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## Summary

Drilling in challenging environments with different drilling hazards cause a lot of non-productive time (NPT), ie time where the rig is not drilling. Much of the challenging environments are in water depth demanding the use of floating drilling facilities. The result of NPT and high rig costs is a lot of money spent on nothing productive. To solve the challenges associated with challenging environments and high percentage of non-productive time, there is in particular one drilling method many operators have been looking at for the last decade, and that is managed pressure drilling (MPD), with its different variations.

Even though there are several challenges associated with combining MPD and floaters and bringing them in to some geological areas, the involved parties in the industry seem to be determined to solve the challenges and take the technology into the future.

Due to its experience with MPD from jack-ups and platforms, the operator BG Group is now looking towards utilizing MPD from floaters in several of their assets around the globe. The scope of this thesis is to look into the technology existing today and the experience gained up to date with MPD from floaters in various locations, which then could be useful for BG Group.

The specific challenges for MPD from floaters, such as variations in drilling fluid temperature, surge and swab due to heave motions and riser margin, should be analyzed from a risk perspective. The proven benefits of performing MPD which gives a more accurate pressure control during the drilling operation and earlier detection of influx and losses suggests that MPD from floaters should be taken into use. The risks for bad weather conditions and possibilities of riser disconnect should be included in an overall risk analysis.

Looking at the operations performed up to date on floaters, it is clear that a thorough planning process is crucial for a successful operation. Close collaboration in the planning process between operator, service companies and rig contractor with regard to equipment, procedures, HSE and last, but not least personnel training is of great importance.

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## List of Abbreviations

AFP – Annular Friction Pressure	LCM – Lost Circulation Material
API – American Petroleum Institute	LMRP – Lower Marine Riser Package
ASM – Along String Measurements	LOT – Leak-Off Test
ATR – Above Tension Ring	MD – Measured Depth
BHA – Bottomhole Assembly	MGS – Mud Gas Separator
BHP – Bottomhole Pressure	MFC – Microflux Control
BOP – Blow Out Preventer	MPD – Managed Pressure Drilling
BP – Backpressure	MPO – Managed Pressure Operations
BTR – Below Tension Ring	MW – Mud Weight
CBHP – Constant Bottomhole Pressure	MWD – Measurement While Drilling
CCS – Continuous Circulation System	NCS – Norwegian Continental Shelf
CCV – Continuous Circulation Valve	NPT – Non-Productive Time
DAPC – Dynamic Annular Pressure Control	NRV – Non-Return Valve
DDV – Downhole Deployment Valve	P&A – Plug and Abandon
DG – Dual Gradient	PLC – Programmable Logic Controller
DP – Dynamically Positioned	PMCD – Pressurized Mud Cap Drilling
ECD – Equivalent Circulating Density	PP – Pore Pressure
ENBD – Eni-Near-Balanced Drilling	PSA – Petroleum Safety Authorities
ERD – Extended Reach Drilling	PWD – Pressure While Drilling
FIT – Formation Integrity Test	RCD – Rotating Control Device
FP – Fracture Pressure	RDM – Reelwell Drilling Method
GoM – Gulf of Mexico	ROP – Rate of Penetration
HPHT – High Pressure High Temperature	RPCD – Riser Pressure Control Device
HSE – Health, Safety and Environment	RPM – Rotations per Minute
IADC – International Association of Drilling Contractors	SPE – Society of Petroleum Engineers

TD – Total Depth

TVD – True Vertical Depth

UBD – Underbalanced Drilling

WDP – Wired Drillpipe

# 1 Introduction

As a result of many of the easy prospects offshore has already been drilled, operators are focusing on the more challenging environments; extreme water depths, through depleted formations, High Pressure High Temperature (HPHT)- wells and in general more unexplored frontiers. An HPHT-well is defined by Society of Petroleum Engineers (SPE) as a well where the undisturbed bottomhole temperature at total depth is greater than 150°C, and either the maximum anticipated pore pressure to be drilled through exceeds a hydrostatic gradient of 0.8 psi/ft (0.181bar/m), or if pressure control equipment with a rating in excess of 10000psi (690bar) is required<sup>1</sup>. Much of the remaining resources around the globe might be located in HPHT environments and the challenge is often additionally increased since many of the HPHT prospects around the globe are located in deep water. To be able to increase the recovery in older fields, new wells needs to be drilled, but the problem in older field which have been producing for several years is that the formation pressures decreases. Both pore and fracture pressure decreases as the reservoir is being drained, making the operational window for drilling narrower and harder to drill. One of the more challenging environments is the unexplored frontiers, area where there have been little or no exploration earlier. In these areas, the geology might be uncertain as little or no offset data is available potential drilling challenges are unknown, making it harder to plan drilling operations in these areas.

Another aspect the operators are facing today is the high and increasing rig rates, where the cost of a rig can be in the range \$1 million a day. Drilling in challenging environments with different drilling hazards causes a lot of non-productive time (NPT), ie time where the rig is not drilling. The result of NPT and high rig costs is a lot of money spent on nothing productive. To solve the challenges associated with challenging environments and high percentage of non-productive time, there is in particular one drilling method many operators have been looking towards for the last decade, and that is managed pressure drilling (MPD) with its variations.

Even though the term managed pressure drilling was not launched until 2003, the history of MPD and MPD equipment dates back to the 1930s when the first rotating heads where described in the catalog of Shaffer Tool Company in 1937. These rotating heads are quite similar and based on much of the same principle as the modern rotating control devices (RCD) in use today. In the beginning, RCDs where used for air drilling and underbalanced operations, but over time the industry understood how they could use this equipment to control and manipulate equivalent circulating density (ECD) and from the 1970s RCD equipment was used to control ECD and more effectively control the pressure in the well. The technology used today combines new technology with older principles and techniques to manage common drilling problems.

The first example of offshore managed pressure drilling was seen in the 1970s in Gulf of Mexico (GoM). Managed pressure drilling in the form of mud cap drilling and pressurized mud cap drilling developed throughout the 1980s and 1990s. Development over the last decades have been within the use of precise control of surface backpressure to compensate for ECD, application of constant bottomhole pressure, continuous circulation systems, various dual-gradient systems applicable for deepwater and ultra-deepwater, and various types of down-hole valves<sup>2</sup>.

MPD operations have been conducted offshore from both fixed installations (jack-up rigs and production platforms with surface BOPs)<sup>3, 4</sup> and floating installations (semi-submersibles and drillships with both surface and subsea BOPs) as described in chapter 5. On the Norwegian side of the

North Sea, managed pressure drilling has been used successfully both for production drilling in depleted reservoirs<sup>5, 6</sup>, and for exploration wells from jack-up rigs. BG Norge successfully drilled one eHPHT (extreme HPHT- P>15.000psi) wildcat well, utilizing MPD from a jack-up in 2009-2010<sup>7</sup> and the same rig and MPD equipment have also been used on the British side of the North Sea later. The difference between MPD operations on fixed installations and floating units are that on floaters there is a marine riser between the BOP and the RCD. This difference cause some problems and challenges regarding the operation and where MPD up to date has been utilized. In areas where the weather conditions are quite calm, such as in the Mediterranean Sea, South East Asia and in deepwater fields outside the west coast of Africa, MPD operations from floating units has been performed successfully for several years<sup>8-11</sup>. This development seems to continue, bringing MPD technology into new areas and integrating it more and more in the operations. Even though there are challenges associated with combining MPD and floaters and bringing them in to some areas, the involved parties in the industry seem to be determined to solve the challenges and take the technology into the future.

Due to its experience with MPD from jack-ups and platforms, the operator BG Group is now looking towards utilizing MPD from floaters in different locations around the globe. The scope of this thesis is to look into the technology existing today and the experience gained up to date with MPD from floaters in various locations, which could be useful for BG Group in their planned operations in the future. The first chapters contains an overview of the MPD technology, the drilling hazards which MPD can be used to mitigate and an introduction to the MPD equipment necessary for operations from floaters. Further on, it is described what technology exists today and the operations performed and experience gained in different geological areas. A part of the thesis is looking a bit into the future, describing what might happen in the forthcoming years with this technology and what might be standards with regard to MPD from floaters, both worldwide and in Norway. In the end there is a chapter describing a project that BG Group are involved in where MPD from floaters are planned to be used in the near future.

## 2 Background

This chapter describes the principles and variations of MPD compared to conventional drilling and UBD, a short recap of wellbore pressures, a description of the drilling hazards which MPD is capable of mitigating and some of operational aspects to be aware of in MPD operations from floating units.

### 2.1 Wellbore Pressure

When drilling, there are pressure boundaries in the formation that is important to know to be able to drill successfully. There is an upper and a lower pressure limit, and the difference between them is known as the margin or the operating window. The lower limit is normally bounded by the pore pressure (PP) and the well-bore stability, while the upper limit is bounded by differential sticking, lost circulation, and fracture pressure (FP)<sup>2</sup>. These limits, also known as operational margins are the boundaries for the operational window. The operational window is also known as drilling window.

In most drilling operations, pore pressure represents the limit for the bottomhole pressure to avoid influx and kicks. In some cases the well-bore stability gradient is governing the lower limit, but usually it is the pore pressure. The upper limit is normally governed by the fracture gradient or the lost circulation gradient which are closely related.

The three main variations of drilling is named after its relation to the pressure limits, as seen in Figure 2-1; underbalanced, managed pressure and conventional.

Underbalanced drilling or underbalanced operations are having a bottomhole pressure (BHP) during operations below the lower pressure limit:

$$\text{BHP} < \text{Pore Pressure} \quad (\text{Eq. 1})$$

Managed pressure drilling operations are trying to keep a constant bottomhole pressure slightly above or balancing on the pore pressure curve. However there are also applications of MPD that uses the whole available operating window in the operation.

In conventional drilling, the bottomhole pressure is kept above the lower limit with a margin and below the upper limit.

$$\text{Pore Pressure} < \text{BHP} < \text{Fracture Pressure} \quad (\text{Eq. 2})$$

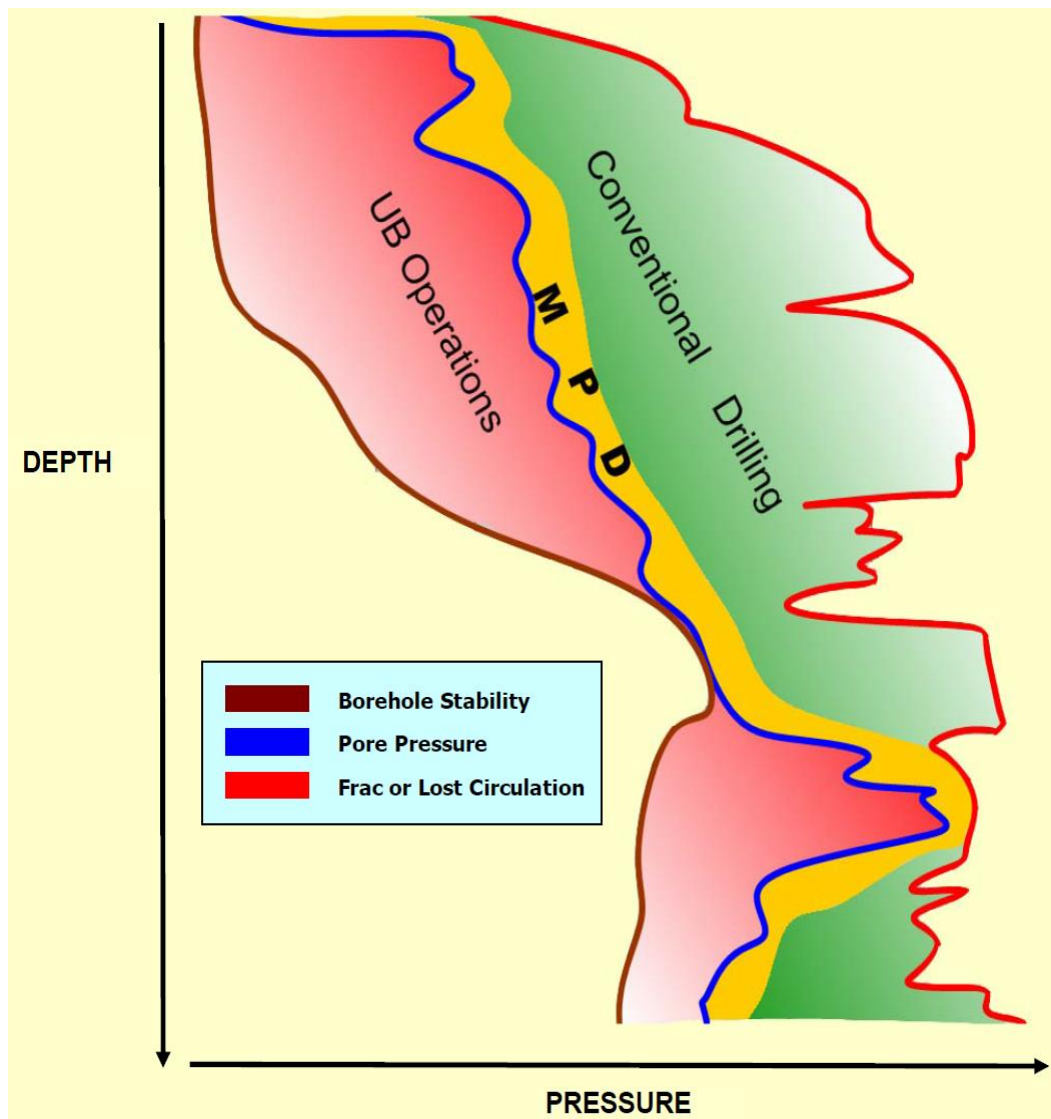


Figure 2-1 Drilling window for conventional drilling, MPD and UBD<sup>12</sup>

## 2.2 Conventional Drilling

In order to see the advantages MPD can have for the drilling process, one must first understand the concepts of conventional drilling hydraulics and see and accept its limitations.

Conventional drilling with weighted mud and open-to-atmosphere mud return system were first introduced in Spindeltop, Beaumont, Texas in 1901. There have been improvements, but the hydraulic principle is still the same over a decade later. Now days, the conventional drilling circulation flow path starts in the mud pit, drilling mud is pumped downhole through the drill string and –bit, up the annulus, exits the top of the annulus open to atmosphere via a bell nipple, through a flow line to eventually the mud-gas separator or directly to shaker, then back to the mud pit. The process is illustrated in Figure 2-2. Both the wellbore and the mud pit are open to the atmosphere, making the system an open vessel, and pressure readings in the flow line at surface will be equal to atmospheric. Drilling in an open vessel presents a number of challenges for drillers and drilling engineers, whit regards to downhole pressure control and kick – and loss detection.

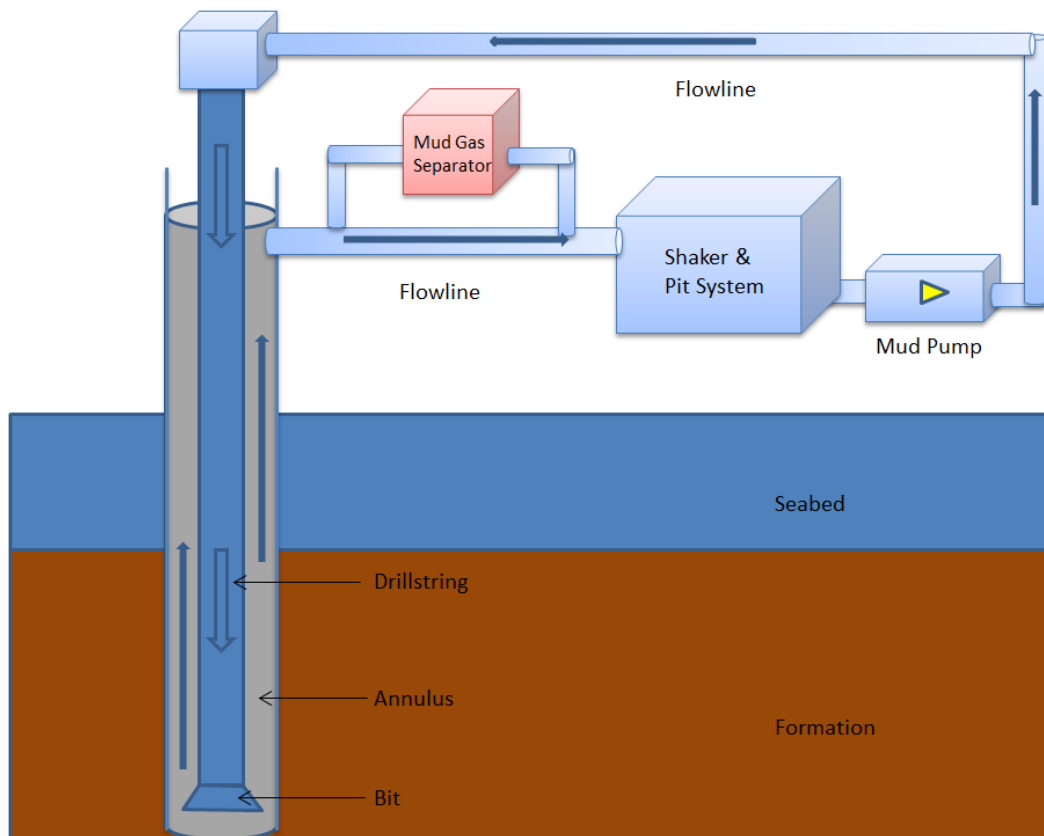


Figure 2-2 Basic principle of the circulation path in a conventional drilling system

In conventional drilling the pressure exerted in the wellbore is higher than the pore pressure in the exposed formation. Wellbore pressure is controlled by adjusting mud density and flow rates of the mud pumps. By adjusting the pump rate, pressure profile will change in the wellbore. However, this will affect the hole cleaning and could have an impact on the drilling progress, so careful evaluation is required before changing pump rates. During operations, the returning well flow and not pressure, is often an indication of a well control incident. Overflow of the bell nipple might be an indication of an occurring kick, while if the return column falls it is likely that the fracture gradient is exceeded and losses has occurred. This result of this is often that the well is shut-in for monitoring and eventually some method of well control to be initiated.

In dynamic conditions, when circulating the hole, bottomhole pressure (BHP) is defined as the sum of mud weight hydrostatic head pressure ( $MW_{HH}$ ) and annular friction pressure (AFP) during circulation:

$$BHP_{DYN} = MW_{HH} + AFP \quad (\text{Eq. 3})$$

This sum of pressure effects in dynamic conditions are called Equivalent Circulating Density (ECD) or Equivalent Mud Weight (EMW), and are a very important factor in drilling operations. It is the effective density/weight exerted by a circulating fluid against a formation, and it takes into account the static density/weight and the pressure drop in the annulus above the point being considered.

In static conditions, when pumps are shut off during connections or other incidents, only hydrostatic head pressure from the mud in annulus is determining BHP and the mud weight is designed to provide a bottomhole pressure higher than the pore pressure to prevent influx:

$$BHP_{STAT} = MW_{HH} \quad (\text{Eq. 4})$$

Figure 2-3 and Figure 2-4 illustrate the connection between dynamic and static conditions and how the pressure fluctuates between them when pumps are shut off during connections or other events. As seen in the figures, the annulus friction pressure increases with the depth of the well. Figure 2-3 is an idealized situation of the drilling operation, while in reality the conditions are more like in Figure 2-4 where the pore and fracture pressures are non-linear. The operating window is different from object to object, and in this figure one can see a slightly narrow operating window to illustrate the limitations of the conventional drilling. During connections, the BHP in the well decreases to below the pore pressure and influxes can occur, while further down in the well the dynamic pressure exceeds the fracture pressure allowing losses to take place. This is one of the limitations for conventional drilling, not being able to adjust the hydraulics to navigate thru narrow windows.

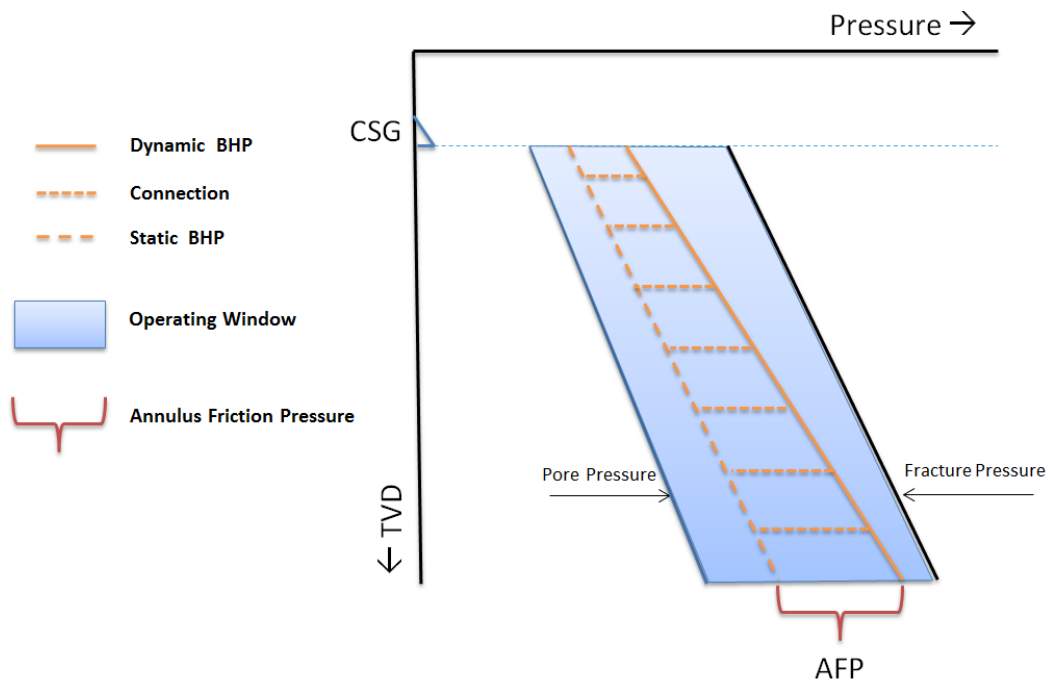


Figure 2-3 Hydraulics of conventional drilling



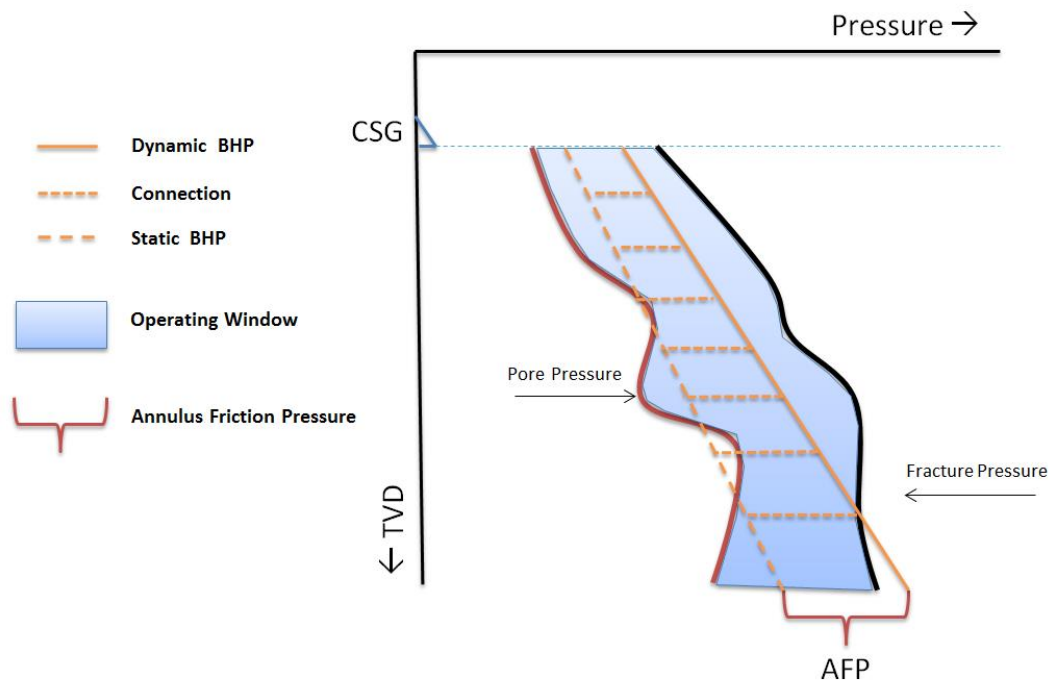


Figure 2-4 Hydraulics of conventional drilling in narrow operating window

## 2.3 Underbalanced Drilling

Underbalanced drilling (UBD) is as old as drilling itself. Before using weighted mud to create overbalance in the wellbore, they used water for drilling. With regards to HSE, this was not a good solution but they did not have any alternative until the introduction of weighted mud in Spinderton in 1901. During the last 100 years both safety and technology has evolved, and the reason for using this technique has changed from being the only option over to a productivity perspective. Now it is regarded as a safe operation both on- and offshore as long as all the right procedures are followed<sup>13</sup>.

