce why there is use for advanced drilling methods, such as MPD. It also gives a description of the basic concepts and variations of MPD, and the problems that it seeks to negate.
- Chapter 5 gives a summary of the equipment common to MPD operations
- Chapter 6 mentions briefly different control system for backpressure MPD.
- Chapter 7 presents the case studies by using OpenLab.
- Chapter 8 gives the result of the case studies.
- Chapter 9 contains the conclusion drawn from the case studies.
- Chapter 10 consist of the references used.
- Chapter 11 contains appendixes.

2 Conventional Drilling

Conventional drilling was first implemented in Spindletop, Beaumont, Texas in 1900. In this drilling method conventional wells are usually drilled overbalanced, a condition where the pore pressure in the exposed formation is lower than the pressure applied in the wellbore. The wellbore pressure is controlled by adjusting flow rates of the mud pumps and the mud density. Once the pumps are being turned off and the mud is not circulating, the well is in a static state and must be overbalanced. When the pumps are turned back on, the system becomes dynamic, and the annular friction pressure gets present (Rehm et al., 2008).
The bottom hole pressure (BHP) in dynamic conditions is defined as the sum of annular friction pressure (P_F) and mud weight hydrostatic head pressure (P_{HH}) during circulation:

$$BHP_{DYN} = P_F + P_{HH} \tag{1}$$

Hydrostatic pressure exerted by the mud in the annulus determines the BHP in static conditions when pumps are stopped for connections or other occurrences. The mud weight is designed to generate a bottomhole pressure higher than the pore pressure to avoid influx:

$$BHP_{STAT} = P_{HH} \tag{2}$$

The relationship between dynamic and static conditions, and how the pore pressure changes when pumps are turned off during connections or other occurrences is illustrated in Figure 2 and

Figure 3. The annulus friction pressure increases with depth of the well, as shown in the figures. Figure 2 depicts an idealized drilling scenario, however in reality, conditions are more like those shown in Figure 3, with non-linear fracture and pore pressure gradients.

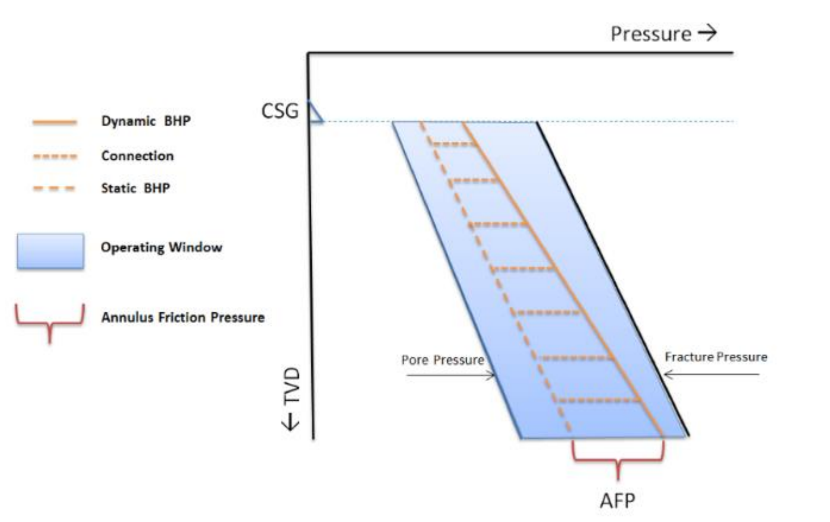

Figure 2 - Hydraulics of conventional drilling (Stødle, 2003)

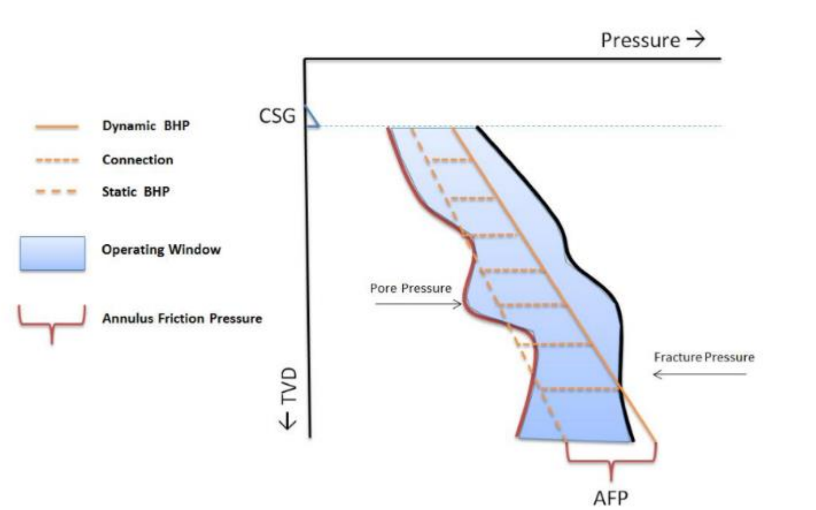

Figure 3 - Hydraulics of conventional drilling in a narrow pressure window (Stødle, 2003)

In dynamic conditions, the sum of pressure effects is called Equivalent Circulating Density (ECD). According to Schlumberger's oilfield glossary, ECD is "the effective density exerted by a circulating fluid against the formation that takes into account the pressure drop in the annulus above the point being considered." In terms of preventing losses and kicks, this value is especially critical in wells with a narrow operational window between pore- and fracture pressure.

3 From Monitoring and Mechanization towards Automated Drilling

Before surface and downhole measurements became conventional, drillers had little to no knowledge of wellbore positioning or the condition in the well. Sensors to measure surface data in real-time have been used since the late 1920s (Islam & Hossain, 2021). These sensors provided essential information about the subsurface and the equipment being used. And made the operation easier for drillers.

Since then, innovative surface and downhole measurement technologies have come a long way in terms of performance, reliability, cost, and availability, and are now being used more frequently for real-time monitoring of wells and equipment. Traditionally it was sufficient with just real-time surface measurements. Nowadays the petroleum industry lays a stronger emphasis on downhole measurements since the wells are more challenging to drill with a narrow operating window.

3.1 Surface Measurements

At the surface, traditional operational data measurements are collected, including drill-string measurements such as rotary torque, hook load, and the block height from which the rate of penetration (ROP) can be determined. A summary of additional surface measurements is listed in Table 1.

Gravdal states the real-time measurements available for the driller are usually limited to: (Gravdal, 2011)

- Hook load – The weight of the drill string, which is influenced by the mud's buoyancy force, the weight of the bit, and the mud flow rate.
- Block position and velocity – The traveling block's position and velocity in relation to the drill floor.
- Surface Torque – The rotational force that causes the drill pipe to revolve.
- Surface RPM – The top drive's rotational speed.
- Mud Pump Rate – The volume rate from the pump. Usually derived by counting the number of piston strokes per unit of time.
- Stand Pipe Pressure – Required pressure for the drilling mud to circulate through the flow line.
- Casing pressure – Pressure of the annular fluid on the casing at the surface when a well is shut in (used for well control purposes).
- Pit level – Constantly monitors the drilling mud level in the mud tanks.
- Mud Inlet Temperature – Typically measures the temperature in the pit but is used as an inlet temperature.
- Gas in mud – Volume fraction of gas in the return flow.

Derived measurements:

- Weight on bit – Derived from hook load.
- Bit depth and total depth – Computed based on tally description, block position and in-slips status.

- Rate of penetration (ROP) – Corresponds to the drilling speed and calculated from the block position evaluation.

Instrumentation to handle the drill string during connections is also important for the driller. A mud logger provides manual measurements to the driller, such as mud density in pit tank, mud rheology, gel properties and oil/water ratio of mud in pit tank.

Most standard drilling operations employ the above-mentioned instruments. Depending on which rig the operation takes place on, the equipment will differ. The preceding list only includes the most essential surface measurements. The following are some additional measurements that are particularly important for pressure control: Flow rate out (derived from a Coriolis flowmeter), mud density out (derived from manual measurements or a Coriolis flow-meter) and mud outlet temperature.

3.2 Downhole Measurements and Telemetry

Downhole measurements have historically been requested to determine formation characteristics and well trajectory. This information could not be gathered in the past without lowering a wire line with special logging instruments, recording the data, and then bringing the measurements to the surface. Later, downhole telemetry allowed certain data to be transmitted to the surface without having to remove the complete drill string out of the well.

Drillers were able to capture real-time data downhole for the first time in the late 1960s when the first Measurement While Drilling (MWD) technology was developed in the 1980s, downhole logging while drilling (LWD) technology was developed to capture formation measures such as gamma, density, porosity, and resistivity (Pastorek et al., 2019). MWD technology can now offer measurements in near real-time (Table 1).

These M/LWD equipment are more precise than surface measuring techniques, which produce data with a lot of noise. Downhole LWD tools can offer geological data measurements, which can help locate hydrocarbon reservoirs in sedimentary aquifers. MWD tools, on the other hand, can measure well data like bottom-hole temperature and pressure, directional data, and drilling mechanics data, which are useful in both petroleum and geothermal drilling. Even though MWD tools collect various measures, practically all MWD tools put on the bottom hole assembly (BHA) will provide temperature, pressure, inclination, and azimuth information, regardless of manufacturer or model. The telemetry for the Rotary Steerable Systems (RSS) is likewise provided by the MWD. Memory Data refers to the measurements that are saved locally. Real-time data refers to data that is sent digitally to the surface. There are several systems available for communicating downhole measurements to the surface.

Table 1 – Summary of types of data typically collected in the surface and downhole tools. Measurements taken in low-temperature (<150° C) drilling; the most common measurements are indicated with an asterisk (*) (Pastorek et al., 2019, p. 2)

	Surface Data	Downhole Data
Mud Data	Pit volume Mud temperature Mud pressure Mud weight Pump strokes	N/A
Well Data	Temperature Pressure Gas measurements	Temperature* Pressure
Directional Data		Inclination* Azimuth*
Drilling Mechanics	RPM Weight on bit Torque Bending moment Rotary torque Hook load Rate of Penetration	RPM* Weight on bit Torque on bit Bending moment Downhole vibration*
Geological Data	Cuttings analysis	Density* Porosity* Resistivity* Gamma*

The downhole equipment can send data to the surface in near real time or store it in a memory device for later examination at the surface. Table 2 lists a variety of mechanisms for transmitting data to the surface.

3.2.1 Mud Pulse Telemetry

The most common and reliable MWD technique available today is mud-pulse telemetry, which feeds data to the surface. Small pressure waves are generated in the mud by this equipment, which are decoded at the surface and used to capture usable real-time data. The pressure signals, which are represented in binary data, are generated using positive or negative pressure pulses, as well as continuous waves. Drillers use this method to acquire continuous measurements. MWD operators will take a stationary measurement every 10 to 30 meters whenever a drill pipe junction is inserted or removed. For a stationary measurement, mud-pulse telemetry typically takes 2 to 7 minutes to receive data and give usable results. This takes longer than connecting the next drill pipe junction, resulting in a few minutes of non-productive time (NPT) for each stationary measurement. (Pastorek et al., 2019).

This method has data volume and speed limits, which reduce as the wellbore length increases. Data collection from downhole could be improved with new technology such as wired drill pipe.

3.2.1.1 Positive Pulse

To restrict mud flow within the drill pipe, positive pulse tools briefly close and open the valve (Figure 4). This results in an increase in pressure that is visible at the surface. The digital information is represented by line codes, which are pulses.

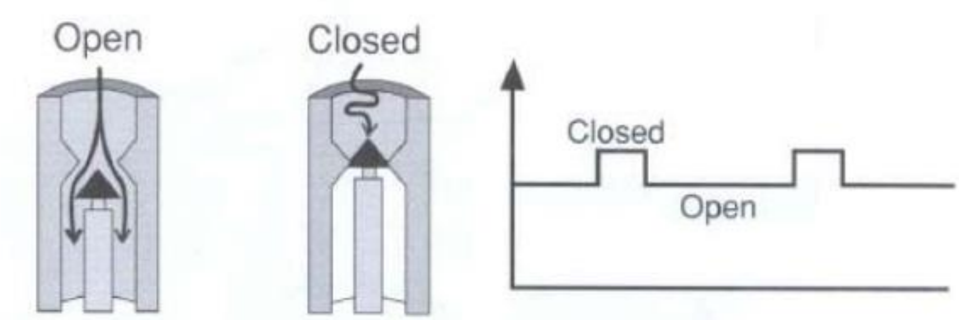

Figure 4 - Positive Pulse

3.2.1.2 Negative Pulse

To release mud from the inside of the drillpipe out to the annulus, negative pulse instruments open and close the valve briefly (Figure 5). This results in a pressure drop that can be seen at the surface. The digital information is represented by line codes, which are pulses.

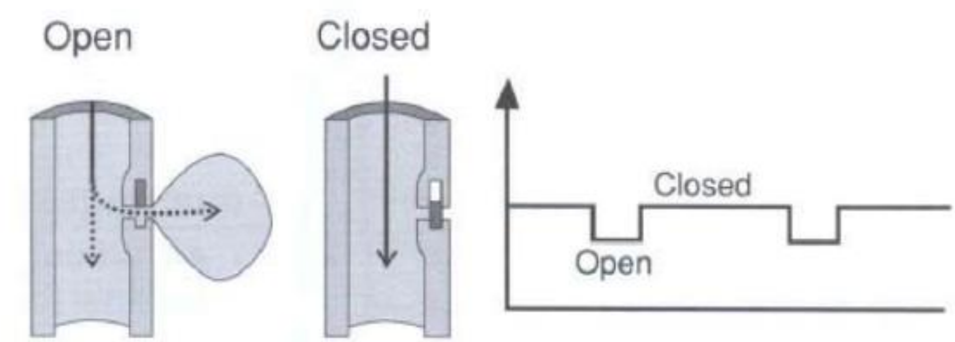

Figure 5 - Negative Pulse

3.2.1.3 Continuous Waves

To generate sinusoidal pressure fluctuations within the drilling fluid, continuous wave tools gradually close and open the valve. To impose the information on a carrier signal, any digital modulation method with a continuous phase can be utilized. Continuous phase modulation is the most extensively used modulation scheme.

3.2.2 Electromagnetic Telemetry

Electromagnetic telemetry (EM) provides data transfer without the use of a continuous fluid column and is often used as a backup to mud pulse telemetry in situations when it isn't possible, such as underbalanced operations using gasified drilling mud or when the surrounding rock is too conductive or resistive (i.e., areas with high water or salt content). An electrical insulator is included in the drill string for electromagnetic telemetry. A tool generates an altered voltage difference between the main drill string (above an insulator in the BHA) and the bottom half of the drill string to convey data (typically the rest of the BHA and the bit). Because EM Tools may receive data from the surface via EM telemetry, fast downlinking is possible. This contrasts with mud pulse-based tools, which require changes in drilling parameters, such as drill string rotation speed or mud flow rate, to get information from the surface.

When drilling deep wells, EM telemetry falls short. Types of formation layers, the signal can quickly deteriorate, becoming undetected after only a few thousand feet.

3.2.3 Acoustic Telemetry

Acoustic telemetry systems use a downhole transmitter to generate acoustic waves that are induced into the drill string. The signal is picked up by a receiver after propagating along the drill string. Acoustic telemetry has a higher and wider operational frequency spectrum than EM systems. Acoustic telemetry can function at higher telemetry rates than EM and mud pulse systems because of the wide range of carrier frequencies available.

Acoustic telemetry, unlike EM systems, is unaffected by formation layers. It's ideal for underbalanced drilling, particularly underbalanced drilling with compressible low weight drilling. Although acoustic telemetry allows data transmission during tripping, in field applications, the receiver is located at the top drive, which prevents data transmission during tripping.

During passage via the drill pipes, the signals are muted. The basic attenuation factor is the intrinsic loss in the drill string, however differences in contact between the drill string and the well wall can increase this value. As a result, signal loss in a horizontal or tilted well is greater than in a vertical well.

Another aspect that contributes to loss in a slanted well is the accumulation of cuttings within the well, which increases wall contact with the drill string, resulting in even more attenuation.

Because it cannot provide as much data as other types of telemetry, this approach is rarely used. However, if acoustic telemetry technology advances, it may become more viable in the future (Gravdal, 2011).

3.2.4 Wired Pipe Telemetry

Wired drill pipe can be utilized in situations where high-speed signal transfer from the well is desirable. This approach employs specialized drill pipe with wire running along the interior of the steel tubing to transport data straight from the surface to the downhole, allowing for near-instantaneous data transmission. Unfortunately, drill pipe can be costly, and proper treatment of pipe sections on the rig floor is required. Its usage in geothermal drilling operations is limited because it cannot be employed in high-temperature conditions. This telemetry system is employed in wells that require precise geosteering or pressure control.

The wired drill pipe telemetry system is now commercialized through National Oilwell Varco as the IntelliServ Broadband Network. The IntelliServ Wired Drill Pipe Network allows for bi-directional and immediate downhole data transmission while drilling. Surveys, downlinks, slide orientations, and other data-driven tasks are completed in seconds rather than minutes with traditional telemetry, saving rig time. Well times can be reduced by multiple days by simply transmitting the same data required to drill a well faster (IntelliServ, 2015).

A live, real-time data stream may be crucial in some MPD applications for the constant adjustment of hydraulic models in control systems. For some applications, wired drill pipe and high-speed data transfer, in combination with improved M/LWD instruments, may become the norm in the future. But it all depends on the MPD system in use and how well it can utilize all the downhole data.

Table 2 - Comparison of conventional downhole telemetry systems (Pastorek et al., 2019)

	Mud-Pulse Telemetry	Electromagnetic Telemetry	Acoustic Telemetry	Wired Drill Pipe
Time to Collect Data	2–7 minutes	<1 minute	2–7 minutes	near instantaneous
Data Quantity	high	medium	medium	very high
Signal Strength	medium	low	low	N/A
Signal Interference	medium	high	medium	low
Cost	low	medium	medium	high

4 Annular Pressure Control

Conventional wells are drilled with overbalanced drilling (OBD), where the wellbore pressure remains within the pressure window in any region of the open hole. Mud density and mud pump flow rate are the most key factors in managing annular pressure. The wellbore pressure (P_W) in static conditions are equal to the hydrostatic pressure (P_{Hyd}) of the mud column in the annulus. In dynamic conditions with circulation of mud, P_W is a function of P_{Hyd} and the annular friction pressure (P_F):

$$P_W = P_{Hyd} + P_F \tag{3}$$

A lost circulation will occur if P_W surpasses P_F at any depth of the open hole, and this is the reason some wells with narrow pressure window cannot be drilled conventionally. There are also other limitations to conventional drilling. Since the drilling fluid pressure is higher than the pore pressure, fluid invasions will occur. As a result of this the formation suffers from permeability damage, which reduces the production quality of the reservoir. Washout or physical blockage produced by the incursion of fluids and/or solids into the formation is the most common source of the damage (Gravdal, 2011).

To proceed with conventional drilling, drillers have two options:

1. Underbalanced Drilling (UBD) where Pw is set to be below the formation pore pressure and influx is intended.
2. Managed Pressure Drilling (MPD) where Pw is set to be within the pressure window with no influx intended.

4.1 Underbalanced Drilling

Underbalanced drilling (UBD) is an old method of drilling. UBD is designed to keep the wellbore pressure lower than the formation pore pressure, allowing formation fluids to enter the well and reach the surface during drilling. A noticeably light fluid is utilized to achieve underbalanced conditions in the well. The most common fluids utilized in UBD are gas, mist, foam, gasified liquid and liquid (Guimerans et al., 2001).

The benefit of using this method is that it reduces formation damage, which leads to higher reservoir productivity. This is also the main reason for using this drilling method. Increased ROP, decreased chance for differential sticking and lost circulation, and longer bit life are all advantages of UBD (Rafique, 2008).

An adjustable choke valve controls the flow out of the well and forces a dynamic back pressure (P_{Dyn}) to the annulus column, instead of, the gas travelling upwards to the annulus and expanding. The result of the gas expansion could lead to a blowout. The main purpose of UBD is to maintain a controlled underbalanced drilling operation. In terms of pressure, UBD can be described with the following equation (Gravdal, 2011).

$$P_{Hyd} + P_F + P_{Dyn} < P_{Pore} \tag{4}$$

A normal UBD equipment setup consists of:
- Choke manifold – The choke opens and closes to manipulate the pressure in the annulus to obtain the desired bottom hole pressure (BHP).
- Separator system – The return fluid consists of different phases (mud, cuttings, hydrocarbon gas and liquid), that need to be separated by high–pressure equipment.
- Rotating control device (RCD) - A sealing device that enables the annulus to be pressurized, to keep drilling operations going while influx occurs.
- Mud-gas injection systems – add gas to the drilling fluid to obtain the desired BHP.

If influx occurs during drilling operations, the hydrocarbon gas gets separated and either sent for flaring or gets compressed and injected into nearby production facilities (Malloy, 2007).

The biggest disadvantage with UBD compared to OBD is the financial aspect, UBD is significantly more expensive due to extra equipment and more advanced planning. Another drawback is that maintaining a continually underbalanced condition is not always achievable since there is no mud cake around the wellbore. This can lead to severe formation damage due to intrusion of drilling fluid into the formation. Making connections, bit trips, or local undetected depletion zones are all examples of drilling operations getting into an overbalanced condition (Bennion, 1998).

These two aspects have contributed to the development of MPD.

Although both UBD and MPD are closed loop systems, underbalanced systems necessitate the use of a multi-phase separator. MPD operations are meant to be balanced or always overbalanced, allowing for no influx of formation fluids, whereas underbalanced operations are designed to run with low bottomhole pressure to allow for inflow of formation fluids. Hence, there is no purposeful influx in an effective MPD operation.

4.2 Managed Pressure Drilling

Managed Pressure Drilling has been used since the early 1900s to control lost circulation and kick. Rotating Control Device did not come on the market until 1937, and MPD with efficient use of ECD was implemented in the 1970s. Today's MPD method implements new development and technology with equipment that was used in the past (Rehm et al., 2008).

The International Association of Drilling Contractors (IADC, 2011) defines MPD as:
"Managed Pressure Drilling is an adaptive drilling process used to precisely control the annular 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."

With MPD, one can operate with a closed system, making it easier to control bottomhole pressure using surface pressure adjustments. In comparison to conventional drilling, the effective BHP can be altered dramatically and fast with less interruptions to drilling ahead.

4.2.1 Advantages

MPD has as its primary goal to avoid non-productive time (NPT) incidents caused by a narrow operating window. As previously stated, the operating window between pore pressure and fracture pressure becomes increasingly narrow, particularly in depleted reservoirs, high-pressure high-temperature (HPHT) wells, and deepwater wells. Studies from a couple of years ago revealed that 20-30 % of the time spent in operations where NPT, and that almost 50 % of the NPT could be due to wellbore pressure problems (Kozicz, 2006). Figure 6 illustrates that 42 % of the NPT caused by wellbore pressure problems could have been reduced by using MPD.

MPD solves many of the drilling issues that contribute to NPT, such as the following (Malloy & McDonald, 2008):

- Stuck Pipe
- Lost Circulation
- Detection of Influx and Well Control
- Instability of the Wellbore

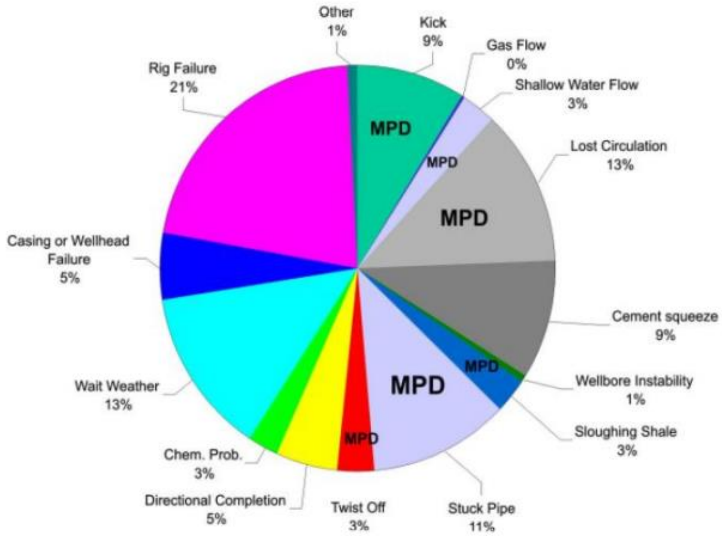

Figure 6 - Causes of NPT and causes that could have been reduced with MPD (Hannegan, 2007)

4.2.1.1 Stuck Pipe

If a pipe cannot be drawn out without causing damage or exceeding the maximum hook load allowed on the drilling rig, it is considered stuck (PetroWiki, 2017).

Differential sticking is one of the most common types of stuck pipe caused by the pressure difference between the wellbore and the permeable zone, which causes a part of the drillstring to be a part of the filter cake. The pipe becomes stuck towards the wellbore due to the overbalance in the wellbore (Rehm et al., 2008). Another cause of stuck pipe is wellbore instability.

Insufficient removal of drilled cuttings, wellbore collapse, formation swelling, or key seating can all induce mechanical sticking (PetroWiki, 2017). The use of MPD can help to reduce this problem by keeping the pressure close to constant. The formation will not be weakened by pressure changes if the pressure is steady. As a result, the risk of mechanical sticking caused by wellbore collapse is reduced.

4.2.1.2 Lost Circulation

One of the most common causes of NPT is lost circulation, which occurs when the formation fracture pressure is exceeded by the wellbore pressure due to pressure fluctuations during connections or tripping. The hydrostatic mudcolumn is reduced as mud is lost, and in worst case scenario this can lead to a kick. A closed-loop MPD system allows for early detection of losses and the implementation of corrective actions, and the formation is the only source of the leaks/losses (Santos et al., 2007).

Mud losses is detected in the pits in conventional open-to-atmosphere systems and in addition to the formation there are several potential leak/loss sources, such as downhole losses, control equipment, surface leaks and loss from solids. As a result, partial losses that occur may go undetective, and correct actions might not be taken. If these partial losses are not treated properly and quickly enough, they can propagate and potentially resulting in total losses.

To avoid losses, the mud weight in both conventional and MPD drilling must be kept below the fracture pressure. Some MPD types allow the use of lighter drilling fluids by applying annular backpressure during connections, allowing the pressure to remain below the fracture pressure even when friction is present. As a result, MPD can be used as a preventative measure for lost circulation (Rehm et al., 2008)

4.2.1.3 Detection of Influx

If the formation pressure exceeds the hydrostatic annular pressure and formation fluids are forced into the wellbore, a kick may occur. The likelihood of a severe kick increases if the formation also has high permeability and porosity. If a kick is not successfully controlled, it may result in a blowout (Petrowiki, 2015).

When a kick is taken, the volume in the pits rises. A kick can be detected in conventional drilling by monitoring the return system or if the well continues to flow after the pumps are turned off. Before initiating well control actions, the well is frequently shut in for monitoring of the wellhead pressure to ensure that a kick has been taken (Nas, 2010). The causes of kicks are not eliminated or changed by installing and employing MPD equipment and procedures, but it has been statistically proven that using an RCD to create a closed wellbore makes drilling operations safer and makes it easier to detect kicks with a closed loop (Jablonowski & Podio, 2010).

4.2.1.4 Instability of the Wellbore

When the mud column's hydrostatic pressure is insufficient to keep the wellbore wall intact, wellbore instability can occur. The formation's collapse pressure can sometimes equal or exceed the pore pressure. Sloughing and packing of the formation around the drill pipe might result in stuck pipe situations. The transition between dynamic and static conditions in the wellbore, is another example that can result in stuck pipe, exposing the formation to a pressure cycle. The pressure may be kept close to constant in MPD operations, eliminating pressure cycles, hence removing the problem of formation weakening. In the event of a high collapse pressure, the wellbore pressure can be raised above the collapse pressure, preventing the wellbore from collapsing.

4.2.2 Categories of MPD

There are two categories of MPD: reactive and proactive (IADC).

When drilling with reactive MPD, all the equipment required to drill in MPD mode is installed, but it is not used until a problem, such as unexpected pressure regimes, arises. When it comes to fluid programs and well construction, the well is planned conventionally, with the option of using MPD as a backup plan if something goes wrong. When using reactive MPD, the operating window is set to normal conditions, where the margin between the pore pressure and the fracture pressure is large enough to allow conventional drilling methods to be used.