The idea of underbalanced drilling is to keep the wellbore pressure lower than formation pore pressure and intentionally allow formation fluids to get to the surface. To achieve underbalanced conditions in the well, a very light fluid is used. The advantage of applying this method is a reduction in formation damage, which results in higher productivity of the reservoir, and is also the main reason for applying this drilling method. Other benefits of UBD are increase rate of penetration (ROP), less potential for differential sticking and lost circulation and increased bit life<sup>13</sup>. Fluids used for underbalanced drilling are mainly classified into gas, mist, foam, gasified liquid and liquid<sup>14</sup>.

Both UBD and MPD comprise a closed loop system, but in underbalanced systems a multi-phase separator is required for the operation. Underbalanced operations are designed to operate with low bottomhole pressure to allow for inflow of formation fluids, while MPD operations are designed to be balanced or overbalanced at all time, not allowing for any influx. A good MPD operation does not have any intentional influx.

The Underbalanced Operations & Managed Pressure Drilling Committee of the International Association of Drilling Contractors (IADC) defines UBD as<sup>15</sup>:

*“A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.”*

## 2.4 Managed Pressure Drilling

The Underbalanced Operations & Managed Pressure Drilling Committee of the International Association of Drilling Contractors (IADC) defines MPD as<sup>15</sup>:

*“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.*

- *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.”*

In NORSOK D-010: Rev. 4, draft version, 20.12.12, MPD operations using jointed pipe which can be rotated at surface and the following system<sup>16</sup>:

*“MPD: Systems manipulating annular pressure at surface to control and manage downhole pressures using static underbalanced fluid. “*

*Note; this standard does not cover MPD operations using a subsea BOP. But some of the requirements stated in the standard are applicable for subsea BOP use also. This version of the standard is not the final one, so this is subject to change.*

MPD is often referred to as an advanced form of primary well control, due to the system’s ability to precisely manage the column of annulus fluid acting on the exposed wellbore. Bottomhole pressure can be controlled more precise and effective than in conventional drilling where mud weight and pump rate adjustments alone are the tools. By closing in the system with a RCD and a MPD manifold system, as seen in Figure 2-5, and applying backpressure through chokes and designated backpressure pump in the MPD manifold makes it possible to have a pressurized system and controlling the pressure in the wellbore more precisely.

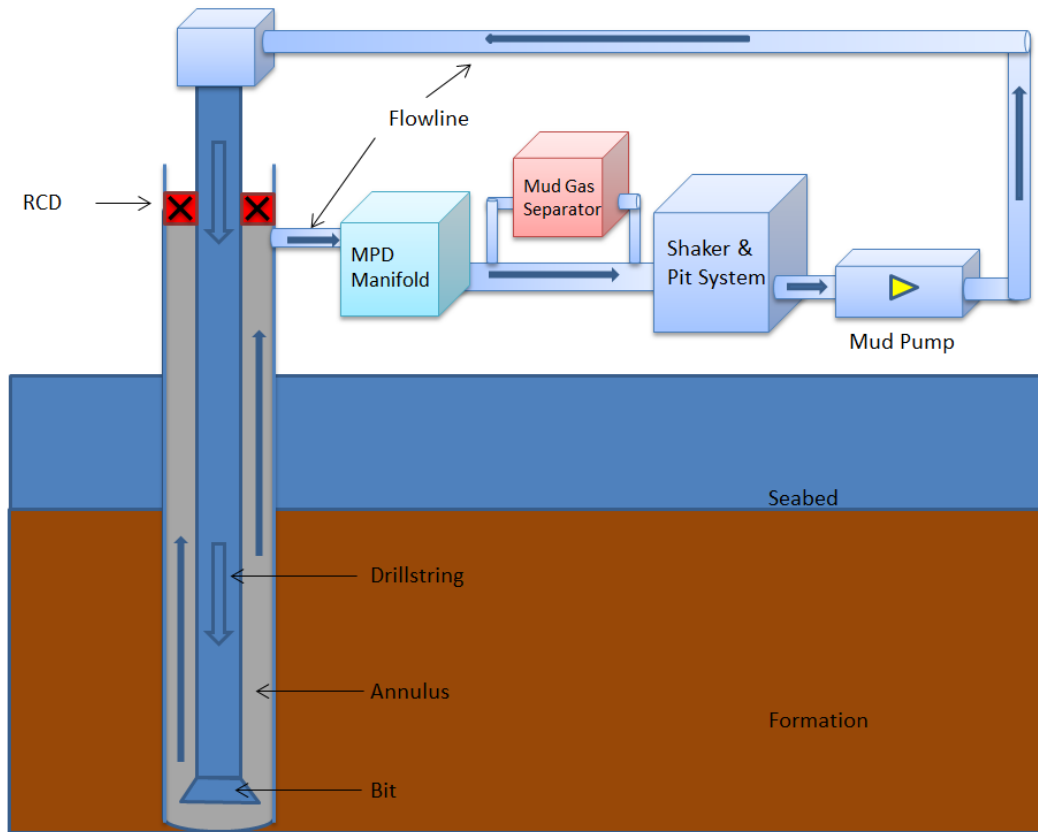


Figure 2-5 The principle behind the closed MPD system

Backpressure (BP) is applied from surface to achieve overbalance in the well. While circulating the system, the formula for bottomhole pressure or equivalent mud weight is:

$$BHP_{DYN} = MW_{HH} + AFP + BP \quad (\text{Eq. 5})$$

In dynamic conditions, applied backpressure is usually low and often close to zero. The mud weight used in MPD operations are often so low that the hydrostatic head pressure of mud alone is not enough to keep the well overbalanced when pumps are shut off. So in static conditions, backpressure of roughly the same value as the annular friction pressure during circulation is applied:

$$BHP_{STAT} = MW_{HH} + BP \quad (\text{Eq. 6})$$

The principle with the applied backpressure and the pressure regimes in both MPD- and conventional drilling is illustrated in Figure 2-7. Applying backpressure makes it possible to keep a near constant BHP, if required, during the entire operation. The need to keep a near constant BHP is present when having narrow operating margins, where even slight variations in pressure can lead to influx or fracturing the formation. Some prospects have so narrow windows that they would be impossible to drill conventionally. In order to maintain a constant BHP, a closed circulation system is required, which is different from the conventional open-to-atmosphere system. This close system can be seen as a pressurized vessel. A near constant bottomhole pressure can be maintained by following specific procedures when making connections. Pumps are shut down step wise and backpressure is increased with the same amount to achieve a bottomhole pressure during connections being the same as during drilling. This sequence is known as transient phase and is illustrated in Figure 2-6. The

sequence is reversed when the pipes have been connected and drilling is to be continued. This process can be eliminated if continuous circulation equipment is used, as the continuous circulation maintains the ECD during connections.

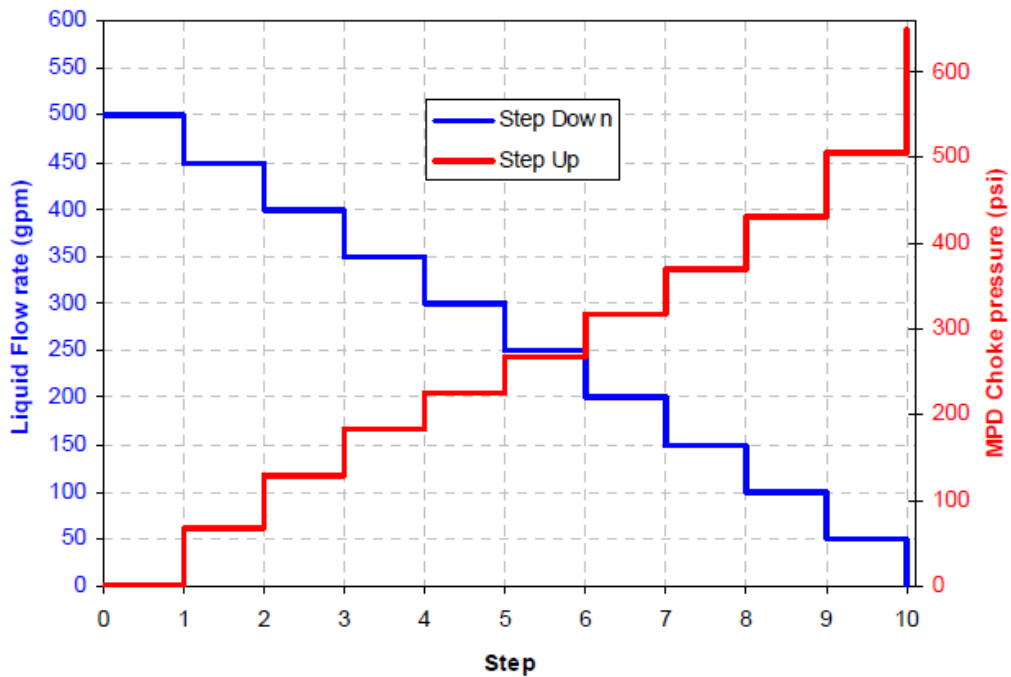


Figure 2-6 Step down, step up process of mud pumps and the backpressure during connections<sup>17</sup>.

Having a BHP slightly overbalanced, or as close to balance as possible, allows the driller to safely drill through narrow operating windows without having to set casing prematurely and change MW. In Figure 2-8, the same narrow operating window as in Figure 2-4 is illustrated with the hydraulics of MPD, illustrating how one can navigate into narrow windows without the dynamic or static pressure crossing either the pore – or fracture gradients. Drilling through narrow operating window is just one of the challenges solved with MPD, other benefits are described later.

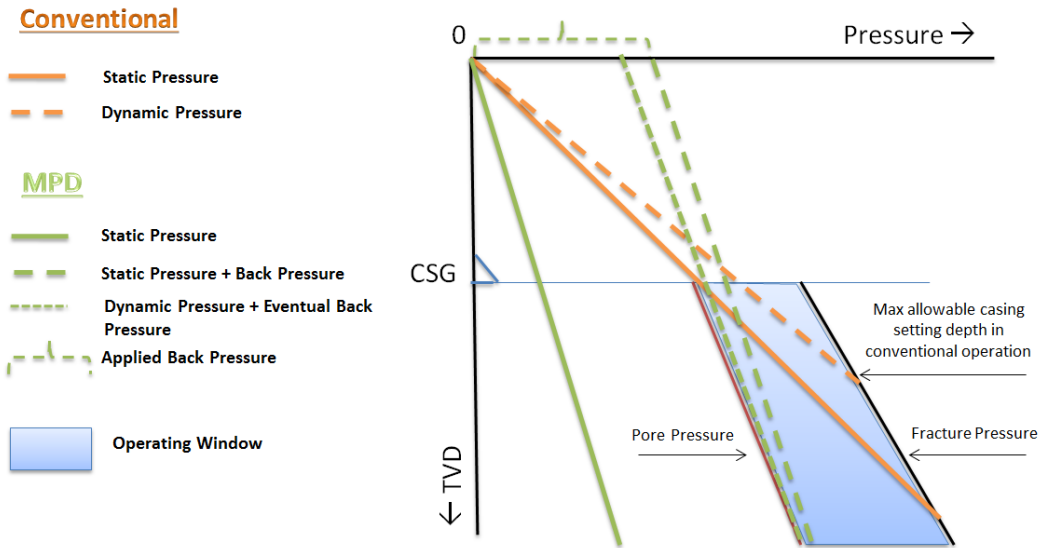


Figure 2-7 the principle of conventional drilling hydraulics compared to Managed Pressure Drilling

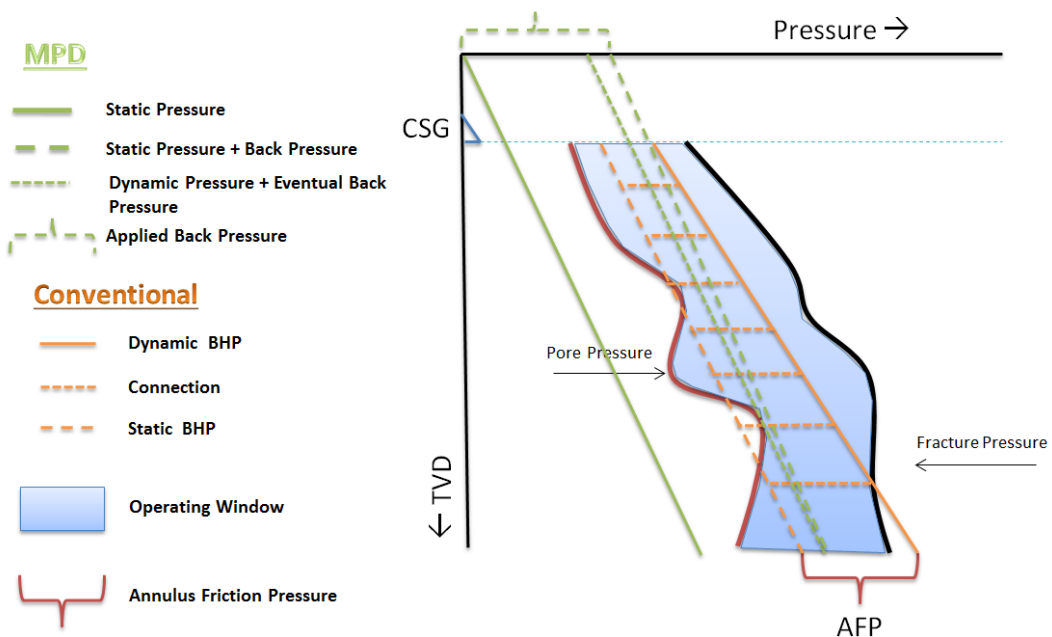


Figure 2-8 MPD in a narrow operating window

Note; Even though in these examples which illustrates the most common situations, the static mud weight of the mud used in MPD operations are below pore pressure, ie static underbalanced fluid, statically overbalanced fluid can be used in MPD operations too, eg for wells where the problem is not necessary a very tight drilling window, but other problems.

## 2.5 Categories of MPD

The Underbalanced Operations & Managed Pressure Drilling Committee of the International Association of Drilling Contractors (IADC) separates MPD into two categories, *reactive and proactive*, defined as<sup>15</sup>:

*“Reactive MPD - Using MPD methods and/or equipment as a contingency to mitigate drilling problems as they arise.*

*Proactive MPD - Using MPD methods and/or equipment to actively control the pressure profile throughout the exposed wellbore.”*

### 2.5.1 Reactive MPD

Conventional drilling operations are planned and performed, utilizing MPD procedures and/or equipment as a contingency to mitigate drilling problems after they occur. Reactive MPD is most common in onshore applications, and it allows the operators to react more safe and efficiently. Rotating Control Devices are often used as an insurance tool on the onshore drilling locations<sup>18</sup>.

### 2.5.2 Proactive MPD

The whole drilling program, including casing program, fluid program and drilling plan, is designed to take advantage of the ability to control the wellbore pressure, and thus be able to drill the most challenging prospects. This approach to MPD is used to be able to:

- a) Optimize the casing design with fewer casing strings, optimized casing seats and still be able to reach target,
- b) More precisely control mud densities and mud costs thru the operation,
- c) Precisely control the wellbore pressure and early well-control incident detection.

By summarizing these it is seen that proactive MPD enables drilling of operationally challenging, economically challenging and “undrillable” wells<sup>12</sup>. The most common variations of proactive MPD for offshore applications are Constant Bottom Hole Pressure (CBHP), Pressurized Mud Cap Drilling (PMCD), Dual Gradient (DG) and Returns Flow Control (HSE approach). The theme for CBHP, PMCD and DG are all to manipulate the wellbore pressure profile to manage or overcome drilling problems, while the HSE approach is mainly used to divert return flow away from the drill floor and personnel, and is in some cases regarded as a reactive MPD operation.

## 2.6 The Benefits of MPD

Some years ago, studies indicated that some 20-30% of the time spent in operations where NPT, and as much as 50% of these again could be related to wellbore pressure issues<sup>19</sup>. This is illustrated by Figure 2-9 where a total of 42% of the causes to NPT were wellbore pressure related issues that could have been reduced using MPD. By looking at drilling hazards and drilling incidents that affects the NPT in drilling operations, Malloy and McDonald<sup>20</sup> have identified problems closely related to NPT that can be mitigated using MPD approaches:

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

Don Hannegan states that drilling hazards have two things in common<sup>3</sup>:

“ 1) They may be addressed to some degree or other by drilling with more precise wellbore pressure management for drilling efficiency, mud cost savings and enable drilling otherwise “un-drillable” prospects.

2) Drilling-related hazards have the potential to escalate to become a root cause or contributing factor to a well control or HSE event, directly or indirectly.”

Summarizing these problem areas and hazards, and looking at some other benefits with MPD, it is clear that MPD technology allows for drilling of previously thought un-drillable prospects with increased operational safety, at lower costs and decreased operational time.

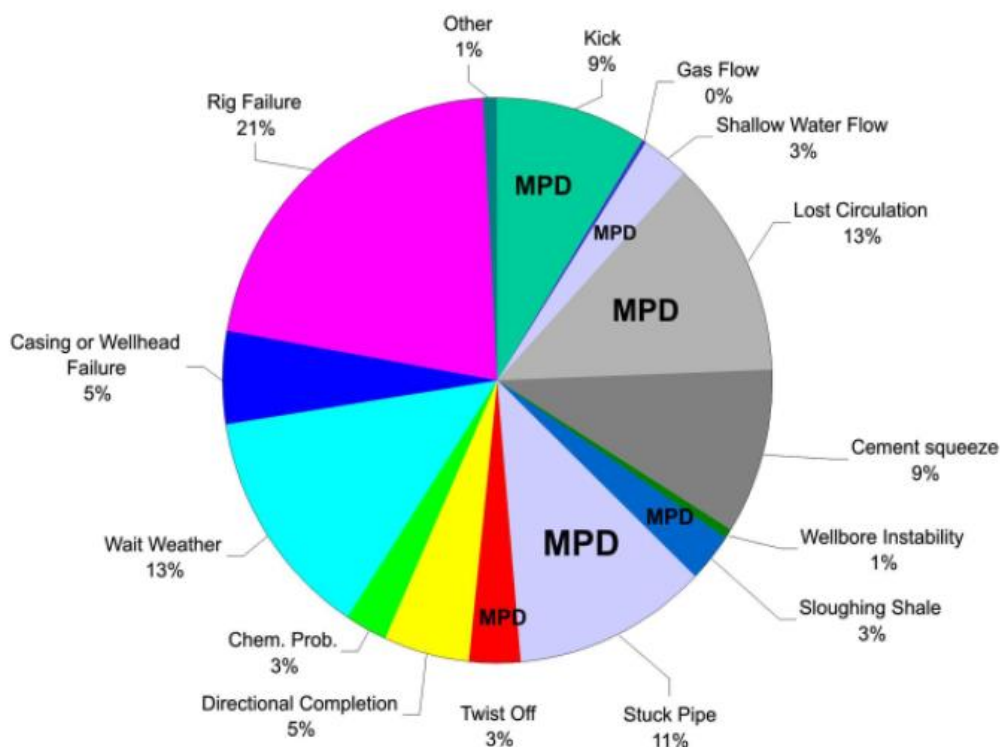


Figure 2-9 Causes of NPT and which causes could have been reduced with MPD<sup>21</sup>



### 2.6.1 Influx Detection and Well Control

This chapter is mainly based on a paper by Steve Nas<sup>11</sup>, unless otherwise is stated in the text.

Even with managed pressured drilling and close control of the bottomhole pressure, underbalanced conditions and potential inflow can occur and kick detection and well control procedures must at all-time remain in place. If the operator doesn't know exactly the pore pressure profile of the formations being drilled, kicks can be taken. The causes of kicks are not eliminated or changed with the installation and use of MPD equipment and procedures, but it has been statistically proven that the use of an RCD to create a closed wellbore makes drilling operations safer and easier to detect kicks with a closed loop<sup>22</sup>.