Proactive MPD is when the drilling operation is designed to take full advantage of the ability to manipulate the annular pressure profile more precisely, and it makes it possible to drill operationally challenging, economically challenging and “undrillable” wells (Malloy et al., 2009). The most common types of proactive MPD are Constant Bottom Hole Pressure (CBHP), Dual Gradient (DGD), Return Flow Control (HSE approach) and Pressurized Mud Cap Drilling (PMCD). CBHP, DGD and PMCD all aim to manipulate the annular pressure profile, while the HSE approach is primarily used to divert return flow away from the drill floor and personnel and is sometimes considered as a reactive MPD operation.

The biggest advantage with MPD is that the non-productive time (NPT) gets significantly reduced, while increasing safety. The bottomhole pressure with MPD operations can be regulated more precisely and effectively than in conventional drilling, which relies solely on mud weight and pump rate modifications (Bjørkevoll et.al., 2008).

4.2.3 MPD Methods

MPD can be classified into four types: Returns Flow Control (HSE approach), Dual Gradient Drilling (DGD), Pressurized Mud Cap Drilling (PMCD) and Constant Bottom Hole Pressure (CBHP). each with its specific application area depending on formation properties and specific requirements for the project (Hannegan, 2007).
The Constant Bottomhole Pressure variation of MPD have the broadest variety of applications, as it may be used to reduce many of the subsurface problems. The simulations in the case studies (Chapter 9) are based on CBHP, hence CBHP will be the main focus in this subchapter.

4.2.3.1 Returns Flow Control

Returns Flow Control (HSE approach) is a passive form of the MPD system. According to IADC, Returns Flow Control is defined as "MPD technique which diverts returned fluid flow away from the rig floor in order to handle any formation fluid influx, thereby avoiding closing of a blowout preventer (BOP), with the subsequent well control steps that are customarily required. RFC is drilling with a closed annulus return system (RCD) immediately under the rig floor for complete assurance of the total diversion of any rapidly developing kick." (IADC, 2017)

4.2.3.2 Dual Gradient Drilling

The dual gradient (DGD) approach works by introducing a lighter fluid than the mud used in conventional drilling to achieve a lower bottomhole pressure (Rehm et al., 2008), and it is frequently used in deep water, where the total column of mud in the marine riser can cause substantial well overbalance. Figure 7 illustrates the two separate fluid with different pressure gradients, resulting in an overall hydrostatic pressure in the wellbore that fits within the narrow operating window. This MPD approach saves the operator a lot of time dealing with complications like lost circulation, tight margins, and the usage of additional casings (Malloy, 2007).

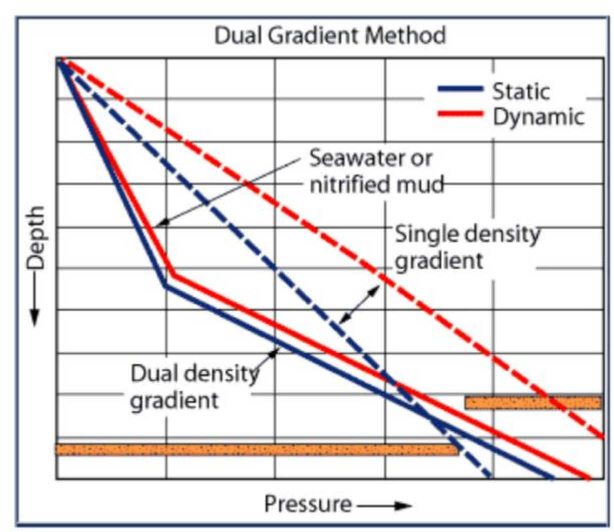

Figure 7 - Dual Gradient compared to single gradient (Malloy, 2007)

4.2.3.3 Pressurized Mud Cap Drilling

The aim of Pressurized Mud Cap Drilling (PMCD) is to maintain circulation while drilling in severely fractured strata or in karst formations. Pumping fluid down the well bore and drill pipe and injecting the mud into the formation fractures in the well solves this problem, allowing drilling to continue. This method can be used as both a reactive and proactive MPD strategy (Rehm et al., 2008).

4.2.3.4 Constant Bottom Hole Pressure

The goal of the constant bottom hole pressure (CBHP) approach is to regulate and keep the bottomhole pressure approximately constant during all phases of the drilling process. Drilling issues including loss of circulation, influxes, hole collapse, and differentially trapped pipe caused by significant pressure variations, which are common in conventional drilling, can be avoided using the CBHP MPD technique. To optimize the process, the approach employs both precise backpressure control and continual flow measurements. This approach is suitable for prospects with narrow and/or uncertain drilling windows, HPHT-wells, depleted reservoirs, and prospects with a history of drilling issues (Gravdal, 2011).

A dynamic backpressure (P_{Dyn}) is exerted from the surface to produce overbalance in the well. Like UBD we have that

$$P_W = P_{Hyd} + P_F + P_{Dyn} \tag{5}$$

To maintain the well pressure within the pressure window in the open hole, the choke valve is opened or closed, changing the backpressure:

$$P_{Pore} \leq P_W < P_{Frac} \tag{6}$$

Here, P_{Pore} is the pore pressure and P_{Frac} is the fracture pressure. Other limitations such as differential sticking and wellbore stability could be taking into consideration (Rehm et al. 2008). Then we have that

$$P_{Pore} < P_{wbs} \leq P_W < P_{ds} \leq P_{Frac} \tag{7}$$

Here, P_{wbs} is the wellbore stability pressure and P_{ds} is the differential sticking pressure.

The concept of the applied backpressure and pressure regimes in MPD and conventional drilling is shown in Figure 8, and in figure 9 the same concept is shown only with a narrow operating window. Even though the static mud weight of the mud used in MPD operations is below pore pressure in these examples, i.e., static underbalanced fluid, statically overbalanced fluid can be used in MPD operations as well, e.g., for wells where the problem is not necessarily a very tight drilling window, but other issues.

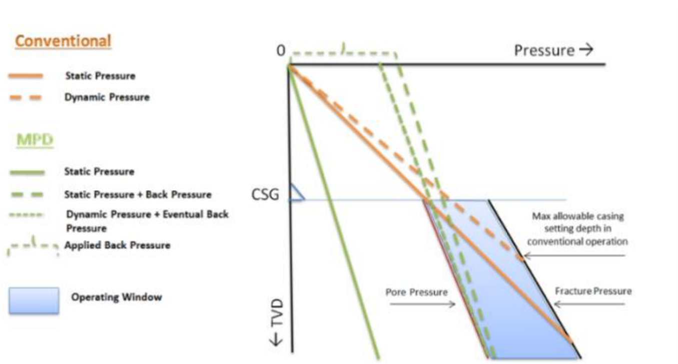

Figure 8 – The principle of conventional drilling hydraulics compared to MPD (Stødle, 2003)

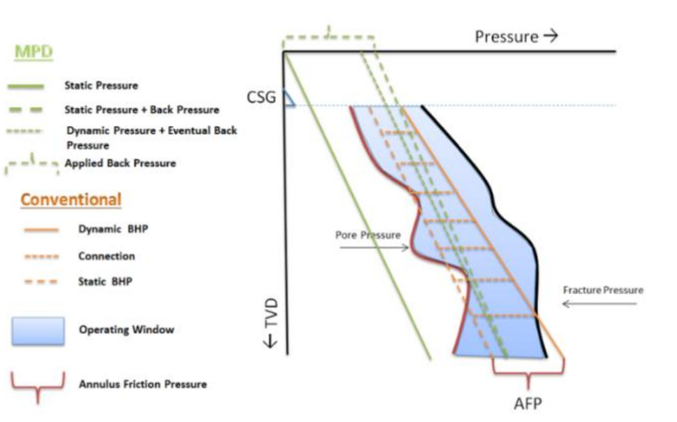

Figure 9 - The principle of conventional drilling hydraulics compared to MPD in a narrow operating window (Stødle, 2003)

5 Instrumentation and Equipment for Managed Pressure Drilling

Most MPD operations are carried out in a closed circulation loop with a Rotating Control Device (RCD), at least one Non-Return Valve, and a Choke Manifold system in the drill string. There are numerous types of equipment used while drilling in MPD mode. The types of equipment utilized relies on the MPD drilling method, the drilling environment, as well as the operation's complexity and particular needs. This bachelor thesis focuses on MPD equipment used on floaters and fixed rigs (Rehm et al., 2008)

According to Don Hannegan (Hannegan, 2006-2007), the following are essential tools for MPD operations:

- Rotating Control Device
  - Floating rigs:
    - External Riser RCD
    - Internal Riser RCD
    - Subsea RCD
  - Fixed rigs:
    - Passive and active annular seal design models
    - Marine Diverter Converter RCD
    - Bell Nipple Insert RCD
    - Internal Riser Rotating Control Head (in marine diverter or surface annular)
- Non-Return Valves
- Choke Manifolds
  - Manual
  - Semi-automatic
  - PC Controlled Automatic

5.1 Annular Seal

The conventional Rotating Control Device and the Pressure Control Device (PCD), invented by WELLIS MPcD, with non-rotating sealing elements, are the two basic forms of annular seals.

5.1.1 Rotating Control Device

The top of the annulus is sealed with a Rotating Control Device (RCD), which diverts the mud return to the MPD choke-manifold system. This rotating sealing element allows the drill pipe to rotate and keeping the drilling operation ongoing while maintain the annulus pressure.

5.1.1.1 External Riser RCD (ERRCD)

External Riser RCD, as Hannegan pointed out, is meant to be employed in MPD applications on floating drilling vessels that are susceptible to hydrodynamic upward loadings caused by waves. The length of flexible flowlines is determined by the maximum potential wave heave.

Furthermore, the size of flexible flowlines is determined by the maximum return flow rate (Hannegan, 2009).

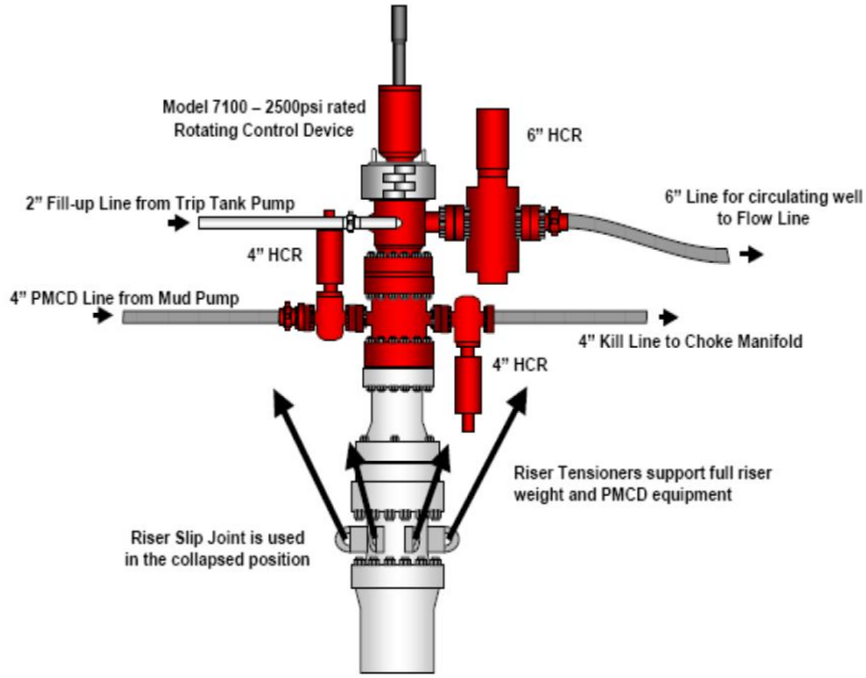

Figure 10 - External Riser RCD (Chustz et al., 2008)

Figure 10 is an illustration of External Riser RCD used in floating drilling applications.

5.1.1.2 Internal Riser RCD

The use of a surface BOP is one way to allow MPD from a floating rig. A normal blow out preventor (BOP) stack can be nippled up on the marine riser and the RCD and flow spool can be hooked up on top of the surface BOP with the installation of a high-pressure riser or internal riser. The entire system functions more like a surface stack on a platform or a jack-up in this configuration. When compared to fixed surface stacks, the MPD system's setup would be relatively similar, apart from the usage of hoses rather than fixed pipe construction. The most common difficulty with surface BOP stacks on semisubmersible rigs is stack alignment (Nas et al., 2009). Internal Riser RCD, according to Hannegan, is developed for a variety of DG approaches. The tool is used to create a subsea annular barrier (Hannegan, 2009). For specialized uses, Internal riser RCD can be employed in a marine diverter.

5.1.1.3 Subsea RCD

Subsea RCD designs are applicable to riserless drilling, with or without riserless mud recovery, and to multiple types of dual-gradient drilling with a marine riser system (Aadnoy et al., 2009). Drill ships may also require a higher spool or swivel flange to handle changes in heading.
The name is derived from the usage of the RCD with Subsea BOPs.

5.1.1.4 Passive Rotating Control Device

The passive system is the most common in MPD operations, and it uses a "stripper rubber", which is an annular seal element, to seal of the annulus. The "stripper rubber" is undersized to the drill pipe, making a tight seal that gets even tighter when the annulus pressure is exerting stress on the sealing element during operations (Figure 11). The "stripper rubber" will eventually wear and not function optimal at low pressures and must be replaced before it leaks in the seal around the drill pipe. (Rehm, et al., 2008)

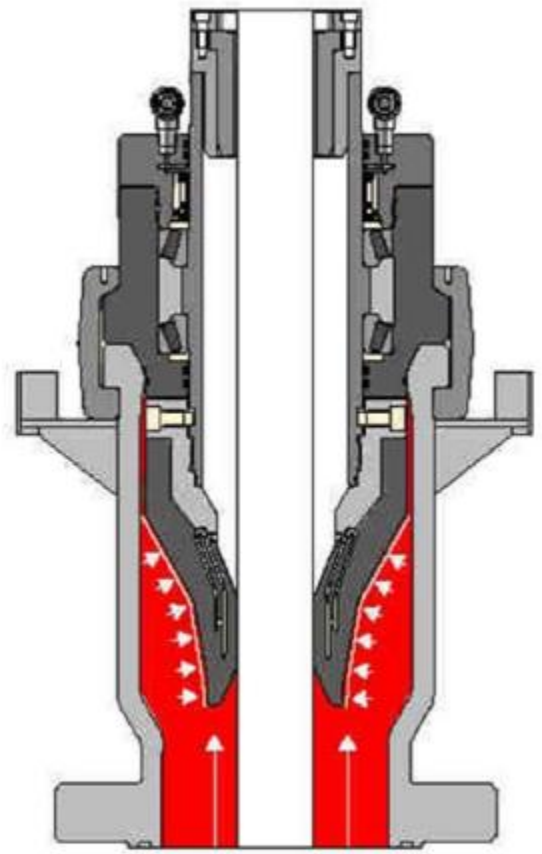

Figure 11 - RCD with annulus pressure marked in red (Sveinhall, 2010)

5.1.1.5 Active Rotating Annular Preventer

The active system consists of hydraulically driven packers to seal off the packer element against the drill pipe. This system is almost completely automated, and the driller must only open and close the packer. The lifespan of this packer is longer than compared to the packer used in passive systems. However, this packer is not often used due to its large footprint and other technological challenges (Rehm, et al., 2008).

5.1.1.6 Marine Diverter Converter RCD

The RCD marine diverter converter transforms a standard marine diverter into a rotating diverter. This form of RCD can be employed in MPD applications when the rig and drillstring have little or no relative movement51. The casing of a Marine Diverter Converter is clamped or latched to an RCD. The RCD-equipped housing is installed into a marine diverter above the water's surface to enable conversion between open and non-pressurized mudreturn system drilling and a closed and pressurized mud return system used in controlled pressure or underbalanced drilling

RCD is installed in a marine diverter, to successfully deflect any influx while drilling. The use of this type of RCD is often restricted to fixed rigs.

5.1.1.7 Bell Nipple Insert RCD

Bell Nipple Insert RCD is a rotating control device for higher marine risers. There should be no wave heave while using this sort of RCD because it has a fixed design (Hannegan, 2009).

5.1.2 Pressure Control Device

Pressure control device (PCD) consist of non-rotating sealing elements, as mentioned before. The PCD provides real-time monitoring and logging of the sealing elements. The pressure gets evenly distributed because the PCD consist of several seals, this makes the seals more enduring and will expand their lifespan. Figure 12 illustrates a PCD package, while Figure 13 shows the inside of the seal cartridge. The seals are lubricated during operations, to avoid high friction and temperature (WELLIS MPcD, n.d.).

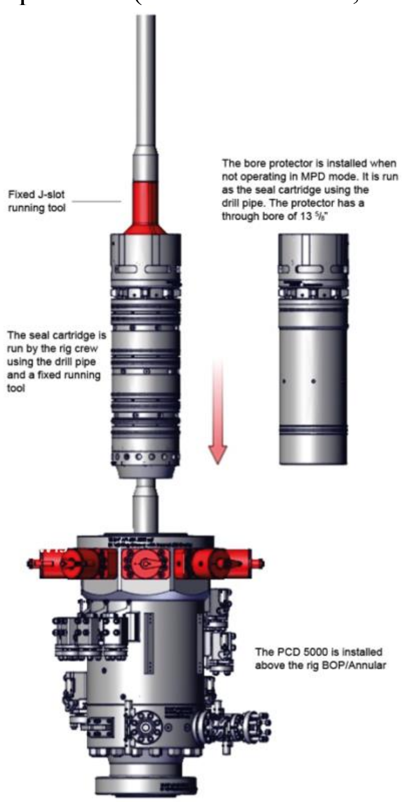

Figure 12 - Installation and operation of the PCD. Courtesy of WELLIS MPcD (WELLIS MPcD, n.d.)

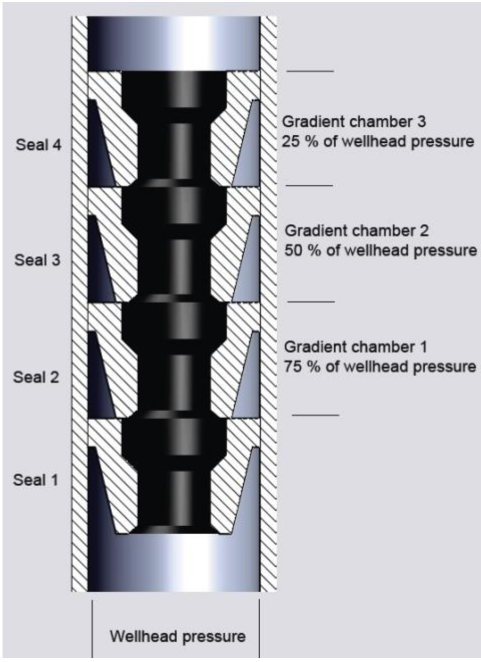

Figure 13 - Inside of the seal cartridge, consisting of four seals. Courtesy of WELLIS MPcD (WELLIS MPcD, n.d.)

5.2 Non-return valve

A Non-Return Valve (NRV) is used to prevent generation of U-tubing between the annulus and the drill string during connections. If a U-tubing Is present, then the drilling fluid fluctuate up to the drill pipe and may cause a blowout. For redundancy, two or more NRVs are installed. Wireline retrievable valves are another alternative for redundancy, as they reduce tripping and improve operating efficiency and safety (Rehm et al., 2008). The NRV must constantly be working because backpressure is needed to compensate for annular friction losses most of the time during static conditions. Currently there are several types of Non-Return Valves in use:

- Basic Piston Type Float:
  A simple piston is driven closed by a spring in the piston NRV, which resembles an engine valve mechanism.
- Hydrostatic Control Valve (HCV):
  The HCV adjusts the mud level in the riser to remove the pressure difference caused by the sea water column.
- Pump-Down Check Valve (Inside BOP)
- Wireline Retrievable Non-Return Valve (WR-NRV)

5.3 Choke Manifolds

One of the most important instruments for enabling MPD applications is the choke manifold system. A choke must be built in the return flow line to allow back pressure to be applied during the drilling process. If a choke is employed and surface pressure is required during hookups, the ability to energize the choke by pumping across the wellhead may be required (Nas et al., 2009). A separate MPD choke manifold should be used whenever possible to avoid using additional well control equipment for normal drilling operations (Nas et al., 2009). Therefore, given the primary use of a choke manifold in well control operations, employing a separate choke manifold is a necessary. The system includes a choke, pressure gauges, a Coriolis flow meter, an advanced control system, and a backpressure pump. Although not all of this equipment is required in a choke manifold system. In MPD applications, there are three choke options: manual choke, semi-automatic choke, and PC controlled automatic choke.

5.3.1 Choke

During drilling, returns are pumped via the choke, which should result in little or no back pressure when fully open. During circulation, backpressure is controlled by adjusting the opening of the choke between open and closed positions. The choke must be exact and consistent, and two chokes chould be set up for redundancy. The control system should be set up so that if one choke fails, flow is promptly directed to the other. Because the MPD choke is used continuously during MPD operations, a conventional rig choke manifold system is required for well control events.

5.3.2 Control System

Manual, semi-automatic, or completely automatic control of the choke mechanism is available:

- Manual – Can be operated manually
- Semi-Automatic – Capable of automatic surface backpressure set point control.
- PC Controlled Automatic – Automatic control of any pressure variable desired

NORSOK D-010 specifies that a manual MPD choke system is not acceptable as part of the primary well barrier (Standard Norge, 2012) on the Norwegian Continental Shelf (NCS).

5.4 Other Equipment

In addition to the above-mentioned equipment in MPD, some applications require additional equipment.

5.4.1 Backpressure Pump

The choke provides backpressure when the mud is flowing. Decreasing mud flow will limit the choke's ability to provide backpressure. A backpressure pump connected to the choke and control system can automatically ramp up if the choke cannot produce enough backpressure or if extra backpressure is necessary during connections and tripping. In the event of a rapid loss of pressure due to mud pump failure or human error, a backpressure pump in the MPD equipment serves as a redundancy. When pressure loss occurs unexpectedly, it is rare that a choke can be reopened quickly enough to prevent the loss of BHP control.

5.4.2 Coriolis Flowmeter

Coriolis flowmeter are the ideal tool accurately monitoring flow, temperature, and density of the mud. Because the premise behind the meter is to have a pressure drop, it works effectively in a closed well bore in combination with a choke manifold.

5.4.3 Continuous Circulation System

The Continuous Circulation System unit seals around the tool joint, allowing for a "wet" connection while maintaining consistent downhole pressure. Offshore, the concept has been tested and employed on both fixed and floating drilling rigs (Rehm et al., 2008). As shown in Figure 14, the unit comprises of a series of rams and snubbing equipment. Even though the system has been successful in usage, it has a large footprint and is difficult to install or remove from the rig floor if necessary.

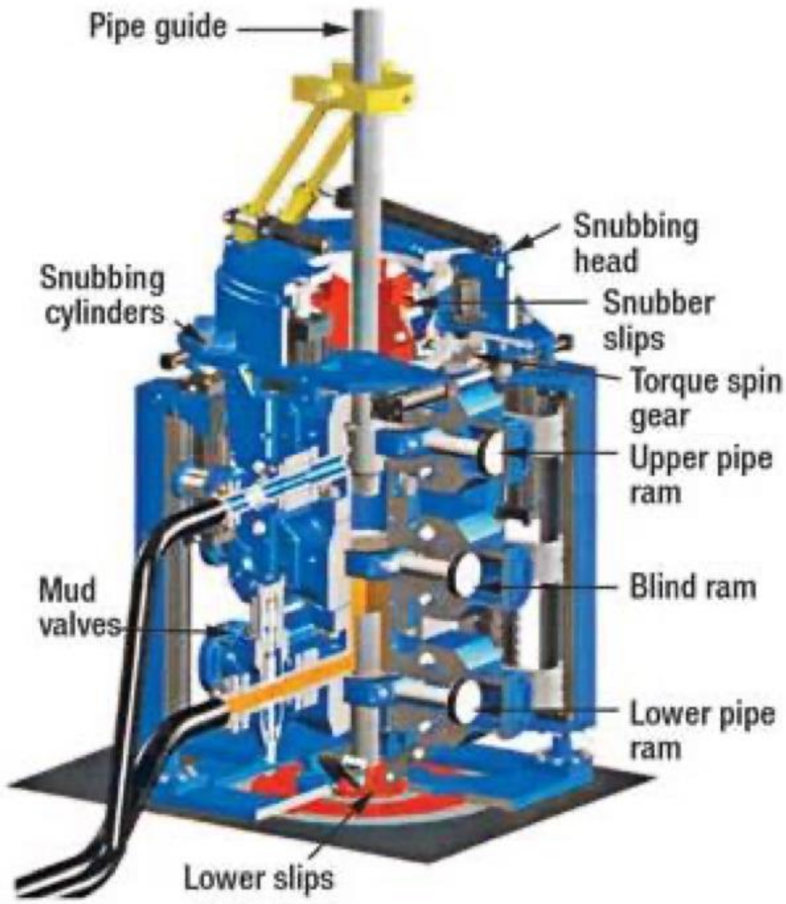

Figure 14 - Continuous Circulation System unit (Malloy, 2007)

5.4.4 Continuous Circulation Valve

On the Norwegian Continental Shelf (NCS), a continuous circulation valve was built for usage on depleted- and HPHT-fields (Torsvoll et al., 2006). The downhole pressure will remain constant even during drillpipe connections if a system to obtain circulation is used throughout the drilling operation. Drilling can be done properly even through narrow drilling windows 62 by managing the downhole pressure between a maximum pore pressure and a minimum fracture pressure. As a result, the mud can be built for dynamic conditions, because the wellbore is never static due to continual circulation

5.4.5 ECD Reduction Tool

A pressure differential is established using an ECD-reduction tool developed by Weatherford, which adjusts the annular pressure profile in a similar fashion to a dual-gradient system (Rehm et al., 2008). The tool's downhole pump lowers annulus pressure, allowing it to employ a little heavier mud while safely travelling through limited operating windows.

6 Control System for Back Pressure Managed Pressure Drilling

Well control is a critical procedure in drilling, particularly in offshore exploration and production. When most of the hydrocarbon resources are located in deepwater (Graham et al., 2011) or present operational challenges ranging from depleted formations (such as reservoirs with tight pressure windows) to high-pressured formations, it becomes much more difficult.

6.1 Manual Control

Traditionally, the MPD choke has been controlled manually by human operator based on pre-calculated values of choke opening versus back-pressure measurement. However, this requires careful operation of the choke, based on the operator’s experience, and relies on extra awareness and training.
Because this approach of regulating the MPD choke lends itself to automated control, it is now usual to employ automatic choke control based on various control systems.

6.2 Automated Control

6.2.1 Simple PI Control

A PI controller controls the choke opening automatically during connections to maintain the desired BHP by applying the right amount of back pressure. The formula for a PI control is (Meling, 2015):

$$u(t) = u(t-1) + k_p[e(t) - e(t-1)] + k_i\left[\frac{T_s}{2}e(t) + \frac{T_s}{2}e(t-1)\right] \tag{8}$$

Where,

$u(t) = choke\ opening\ at\ time\ t$

$u(t-1) = choke\ opening\ at\ previous\ time\ step$

k_p = dimensionless parameter

$e(t) = the\ error\ between\ the\ reference\ value\ and\ the\ measured\ value$

$e(t-1) = error\ at\ previous\ time\ step$

$k_i = dimensionless\ parameter$

$T_s = time\ step, [1\ s]$

6.2.2 Hybrid Control

The problem with using PI controllers in MPD systems is related to non-linear pressure effects and varying well depth and mud properties that changes the dynamics of the system. The performance of the PI controller is therefore dependent on the ability to tune the control parameters (Kc and Ti) and different methods for gain-scheduling have therefore been explored.

One approach is to use Machine Learning methods to train the control parameters based on simulations.

6.2.3 Model Predictive Control

A model predictive controller is based on iteration and finite horizon optimization of a system. This control system is designed to predict future behaviour of the process by evaluating the process model at the current time step, and it is repeated over time based on new process data to optimize the predicting model over time.

7 Case Studies

7.1 Description of OpenLab

OpenLab is a drilling simulator available online. It is this simulator I have used to do the simulations in this task. More literature about the simulator can be found at https://openlab.app/publications/.

7.2 Description of Simulated Case

The motivation for doing these case studies is to quantify the accuracy using wired pipe and using surface backpressure to maintain a CBHP, to later discuss these results against the cost of using wired pipe. To study it, simulations are done with a flow sweep where the pump rate changes as shown in Figure 15.