In normal circulation, the flow in and out of the well is in a steady state condition. The amount going in must come out. During a kick this balance is disturbed and the return flow will increase. In open-to-atmosphere systems the pit volume will also increase as formation fluid is added to the circulation system. To detect a kick in this system, monitoring of the return system is required and in some cases this is done manually. Kicks can also be detected when pumps are shut off and the well is supposed to stop flowing. If returns are still taken, a kick could be occurring. To stop the pump to check for flow is often practiced, even though it can be a time consuming process and allow for increased inflow of formation fluid leading to a larger kick volume in the wellbore. To be sure if a kick is actually being taken, the procedure is often to shut in the well to monitor the well head pressure and eventually initiate well control actions.

In a closed wellbore with an RCD, the principle behind kick detection does not actually change. Use of reliable mass flow meters in combination with accurate standpipe pressure sensors, makes it possible with automatic kick detection systems. Today the use of a Coriolis mass flow meter is most common to measure flow out or the lack of flow out of the well. An advanced flow detection device can be able to pick up an influx/loss of less than ¼ barrel<sup>7</sup>. Using advanced control systems, even automatic actions can be taken by the control system to stop kick situations. Increased choke backpressure can be applied automatically by the system to increase the ECD and limit the duration of the kick, as seen in Figure 2-10.

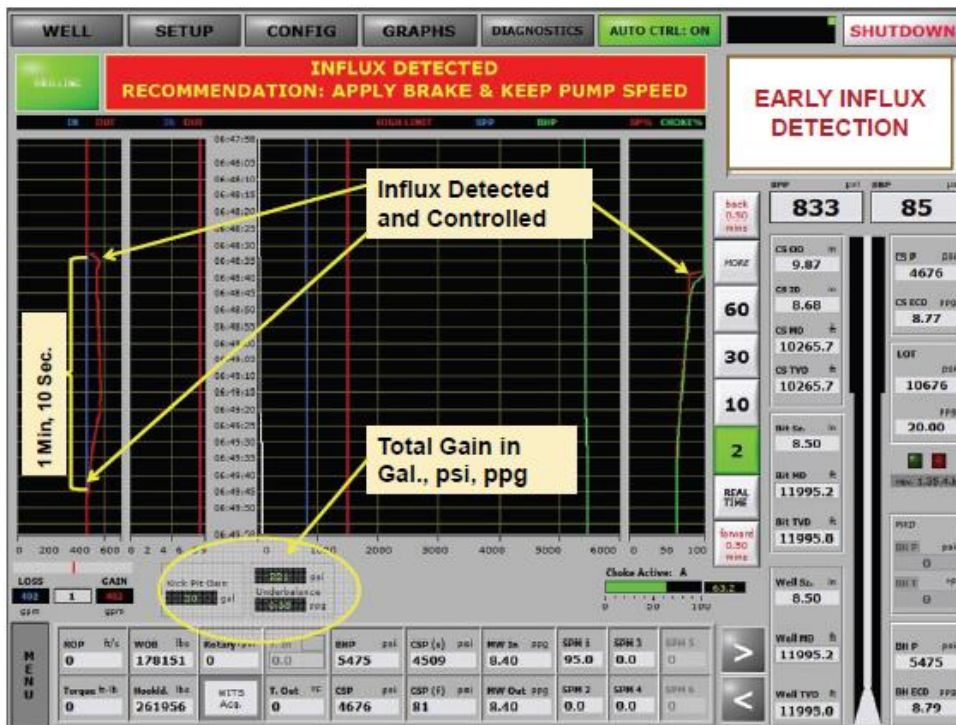


Figure 2-10 Automatic control of kick by increasing backpressure. Courtesy of Weatherford

Utilizing a Coriolis flow flow meter in combination with an advanced control system, makes correct handling of wellbore ballooning/breathing (as is particular common in HPHT-wells) easier. Drilling in overbalanced conditions, the overbalance, especially when pumps are started, can create small fractures and some drilling mud escapes into the fractures. When pumps are shut off, wellbore pressure decreases and the fractures close, forcing mud back into the formation. This phenomenon is known as ballooning. Influx is seen in the return system and is often misinterpreted as formation influx/kick. One of the procedures in this situation is to weigh up heavier mud causing higher ECD when drilling continues and larger fractures could be induced. If this action is performed several times, mud weight could be too high resulting in an ECD which fractures the formation causing huge losses. Having near balanced conditions in both static and dynamic conditions, much of the problem with ballooning is eliminated. But in HPHT wells, this phenomenon is still common.

Having an advanced control systems, combined with skilled operators analyzing what is happening at all time can by looking at the trends and be patient determine by just looking at the monitors what is ballooning/breathing and actual loss/influx. These procedures cuts down a lot of time, non-productive time, spent on flow checks and discussions to differentiate between the situations. In Figure 2-11, an example of detection of wellbore ballooning is illustrated using an advanced control system from Weatherford. In the figure it is seen to the left flow in (blue) decreasing to zero when the pumps are shut off, while flow out of the well (red) is decreasing at a much slower rate until reaching zero. As it decreases to zero is a good indication of ballooning, cause if it was a real inflow situation the red line showing flow out would stay at a constant rate or increase.

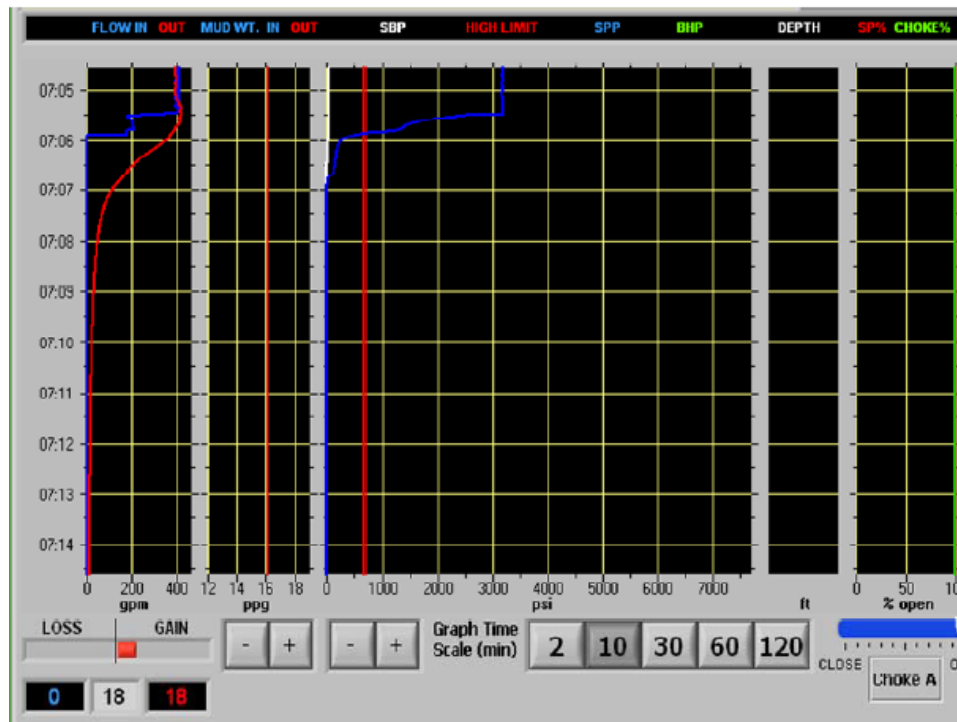


Figure 2-11 Indication of ballooning. Courtesy of Weatherford

Having a MPD system installed, give the operator two choices to circulate out the formation fluid; use the MPD equipment and choke manifold or use BOP and rig choke manifold. By quickly evaluating the situation and the kick volume, the MPD operator and driller have to determine which method to choose to handle the kick. The MPD system has its limitations with regard to determination of formation pressure and RCD pressure rating.

### 2.6.2 Loss Circulation

Lost circulation can occur as a result of wellbore pressure exceeding formation fracture pressure due to pressure fluctuations during tripping or connections. This can be a very costly incident, depending on the amount of losses and type of mud in hole. But most important, loss of mud reduces the hydrostatic mudcolumn leading to an increased chance of taking a kick. In MPD operations, the bottomhole pressure can be kept near constant during the entire operation, thus pressure fluctuations are greatly reduced together with the risk of lost circulation. In addition, having a closed-loop MPD system makes it possible to detect losses early and corrective measures can be taken. In a closed-loop, losses can only be ascribed the formation.

In conventional open-to-atmosphere system, losses are detected in the pits, and they can be ascribed different sources, such as downhole losses, surface leaks, control equipment and loss from solids. Due to the different potential leak/loss sources, the correct actions might not be taken, and for instance partial downhole losses could grow into larger and potentially total losses. Even small, partial loss cases could be detected early in a closed-loop MPD system and the problem can be handled correctly, with a successful outcome<sup>23</sup>. Practices as of today for handling losses involves lost circulation material (LCM) pills containing fine, medium and coarse grain calcium carbonate particles are mixed and pumped down. In case a LCM pill does not work, or the losses are very high, a cement

plug is often set. But setting cement plugs are a time and cost consuming operation and could affect production, so operators see MPD methods as a solution to formation losses in some areas<sup>24</sup>.

### **2.6.3 Stuck Pipe**

One of the most common stuck pipe cases is a result of high differential pressure between wellbore and a permeable formation, and is called differential sticking. Often a well kick situation is the result of pipe sticking. A mud filter cake builds up against the wall of a low pressured permeable zone, and if the drill pipe gets in contact with the wellbore wall, the mud in the filter cake can leak away from behind the pipe, creating a low-pressure zone between pipe and formation. In combination with the overbalance in the wellbore, the pipe gets stuck towards the wellbore. In MPD operations, the intention is to keep the wellbore pressure close to balance, thus leading to a much lower differential pressure between wellbore and formation, and the sticking tendencies are reduced<sup>2</sup>. Another case of stuck pipe is the result of wellbore instability issues.

### **2.6.4 Wellbore Instability**

Wellbore instability can occur when the hydrostatic pressure of the mud column is not sufficient to maintain the integrity of the wellbore wall. Sometimes the collapse pressure of the formation is equal to or greater than the pore pressure. Parts of the formation can slough off and pack around the drill pipe creating stuck pipe situations. Another case that can lead to pack off and stuck pipe is the transition between dynamic and static conditions in the wellbore, when mud pumps are stopped and started over and over exposing the formation to a pressure cycle. Depending on the porosity and permeability of the formation, the cycle tends to induce fatigue to the in-situ stresses of the formation, leading to sloughing off the formation<sup>20</sup>. In MPD operations, the pressure can be kept close to constant, removing these pressure cycles and thus removing the problem of weakening the formation. And in case of a high collapse pressure, the wellbore pressure can be adjusted to above collapse pressure, avoiding the problem with wellbore collapsing.

### **2.6.5 HSE**

Being able to reduce and mitigate these drilling hazards described above does not only help reducing the overall NPT, but it also contributes to an increase in HSE for the operation. By being able to control the wellbore pressure and avoiding potential hazardous kick situation, increases the safety of all rig personnel and the overall operation. And even if some small influxes occurs, these can be detected and handled earlier and at a safer manner, which increases the safety of the operation as the volume of influxes are reduced. Being able to ascertain downhole parameters during the operation increases the overall safety of the operation, and knowing the limits of the formation can help designing the safest well, not risking having poor cement jobs, casings set at wrong depths and worst case have to deal with underground blowout due to lack of understanding of the formation limitations.

### **2.6.6 Other issues solved with MPD**

Time is money in the oil business, and in the offshore oil business time is the biggest cost contributor. A time consuming operation is tripping in and out of the hole, and if excessive tripping can be avoided, much time and money can be saved. Increasing the rate of penetration (ROP) could lead to less time consumption, but it often lead to excessive bit wear leading to tripping out to change bit and in hole again. Managed pressure drilling applications can, by drilling in close to balanced conditions with the same mud weight, increase both the ROP and increase the lifetime of the bit<sup>25</sup>. The relationship between overbalance pressure and ROP is seen in Figure 2-12, and the trend that

pressure in the well affects ROP is valid for the different rock types<sup>26</sup>. Being able to drill with the same mud weight through longer sections, without having to stop operations to weigh up new, heavier mud, saves a lot of time and costs related to the mud, and allows for continuous drilling towards target.

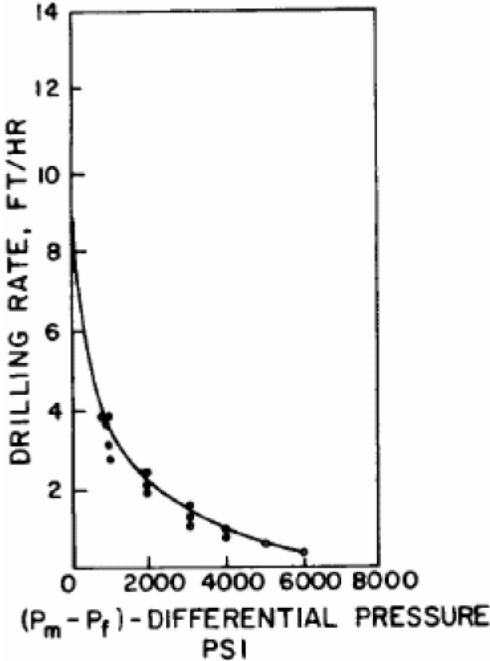


Figure 2-12 Relationship of overbalance pressure to ROP<sup>26</sup>

The problem in many deepwater prospects, HPHT prospects, pre-salt formations and some difficult shallow water prospects is the small margins between pore and fracture pressure. The traditional method of solving this problem has been to adjust the mud weight, but to be able to drill with higher mud weight, casings has to be set to avoid problems with fracturing or other incompatibilities with the formation. The problem with this is that one can risk running out of casings without reaching target, or that the hole at total depth (TD) is smaller than desired. Worst case is to abandon the well before reaching TD. Being able to adjust the equivalent mud weight by MPD methods, the driller can navigate through the narrow operating window, reaching longer before having to set casing. In Figure 2-13, an example from a well in Gulf of Mexico (GoM) illustrates this. To the right in the figure is an illustration of the planned casing programs for conventional drilling (black) and for MPD operation (blue). Being able to have a larger hole at TD, is important for the productivity of a completed well, and is valued by the operators<sup>7</sup>.

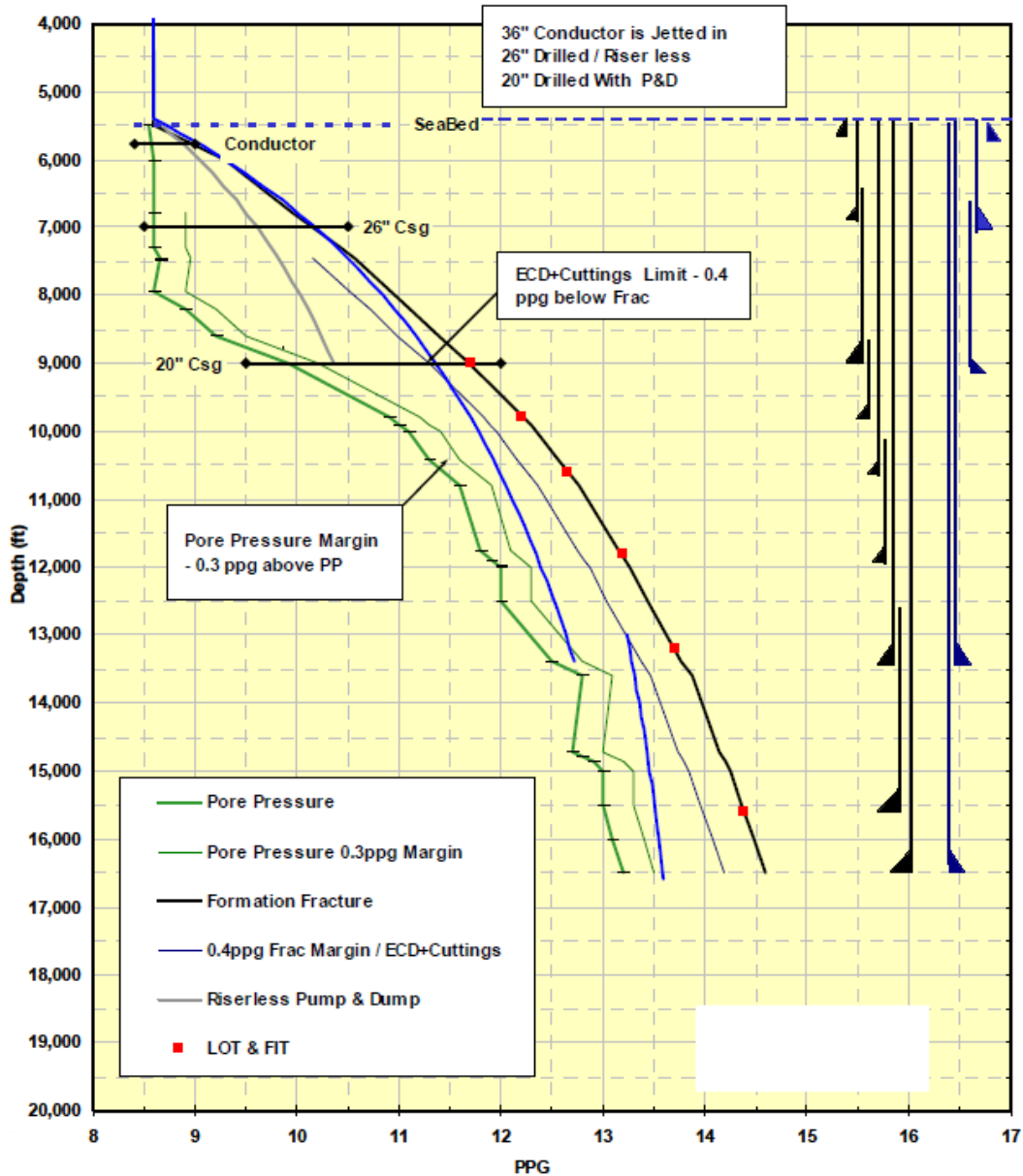


Figure 2-13 Example from a deepwater well in Gulf of Mexico with narrow margins<sup>27</sup>

Another problematic field which can be partly solved when planning for MPD operation instead of conventional operation is the huge uncertainty with regard to cost estimation. The main contributor to the uncertainty is the risk of NPT. Since part of the object of MPD is to reduce NPT, operations involving MPD will have less risk of NPT and the cost uncertainty will be reduced. How the choice of drilling technology and approach to the operation affects cost uncertainties between conventional drilling and MPD is illustrated in Figure 2-14 where a wider distribution spread relates to greater uncertainty.

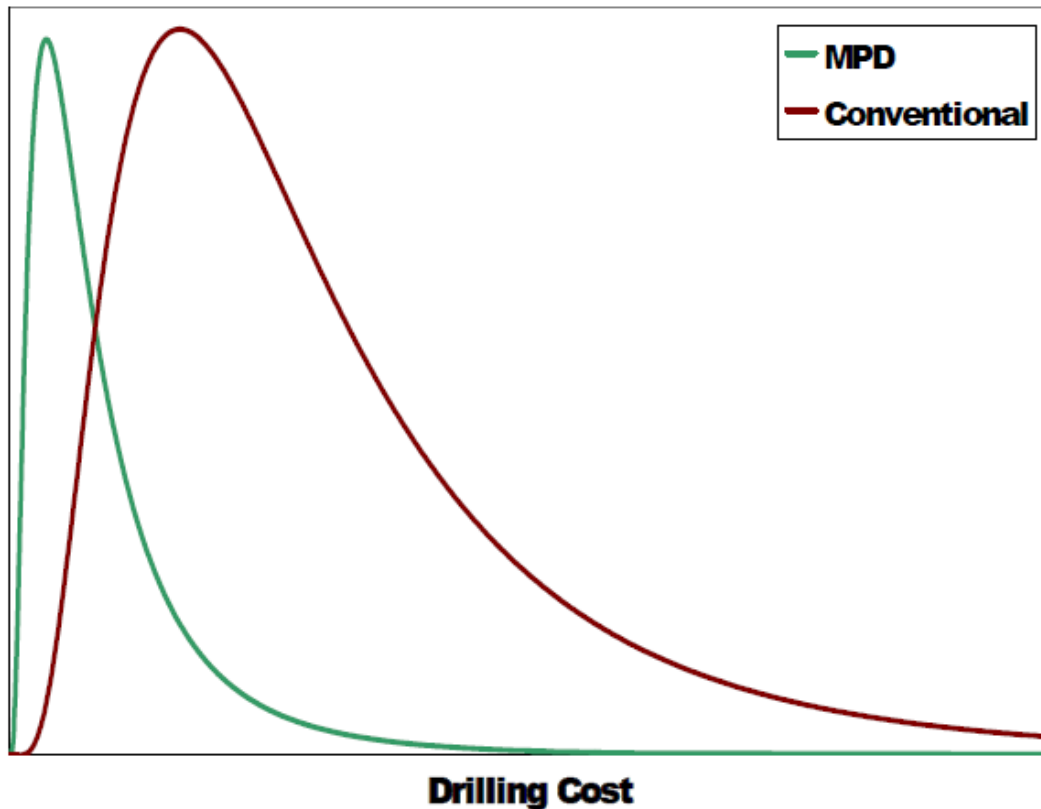


Figure 2-14 Cost uncertainty between conventional drilling and MPD <sup>25</sup>

In deepwater drilling and especially deepwater HPHT-drilling, gas in the riser could be a serious problem. Unintentional gas inflow from the formation tends to mix with oil-based drilling mud, and circulated up with the return flow. It has been seen that the gas will dissolve out of the mixture at a depth between 2000 ft (610 m) to 3000 ft (915 m) below drill floor<sup>28</sup>. In many deepwater fields, this depth is above the BOP, thus it is no longer able to close in and prevent the gas to migrate further up. Conventional practice of solving gas in the riser is to use the rig diverter system to vent it out, but the operation involves huge risk and not sufficient control over the situation. Having a MPD system installed allows for a more controlled and safer handling of the issue. By having a RCD and flow spool installed, fluids and gas are diverted away from the rig floor and into the MPD choke manifold system and further into a mud/gas separator system.