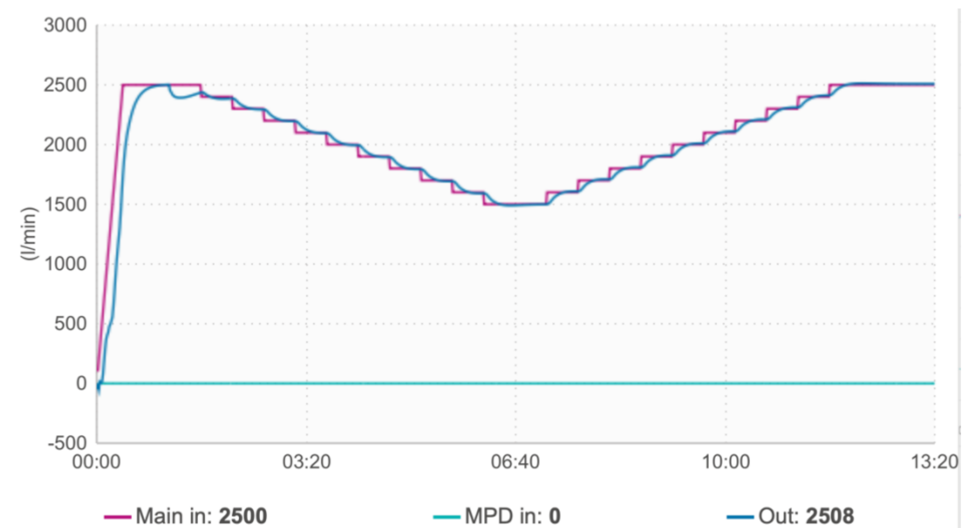

Figure 15 - Flow sweep

By performing a flow sweep, the pressure conditions in the well change and therefore the choke regulator must compensate for the change in bottom hole pressure. When the well is 3500 m long, the flow out will look a little different than at the well of 2500 m. As the well is longer, there will be a different dynamic, and it will take a little longer from flow in changes, until you see a change in flow out. This will not lead to a significant change in these case studies.

Two simulation cases are performed, one where the CBHP was based on surface measurements (case one) and one where the CBHP was based on downhole measurements (case two). The drilling fluid used in the simulations has a density of 1.65 s.g. at 50°C and is an oil-based mud. In both cases, simulations were performed where the well was 2500 m and 3500 m long. The surface measurements use the pressure measurement form the MPD-choke, i.e., back-pressure. Furthermore, it is assumed that by keeping this constant, the BHP is more or less constant. The downhole measurements are with wired pipe. This is because wired pipe is the only way to send measurements fast enough from the bottom of the well so that it can be used directly in a PI-controller when using MPD.

In this thesis, a PI controller is used, and tuning is conducted to proportional gain and integral gain terms. The backpressure will be the reference value. The choke opening is the output from the regulator $(u(t))$, and used as input in the simulations to keep the BHP constant. The simulations are based on an offshore installation, and they do not consider that floaters move up and down and create wave heave.

7.3 Simulations Results

7.3.1 Case one

In this thesis the simulations of CBHP are based on surface measurements when the well is 2500 m long and 3500 m long.

7.3.1.1 2500 m

The backpressure is set to be 22 bars (reference value), which corresponds to 380 bar BHP at 2500 L/min. The control settings are shown in the Matlab-code (Appendix 11.3). Initial choke opening is 25 % and the choke opening is then controlled by the PI-controller during the flow-sweep (Figure 15). The resulting choke opening, backpressure and bottom hole pressure is shown below.

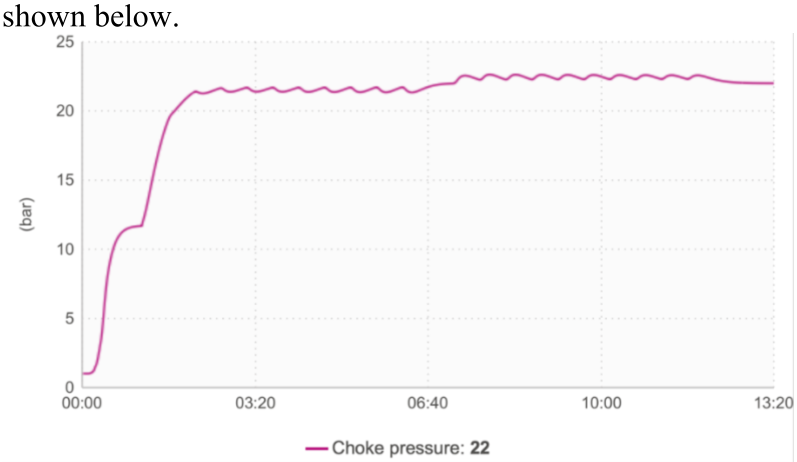

Figure 16 - Pressure at the MPD backpressure pump

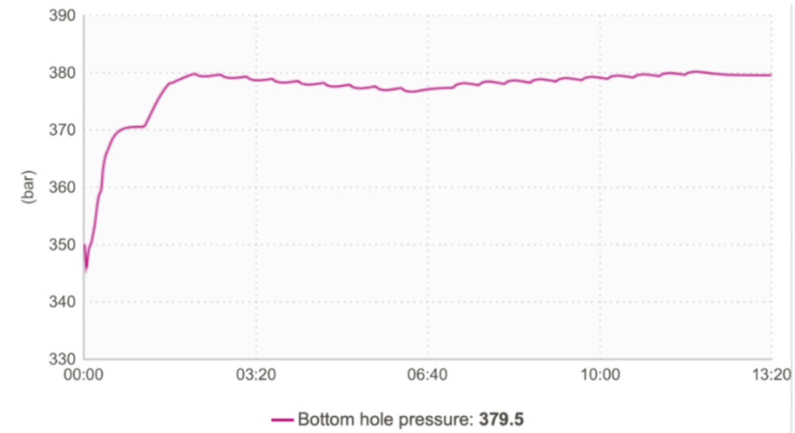

Figure 17 - Pressure measured at the bottom of the hole (BHP)

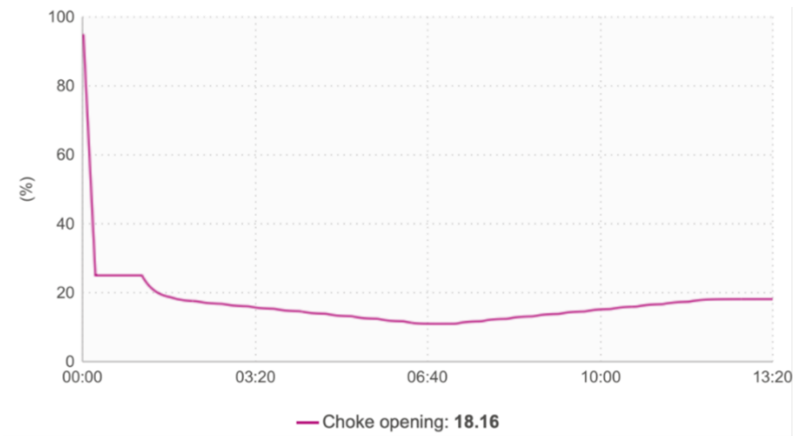

Figure 18 - Opening at the MPD choke

The simulation performed in OpenLab when MPD is controlled against a reference value of 22 bar constant backpressure, leads to a BHP of 379.5 bar (Figure 17). This differs by 0.5 bar from 380 bar BHP (corresponding reference value).

7.3.1.2 3500 m

This simulation has a constant backpressure at 12 bars (reference value), corresponding to 500 bar BHP at 2500 L/min. The control settings are shown in the Matlab-code (Appendix 11.4). Initial choke opening is 25 % and the choke opening is then controlled by the PI-controller during the flow-sweep (Figure 15). The resulting choke opening, back-pressure and bottom hole pressure is shown below.

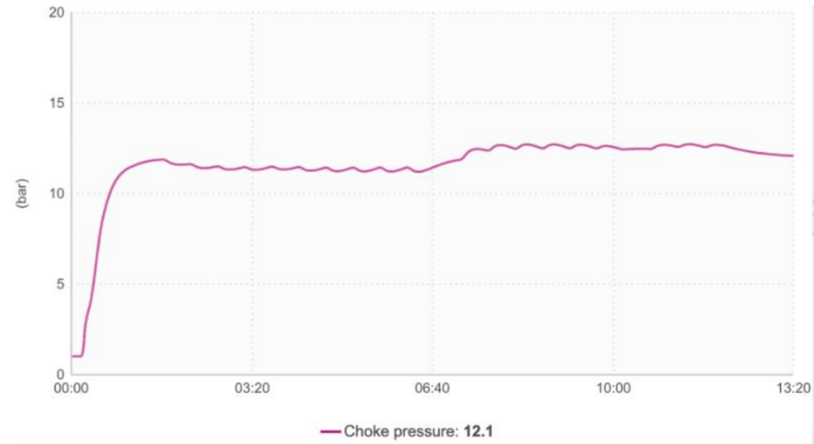

Figure 19 - Pressure at the MPD backpressure pump

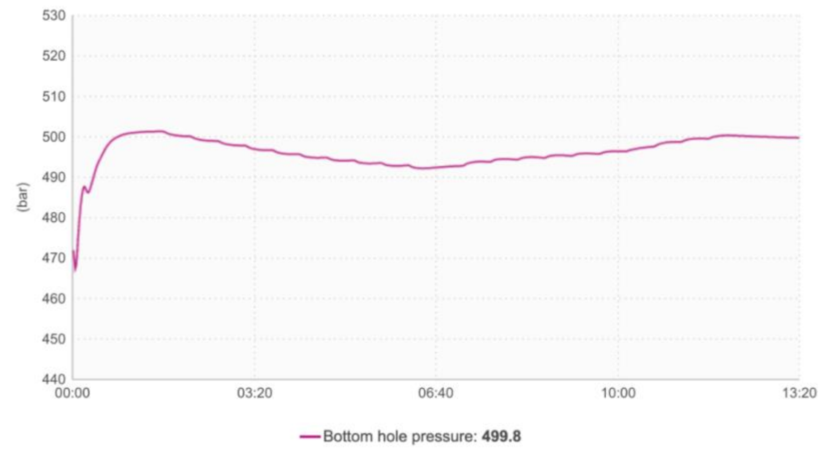

Figure 20 - Pressure measured at the bottom of the hole (BHP)

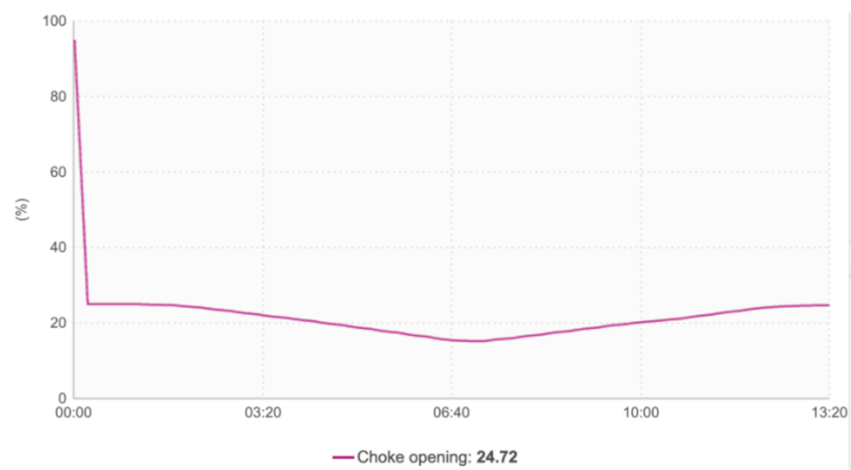

Figure 21 - Opening of the MPD choke

The simulation done in OpenLab when MPD is controlled against a reference value of 12 bar constant backpressure, leads to a BHP of 499,8 bar (figure 20). This differs by 0.2 bar from 500 bar BHP (corresponding reference value).

7.3.2 Case two

In this thesis the simulations of CBHP are based on downhole measurements when the well is 2500 m long and 3500 m long. Here we assume that a wired pipe is used and that the measurements are sent up to the control system.

7.3.2.1 2500 m

This simulation has a BHP of 380 bar (reference value), and it is controlled against measurement from BHP. The control settings are shown in the Matlab-code (Appendix 11.3). Initial choke opening is 25 % and the choke opening is then controlled by the PI-controller during the flow-sweep (Figure 15). The resulting choke opening, back-pressure and bottom hole pressure is shown below. The simulations shows that when using a wired pipe, you can send the measurements quickly enough to the surface so that it can be used directly in the PI controller when drilling with MPD. In this way it is possible to precisely control the annular pressure profile throughout the wellbore.

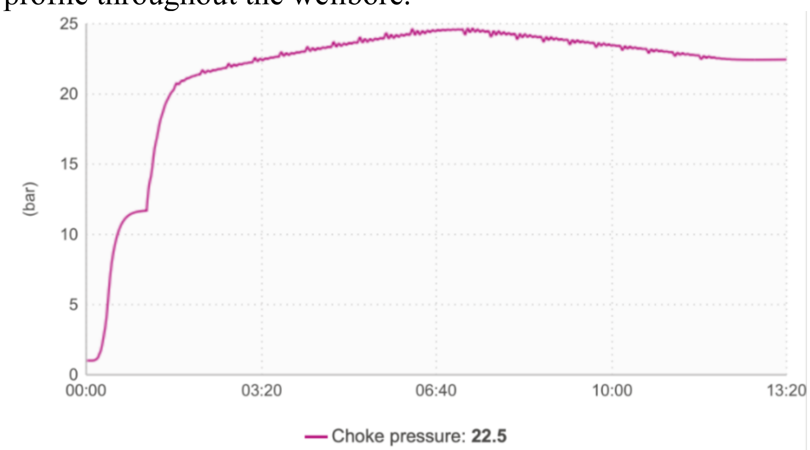

Figure 22 - Pressure at the MPD backpressure pump

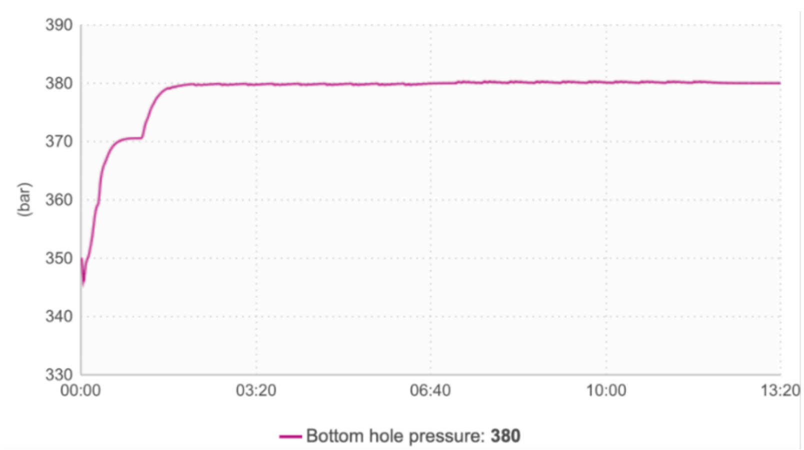

Figure 23 - Pressure measured at the bottom of the hole (BHP)

Figure 24 - Opening of the MPD choke

7.3.2.2 3500 m

This simulation has a BHP of 500 bar (reference value), and it is controlled against measurement from BHP. The control settings are shown in the Matlab-code (Appendix 11.4). Initial choke opening is 25 % and the choke opening is then controlled by the PI-controller during the flow-sweep (Figure 15). The resulting choke opening, back-pressure and bottom hole pressure is shown below.

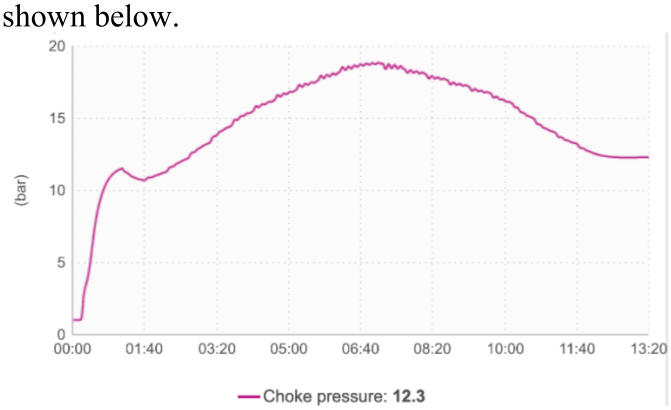

Figure 25 - Pressure at the MPD backpressure pump

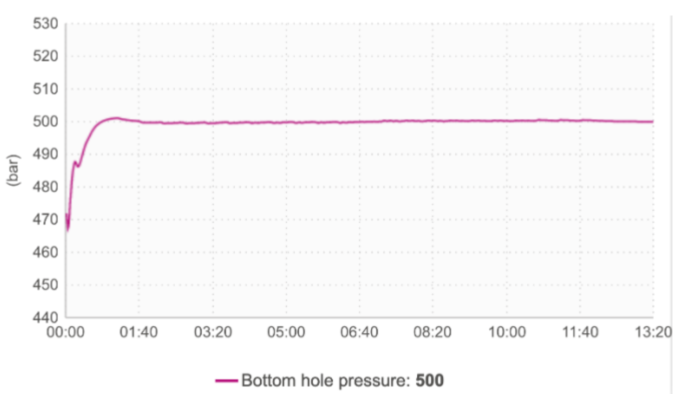

Figure 26 - Pressure measured at the bottom of the hole (BHP)

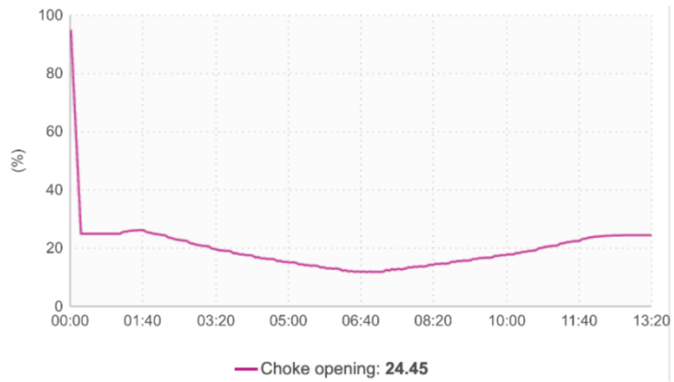

Figure 27 - Opening of the MPD choke

7.3.3 Comparison of simulation results

To illustrate the performance of the BHP control for the two cases and for the different depths we refer to Figure 28 and Figure 29 as shown below. As can be seen, the pressure is maintained close to the reference BHP (380 bar at 2500 meter and 500 bar at 3500 meter) when using downhole measurements and wired pipe as part of our control system. The ability to maintain the required bottom hole pressure is not as accurate when using surface pressure measurements, as expected, and the deviation is bigger as the well depth increases.

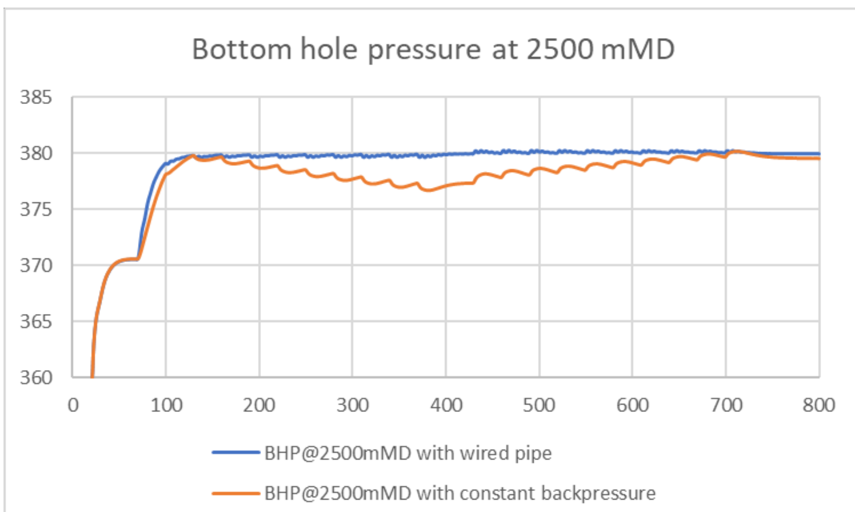

Figure 28 - Comparison of bottom hole pressure at 2500 meter with the two control strategies with and without wired pipe

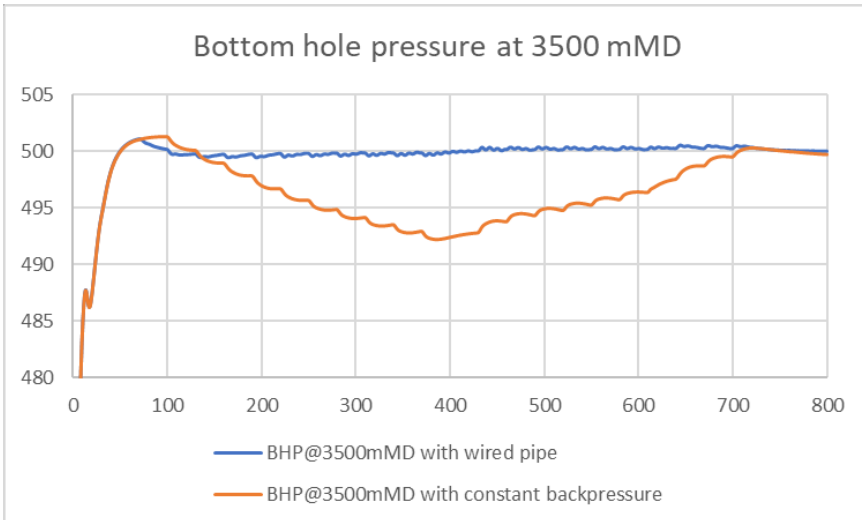

Figure 29 - Comparison of bottom hole pressure at 3500 meters

8 Discussion

8.1 Ability to control pressure precisely vs costs

The results of the case study show that it is easier to control the bottom hole pressure by using downhole measurements using a wired pipe (case two), and especially in longer wells (Figure 28 and 29).

In a longer well, there will be more dynamics, because the drilling fluid is compressible. When pumped from the top, a pressure is applied which compresses the drilling fluid, and it will circulate with the effect that it is compressed. There is a friction in the whole system, and it is therefore necessary with a pump pressure to make the drilling fluid circulate through the system. Part of this friction is in the annulus (from the bottom hole and up to the surface). This friction against the drilling fluid will be greater in a longer well.

When we do a flow sweep, the frictional pressure loss in the annulus will change as a function of the flow rate. The friction against the drilling fluid is greater at 2500 L/min than for 1500 L/min. This difference will be greater when the well is longer, and a change in the flow rate entails a relatively large change in bottom hole pressure for a longer well. This makes it difficult to use the pressure measurement on the surface to maintain a constant bottom hole pressure for a longer well.

When drilling with MPD, the quickest way to modify the bottom hole pressure is to apply backpressure from the surface, which has an immediate effect. Although this technology allows for more precise control of wellbore pressure, it is critical to understand its limitations. When using backpressure to maintain a CBHP, the pressure is only constant at one point in the well, as seen in Figure 30 by the junction of the red and blue lines. These two lines suggest that an endlessly long open hole section is not achievable. It is feasible to improve the open hole section by keeping a goal pressure higher up in the well, as indicated to the right in Figure 30. There will be some cyclic loading on the formation above and, if possible, below the point of constant BHP when using surface backpressure to maintain a CBHP throughout drilling and connection. This repeated stress could weaken the formation and cause problems with well stability.

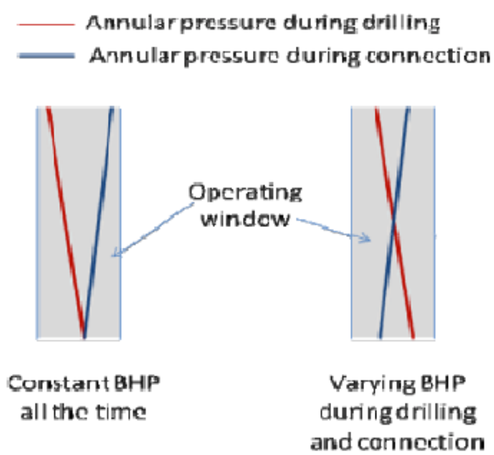

Figure 30 - Intersection between annular pressure during drilling and connection (Vaaland, 2010)

Another point to consider is that when a wellbore is static, the pressure in the horizontal leg approaches a constant. In this static condition, any backpressure applied to the well will have the same impact throughout the time. When circulating, however, the ECD is always larger at the end of the horizontal interval, which must be considered when the operational window is narrow (Stone & Shifeng, 2008).

It will be necessary to obtain relevant information about a drilling project, such as financial and environmental aspects before companies begin the drilling process. Fosse has collected relevant data to make a cost estimate using regular drill pipe and wired drill pipe (Table 3).

Table 3 - Cost of regular and wired drill pipe (Fosse, 2015)

Type of pipe	Length of well [m]	Joints needed	Per joint [$]	Surface Eq. [$]	Total [$]
Regular Drill Pipe	5000	500	5000	0	2 500 000
Regular Drill Pipe	2200	220	5000	0	1 100 000
Wired Drill Pipe	5000	500	8000	200 000	4 200 000
Wired Drill Pipe	2200	220	8000	200 000	1 960 000

The data from table 3 shows that the total cost will increase in line with the length of the well if a wired pipe is used, and this information must be weighed against other factors to decide which method to use. For example, if it is not possible to hold a CBHP using backpressure from the surface due to depleted reservoir, HPHT wells, deepwater wells and extended Reach Drilling (ERD) wells, wired pipe is the best telemetry to use because the benefits outweigh the costs.

WDP Drill Faster Savings Summary

	Data	Value	Percentage
	Data Transmission Time	29.3	38.2%
	Increased Drilling Performance (ROP)	26.4	34.2%
	Bit/BHA Run Reduction	12	15.8%
	Hole Cleaning Time Optimisation	6.7	7.9%
	Trip Speed Optimisation	3.5	3.9%

Total Time Saved (Hours): 77.9

Total Time Saved (Days): 3.2

Figure 31 - Time-savings summary, 5000 m long well (Fosse, 2015)

WDP Drill Faster Savings Summary

	Data	Value	Percentage
	Data Transmission Time	8.8	38.1%
	Increased Drilling Performance (ROP)	5.4	23.8%
	Bit/BHA Run Reduction	4	19.0%
	Hole Cleaning Time Optimisation	4.4	19.0%
	Trip Speed Optimisation	0.2	0.0%

Total Time Saved (Hours): 22.8

Total Time Saved (Days): 0.9

Figure 32 - Time-savings summary, 2200 m long well (Fosse, 2015)

Another crucial part to take into consideration when choosing between backpressure from the surface and wired pipe to maintain a constant BHP is the time saved by choosing wired pipe. Figure 31 and Figure 32 are based on the same wells as in table 3. The time reductions demonstrated in the Figure 31 and 32, demonstrate how oil firms can save money by utilizing wired drill pipe (WDP). If an operator is in the early stages of planning a new field, they can contact WDP technology vendors for calculations on how many wells they will need to drill to break even.

The outcome shows whether the oil firm would save money by using WDP technology or not, making it simple for the operator to decide whether to invest in WDP. If the customer can get close to a break-even price (the higher cost of investing in WDP equals the time saved on transmission speed).

It will always be a more expensive option to choose the WDP over the regular drill pipe but looking at it in a bigger picture; you might end up saving money.

This type of comparison of whether to use a wired pipe also depends on the types of drilling fluids used in the drilling operation. The case study in this thesis is based on an oil-based mud with a density of 1.65 sg at 50 degrees Celsius. This is a high density and will give a high friction and a high friction pressure drop. The fact that it is an oil-based drilling fluid says something about the compressibility. For future work, it may be interesting to use another drilling fluid and compare the results to study how much effect the choice of drilling fluid has when assessing whether wired pipe should be used or not. It is the stability of the well that determines the type of drilling fluid and the type of additive that must be used. The mixture must both clean the well and maintain well control. The use of oil-based drilling fluid will be able to reduce friction more than the use of water-based drilling fluid. Oil-based drilling fluids reduce the friction between the drill string and the casing or hole wall, which can be especially important in long, horizontal sections.