Other benefit with the closed-loop MPD system is the ability to apply backpressure and earlier detection of the gas. Applying backpressure will pressurize the whole system preventing some of the gas expansion in the riser, meaning much of the expansion process will not occur before entering the separation system. Thru the continuous flow modeling and detection of flow out, volume changes in the circulating system due to gas and riser gas enable an earlier detection of the migrating gas<sup>28</sup>. In case a gas kick is not detected and it migrates up the well and into the riser, there are solutions for handling riser gas, as described in section 4.3.

## 2.7 Considerations for MPD Operations from Floaters

All of the variations of MPD involve manipulation and management of the pressure profile in the exposed wellbore. Downhole hydraulics is determined by these factors; wellbore geometry, drilling fluid density, drilling fluid rheology, annular backpressure, ROP, pump rate, wellbore strengthening and annular friction pressure. Many of these parameters are independent of each other and the relationship between them is not always clear. But these individual factors can be manipulated to accomplish the objectives of MPD and avoid drilling problems and NPT. Correct understanding and analysis of the wellbore hydraulics, fluid properties operational limitations together with good engineering is required to have a successful MPD operation, especially MPD operations from floaters. If not handled correctly, these operational parameters described below could be a huge risk for the execution of an MPD operation.

### 2.7.1 Fluid Properties

Due to downhole temperature and pressure exerted on the drilling mud, the properties of the mud could be interrupted and affect the operation itself. Also, in offshore operations when having a long marine riser, the temperature of the mud can be affected by the cold seawater surrounding the marine riser. Especially for MPD operations, the density of the mud is crucial for a successful operation and proper modeling of the behavior of the mud is important in the planning process. High temperature decreases the density, while high pressure increases the density and depending on which is the dominant factor one can see a decrease or an increase in the downhole density compared to the one seen at surface. This process is seen both in dynamic and static conditions. In dynamic conditions, if temperature is dominant over pressure, as often seen in shallow to medium ranged wells, the actual ECD could actually be lower than the surface density<sup>17</sup>. Or when pressure is dominant over temperature, as often seen in deeper wells, the ECD is higher than the surface density<sup>17</sup>. But there are no “rule-of-thumb” here, and proper modeling and evaluation of each individual operation is necessary.

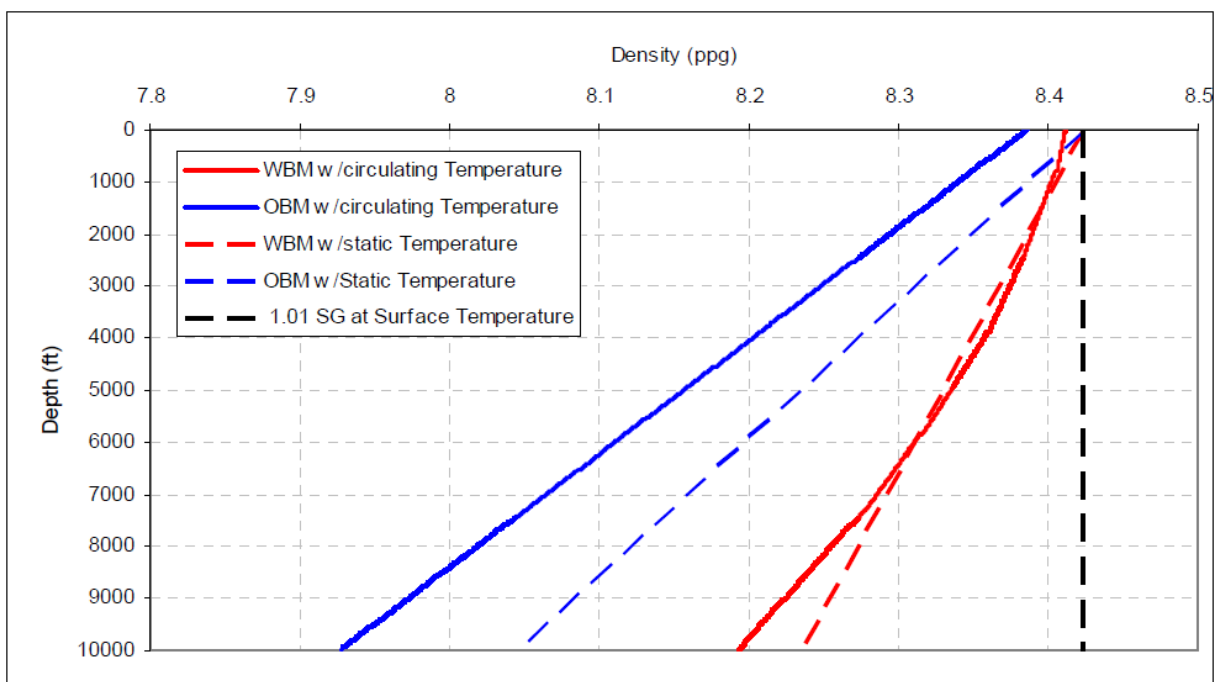


Figure 2-15 The experimental result of how temperature affects density in OBM and WBM<sup>17</sup>



In static conditions, there is no frictional pressure loss and the mud density is mostly affected by the temperature and the thermal expansion as the fluid temperature tends to increase until equalizing with the geothermal gradient of the formation. When circulation starts again, a cooling effect is often seen and the result is that the temperature decreases a bit which again affects the density. In Figure 2-15, it is seen how the temperature of the formation affects the density of the mud both in dynamic and static conditions.

For MPD operations, correct modeling and calculation of the annular friction losses taking into account the actual density due to pressure and temperature effects are important. A reduced mud density will also lower the friction loss pressure in the annulus, affecting how the MPD procedures are set up. One might think that the effect of pressure and temperature, as they are opposite, will cancel each other out, but that is not something one can count on, it has to be determined. The magnitude of the impact on an MPD operation depends on the magnitude of the temperature and pressure, the type and composition of the drilling fluid and the circulation time<sup>17</sup>. The changes occurring in static conditions could be avoided if continuous circulation systems (will be presented later) are implemented in the MPD operation, since one will have continuous dynamic conditions.

### **2.7.2 Surge and Swab**

Bottomhole pressure is affected by the up- and downward movement of the pipe. This movement occurs naturally when tripping in and out of the well, but on floating drilling units this movement also occurs during connections. When moving pipe down into the well, the fluid in the well must move up as the well is being displaced by the pipe. The combination of down moving pipe with fluid moving up creates a piston effect increasing the pressure in the well bore. This increase is called surge. Moving the pipe upward, fluid moves down to replace the volume that was occupied by the pipe creating a decrease in bottomhole pressure. The decrease in pressure is referred to as swab pressure. The amount of surge and swab seen is affected by the tripping speed, fluid properties, well bore geometry and the installed downhole tools. They can to a certain extent be mitigated by good procedures, planning and optimizing the fluid properties.

Floating drilling units move vertically with the waves, also referred to as heave motion. During drilling, the drill string is isolated from the heave motion of the rig by an active heave compensation system. But when making connections, the drill string is disconnected from the heave compensation system and hung off in the rotary table. As the drill string is now a fixed part of the rig it moves up and down with the heave motion, creating a continuous surge-swab motion as long as the drill string is connected to the rig. As seen in Figure 2-16, the drillstring acts as a piston in the open hole, causing pressure fluctuations. The heave motion seen in the North Sea and similar conditions can be several meters (3+ meters (10+ ft)) in amplitude over a period of 10-20 seconds. The pressure fluctuations observed as a result of heave motion has been of a magnitude higher than the standard limit for pressure regulation accuracy in MPD control systems, which is around  $\pm 2.5$  bar (36.5 psi)<sup>29</sup>. Experimental tests performed on the onshore full-scale drilling test facility Ullrig in Stavanger, have given results of downhole pressure fluctuations up to 30 bar (435 psi), with heave of 3.5 meter (11.5 psi) over a period of 17-18 seconds, i.e. typical North Sea conditions<sup>30</sup>.

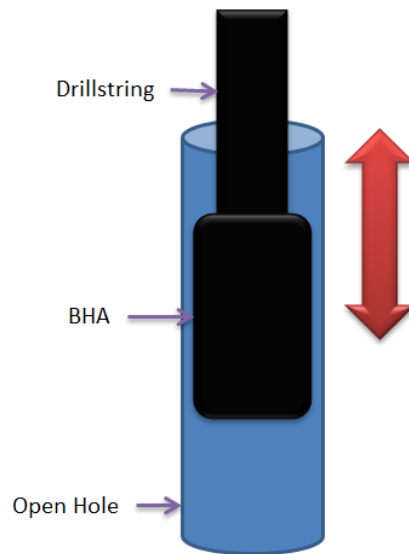


Figure 2-16 the piston movement of the drillstring during connection

The result of these pressure fluctuations is that during surge there is a huge risk of having a lost circulation system, especially when operating in narrow windows. When losing mud into the formation, the hydrostatic pressure of the well decreases and possibly allowing for uncontrolled influx from the reservoir. The same can occur during swabbing when the hydrostatic pressure decreases in the well and formation fluid can enter the well from the reservoir. Worst case scenario in both cases is a blowout. During conventional drilling in reservoirs with good operational margins, the risk is lower and operations proceed up to a certain level of heave when the heave compensating system limits the operation.

For MPD operations however, when the reason for using MPD often is narrow operating windows in depleted reservoirs, HPHT-conditions and deep water, one might have to take actions with regards to the pressure fluctuations occurring. Depending on the system and principle used for the MPD operation, there are some disagreements with regard to how to act with the phenomenon. For some of the systems and principles used for MPD operations, compensation of the pressure fluctuations is necessary for the operation to be executed as intended. Other systems are not that depending on the precise management of the bottomhole pressure, thus the pressure fluctuations seen downhole is not crucial for a successful operation<sup>31</sup>. If precise management of the bottomhole pressure at all time is necessary, one will need to have a control system capable of working with the heave motion seen in the North Sea and similar conditions. The system must be able to use heave data, height and period, to open and close the choke to regulate backpressure and thus the bottomhole pressure relative to the heave motion. A system capable of such control has not yet been commercially introduced.

### 2.7.3 Riser Margin

In normal operating conditions on floaters, there is drilling mud from the rotary table on the rig down to the bottomhole. However, there is always a risk that the rig can drift off or have to intentionally dislocate the riser from the BOP. In such situations, the mud column above the BOP is replaced by the seawater and a hydrostatic pressure equal to the water depth is exerted on the top

of the well, which now is the BOP. The pressure exerted downhole is now a dual-gradient system with seawater above and mud below the BOP and this dual gradient situation might be too low to balance the pore pressure; hence there must often be a mud design where a heavier mud can balance the pore pressure in such a situation. The riser margin is calculated and added to the mud weight.

For MPD operations and in particular deepwater operations, having a riser margin is difficult or even impossible to maintain. In deepwater, where water depth can be several thousand meters and the margins can be very narrow, the hydrostatic head exerted by mud in riser is significant, and removing it would affect the downhole pressure considerably. So especially for deepwater operations, this issue needs to be solved to make these deepwater operations completely safe. As the goal in MPD operations is to control bottomhole pressure and not exceed the formation limits, the mud used are often underbalanced or just balancing the pore pressure to avoid a high ECD. Adding a riser margin is not possible to be able to still have a MPD operation. So the problem is then with an underbalanced mud or balanced that in the event of a riser disconnect, the pressure exceeded on the formation would be less than the pore pressure giving influx into the wellbore. While the BOP is closed, pressure will build up in the well below and make reconnection a great and dangerous challenge.

As seen here, there is a challenge to solve with regard to MPD from floaters and riser margin in the operations. In case of planned disconnection, weighted pills could be set below the BOP to achieve a hydrostatic pressure at bottom balancing the pore pressure with a safety margin, but for unplanned disconnections that solution is not practical. One way to reduce the risk of disconnecting when not having a riser margin is to use anchored rigs, even in deep water, as they are less exposed to the risk of drifting off. For many deep water and especially ultra-deep water wells, it is not possible to apply a riser margin neither for conventional drilling or MPD, and that is something the involved parties might have to live with and at least take into consideration in their risk analysis.

But apart from that, it does not seem to be a practical solution to the problem at this point, and for some operations one might have to apply for permission to not have a riser margin for some parts of the operations.

### **3 Variations of MPD**

Historically, MPD has been divided into four different branches; Constant Bottomhole Pressure, Pressurized Mud Cap Drilling, Dual-Gradient and Returns Flow Control, each with its own application area. As a consequence of more operations moving to deeper water depths, the use of Dual-gradient drilling has increased and is often considered as a separate technology. Pressurized Mud Cap Drilling is a technology commonly used in the South-East Asia region. Returns Flow Control is a HSE approach to MPD where MPD equipment is used to enhance the safety during operations by diverting flow away from the rig floor e.g. The Constant Bottomhole Pressure variation of MPD is a technique used all over the world, both on- and offshore, and this is a technique already used in Norway on fixed installations. This technology might be the one with the widest range of application areas, and it can be used to mitigate many of the problematic situations encountered subsurface, and it is this technology the main focus on this thesis will be on.

#### **3.1 Constant Bottomhole Pressure**

As the name constant bottomhole pressure implies, the purpose of this method is to manage and keep the bottomhole pressure near constant during all phases of the drilling operation. Drilling problems such as loss of circulation, influxes, hole collapse and differentially stuck pipe caused by severe pressure fluctuations as seen in conventional drilling could be avoided using the CBHP MPD approach. CBHP is also known as “walking the line” between pore and fracture pressure gradient, keeping the well out of trouble. The method uses both precise backpressure control and constant flow measurements to optimize the process. This method is applicable for prospects with narrow and/or relatively unknown drilling windows (wildcats), HPHT-wells, depleted reservoirs and prospects known to cause problems during drilling. When drilling in unknown formations, where the operating window is relatively unknown, the CBHP method is ideal for determining the actual drilling window encountered through identification of very small amounts of formation influxes and mud losses. This ability makes it possible to drill safer, more efficiently and at a reduced cost<sup>7, 18</sup>. CBHP could also be the most suitable method for drilling challenging prospects at moderate water depths from floating drilling rigs on the NCS in the future.

#### **3.2 Pressurized Mud Cap Drilling**

Pressurized mud cap drilling is a variation of MPD most practiced offshore in South-East Asia where the risk of drilling into severely fractured formations or cave systems are significant. These scenarios often lead to severe to total losses and the potential risk of having kicks as a worst case consequence<sup>32</sup>. This method is also believed to be applicable in the pre-salt areas in Brazil, where often huge losses are experienced.

The method enables higher ROP and lower-cost drilling in loss-zones. If losses are encountered, a cheap and expendable fluid like seawater is pumped down the drill string while heavier, viscous mud is injected down annulus. Together with a RCD, the heavier mud in the annulus acts as a pressurized barrier to avoid potential kick migration up the annulus. As drilling continues into lower fractured zones, cheap fluid is still in use and the fluid and cuttings are forced into the open formations. Gas in lower formations migrates up to the open formations above where the pressure is lower. When

losses have decreased to an acceptable level, conventional drilling or other MPD methods continues. This method could both be regarded as a reactive and proactive MPD method. Because of the application area, this MPD method has not been regarded as a method for use in many regions, among them Northern Europe.

### 3.3 Dual-Gradient Drilling

The dual-gradient method is based on the principle of introducing a lighter fluid than the mud used in conventional drilling, to obtain a lower bottomhole pressure. This application of MPD is often applicable in deep water where the total column of mud in the marine riser can create some significant overbalance in the well. There are different approaches to achieve DG conditions, where you can either choose to inject lighter fluid or gas at a point in the riser system or at seabed. Another method is to displace the riser, or part of the riser, with lighter fluid like seawater, while drilling mud and cuttings are diverted to a pump at seabed and a separate return system to surface. A new method is to have a mud return pump mounted on the marine riser to adjust the height of mud in the riser, leaving the top of the riser filled with air as described in section 6.3.2. These approaches “trick” the formation to “think” that the rig is placed closer to the seabed. The different fluids have two different pressure gradients producing an overall hydrostatic pressure seen in the wellbore, which fits in the narrow operating window, as illustrated in Figure 3-1. This method saves the operator for a lot of time dealing with lost circulation issues, tight margins and the use of additional casings or in the worst case running out of casing strings before reaching total depth<sup>33</sup>.

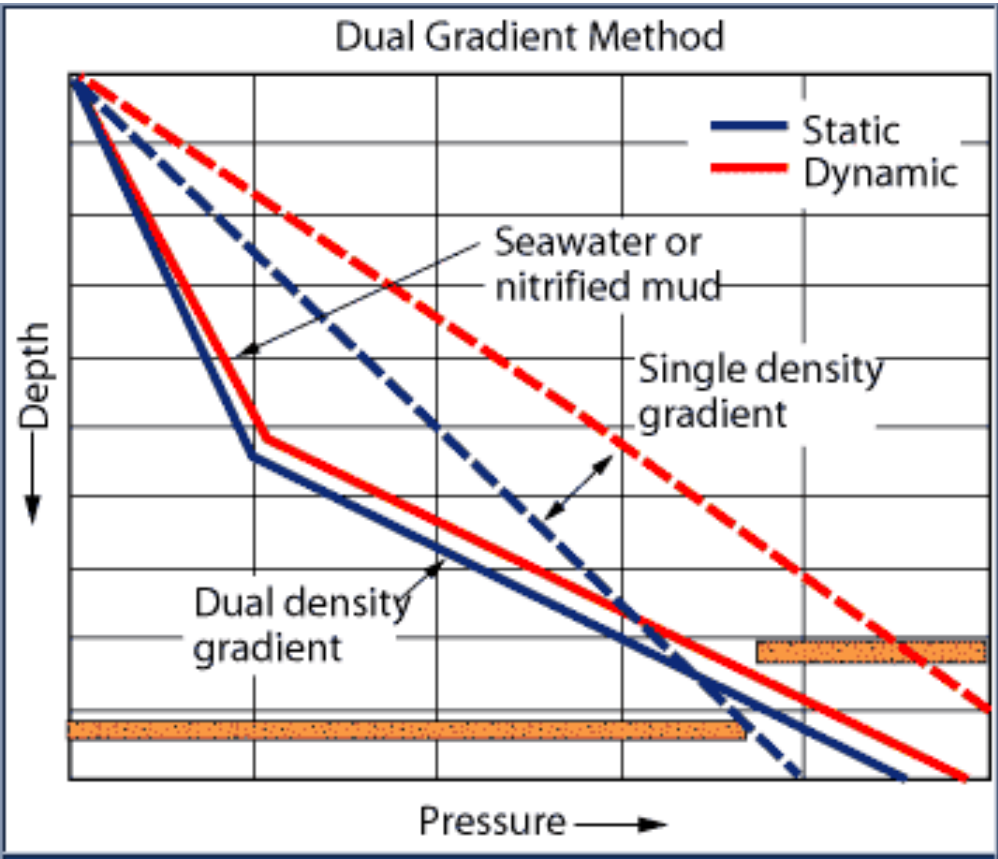


Figure 3-1 Dual gradient compared to single gradient<sup>33</sup>

### **3.3.1 Riser less Dual-Gradient**

Dual gradient systems also include riser less application. In this application, a suction-module and an annulus return pump is installed on the seabed handling cuttings and mud returns. This is often referred to as Riserless Mud Recovery (RMR<sup>TM</sup>), a technology often associated with the company AGR, a technology with a good track-record especially for top hole drilling<sup>34</sup>. Most top hole sections are drilled without a marine riser, with seawater as drilling fluid. If specific properties of the fluid are needed, additives could be added to the seawater or other specific drilling mud could be used, often weighted mud heavier than seawater. This mud and associated cuttings are dispersed to the seabed. In these cases one will have a dual-gradient system, with weighted mud below the mud line and seawater above, so the hydrostatic gradient is composed of two fluids.

### **3.4 Returns Flow Control (HSE)**

Returns Flow Control is a passive variation of the MPD system where conventional drilling is applied while the return flow is directed through the MPD equipment, away from the drill floor, measuring and comparing flow in and flow out of the well. This technique does not involve any control of the annular pressure, but the system is in detection mode being able to provide early warnings of abnormal flow situations. Could be used if drilling exploration wells where the pressure limits are unknown and the MPD choke could be automatically closed in if influx is detected. Having a RCD allows for circulating influx out without having to close in the BOP, minimizes risk of having hydrocarbons, such as dangerous H<sub>2</sub>S-gas, released on the drill floor and pipe can be moved while circulating out the influx.

## 4 MPD Equipment

Most MPD operations are practiced while drilling in a closed circulation loop utilizing a Rotating Control Device (RCD) with at least one Non-Return Valve in the drill string, and a Choke Manifold-system of some sort. Included among this equipment are a number of variations of them and other equipment also used in combination with the above mentioned equipment. Depending on the complexity and the specific needs for the operation, more advanced or customized equipment could be utilized. In this chapter, equipment that is suitable for use on floating units is described. Other equipment not mentioned here might be applicable for use on fixed installations and onshore.