For future work, it is also possible to create a better control system than that used in this thesis. In this thesis, the backpressure choke is used with a constant backpressure pressure of either 12 or 22 bar. In reality, this would be a little more advanced. It is possible, for example, to use a table, which is based on some simulations of which backpressure one may have. The table would be such that there would be 12 bar constant backpressure for a flow rate of 2500 L/min and another constant backpressure for another flow rate. The control system would look up in a table depending on the flow rate used. In this way one could have compared how good such a table would be in relation to the use of wired pipe. The result will not be as good as when using a wired pipe, and this table has its limitations. There will be great uncertainty associated with this table and it will also be pre-generated. This means that if you are going to change the drilling fluid that has a different density or change the bottom hole assembly (BHA) that will affect the pressure drop in the well, you must make a completely new table that takes these changes into account.

MPD is only used when there is something with the pressure to be addressed, either you will have the opportunity to change the pressure very quickly throughout the well or you will control the pressure towards a pore pressure that varies with the depth as the well is drilled deeper and deeper. The use of a simulator that simulates the pressure quite accurately will probably always be an advantage then. It is important to point out that a simulator is only based on a model from reality. If you have the wrong input in the model, you get an output that does not represent the case that you are facing when drilling.

9 Conclusion

To assess whether wired pipe or backpressure from the surface should be used to maintain a constant bottom hole pressure, several important factors come into play:

- The complexity and length of the well:
  - If it is possible to obtain good results with surface backpressure, a wired pipe is not necessary.
  - If the results are not sufficient with surface backpressure due to depleted reservoir, HPHT wells, deepwater wells and ERD wells. Wired pipe may be the only solution.
- Cost:
  - It is extremely expensive with wired pipe compared to surface backpressure.
  - How many wells is needed to drill to reach break-even price, this will tell if it is feasible or not with wired pipe.
- Drilling fluid:
  - Oil-based drilling fluid will be able to reduce friction more than water-based drilling fluid.
  - A high density will give a high friction pressure drop.
  - Greater friction against the drilling fluid in longer wells.
- Control strategy:
  - The choice of control strategy depends on how accurate one must have pressed. Whether the pressure can be ± 5 bar depends on how narrow the pressure window is.
  - The pressure window is not always known in advance.
  - Can control the pressure more accurately with wired pipe.
  - In cases where the pressure does not need to be controlled accurately, surface measurements may be sufficient.
- Model:
  - Uses a simulator based on a model from reality.

- Wrong input will give wrong output

All the above-mentioned factors must be weighed against each other to determine if wired pipe is the best solution for maintaining a constant BHP, or if backpressure from the surface is more than good enough.

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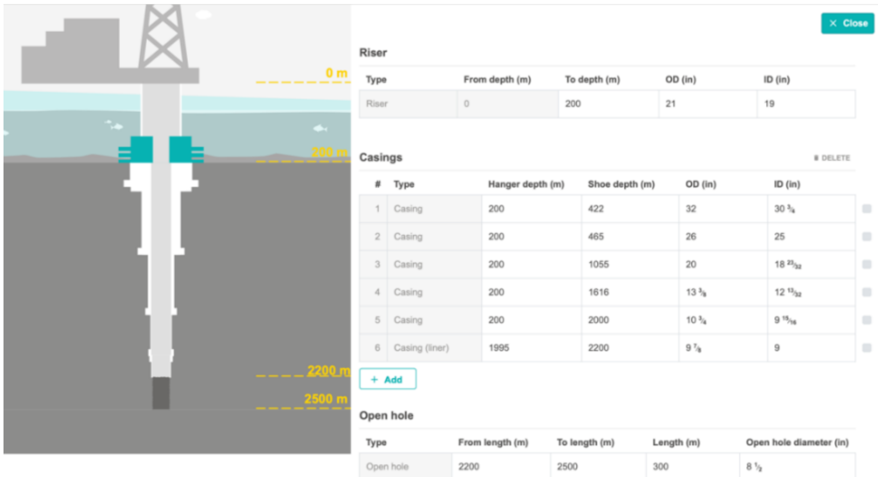
11 Appendix

11.1 OpenLab, 2500 m long well



Type	From depth (m)	To depth (m)	OD (in)	ID (in)
Riser	0	200	21	19

#	Type	Hanger depth (m)	Shoe depth (m)	OD (in)	ID (in)
1	Casing	200	422	32	30 3/4
2	Casing	200	465	26	25
3	Casing	200	1055	20	18 23/32
4	Casing	200	1616	13 3/8	12 13/32
5	Casing	200	2000	10 3/4	9 15/16
6	Casing (liner)	1995	2200	9 7/8	9

Type	From length (m)	To length (m)	Length (m)	Open hole diameter (in)
Open hole	2200	2500	300	8 1/2

Figure 33 - Hole Section

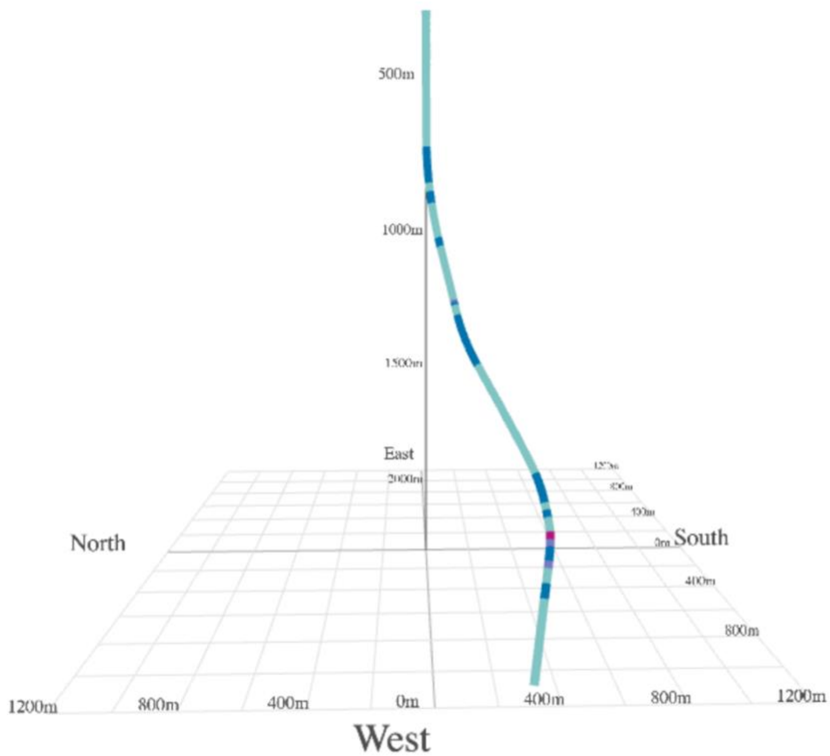


Figure 34 - North-South Wellpath

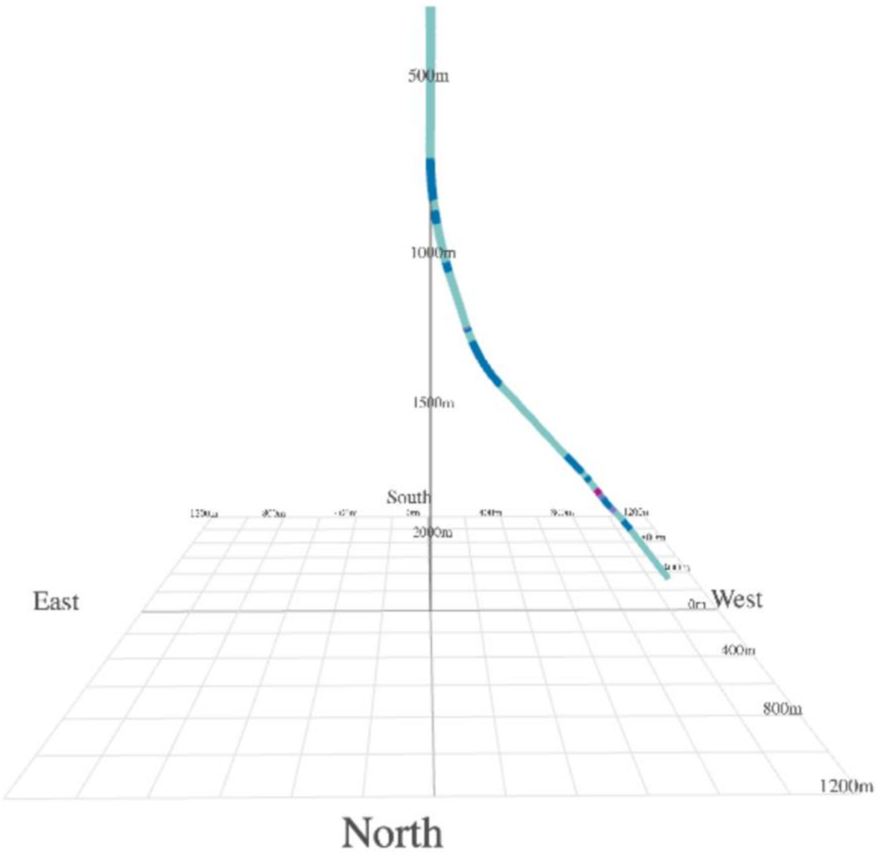
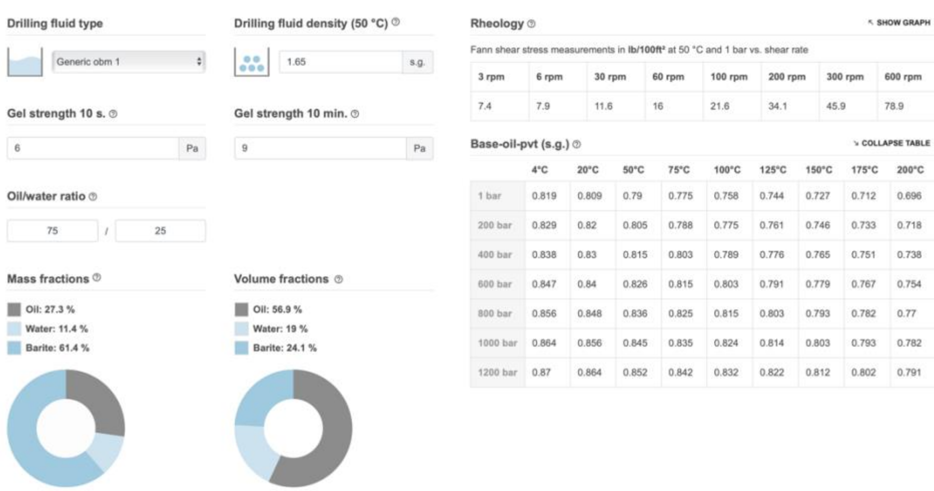


Figure 35 - East-West Wellpath

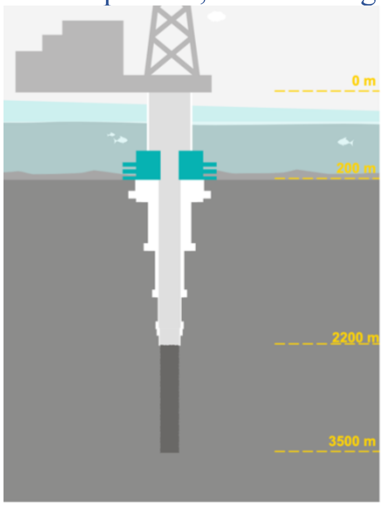


3 rpm	6 rpm	30 rpm	60 rpm	100 rpm	200 rpm	300 rpm	600 rpm
7.4	7.9	11.6	16	21.6	34.1	45.9	78.9

	4°C	20°C	50°C	75°C	100°C	125°C	150°C	175°C	200°C
1 bar	0.819	0.809	0.79	0.775	0.758	0.744	0.727	0.712	0.696
200 bar	0.829	0.82	0.805	0.788	0.775	0.761	0.746	0.733	0.718
400 bar	0.838	0.83	0.815	0.803	0.789	0.776	0.765	0.751	0.738
600 bar	0.847	0.84	0.826	0.815	0.803	0.791	0.779	0.767	0.754
800 bar	0.856	0.848	0.836	0.825	0.815	0.803	0.793	0.782	0.77
1000 bar	0.864	0.856	0.845	0.835	0.824	0.814	0.803	0.793	0.782
1200 bar	0.87	0.864	0.852	0.842	0.832	0.822	0.812	0.802	0.791

Figure 36 - Drilling fluid properties

11.2 OpenLab, 3500 m long well



Close

Riser

Type	From depth (m)	To depth (m)	OD (in)	ID (in)
Riser	0	200	21	19

Casings DELETE

#	Type	Hanger depth (m)	Shoe depth (m)	OD (in)	ID (in)
1	Casing	200	422	32	30 ¾
2	Casing	200	465	26	25
3	Casing	200	1055	20	18 21/32
4	Casing	200	1616	13 ⅜	12 13/32
5	Casing	200	2000	10 ¾	9 15/16
6	Casing (liner)	1995	2200	9 ⅞	9

+ Add

Open hole

Type	From length (m)	To length (m)	Length (m)	Open hole diameter (in)
Open hole	2200	3500	1300	8 ½