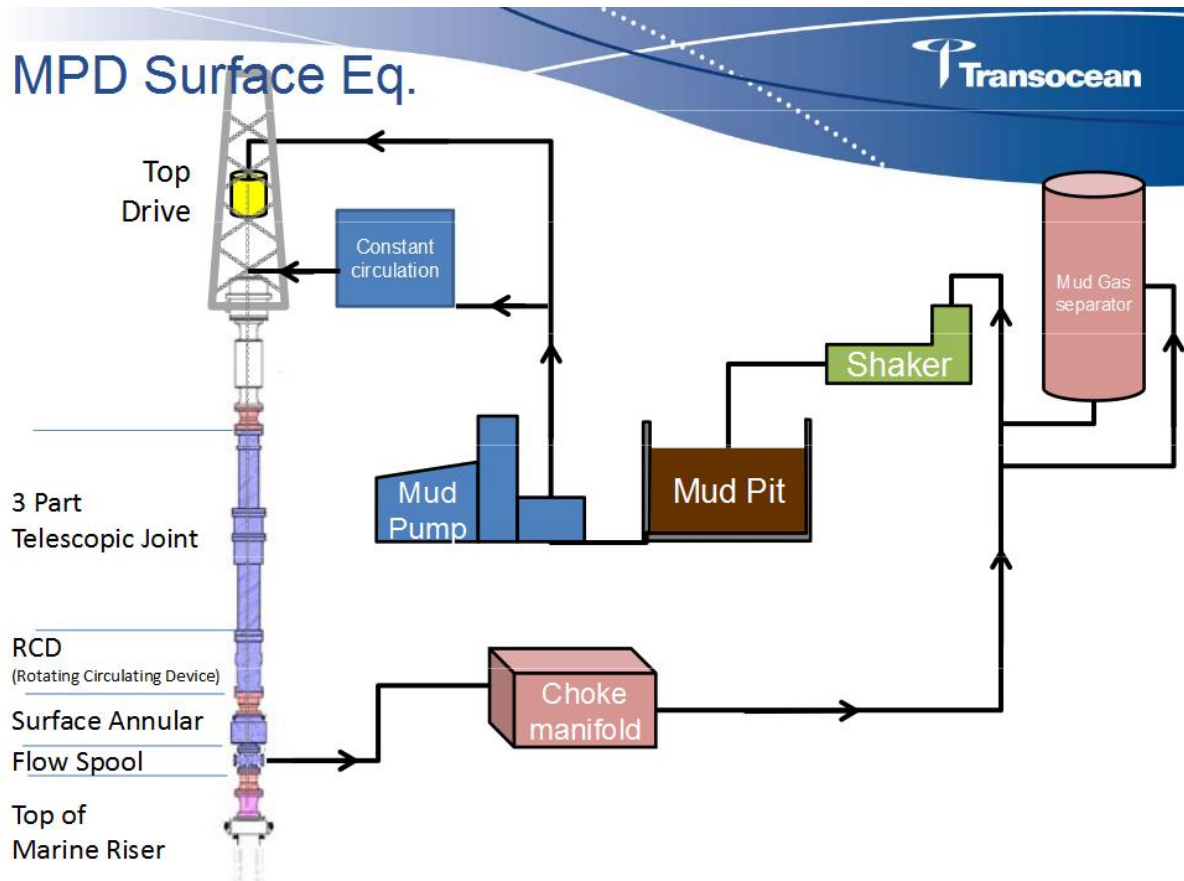


Figure 4-1 Setup of a MPD system used on Transocean rigs in Africa. Courtesy of Transocean<sup>35</sup>

### 4.1 Annular Seal

There exist two main types of annular seal types, the conventional Rotating Control Device described in the following section, and the newly developed passive sealing element, Riser Pressure Control Device (RPCD), developed by SIEM WIS with no rotating elements.

#### 4.1.1 Rotating Control Device

A Rotating Control Device (RCD) is used for sealing of the wellbore and diverts the well flow to the MPD choke-manifold system via a flow spool placed beneath the RCD. This rotating sealing element allows drill pipe to enter and exit the wellbore while annulus pressure is maintained, and also allows for rotation of the drill pipe. The RCD can be divided into two groups, passive rotating devices and active rotating annular preventers.

The passive system, in form of the RCD, is a rotating packer with an undersized annular seal element or “stripper rubber”. The undersized element forms a seal to the drill pipe under zero pressure, and the seal is made stronger when exposed to annulus pressure. In Figure 4-2 this is illustrated, with annulus pressure in red applying force towards the sealing element when operating. The rubber element needs to be replaced periodically due to wear, and factors affecting the lifetime of the element is determined by surface pressure, rotation (RPM-rotations per minute) and condition of drill pipe. The condition of the drill pipe needs to be reviewed to ensure that lifetime of rubber is maximized. The passive system is the most common in MPD operations<sup>2</sup>.

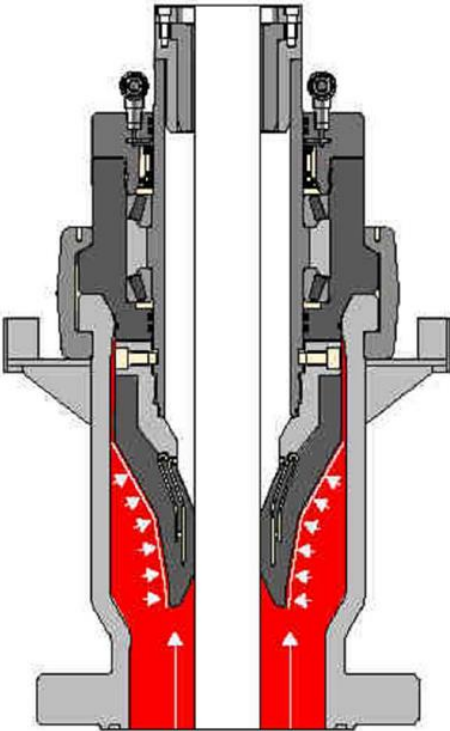


Figure 4-2 RCD with annulus pressure in red<sup>36</sup>

The active system consists of a rotating annular preventer with a hydraulically actuated annular packer, same as seen on top of the BOP-stack. The packer element is more durable than the one used in passive systems, but due to its larger footprint and other technological issues it is not that used in MPD operations<sup>2</sup>.

For floating applications, there have been several different types of RCD used and the placement of these have also varied since MPD became an alternative for drilling wells from floating units. After several years of development and testing, two solutions are now used and further developed. The solutions are, as seen in Figure 4-3, placing the RCD below the tension ring and above the tension ring. To achieve satisfactory heave compensation for the rig, placing the RCD below the tension ring seems to be the best solution allowing full use of the rigs telescopic joint. In combination with the RCD installed on the riser, an annular preventer and a flow spool is also installed. This equipment is required to facilitate changing of the RCD sealing elements while circulation continues and pressure is held in the well. The riser annular preventer are used instead of using the rig’s subsea annular



preventer. When the sealing element needs to be changed, the riser annular closes around the drillpipe, sealing of the annulus pressure below. The sealing element can be removed and replaced using a running tool installed on the drillpipe. As the sealing element is replaced, drilling mud continues to be circulated through the flow spool as during regular operations. Lifetime of the sealing element is much dependent on the rig alignment and conditions of the drillpipe and tool joints. Lifetime is significantly weakened if the rig is not properly aligned with riser and subsea package.

Regarding normal specifications for pressure on the RCD used on floating units, they are usually rated to a static pressure of 2000 psi (138 bar). During rotation of pipe, in dynamic conditions, the pressure rating decreases to 1000 psi (69 bar) and 500 psi (34.5 bar) at 100 and 200 rpm respectively<sup>28</sup>. These ratings are in line with the ratings of most marine risers and riser seals, so RCD equipment should not be a limiting factor.

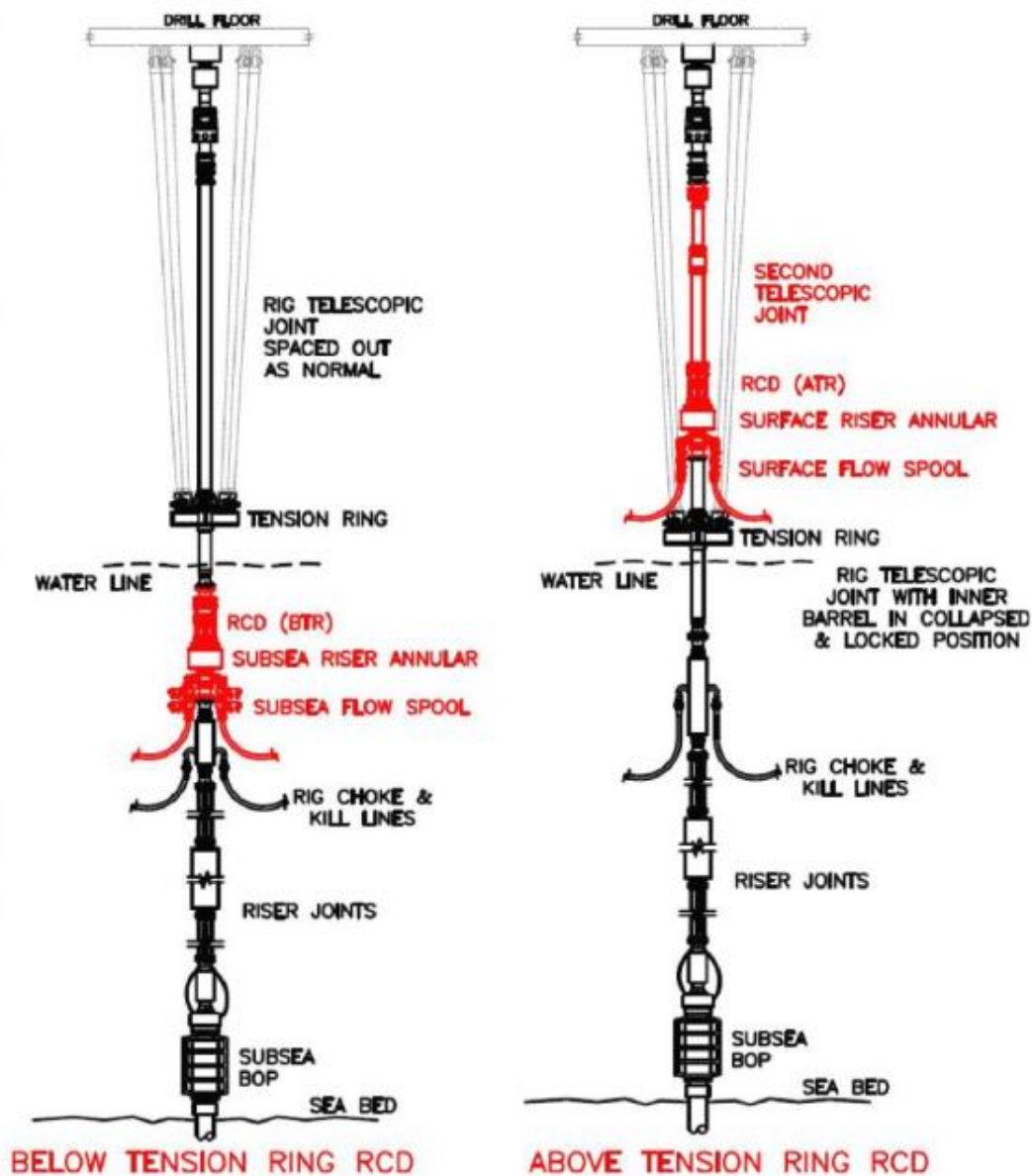


Figure 4-3 Placement of the RCD on floating drilling units<sup>9</sup>

### 4.1.2 Pressure Control Device

A new seal solution has been developed which distributes the well pressure over several seals. The gradient chamber pressures are monitored at all time. A schematic is shown in Figure 4-4

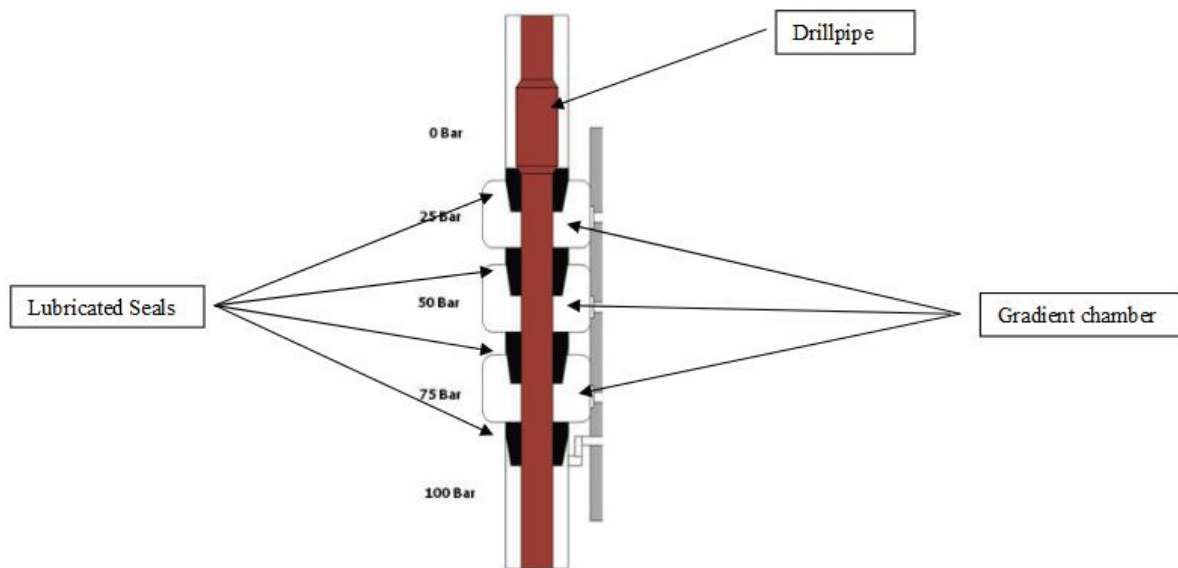


Figure 4-4 Principle of the Riser Pressure Control Device. Courtesy of SIEM WIS

The seals are lubricated to avoid high temperatures and to keep the friction low. The rubber material is custom designed to allow for pipe joint movements. The SIEM WIS seal has been successfully tested in april 2010 at the Gullfaks field<sup>37</sup>.

## 4.2 Slip-joint

The slip joint is a telescopic joint between the top of the marine riser and the rig. Top of the riser, defined as where the tension ring is, is usually just above the water line. From the tension ring and up to the rigs drill floor, is a telescopic joint that allows the marine riser to be relatively unaffected by the heave motions. In heave, the joint telescopes in or out by the same amount as the heave motion is. In MPD operations, a RCD are installed either between the tension ring and the slip joint, above tension ring (ATR RCD) or below the tension ring (BTR RCD). The RCD creates a closed-loop system, such that no return flow is led up inside the slip joint and will not reach the conventional return flowline. But the slip joint is still necessary to provide a proper alignment of the rig and drillpipe to the RCD and riser, allow for switching between MPD- and conventional drilling as the conventional return system will be available after removing RCD assembly and the risk of spill into the sea in case of leaks in the RCD seals as leaks will be contained in the slip joint.

For conventional drilling operations, there are some more or less standardized slip joints commonly used. Different solutions has been evaluated for use in MPD operations, for instance Statoil had a vision with a 7 barrel slip joint which did not prove to be a success, and it seems that the best and most common practice at the moment is the use of a 3 part slip joint<sup>9, 31</sup>. However, for calmer environments, a standard slip joint could also be used as it delivers enough compensation for heave

movement in calmer areas. The 3 part slip joints existing today allows for compensation of around 8 meters of heave<sup>31</sup>. But as a general rule of thumb in this matter, the type of slip joint for a MPD operation must be individually evaluated.

### 4.3 Riser Gas Handling

To handle the problem with gas in the riser in deepwater operations, there are solutions to degas the riser and redirect potential harmful gas before it reaches the drillfloor which increases the safety of the rig personnel significantly. The principle behind the system is to have a RCD to close in the riser, a flowspool with hoses leading up to the rig, control valves, a high-rate mud gas separator and an automatic control system<sup>38</sup>. This equipment allows the gas to be circulated out safely under controlled pressure. Compared to conventional MPD systems, these riser gas handling systems are designed for this and the equipment is customized to handle large amount of gas. A riser gas handling system can be used both in MPD operations and in conventional drilling. The riser equipment in Figure 4-5 is installed at a predetermined height in the riser.

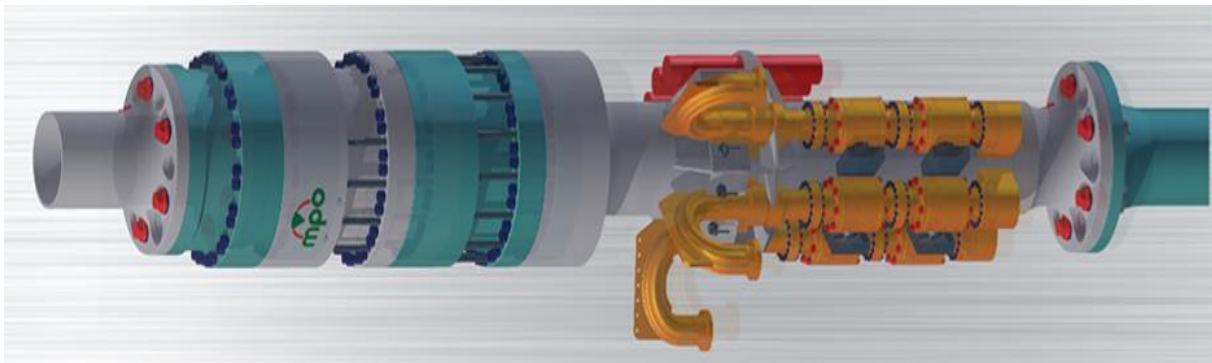


Figure 4-5 Riser Gas Handling system from MPO – Managed Pressure Operations<sup>38</sup>

### 4.4 Active Choke Manifold Systems

A choke manifold system is one of the most important tools to enable MPD applications. The system often consists of a choke, pressure gauges, a Coriolis flow meter, an advanced control system and a backpressure pump. All this equipment doesn't have to be installed in a choke manifold system, it depends on the vendor delivering the system, but the basic principle of the system utilizes some or all of this equipment. The Microflux<sup>TM</sup> Control System from Weatherford in Figure 4-6 is an example of a choke manifold system which incorporates an advanced control system, an automated choke, a Coriolis flow meter and pressure sensors. The figure illustrates how the system is delivered to the rig, and as seen, the system sets a footprint which needs to be planned for. As described in chapter 5, there are also other providers of such MPD equipment. In CBHP (and PMCD) applications of MPD, this type of equipment is necessary to perform operation and to control the bottomhole pressure.



Figure 4-6 Microflux™ Control System. Courtesy of Weatherford

#### 4.4.1 Choke

During drilling, returns are circulated through the choke, and when the choke is fully open there should be little or no back pressure. By adjusting the opening of the choke between open and closed position, backpressure is adjusted during circulation. The choke needs to be accurate, fast and highly reliable. For redundancy, two chokes should be mounted in parallel in case plugging or other malfunction of the operating choke, and the control system should be programmed so that if failures on one choke flow is directed automatically to the other. Since the MPD choke is used continuously during MPD operations, a conventional rig choke manifold system is required designated for well control events. In Norway, this is stated as a requirement in NORSOK D-010<sup>16</sup>.

#### 4.4.2 Control System

The choke system can be controlled manually, semi-automatic or fully automatic. In all applications of MPD in the last years in offshore environments that the author has found, automatic control systems have been used. For use on the Norwegian Continental Shelf (NCS), NORSOK D-010 states that a manual MPD choke system is not accepted as a part of the primary well barrier<sup>16</sup>, so fully automated control systems are the only option in Norway. The chokes are hydraulically controlled by a Programmable Logic Controller (PLC) system, using real-time control system software, flow rate data, surface pressure, temperature, and real time data from Measurement While Drilling (MWD)-equipment to control and maintain a constant BHP. The PLC adjusts the choke to openings determined by a dynamic hydraulic flow model. The flow model runs in real time, continuously updating the calculations as new measurements come on line. The accuracy of the control system is limited by the amount and accuracy of the input data, and it could also be limited by the processing capacity of the computers used. For redundancy, these control systems must have a manual override function, so that the MPD operator can intervene in emergency situations.

#### 4.4.3 Backpressure Pump

Closely related to the choke manifold and control system is the backpressure pump. The choke creates backpressure when there is mud flowing, but when mud flow decreases it is limited how much backpressure the choke can induce, and how fast the choke can act to provide the required backpressure. If the choke cannot provide sufficient backpressure or if extra backpressure is required during connections and tripping, a backpressure pump connected to the choke and control system can automatically be ramped up. A backpressure pump in the MPD equipment is also a redundancy in case of sudden loss of pressure caused by mud pump failure or by human errors. It is unlikely that a

choke can be closed fast enough to prevent the loss of BHP control when pressure loss is experienced suddenly.

#### **4.4.4 Coriolis flowmeter**

A flow meter consists of three important parts; primary device, transducer and transmitter. The transducer registers and measures the fluid that passes through the device with a sample rate of multiple times per second, and the transmitter produces a signal for the control system. Coriolis mass flow meters are the preferred tool for accurate measuring of flow, temperature and density of the mud, even when the mud contains cuttings. The Coriolis mass flow meter suits well in a closed well bore in combination with a choke manifold since the principle behind the meter is to have a pressure drop.

### **4.5 Mud Gas Separator**

If gas is detected in the returns fluid, it will be routed through the mud gas separator (MGS) where gas typically is vented up to the highest point on the rig or other suitable locations. Compared to UBD, the MGS used in MPD operations are often the standard rig MGS with regular capabilities. Fluid in the returns continues to the shakers where solids are removed and the rest of the procedure is the same as for conventional drilling. In Figure 4-1, the location of the MGS and its relation to the other topside equipment can be seen.

### **4.6 Real-Time Data Acquisition**

The tools used for data acquisition works in close collaboration with the control system, since measurements from the flow meter and pressure readings from downhole is important input data for the control system to optimize the process. In addition to the equipment mentioned below, also accurate measurements and data from the rig pumps and mud properties are required for optimization of the hydraulic models used in the control system

#### **4.6.1 Pressure-While-Drilling**

To have knowledge of the formation pore pressure during drilling in narrow operating windows is essential in MPD operations. Use of Formation-Pressure-While-Drilling (PWD) tools installed in the bottomhole assembly (BHA) allows for continuous measurements of formation pressure during the operation. For accurate measurements of the bottomhole pressure, an Annulus-Pressure-While-Drilling tool should be installed. Also, for precise control of ECD, several sensors can be placed along the drill string when using wired drill pipe to be able to control and adjust the annular pressure. Both the formation pressure and the annulus pressure are necessary for the hydraulic model in the MPD control system/simulator, which needs a continuous feed of data to be correctly calibrated at all time. Precise measurements from PWD-tools are also necessary when handling kick in MPD mode.

#### **4.6.2 Mud Pulse Telemetry**

The most common method of data transmission between downhole MWD tools and surface is mud pulse telemetry. A valve in the BHA is operated to restrict the mud flow according to the digital information to be transmitted. This activity creates pressure fluctuations representing the information to be sent. The pressure fluctuations are received by pressure sensors at surface and

processed to reconstruct the information. This technology has limitations in amount and speed of data, which also decreases with the length of the wellbore. To obtain better data acquisition from downhole, new technology like wired drill pipe could be used.