Figure 37 - Hole Section

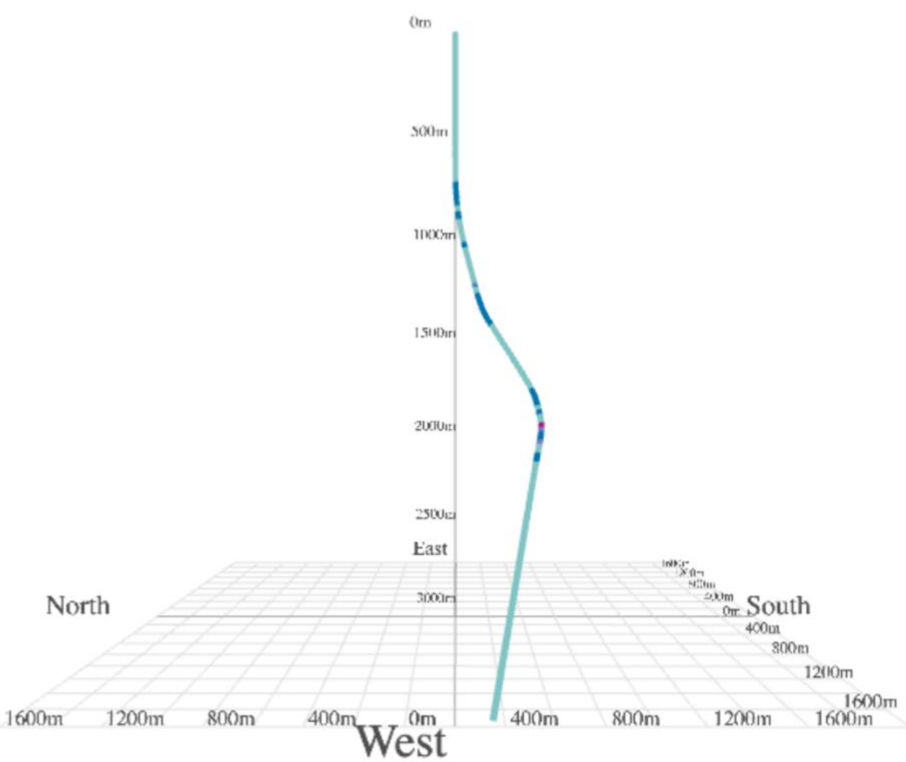


Figure 38 - North-South Wellpath

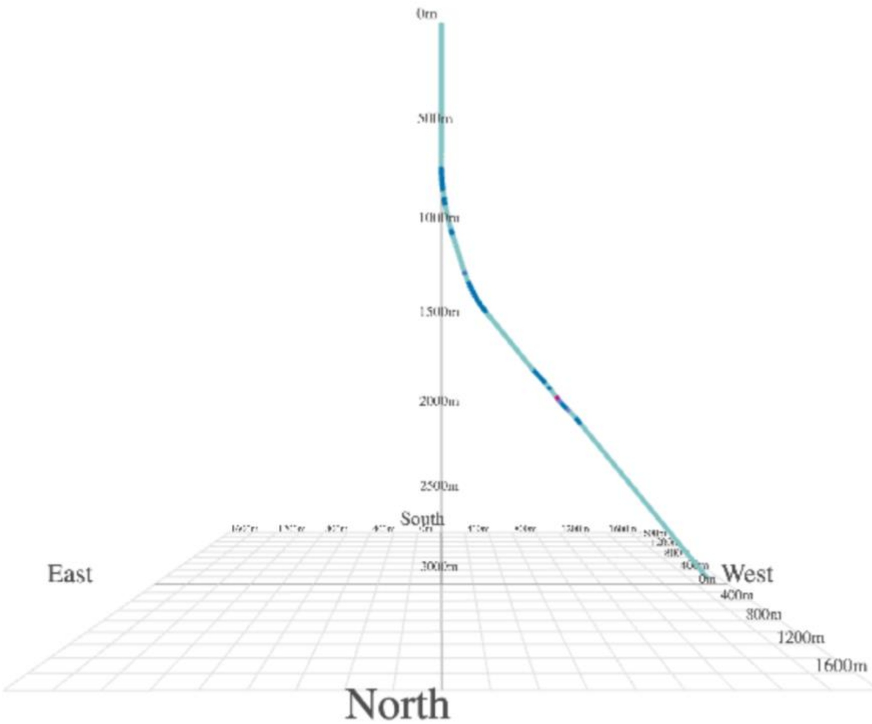
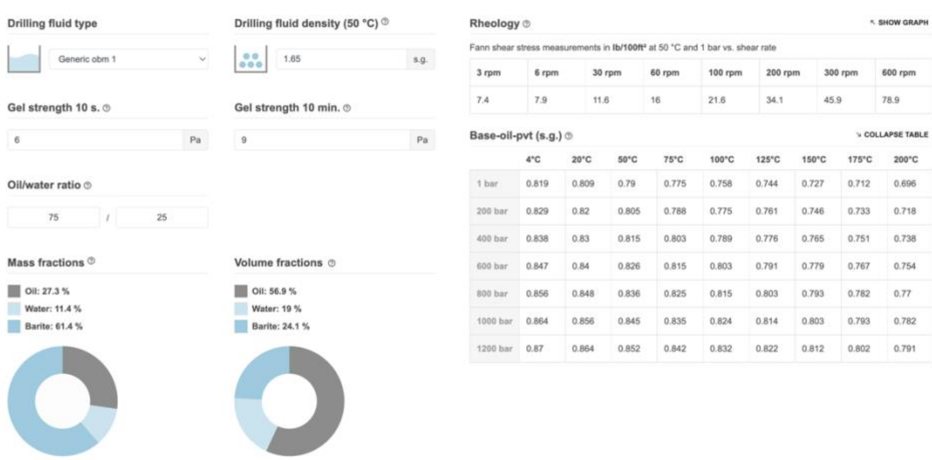


Figure 39 - East-West Wellpath



3 rpm	6 rpm	30 rpm	60 rpm	100 rpm	200 rpm	300 rpm	600 rpm
7.4	7.9	11.6	16	21.6	34.1	45.9	78.9

	4°C	20°C	50°C	75°C	100°C	125°C	150°C	175°C	200°C
1 bar	0.819	0.809	0.79	0.775	0.758	0.744	0.727	0.712	0.696
200 bar	0.829	0.82	0.805	0.788	0.775	0.761	0.746	0.733	0.718
400 bar	0.838	0.83	0.815	0.803	0.789	0.776	0.765	0.751	0.738
600 bar	0.847	0.84	0.826	0.815	0.803	0.791	0.779	0.767	0.754
800 bar	0.856	0.848	0.836	0.825	0.815	0.803	0.793	0.782	0.77
1000 bar	0.864	0.856	0.845	0.835	0.824	0.814	0.803	0.793	0.782
1200 bar	0.87	0.864	0.852	0.842	0.832	0.822	0.812	0.802	0.791

Figure 40 - Drilling fluid properties

11.3 Matlab, 2500 m long well

The methods used, such as the PI controller and the matlab client from OpenLab are available at https://openlab.app/ .

```
% NOTE: You need Matlab R2016b version to run the OpenLab simulator

clear variables;
clc;
close all;

% Add to the matlab path the folder where this file is located and all the
% subfolders
addpath(genpath(pwd));

IdentityServerURL = 'https://live.openlab.app/';

[username, api_key, license_guid] = GetLoginData();

ConfigurationName = 'Yvonne';
SimulationName = 'Flow sweep with bhp control (Matlab)';
InitialBitDepth = 2500; % [m]
InitialTopOfStringPosition = 20;

% Create simulation object
Sim = OpenLabClient(IdentityServerURL,
username,api_key,license_guid,ConfigurationName,SimulationName,InitialBitDepth,
InitialTopOfStringPosition);

% Ramp settings
RampIndex = 1;
RampValuesDown = (2500:-100:1500)/60000; % [m3/sec]
RampValuesUp = (1500:100:2500)/60000;  % [m3/sec]
RampValues = [RampValuesDown RampValuesUp]; % [m3/sec]
RampStepDuration = 30; % [sec]
RampStartTime = 70; % [sec]
RampTimeSteps =
RampStartTime:RampStepDuration:length(RampValues)*RampStepDuration-
1+RampStartTime;

% Time steps to simulate
MaxTimeSteps = (RampTimeSteps(end)+100);

% Controller settings for MPD based on downhole measurement
%{
Kp = -0.015; Ki = Kp/10; Ts = 1;
ReferenceBHPPressure = 380 * 1E5; % [Pa]
InitialChokeOpening = 0.25; % [closed: 0, open: 1]
%}

% Controller settings for MPD based on surface measurement (Back pressure)
```

```
Kp = -0.005; Ki = Kp/10; Ts = 1;
ReferenceChokePressure = 22 * 1E5; % [Pa]
InitialChokeOpening = 0.25; % [closed: 0, open: 1]

ReferencePressure = ReferenceChokePressure;
PI = PIcontroller(Kp, Ki, Ts, ReferencePressure,InitialChokeOpening); % Create PI controller
object, pressure in [Pa]

if Sim.IsOK
   try
      for timeStep = 1 : MaxTimeSteps
         tStartStep = tic;

         if timeStep >= RampStartTime % Flow sweep and PI control of the choke
            if (RampIndex < length(RampTimeSteps) && RampIndex < length(RampValues))
               if (timeStep >= RampTimeSteps(RampIndex) &&  timeStep <
RampTimeSteps(RampIndex + 1))
                  FlowRateIn = RampValues(RampIndex);
                  if (timeStep == RampTimeSteps(RampIndex + 1) - 1)
                     RampIndex = RampIndex + 1;
                  end
               end
            elseif (RampIndex == length(RampTimeSteps) && RampIndex ==
length(RampValues))
               FlowRateIn = RampValues(RampIndex);
            end

            if timeStep == RampStartTime
               % Reset PI controller before usage, set reference value and initial output (= initial
               % choke opening)
               PI.Reset(ReferencePressure,Sim.ChokeOpeningStatus);
            end

            %ChokeOpening  = PI.GetOutput(Sim.BottomHolePressure); % Get choke opening
from PI controller
            ChokeOpening  = PI.GetOutput(Sim.ChokePressure); % Get choke opening from PI
controller

         else % Constant flow rate and choke opening
            FlowRateIn = RampValues(1);
            ChokeOpening = InitialChokeOpening;
         end

         % Set setpoints to the simulator
         Sim.FlowRateIn = FlowRateIn;  %  [m3/sec]
         Sim.ChokeOpening = ChokeOpening;  %   [0-1]
```

```
        Sim.ChokePumpFlowRateIn = 0/60000;  %  [m3/sec]
        Sim.TopOfStringVelocity = 0;  %  [m/sec]
        Sim.SurfaceRPM = 0/60;  %  [revolutions per sec.]
        Sim.ROP = 0/3600;  %  [m/sec]

        % Step simulator
        Sim.Step();

        if ~Sim.IsOK % Simulator fails
          break;
        end

        display(['Total step duration: ' num2str(toc(tStartStep))]);
      end

      % Stop simulation process
      Sim.Stop;

    catch exception
      % Stop simulation
      Sim.Stop;
      rethrow(exception);
    end

end
```

11.4 Matlab, 3500 m long well

The methods used, such as the PI controller and the matlab client from OpenLab are available at https://openlab.app/ .

```
% NOTE: You need Matlab R2016b version to run the OpenLab simulator

clear variables;
clc;
close all;

% Add to the matlab path the folder where this file is located and all the
% subfolders
addpath(genpath(pwd));

IdentityServerURL = 'https://live.openlab.app/';

[username, api_key, license_guid] = GetLoginData();

ConfigurationName = 'Yvonne version 2';
SimulationName = 'Flow sweep with bhp control (Matlab)';
```

```
InitialBitDepth = 3500; % [m]
InitialTopOfStringPosition = 20;

% Create simulation object
Sim = OpenLabClient(IdentityServerURL,
username,api_key,license_guid,ConfigurationName,SimulationName,InitialBitDepth,
InitialTopOfStringPosition);

% Ramp settings
RampIndex = 1;
RampValuesDown = (2500:-100:1500)/60000; % [m3/sec]
RampValuesUp = (1500:100:2500)/60000;  % [m3/sec]
RampValues = [RampValuesDown RampValuesUp]; % [m3/sec]
RampStepDuration = 30; % [sec]
RampStartTime = 70; % [sec]
RampTimeSteps =
RampStartTime:RampStepDuration:length(RampValues)*RampStepDuration-
1+RampStartTime;

% Time steps to simulate
MaxTimeSteps = (RampTimeSteps(end)+100);

% Controller settings for MPD based on downhole measurement
%{
Kp = -0.015; Ki = Kp/10; Ts = 1;
ReferenceBHPPressure = 500 * 1E5; % [Pa]
InitialChokeOpening = 0.20 ; % [closed: 0, open: 1]
%}

% Controller settings for MPD based on surface measurement (Back pressure)

Kp = -0.005; Ki = Kp/10; Ts = 1;
ReferenceChokePressure = 12 * 1E5; % [Pa]
InitialChokeOpening = 0.25; % [closed: 0, open: 1]

ReferencePressure = ReferenceChokePressure;
PI = PIcontroller(Kp, Ki, Ts, ReferencePressure,InitialChokeOpening); % Create PI controller
object, pressure in [Pa]

if Sim.IsOK
   try
      for timeStep = 1 : MaxTimeSteps
         tStartStep = tic;

         if timeStep >= RampStartTime % Flow sweep and PI control of the choke
            if (RampIndex < length(RampTimeSteps) && RampIndex < length(RampValues))
```

```
            if (timeStep >= RampTimeSteps(RampIndex) &&  timeStep <
RampTimeSteps(RampIndex + 1))
                FlowRateIn = RampValues(RampIndex);
                if (timeStep == RampTimeSteps(RampIndex + 1) - 1)
                    RampIndex = RampIndex + 1;
                end
            end
        elseif (RampIndex == length(RampTimeSteps) && RampIndex ==
length(RampValues))
            FlowRateIn = RampValues(RampIndex);
        end

        if timeStep == RampStartTime
            % Reset PI controller before usage, set reference value and initial output (= initial
            % choke opening)
            PI.Reset(ReferencePressure,Sim.ChokeOpeningStatus);
        end

        %ChokeOpening  = PI.GetOutput(Sim.BottomHolePressure); % Get choke opening
from PI controller
        ChokeOpening  = PI.GetOutput(Sim.ChokePressure); % Get choke opening from PI
controller

    else % Constant flow rate and choke opening
        FlowRateIn = RampValues(1);
        ChokeOpening = InitialChokeOpening;
    end

    % Set setpoints to the simulator
    Sim.FlowRateIn = FlowRateIn;  %  [m3/sec]
    Sim.ChokeOpening = ChokeOpening;  %   [0-1]
    Sim.ChokePumpFlowRateIn = 0/60000;  %  [m3/sec]
    Sim.TopOfStringVelocity = 0;  %  [m/sec]
    Sim.SurfaceRPM = 0/60;  %  [revolutions per sec.]
    Sim.ROP = 0/3600;  %  [m/sec]

    % Step simulator
    Sim.Step();

    if ~Sim.IsOK % Simulator fails
        break;
    end

    display(['Total step duration: ' num2str(toc(tStartStep))]);
end
```

```
        % Stop simulation process
        Sim.Stop;

    catch exception
        % Stop simulation
        Sim.Stop;
        rethrow(exception);
    end

end
```