#### **4.6.3 Wired Drill Pipe**

Typically, data from downhole measurements are being transferred to surface by mud-pulse telemetry, which has its limitations in both transfer capacity and transferring speed. Transferring speed using wired pipe can be up to 57,600 bytes per second, a huge increase compared to conventional telemetry like mud pulses which have around 20 bytes per second<sup>39</sup>. This technology also offers a huge increase in the amount of high resolution data that can be transferred over great distances which are useful in deepwater and for extended reach wells<sup>4</sup>. Live, immediate data feed can in some applications/systems of MPD be important for constant adjustment of hydraulic models in the control systems. In the future, wired drill pipe and high speed data transfer could in some cases be the norm for future applications in combination with advanced measurement -/logging-while drilling tools. But it all depends on the MPD system used, and how they are able to utilize all the data provided from downhole.

### **4.7 Continuous Circulation Equipment**

Continuous Circulation can be defined as<sup>40</sup>: *“The ability to maintain uninterrupted flow of drilling fluid to the well whilst all steps to add (or remove) joints of “drill pipe” to the drilling string are performed within the drilling process, including trips in and out of hole”*

Different equipment that allows for continuous circulation of the system has been developed over the last decade. Continuous flow makes it possible to maintain a near constant bottomhole pressure at all time, since the equivalent mud weight will be kept constant and minimize pressure fluctuations (ballooning/breathing) as normally seen during connections. One advantage with this philosophy is that the possibility of stuck pipe is reduced since cuttings are prevented from dropping to the bottom. Having the mud under constant dynamically conditions, the chance of the mud density being affected by downhole pressure and temperature is minimized. Mud properties are affected both in dynamic and static conditions, but having mud under static conditions are causing more changes than dynamic. Under high pressure, the density can increase, while exposed to high temperature the density can decrease. In static conditions, the temperature of the mud will increase until reaching equilibrium with the formation temperature. Changes in mud properties affect the downhole conditions since the choke and control system operates according to the initial surface mud properties. By keeping a constant circulation, one will also be able to cool down the BHA-equipment continuously, instead of exposing it for constant varying temperatures which can over time degrade the equipment. Communication between downhole and top side can be transmitted through the conventional mud pulse telemetry, allowing for constant input of measurements and log data at all time. During maintenance of the RCD, when the sealing elements need to be changed, circulation can be maintained. Together with the choke manifold system, the wellbore pressure can be controlled, reducing the risk of incidents. In the future, instead of introducing the full MPD package, using continuous flow equipment could be the best solution for many onshore wells when you look at the whole picture. Due to its lower cost (25-30% of an MPD system<sup>41</sup>), smaller footprint and easier to

use, it could be very useful for many onshore wells where the full MPD package might be a bit “over the top”.

Today there are different approaches to how continuous circulation can be obtained, and they are generally divided into Continuous Circulation Systems (CCS) and Continuous Circulation Valves (CCV).

**4.7.1 Continuous Circulation System**

The Continuous Circulation System (CCS)-unit closes around the tool joint and allows for a “wet” connection to be made while maintaining constant downhole pressure. The concept has been tested and used commercially both on fixed and floating drilling rigs offshore<sup>2</sup>. The unit consists of a set of rams and snubbing equipment, as illustrated in Figure 4-7. The rams divides the unit into an upper and a lower chamber. When connections need to be made, the chamber is whole. Mud is pumped into the chamber, pressurizing it before the Kelly is disconnected and a ram seals of the lower chamber allowing for mud to be circulated down the pipe held up by the lower slips in the lower chamber. Pressure is bled of the upper chamber and a new pipe can be set into the upper chamber. The upper chamber is pressurized and the new pipe is lowered down into the lower chamber and connection is made. The new pipe is connected to the conventional rig equipment, so when the connection is completed, conventional circulation can continue while pressure in the CCS chamber is bled of before drilling continues. Although the system has been proven mostly successful in use, the system leaves quite a big footprint and it is challenging to install or remove from the rig floor if necessary. So it demands both deck space on the rig and pre-planning before it could be installed and used.

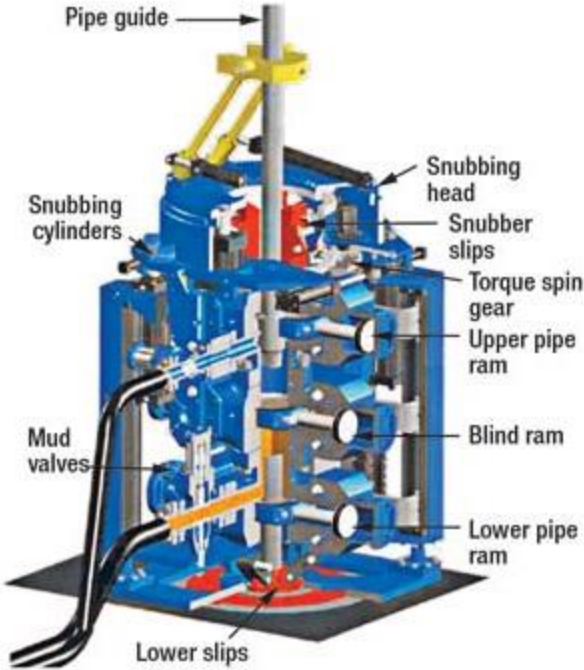


Figure 4-7 Continuous Circulation System unit<sup>33</sup>

#### 4.7.2 Continuous Circulation Valve

A continuous circulation valve (CCV) was designed in Norway intended to be used on depleted- and HPHT-fields on the Norwegian Continental Shelf (NCS)<sup>42</sup>. The system consists of a three-way valve sub installed on top of each drill pipe stand, or every 100m. Number of subs required depends on the length to be drilled with continuous circulation. In addition to the subs, a manifold is required to divert flow from normal circulation to the circulation sub. The manifold is installed on the drillfloor and leaves a quite small footprint. The sub itself has a sideport where a hose connected to the manifold, as seen in Figure 4-8, can be connected, and circulation can be switched from a horizontal entry from the hose or a vertical entry from the Kelly. Check valves are installed both horizontally and vertically to control the flow.



Figure 4-8 Three-way sub in a CCV system<sup>36</sup>

Today there are several different types of this valve from different vendors, but the principle behind it, as seen in Figure 4-9, is the same. In addition to the valve, a manifold is needed to divert the flow from the rig pump manifold between the top drive and the CCV system. There are some challenges with this system, for instance making them reliable over time, designing them for high flow rates and maintaining same ID as the tool joint preventing the valve from being a bottleneck. Compared to the CCS system, it could be more reliable since the principle of the system is simpler with less advanced technology and the footprint of the equipment is far less. But of course, the number of subs needed could be high depending on the length of the section. Number of required subs is defined by the length of the open hole section to be drilled with continuous circulation. In case the integrity of the drillstring is compromised and an emergency well control situation is occurring, the circulation device sub can act as a backpressure /check valve in the drillstring. By applying backpressure uncontrolled flowback from the drillstring can be avoided. A circulation device can be rated to sustain 10,000 psi (690 bar) differential pressure from the bottom<sup>9</sup>, while 15,000 psi (1035 bar) equipment is under development<sup>41</sup>.



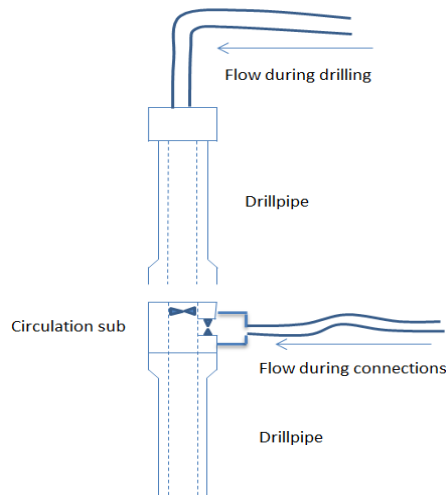


Figure 4-9 Principle of the three-way valve used in continuous circulation systems

## 4.8 Non-Return Valves

The non-return valve (NRV), for some known as a “drill string float valve”, is one of the most important tools to enable MPD operations. Applying annulus backpressure often induces U-tubing between drill string and annulus during connections, pushing drilling mud up the drill string and in worst case blow out the drill pipe. To avoid U-tubing, a NRV is installed close to or in the bottom hole assembly (BHA), and it prevents the mud to return up the drill string when applying backpressure on the annulus side. For redundancy, two or more NRV’s are installed. Another solution for redundancy is to use wireline retrievable valves to avoid tripping operations and enhances the operational efficiency and safety<sup>2</sup>. Since backpressure is applied most of the time to compensate for annular friction losses during static conditions, it is crucial that the NRV is functioning at all time.

## 4.9 Other Equipment

### 4.9.1 Downhole Deployment Valve

A downhole deployment valve (DDV), or a casing isolation valve run as an integrated part of the casing set above the formation of interest. It is designed in a way that it could be used in combination with standard casing programs, often placed inside the 9 5/8” casing. It is operated hydraulically from surface, and the flapper valve is activated after the bit is pulled just above it to isolate the upper part of the well from the pressure below. Figure 4-10 illustrates the functioning of the valve. Pressure in the upper annular is bleed off, before normal tripping continues. Running back in the hole, pipe is run to just above the DDV before the upper annular is pressurized to equal pressure as below the valve. Valve is opened and pipe is run down to the bottom of the open hole. Using a DDV allows for faster tripping without the risk of surge- and swab pressure fluctuations<sup>2</sup>.

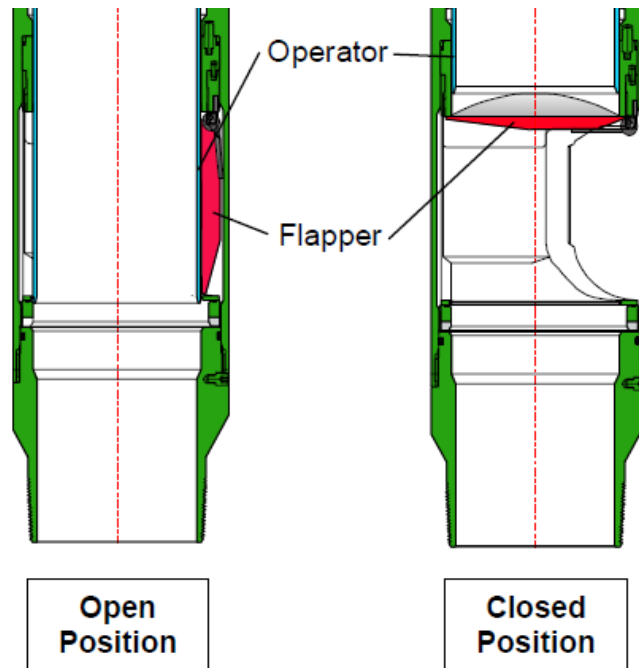


Figure 4-10 Downhole Deployment Valve<sup>43</sup>

Several different companies are manufacturing these types of valves for downhole pressure control in MPD operations, such as the Casing Isolation Valve (CIV) and the Quick Trip Valve (QTV), but the purpose of them is the same as for the DDV and the basic principle for how they work are also the same.

#### 4.9.2 ECD Reduction Tool

Using an ECD-reduction tool developed by Weatherford, a pressure differential is created that modifies the annular pressure profile in similar way as a dual-gradient system<sup>2</sup>. A downhole pump in the tool reduces the pressure in the annulus, making it possible to use a slightly heavier mud while navigating through narrow operating windows safely.

### 4.10 Personnel

As in all other operations, competent people are perhaps the most important factor for success. Without competent personnel on site during MPD operations, all of the advanced equipment and new technology used for MPD operations are useless. As the equipment become more advanced and complex, the need for proper training of the personnel also increases. Even though the equipment become more automated, thus reducing the risk of human error, real time decisions still need to be taken and the personnel need to know what to do. The MPD operator can override the system and manually control the use of the chokes. In most of the success stories with use of MPD on offshore locations, it has been pointed out the importance of proper training and introduction to MPD operation for the rig crew. On the “Mandarin East” well drilled by BG in 2010, they pointed out that the extra money spent on training, risk assessments, workshops and discussions with the crew was a very important factor in the success of applying MPD<sup>7</sup>.

Generally it is recommended that training both is conducted in classrooms and on site, for the best theoretical and practical introduction. The operators and drillers must be familiar with all plans and procedures in case of both normal MPD operations and hazardous events. Procedures relating to tasks and actions that affect the pressure regime of the well are important to have in place. A well control matrix, Figure 4-11, and a decision tree, Figure 4-12, must be developed and prepared in the planning phase and the crew must be familiarized with the plans prior to startup of the operation. These procedures described in the figures below here are from a well drilled by Eni recently, but the setup and criteria's are basically the same for all MPD operations.

Influx Indicators		Volume Gain	< Surface Backpressure plus 150 psi	> Surface Backpressure plus 150 psi	> Backpressure limit (800 psi)
	No Influx	0	NONE. Continue Drilling	Stop drilling. Increase back pressure, pump rate, mud weight, or a combination of all. Circulate out any influx prior to resuming operations.	Stop drilling. Shut in well on rig BOP's and evaluate next action.
	Operating Limit	0-3 bbls	Stop drilling. Increase back pressure, pump rate, mud weight, or a combination of all. Circulate out any influx prior to resuming operations.	Stop drilling. Increase back pressure, pump rate, mud weight, or a combination of all. Circulate out any influx prior to resuming operations.	Stop drilling. Shut in well on rig BOP's and evaluate next action.
	< Planned Limit	3-5 bbls	Stop drilling. Increase back pressure, pump rate, mud weight, or a combination of all. Circulate out any influx prior to resuming operations.	Stop drilling. Shut in well on rig BOP's and evaluate next action.	Stop drilling. Shut in well on rig BOP's and evaluate next action.
	> Planned Limit	>5bbls	Stop drilling. Shut in well on rig BOP's and evaluate next action.	Stop drilling. Shut in well on rig BOP's and evaluate next action.	Stop drilling. Shut in well on rig BOP's and evaluate next action.

Figure 4-11 Example of a well control matrix<sup>9</sup>

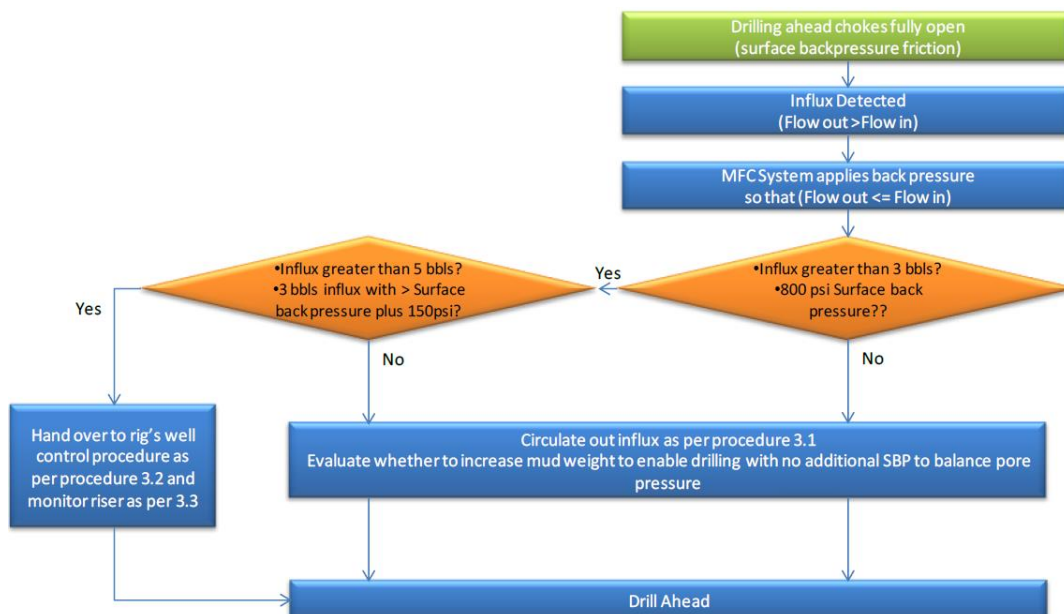


Figure 4-12 Example of decision tree used in a MPD operation<sup>9</sup>

## 5 Existing MPD Technologies and Achievements from Floaters

Managed Pressure Drilling with application of the Constant Bottomhole Pressure and Pressurized Mud Cap Drilling methods have been performed successfully from floaters in several locations around the globe. Several of the major oil companies have implemented the technology on their projects, utilizing the competence of some of the major service companies serving the business<sup>8, 11, 23, 36</sup>. Different techniques and systems have been tried out, and it is difficult to determine which of the different systems are best, since they all have their individual pros and cons. Today, there are three providers of MPD solutions for floating units; Weatherford, MiSwaco – A Schlumberger Company and Managed Pressure Operations (MPO), with Weatherford as the company with most experience over time and a proven system for MPD operations on floaters. MPO is also a good alternative to Weatherford, but their worldwide experience is limited. In addition Halliburton are working on developing their MPD product line including RCD products to be used on floating units, but when these new products are ready for the market is not clear<sup>44</sup>. The experience gained so far using MPD from floaters come from offshore fields, both at normal and deep water depths, in the Mediterranean, Gulf of Mexico, Africa, South-East Asia and most recently South America.

According to an extensive survey performed in 2010 among close to 600 SPE members from both service companies and operators, the overall response to one of the questions was that 40% off all offshore wells would use MPD in 2015 and beyond<sup>45</sup>. From one of the service companies the number was 75%, and certain believe that 100% would be drilled with some form of MPD equipment towards 2020 if government regulations states that. Roughly half way towards 2015, it is clear that, at least in many of the petroleum regions, it is still a long way up to 40, or for that sake 75% offshore wells being drilled with MPD. Up to date, perhaps only in the South East Asia region the number of wells drilled with MPD is quite high. But there is still a long way to go in many regions the next couple of years to reach the anticipated 40%.

### 5.1 MPD Implementation on a Floater in Norway

When planning was commenced in 2007-2008 for a MPD operation on a floater on the Statoil operated HPHT-field Kristin, Solvang et al.<sup>46</sup>, identified some key requirements to enable MPD operation from a floater in a Norwegian Sea area:

- “Be able to pressurize the marine riser to the maximum pressure capacity of its constituent parts.
- Ability to safely install the equipment using simple operational practices and operated as part of marine riser without any modification to the floating drilling installation.
- Provide full-bore capability similar to a conventional rig-up when required.
- Provide the ability to use the standard operating procedures and rigs conventional circulating system when not in pressurized MPD mode.
- Does not lessen the weather (wind, current and wave) operating window of the floating drilling installation.”

They also put focus at the surge and swab problem induced by the heave motion during connections, which they call Closed System Heave due to the closed circulation system when drilling in MPD mode. This project was said to be the first to apply MPD techniques offshore in harsh weather

conditions from a floating drilling unit. In order to perform safe MPD operations in the North Sea and similar, the challenges with implementation of a MPD system and equipment with a control system for suppression of the heave effects needed to be solved first. After having problems with a new designed 7 barrel slip joint, together with other operational issues, this Statoil project was put on hold for an indefinite period of time. As far as the author knows of, this has been the most concrete project in Norway. Even though this project where canceled, or at least put on hold for unlimited amount of time, the requirements stated are still valid for many of the planned MPD operations worldwide.

## 5.2 MPD Systems in Use

Three of the systems that have been used for MPD from floaters are the systems of Weatherford, MPO and MiSwaco. The goal of each system is much of the same, but the way of getting there makes them different.

### 5.2.1 Microflux Control – MPD with Flow Measurement

This section is based on an article and a report by Helios Santos et.al<sup>23, 47</sup>, unless other is stated in the text.

Perhaps the most applied technologies for the CBHP variation of MPD is the Microflux™ control (MFC) system from Weatherford brand Secure Drilling for management of bottomhole pressure and influx- and loss control. In the name of the system, *micro* refers to the total volume of influx of reservoir fluids that can be detected. Since the idea of this technology where launched for onshore application over a decade ago, hard work has been put into first moving the technology to fixed offshore installations, and then further onto floating units and deep water<sup>48</sup>. The systems provides an automated flow and pressure control using software algorithms, real-time trending data, comparing well-bore pressures and flow in and out of the well. The input data composes of typical drilling data inputs like; flow rates in and out, injection pressure/standpipe pressure, surface back pressure, choke position, mud weight and pressure sensors downhole and in surface equipment. Through precise control of the choke position, the downhole pressure can be adjusted by adjusting pressure and/or flow parameters.

The technology makes it possible to make drilling decisions based on real downhole data instead of predicted downhole environments. Any occurring problems could be quickly responded to, hence preventing them to escalate. Included in the MFC system is the solution on most of the drilling problems stated in section **Feil! Fant ikke referansekinden..** It enables an early influx- and loss detection of even micro volumes, automatic calculation of kill mud densities and control of circulation of kick, accurate determination of pore – and fracture pressure gradients, monitoring of surge/swab effects during tripping and automatically detects and distinguish the phenomenon of temperature effect on mud and wellbore breathing/ballooning from an actual influx. Unlike several of the other MPD products available, the MFC-system is based on the principle of *Flow in – Flow Out*, flow measurement. As long as the flow out is equal to the flow in, they know that they are within the operating margins of the formation and it is not that important to precisely control the downhole pressure<sup>31</sup>. They can continue operations until they experience loss or gain, which they can detect within less than 1bbl (1/4 of a barrel) and then weight up new mud or adjust choke/backpressure to continue drilling. The mass-flow measurements taken are very accurate with an uncertainty of  $\pm 0.1\%$

in flow rate measurement and  $\pm 0.0042$  ppg (0.000504 SG) density measurement, and the pressure sensors in the MPD setup has an accuracy of  $\pm 1$  psi (0.0689 bar)<sup>49</sup>.

Another advantage with this MPD technology is its capability to precisely determine the exact downhole margins. Instead of just having the estimated formation pressures and limitations, this system can be used to verify the actual ones. If influxes are detected, surface backpressure is added in intervals until influxes stop. When there is no more influx, the pore pressure can be determined based on the applied backpressure and the current mud weight in hole. Formation integrity (formation pressure) can be verified by performing an open hole leak-off test (LOT) or formation integrity test (FIT) where mud weight is ramped up in intervals of 0.1 ppg (0.012 SG) until losses/leaks occur. These capabilities have proved valuable, saving both time and money in several wells<sup>7, 9</sup>. Conduction of a LOT or FIT is useful in the event of establishing some boundaries for maximum allowable backpressure to be applied, and still not risking the formation's integrity. And being able to perform these tests at all time, with minimum interruption of the drilling without exercising the rig BOP enables more tests to be performed at reduced costs.

The first commercial use of this technology started in 2007, on both onshore and offshore on fixed drilling facilities, while the first well was drilled from a floater late in 2008. Over the years, the method has been used for both hydrostatically overbalanced and hydrostatically underbalanced mud weights, both oil- and water based mud. By now the technology has been tested and developed enough, so it is commonly used and in some cases required to be able to drill successfully in deepwater prospects<sup>50, 51</sup>. It is regarded as an ideal technology to be used for exploratory wells, wells with narrow margins, HPHT-wells, depleted fields, zones with rapid change in pore pressure regime, areas known for a high frequency of kicks and areas with high uncertainty in pressure gradients<sup>2</sup>. As described in section 5.8, this system has proved successful when used together with continuous circulation systems too. As of today, this is perhaps the best suited and proven system for MPD from floaters.

### **5.2.2 Managed Pressure Operations – MPD System**

The company Managed Pressure Operations – MPO, now owned by Aker Solutions, have several different equipment which combined is their MPD system. Their pressure control and manifold, Total Control Driller<sup>®</sup>, MPO Mud Gas Separator, continuous circulation system Non Stop Driller<sup>®</sup>, RCD system and is used with the software control and detection system Predictive Driller<sup>®</sup>. For floaters, especially in deepwater applications, the system is often used with riser pressure control and gas handling system too. MPOs MPD systems have been used on floaters for some years now, first in combination with equipment from other service companies, but in the recent years their own internally developed equipment and systems<sup>52</sup>. Their system is specifically designed and intended to be used on floaters, and that is one of their advantages compared to the other MPD systems on the market. As described later in this thesis, Aker Solutions is planning to implement MPOs MPD system in their future rig design.

### **5.2.3 Dynamic Annular Pressure Control – MPD with Pressure Control**

This section is based on the text book *Managed Pressure Drilling* by Rehm et al.<sup>2</sup>, unless otherwise is stated in the text.

The Dynamic Annular Pressure Control (DAPC) system from MiSwaco, A Schlumberger Company, is a fully automated backpressure control system using a hydraulic model running in real time to

maintain the desired BHP. The equipment is much of the same as used on the MFC-system, but the integration between equipment, control system and hydraulic model differ a bit since the functionality of the system is different than for the MFC-system. In the DAPC-system, the goal is to maintain the bottomhole pressure constant at all time with as little variation as possible utilizing pressure measurements at all time. The system can be configured and scaled for CBHP-drilling, PMCD, influx and loss detection, controlled flow check and dynamic leak-off tests (LOT). By predetermining the desired BHP and entering it into the DAPC system along with well geometry, mud properties, drilling assembly, geological data and temperature, the system automatically calculate the back pressure required to maintain the BHP at the set point and the choke is adjusted accordingly. During operation, the model calculates the BHP as changes occur and new updates for depth, drill string RPM and pump flow rate are received. If available, pressure data from MWD-tools are used for the calibration of the hydraulic model and equipment. The principle layout of the DAPC system is illustrated in Figure 5-1 This system have the capability to automatically redirect the flow to one of the backup chokes in case the active choke becomes nonresponsive or jammed, without any human intervention.

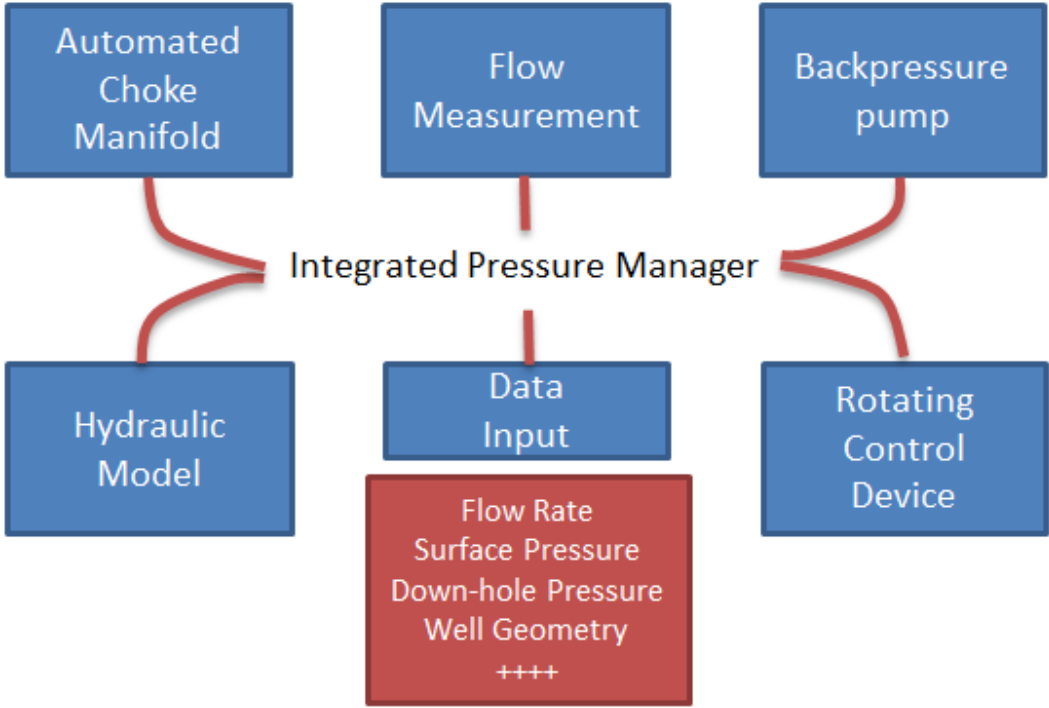


Figure 5-1 The interconnection between the major component in the DAPC-system

This system has up to this date been used on floating drilling units in the South-East Asia region since 2006, both for CBHP and PMCD application with a main focus on the PMCD part. However, the vendor behind this technology is working on developing better solutions for the placement of the RCD (both a ATR- and BTR solution) to increase the use of this technology from floating units<sup>53</sup>. They are currently looking for operators to partner up with to be able to fully test the new equipment, and there are several wells in the planning phase.

### **5.3 Placing the RCD – Below or Above Tension Ring?**

Since the first application of MPD on floating units, one of the big questions have been; what is the optimum place to put the RCD for not to reduce or minimize interference with the other operational limits and specifications?

#### **5.3.1 Experience from Asia**

As much of the first use of MPD from floaters started in Asia, it is natural to look at the experience gained there first. In Asia, various types of MPD technologies have been executed, and different options for installing the MPD equipment have been tested. Various variations with a subsea BOP and different locations of the RCD with regard to tension ring and slip joint, subsea BOP with the RCD installed between BOP and the lower marine riser package (LMRP) and a surface BOP stack (on a floater) with RCD installed at surface. Experience from the South-East Asia region from the last 5-6 years is that a solution with a subsea BOP and a RCD installed below the tension ring seems to be the option for the future<sup>11</sup>.

#### **5.3.2 Best Practices of Today**

By looking at experiences gained over the last years and the practices most common from around the world and, one can see that the solution with a below-tension-ring (BTR) RCD seems to be the best solution, since it enables MPD in severe rig heave environments while also allowing for heading changes on dynamically positioned (DP) floaters<sup>54</sup>. However, there have been drilled wells recently, as described in section 5.8 and 5.9, with and ATR RCD and a mini-telescopic joint above it. These wells have been drilled in West Africa and in the Mediterranean, areas with a history of little heave motions so the requirements for heave compensation was low.

Since 2010, Weatherford have had their SeaShield Model 7875 BTR RCD, in use on DP drillships, moored- and DP semi-submersibles in both deepwater and medium ranged water depths<sup>4,55</sup>. This is the first RCD for use on floating units with a subsea BOP that complies with and is certified to the drill-through specifications of API 16 RCD. The use of a BTR RCD in deepwater have become possible after being designed and tested to support a riser tension requirement up to 3 million lbs<sup>55</sup>, which is sufficient in most applications. A great advantage with the BTR system is that no modifications are required to the telescopic slip joint or the conventional mud returns system.

A common practice, as a safety feature, is to have an annular BOP installed below the RCD and above the flow spool. The annular BOP can be used both during conventional drilling to close in in case of kick in riser and able a more efficient kick circulation. In some setups, the RCD is installed below the sea level, up to 40ft below have been seen, since the tension ring is often located just above sea level.

In drilling operations where Weatherford is the service provider of MPD and RCD services, the setup illustrated in Figure 5-2 is common practice on floating drilling units with a subsea BOP and RCD installed below tension ring.



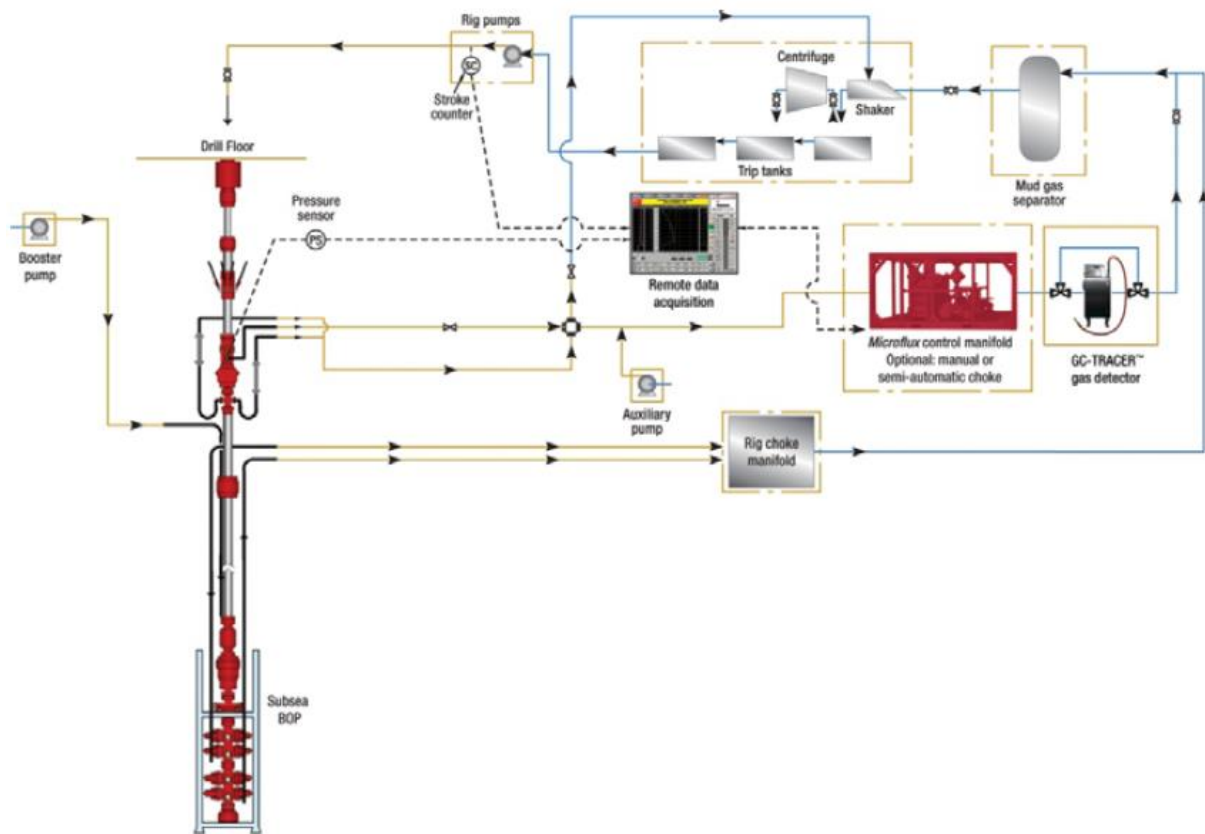


Figure 5-2 MPD system on a floater using equipment from Weatherford<sup>54</sup>

## 5.4 Implementing MPD on Floaters

Much of the problem today with implementation of MPD on floaters, and jack-ups, today is the lack of standardization in rig designs. This requires that every application of MPD on floaters requires a customized approach, including a rig survey to establish deck loads and footprints and other requirements related to the MPD equipment. As a result, modifications are often required, increasing time and costs. Mike Davis, director of global drilling and completions in Repsol, have stated that the biggest issue using MPD from floaters is to get the correct tools built into the rig and the riser<sup>56</sup>. Petrobras have realized the same, saying that most of the upper marine riser systems existing today have restrictions for running RCDs, and they are working on finding methods to more efficiently implement MPD equipment into rigs<sup>24</sup>. Today major modifications to the riser components and eventually manufacturing of new equipment such as slip joints and tension rings, to make them fit with the RCD unit and eventual crossover joints are necessary. As described in the next section, such procedures can be very time consuming, and eventually exclude MPD from the project. In addition to the hardware on the rig, the implementation of MPD on a rig also highly depends on the personnel. A lengthy training process for both rig and operator personnel on safety and operational procedures are required, and all parties involved in the operation have to be familiarized with the system.

Another aspect to consider is that when installing a MPD system on a rig, a requirement is that the system does not put any restrictions to the conventional drilling operations, in case MPD is not necessary. Due to the limitations in deck loads and space, often MPD equipment cannot be installed until the sections planned with MPD is to be drilled, ie the 12 ¼" & 8 ½" sections, which means that

drilling operations must stop before loading and installation can commence. Off course, if this is a procedure required on every rig, every time an MPD operation is to be performed, this is not an ideal solution cause its time consuming, and time is money. But it is seen that the time spent installing MPD equipment and system has paid off in reduced NPT later in the process.

This is the reality today, but there seems to be changes in the near future as operators demand the use of MPD and the drilling contractors are starting to build new MPD-ready units, installing MPD equipment when rigs are in yard for service and training the rig crews towards using MPD systems.

## **5.5 Slip Joint Systems**

As described in section 5.2, MPD operations from floating units usually requires a 3 part slip joint, specially designed for MPD operations. The problem today is that most rigs don't have the correct type of slip joint, and the manufacturing time on a new 3 part slip joint is significant. In case MPD is considered on a future well, the decision should be commenced and planning started up to 2 years in advance to be able to order and have a new 3 part slip joint manufactured. Usually, thoughts of implementation of MPD does not start before the operator realizes that it could be problematic to drill the well conventionally, which could occur one year in advance of the well being drilled. One year in advance could then be too little time for manufacturing of a new slip joint. The problem today with regard to the slip joint thematic seems to be that the use of MPD is not implemented from the beginning of the planning phase.

## **5.6 Control System to Compensate for Heave-Motion**

Depending on whom you ask or which service company providing the MPD system, some will say that rig heave is perhaps the most challenging factor with regard to MPD from floaters and that it is of great importance that this must be sorted out before it could be carried out. As described in section 2.7.2, the pressure fluctuations that can be expected in the North Sea are significant. The surge and swab effects during connections causing these pressure fluctuations can be controlled, but to enable that, a control system that is fast and accurate enough is necessary. Researchers from Norwegian Univ. of Science and Technology and Statoil R&D<sup>30</sup> have performed tests of a control system, both in a drilling simulator and in the same well at Ullrig. The control system performed well in the simulator, but in the real test the heave compensation did not work. They analyzed the cause of the failure, and found that delays in the system played an important role. Delays in the measurements and slow working choke were factors affecting the performance. In addition they realized that effects of the downhole pressure wave propagation started playing an essential role for the application of the control system. The effect of the pressure wave propagation was only captured by the hydraulic model, and not by the choke pressure controller, thus causing problems for the total functionality of the system.

To be able to handle the heave motion on floaters the researchers have come up with a new controller which implements a hydraulic model, a choke pressure controller and a model for heave motion, all in one unit<sup>57</sup>. In combination with this new controller unit, requirements for good measurements are also set and they confines standard top side measurements, measurements of the heave motion of the rig and measurements of downhole pressure. For accurate, live and continuous

downhole measurement they require the use wired pipe. Simulations have been performed with this new setup, and they have given good results with the same well configurations as in previous experiments. Four components need to be in place for this system to be successful;

- Fast control system implementation
- Minimized delays of measurements
- Fast MPD choke
- Wired pipe with continuous measurements during connections

This concept, with the critical components in place, could be a solution for handling the problem with severe heave in MPD operations on floaters.

## **5.7 Using Wired Drillpipe in MPD Operations**

As described in previous sections, wired drillpipe (WDP) is in some application of MPD described as a requirement for successful implementation on floaters. Recent experience from a deep well in Mexico proved that MPD and WDP worked very well together<sup>58</sup>. Along string measurements (ASM) together with the measurements obtained by MWD/LWD tools in the BHA was valuable for the MPD operation. WDP provided a continuous data flow and made it possible to measure the bottomhole pressure when making connections, and these data were used to more accurately adjust the choke position to keep a constant bottomhole pressure. Use of ASM allowed for computation of the fluid density at multiple intervals along the annulus. They discovered how formation pressure and temperature affected the density of the drilling mud, and these changes were fed into the hydraulic model used by the MPD control system. Without the correct hydraulic data input, the MPD system would not work optimal. WDP gave several other advantages too, such as directional control and data to optimize the drilling process by reducing bit bounce, stick/slip and bit whirl which makes it possible to optimize ROP.

## **5.8 Utilizing both Active MPD Choke System and Continuous Circulation**

The Italian oil and gas company Eni has over the last years developed experience using an active, automated MPD choke system, e.g. Microflux Control, in combination with their own continuous circulations systems, Eni Circulation Device – E-CD, to safely drill challenging wells. It started off with wells drilled from fixed installations with great success in 2008. This combination of MFC and E-CD are named Eni-Near-Balanced Drilling (ENBD). With the successful use on fixed installations in mind, Eni decided to use ENBD from floating drilling units in the Mediterranean and in West Africa<sup>9, 59, 60</sup>, which also have proved successful.

Eni have identified several advantages using E-CD in combination with an MPD choke system compared to conventional MPD systems<sup>59</sup>;

- The risk of error during the transient phase is reduced since the process of decreasing mud pump and increasing backpressure is avoided
- Reduced connection time since transient phase is no longer necessary

- No variations in mud rheology and density due to temperature variations downhole improves control of BHP
- Increased life of BHA tools, reducing NPT and costs due to less exposure to high, static temperatures since there will be a continuous mud cooling effect and they are no longer exposed to the start and stop circulation cycles associated with connections.
- Data transfer during connections
- Influxes can be detected during connections

Utilizing ENBD, Eni drilled a deepwater well in Ghana, West Africa in 2012<sup>9</sup>. An offset exploratory well had been drilled there in 2008, experiencing challenging drilling environments including sharp pore- and fracture-pressure gradients and unstable zones. This main wellbore of the offset well was plugged back, and a sidetrack was drilled to overcome the challenges, but the sidetrack did not reach target depth either and the well was permanently plugged and abandoned. In the main wellbore, they experienced several incidents in a rubble zone with pack off around the BHA and they decided to pull out and plug the well. In the sidetrack, they decided to use a higher mud weight to stabilize the formation and prevent sloughing. They experienced less resistance in the wellbore and formation sloughing until encountering higher pore pressure and influxes. An influx of between 16 and 20 bbls lead to shut-in of the well and permanent abandonment. These drilling problems raised the requirement for a complete set of MPD well control equipment. MPD was decided to be used, based on its capability of more precisely monitoring the downhole conditions than in conventional operations and since it can act as an advanced system for early kick detection. This early kick detection in combination with minimizing the kick size makes operations safer.

MPD proved to be a success on the well which achieved several well objectives. They managed to drill the sections deeper, thus allowing setting the casings deeper and eliminating one section. Influxes and losses were identified, and the MPD system was used to control and minimize the influxes safely and circulate them out. Applying backpressure, while pulling out of the hole kept the well steady and free from swabbing influx. The problems previously encountered in the unstable zone were eliminated while at the same time being able to precisely asset the upper and lower limits in the formation. Using both the MPD system and the continuous circulation device helped the operator to drill the well safely to planned TD, without any borehole stability issues, contingency liners or under-reaming any of the hole sections. *“It was proved again here that this technique can successfully drill the undrillable”<sup>9</sup>.*

## **5.9 Use of MPD to Drill Deepwater Well in the Mediterranean**

Implementing MPD on floaters creates a number of challenges, which the operator BP realized when planning to drill a deepwater HPHT-well in the Nile Delta in the Mediterranean<sup>8</sup>. Previously they had drilled several HPHT-wells from jack-ups utilizing MPD technology, in an area known for very tight margins between pore- and fracture gradients, significant NPT due to losses and gains and many of the wells have been ceased before reaching TD. In addition explorers experience extremely unpredictable pore pressure regimes with pikes and regressions in combination with a complex geology making pore pressure prediction difficult, and drilling exploration wells challenging. After using MPD equipment and procedures successfully to overcome these challenges when drilling from a jack-up, they were going to use the same technology from a semi-submersible rig. They had to go

through a long planning phase, where they early identified several areas which they had to focus on upon start of the operation; incorporating the RCD into the riser string, maintaining suitable heave compensation for the rig, using the marine riser as a pressure containment vessel and the surface system layout. In addition extensive crew training and introductions to the new equipment were held.

When incorporating the RCD into the riser they had to consider, among others, rig motion characteristics and required heave compensation, crossover components to be able to connect the parts and limitations with regards to running and installing riser. Customized equipment had to be built, for instance a new “mini” telescoping joint. All new components needed to have the proper tensile and pressure ratings and sufficient inner diameters allowing for running of various equipment and tools. The new mini telescoping joint was built after specifications to comply with the required heave compensation for the specific area. The marine riser and all its components had to be analyzed and operating limits had to be set in terms of maximum allowable mud weight and maximum allowable surface backpressure. With this as a basis, operating procedures were set for a pressure relief line in the surface MPD system to protect the riser in case of over pressure. The installation of the surface equipment necessary for MPD operations and the routing of the flow lines between the various components were designed around the layout of the rig to optimize the working environments and not to intervene with other operations on the rig. Risk analysis had to be performed before the final installation could be carried on. The MPD system used was MFC from Weatherford.

After a long planning phase, the well was drilled and successfully reached target, a target significantly deeper than any other wells drilled in this area previously. They had positive experiences with the use of MPD equipment to perform Pressure Build-Up test with the choke closed to discover and identify influx, instead of the more time-consuming process of performing flowchecks to monitor flowback from the well. These Pressure Build-Ups gave the operators and driller better results than the conventional flowchecks. Even with the MPD equipment and procedures in place, they made it clear that the BOP was the primary means of securing the well and the driller had responsibility of closing the well and this responsibility was separate of the MPD operation. A close collaboration between MPD operators and the rigs drilling crew were crucial for the success of the well and MPD operation completed in March 2011.

## **5.10 Deepwater Managed Pressure Drilling Enhances Safety**

As described in section 2.6.6, gas in riser has been known to cause problems in deepwater drilling operations due to gas being mixed with oil-based mud and circulated undetected up the well before breaking out of the mixture at around 2000 ft (610 m) to 3000 ft (915 m) below drill floor, which is often above the subsea BOP.

Since 2010, automated Microflux Control system and BTR RCD has been successfully used in deepwater operations<sup>28, 55</sup>. This setup with the BTR RCD, as seen in Figure 5-2, are beneficial since few modifications on the rigs telescoping slip joint and/or mud returns system are required, it has a high tensile rating and it allows for heading changes and heave compensation can be maintained without limitations.

The MPD system can be used both proactive and reactive towards the mitigation of gas in drilling riser. In the proactive approach, the automatic early kick detection and control capacities are utilized to minimize the amount of influx entering the oil-based mud and dissolving. The influx and subsequent dissolving cause anomalies in the well flow which the system can detect, and then close in on the choke to increase the BHP to regain control of the well. In the previous deepwater wells drilled, the system has proved successful by detecting flow anomalies which has been kept to a minimal volume and circulated safely out using the well control equipment of the rig. If an influx makes it above the subsea BOP, the MPD system can be used to circulate the influx out of the riser in a controlled manner. After the subsea BOP is closed, the annular preventer below the RCD is also closed, and the mud in the riser can be circulated out through the MPD choke manifold and the mud gas separator. After the influx is circulated out, the mud in the riser can then be weighted up before the BOP is opened and the rest of the well circulated to a higher mud weight. During this circulation, the MPD system is used to apply backpressure to avoid more formation influx.

## **5.11 Discussion**

After developing from simple land rig applications, it is now clear that Managed Pressure Drilling is starting to get foothold in offshore environments too. As seen in this work, the technology has to a great extent been used in the South East Asia region, and now it is getting foothold in the seas surrounding Africa and offshore South America.

The development of this technology has been led by several companies, with Weatherford and their brand Secure Drilling and Microflux Control system in front. All of the big service companies are starting to see the value of this technology and the future market of MPD from floaters, and are improving and developing their own technologies. Many of the vendors and operators believe that in some years, a significant number of offshore wells will be drilled using MPD technology for at least part of the well construction process<sup>45</sup>.

Summarizing what is seen above here, one can see that a key point leading up to a successful MPD operation is good planning, and to involve project personnel from the MPD service provider early in the process, and take advantage of their experience from previous MPD operations. A close collaboration between service companies and operator regarding all aspect of the MPD operation from the beginning is the first step towards a successful operation

## **6 The Future of MPD for Floaters – New Technology and Implementation**

Over the last years, several of the big oil and gas companies worldwide have taken interest in the MPD technology in offshore environments both after experiencing its benefits themselves, encountering problems in wells which could have been avoided using MPD methods and after seeing what other companies have gained by using this rather new technology. Service companies, operators and drilling contractors are taking interest in the technology and they are slowly starting to think ahead to be able to use MPD in future operations. As described in the last chapter, the experience gained so far is obtained in the Mediterranean, Gulf of Mexico, offshore Africa and South-East Asia. But now the MPD activity is approaching new frontiers such as offshore Brazil and maybe in the future northern Europe and Norway. The difference between the previous mentioned areas and northern Europe are the rough weather conditions frequently experienced in this part of the world, so all of the technology, equipment and methods may not be directly transferable to the conditions seen here. However, much of the experience obtained internationally could be evaluated as part of the process of bringing MPD from floaters into this part of the world too.

### **6.1 International Trends**

The offshore area which has experienced most growth recently and still is expected to grow significantly for the next 10-20 years are Brazil, and it could also be the next area where MPD will break through. As MPD from floaters are common in the South East Asia region, and has begun to gain a foothold in the surrounding oceans of Africa, MPD has just recently been deployed on floaters offshore Brazil. Many exploration wells have been drilled in areas where huge losses have been experienced, mainly in formations below the thick salt layers, in the formations best known as pre-salt formations, see Figure 6-1. Several of the big players in Brazil, Petrobras, Repsol and BG Group, have experienced problems and are planning to utilize MPD in their future development and exploration programs<sup>24, 56</sup>. In addition to these areas in Brazil, the French giant Total foresees MPD to play an important role in HPHT drilling all over the globe in the coming years<sup>61</sup>. They expect that in a while, everybody involved in HPHT operations will have to use MPD tools to be able to reach their targets, targets that is often on the limit of what is possible to achieve. As seen in section 5.8, the Italian company Eni is putting a lot of resources into developing their continuous circulation system in combination with an active choke system, and this work is continuing in the next years with further development and wells being drilled from floaters. As described in chapter 7, BG Group is also involved in operations utilizing the MPD technology to drill a HPHT-well.

#### **6.1.1 Petrobras**

The Brazilian national oil and gas company Petrobras experienced “large formation losses, high pore pressure, a narrow operating window and high risk of ballooning”<sup>24</sup> on an exploration well, making it challenging and unable to reach total depth. To prevent further losses, they realized that they had to implement MPD for the rest of the drilling campaign to be feasible at a reasonable cost. From 2010 to 2012 they drilled 67 conventional wells and 29 of them had problems with kicks and losses. Time spent solving these problems added up to 4,600 hours and 191 days<sup>24</sup>, lost time which costs a lot more than MPD equipment and installation. By implementing MPD into their future campaign, they aims to reduce fluid gains and losses, increase rate of penetration, extend TD, prevent problems

related to wellbore ballooning, reduce the likelihood of drill string sticking, minimize formation damage and well stability issues and it will also open up possibilities for switching over to PMCD. After the first successful use of MPD from a floater, where they drilled the 12 ¼" and 8 ½" sections with a hydrostatically underbalanced fluid, they will now drill at least 25 exploration wells and some development wells using MPD. The wells will be drilled in shallow to ultra-deepwater fields in the Santos Basin up to 2017, many of the wells into pre-salt formations as seen in Figure 6-1. For this to be run as smoothly as possible, they will carry on with the work and procedures established during planning and execution of the first MPD well drilled, including specific procedures for MPD operations and contingency plans for casing and liners.

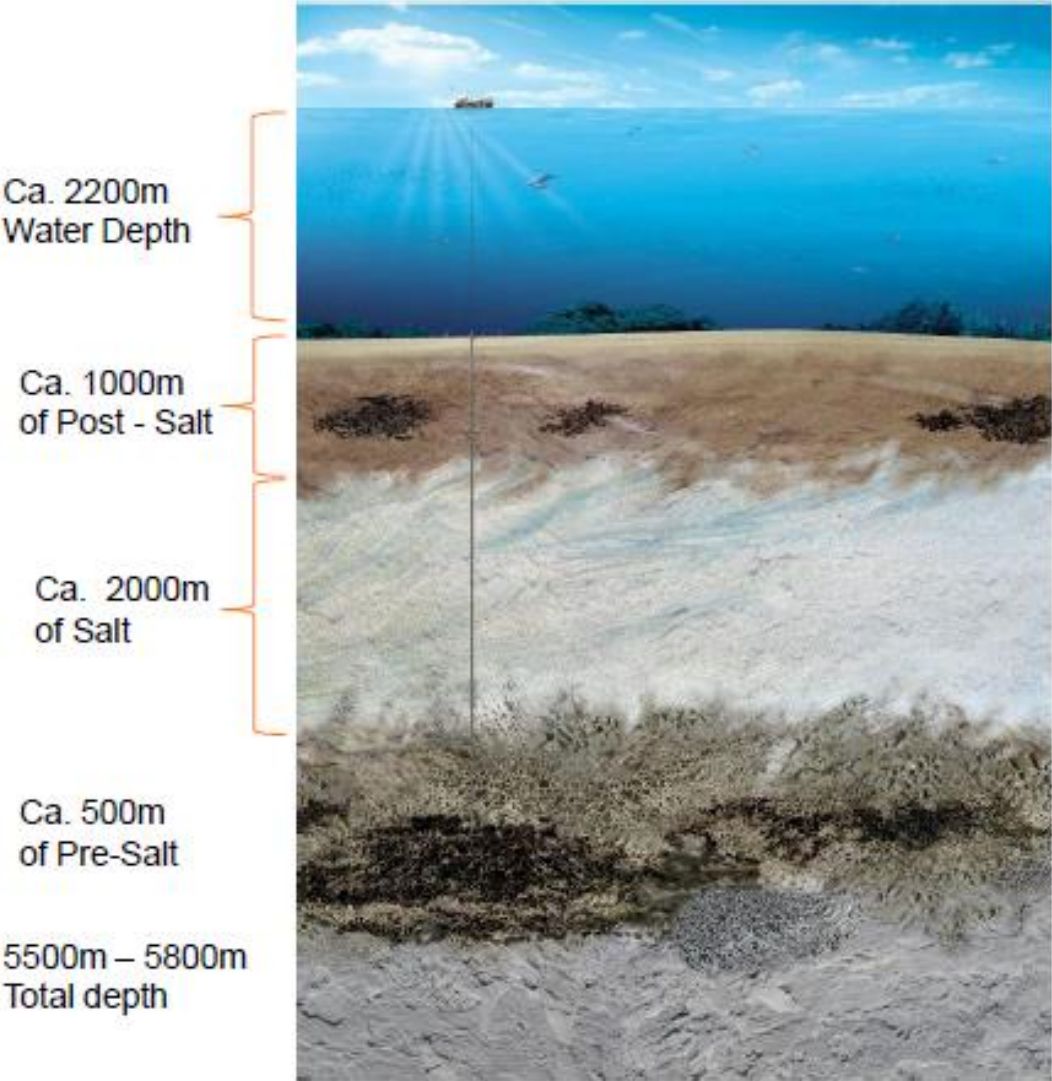


Figure 6-1 Pre salt formations outside Brazil. Courtesy of BG Brazil

By mid-2014, Petrobras anticipates having six rigs ready and equipped with MPD equipment. Petrobras, having worked together with Secure Drilling, now a part of Weatherford, for many years, participating in the development of the MFC MPD system, have chosen Weatherford equipment to



be installed on their rigs for the coming years. Included in this strategy is further development of the training procedure for the rig crew conducted prior to the first well being drilled, including internal training, hands-on training for the well design team provided by the service companies and more advanced training in MPD and RCD technology for the rig crew. All to get the involved personnel familiarized with the technology. During planning of the first well, procedures and standards for MPD and mud cap drilling was developed and an extensive process of defining procedures related to well control. Towards commencing of this drilling campaign, well control procedures and the use of MPD will be further discussed in collaboration with the partners, among them BG Group. BG Group as a partner is contributing and sharing their experience in MPD from the North Sea and offshore Tunisia. This campaign could provide both BG Group and Petrobras with a lot of valuable experience for the future, making the two companies among the industry leaders in deepwater use of MPD.

### **6.1.2 Repsol**

Spanish oil and gas company Repsol sees managed pressure drilling as the biggest technological game changer today, and Mike Davis, director of global drilling and completions believes that in 5 to 10 years MPD will be used in everyday operations<sup>56</sup>. In their future plans to expand and increase production, MPD plays a significant role for drilling wells more effectively and safe. For their future drilling campaign in West Africa and Brazil they have contracted two drillships, one being built new with MPD equipment completely built in (Rowan Renaissance), while the other is to be fitted with MPD equipment before the campaign commences (Ocean Rig Mylos). Having the rigs ready for MPD enables them to use the technology as a contingency plan if necessary; they don't need to implement MPD on the rig as it is already there. As one of the rigs is being built new with MPD equipment was an important factor when they decided for rig provider. Repsol believes that in the coming years more rigs will come from the shipyard with MPD equipment installed, since the incremental cost related to installation of MPD equipment in the shipyard is relatively small compared to installing it later.

For their campaign in Brazil they are facing the same drilling hazards as described in section 6.1.1 for Petrobras, and Repsol is also looking at the MPD technology as the solution to mitigate the hazards and being able to drill to TD with the correct casing sizes across the pay zones. As MPD is not only a way to mitigate drilling hazards, but also, by many considered as a way to conduct safer drilling operations and reducing the risk of unwanted well control incidents and potential disasters. But for the technology to completely be accepted in all countries as a safe way of drilling, the operators must collaborate with the authorities and identify hazards and assess the risks associated with MPD drilling, and prove that MPD is a safe technology for the future.

### **6.1.3 Rig Design**

As described in section 5.4 and in the previous sections, implementing MPD equipment on existing floaters is a costly, time consuming and also often a challenging procedure. But planning and building new rigs with MPD equipment installed in the building yard reduces the cost and much of the extra time spent installing it later. The cost of this is of course something that the rig owner must take, but moving the ownership of MPD equipment such as flow, spool, RCD housing, riser equipment associated with MPD and the correct slip joints over to the drilling contractors, will enable MPD deployment more as a standard package, a "plug-and-play" solution. By having the MPD capabilities built into the rig will again make the rig more attractive to operators in the market for a rig for a MPD operation. This is something that Repsol emphasized on when contracting new rigs for their

campaign described in section 6.1.2, and is also something they will focus on in the coming year and contracting periods<sup>56</sup>. This is something that the author believes could be a trend in the future, rigs already equipped with MPD equipment would be more sought after in the market, because operators that have experienced the benefits with MPD will value its existence on the rig when hiring. Rowan as described in section 6.1.2 is one of the drilling contractors having MPD equipment built into the rigs (drillship) in yard during construction, while Aker Solutions (designer of rigs) is another company planning for the same. Aker Solution recently acquired the company Managed Pressure Operations (MPO)<sup>62</sup> and they are planning to integrate the MPD system from MPO in their rig design, and also supply MPD equipment and riser gas handling system as part of the complete drilling package to the clients.

In addition to contractors and designers integrating MPD equipment in their rig design, there are some designers are practically “designing” their new rig-concept around the MPD system. Stena Drilling, with designer Gavin Humphreys in front have designed both a drillship (DrillSLIM) with surface BOP, high pressure riser and MPD equipment, and a semisubmersible (Stena Advance) with MPD frame and platform highly integrated in the rig<sup>63</sup>. This platform is independently (off the marine riser tensioners) compensated and configured to support an inner high pressure riser locked into the lower marine riser package (LMRP) and on top there is an MPD frame where the MPD equipment is installed. The way the system works is illustrated in Figure 6-2 and Figure 6-3, describing both conventional operations, transition to MPD mode and preparation to MPD mode.

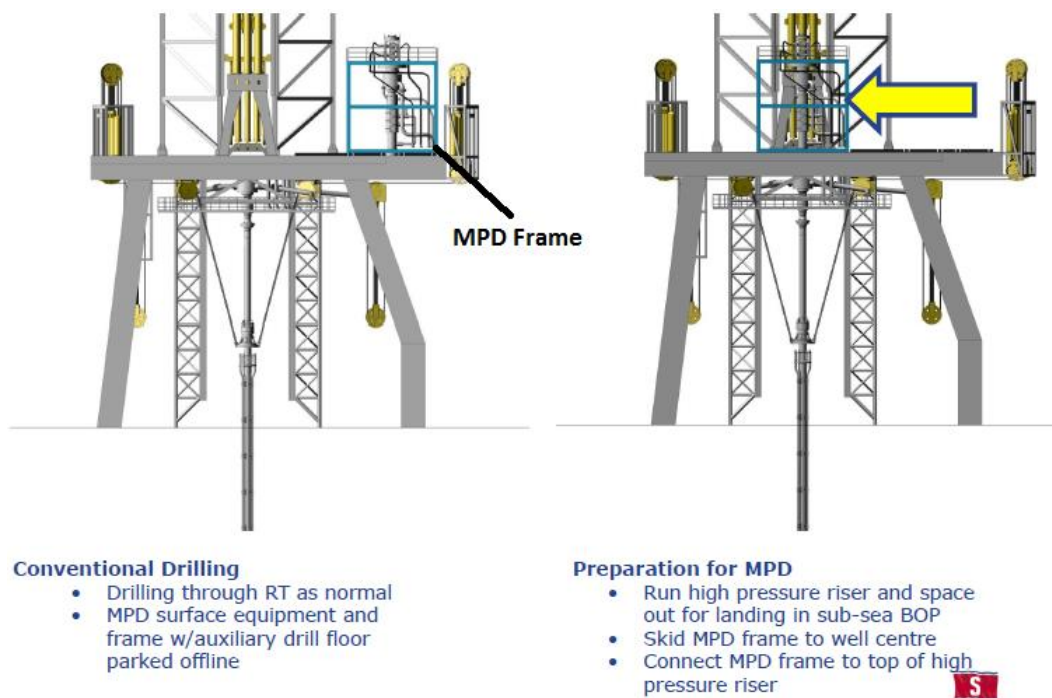


Figure 6-2 The transition from conventional drilling to MPD mode. Courtesy of Stena Drilling

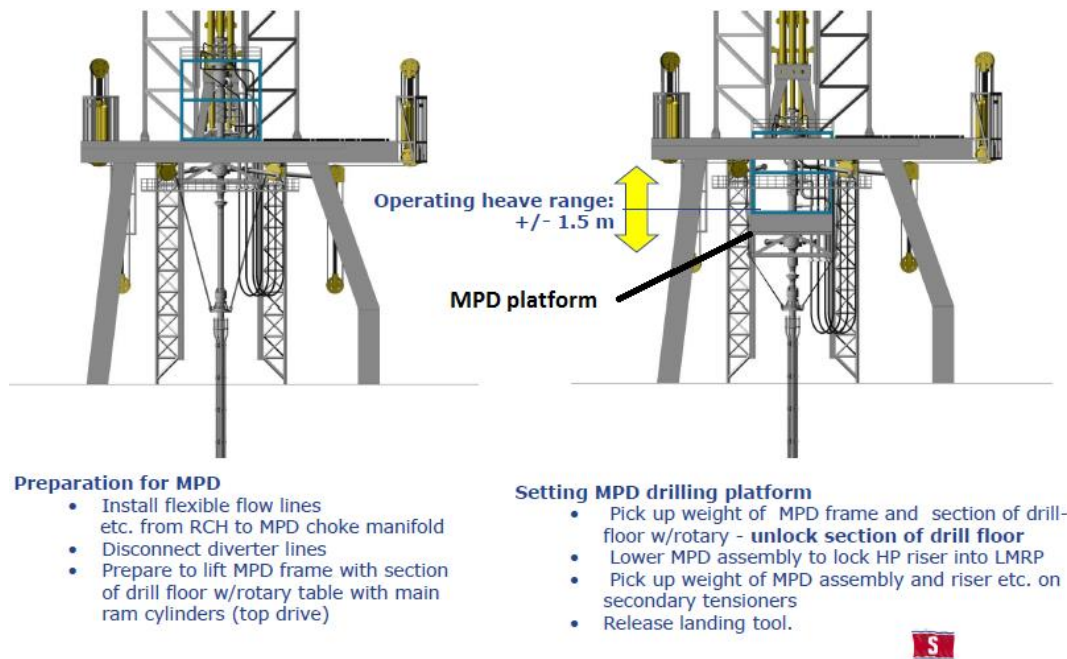


Figure 6-3 Preparing and connecting the MPD system and setting the MPD platform in drilling mode. Courtesy of Stena Drilling

Building such MPD capabilities into the rig design enables a solution from the outset. It will eliminate or at least cut lead times since equipment is in place and crew is already trained, and during operations transition from conventional drilling to MPD can be performed. Constant bottomhole pressure, dual gradient and pressurized mud cap drilling are all MPD techniques which can be achieved with this setup.

As this is just a design on the drawing board, no one knows if it will ever be realized and perhaps it might not be the solution for the future. But maybe some new thinking from the designers of rigs is one of the ways to go to bring MPD operations from floaters into the future, new thinking and new technology have been important in the industry previously.

## 6.2 Trends in Norway

In Norway, Statoil has been working on implementing MPD on floaters since 2007 as described in section 5.1. That first attempt stranded, but research and work have continued since that including work with RCD elements, riser slip joint and of course the automated control system to prevent downhole pressure fluctuations due to heave motion on the rig. The work on the control system described in section 5.6 is under constant development with simulations and field trials, but it is difficult to predict when it will be ready for a real offshore field trial or real use. Even though simulation test results are improving, there is still a lot of work and research to do with this concept and until fully realized it could take several years.

Due to no previous experience with MPD from floaters in Norway, the author of this thesis believe that the rest of the industry might be waiting for a big operator like Statoil to make the first move and initiate the first MPD operation from a floater on the NCS. As it is a big operation, involving quite

new technology for many of the involved parties in Norway, the resources of Statoil might be required for the first implementation. The technology, procedures and operational aspects in MPD operations are not well described in the Norwegian standards and the common regulations used in Norway. The operators and eventually the service companies will have to convince and assure the Norwegian government with The Petroleum Safety Authorities (PSA) in front, that MPD procedure and MPD equipment fulfills the requirements of well barriers and well control at all time. With regard to well control, one of the requirements in Norway is that if well control is lost, the control shall be regained by drilling a relief well. With that in mind, one must be aware that this relief well most likely will be drilled from a rig without MPD equipment, meaning that it must be technological possible to drill a conventional well into that prospect. So planning to *drill the undrillable* might not be possible due to well control requirements, but most of the drilling prospects are possible to drill even though it will take longer time and might require more casing/liner strings to reach TD. The process leading up to the first MPD operation from floater here in Norway is depending on collaboration between service companies, operators and the responsible authorities.

Another involved party in the implementation of MPD from floaters in Norway is the drilling contractors, and recently the CEO in Odfjell Drilling, Simen Lieungh, got engaged in the "discussion"<sup>64</sup>. As he said: "The technology is ready, but we lack interaction and willingness to utilize it on floaters". In his comment in the newspaper, he has some good arguments. The technological boundaries have been pushed thru many years and thru continuous collaboration between both national and international operators and service companies, together with the authorities they can still be pushed in the coming years. He says that this is important to be able to drill safer and exploit the hard reserves in mature fields, and MPD from floaters would be this technology enabling this in Norway. To be able to drill 1000 new wells in mature fields, as Petoro, the state controlled licensing owner in Norway, has expressed desire of, and increase the recovery to 60 per cent, as Statoil are aiming for, MPD from floaters could be one of the ways of reaching those targets in the mature, depleted fields.

According to the CEO, the rig industry have been pushing on the operators and service companies to implement MPD technology on floaters, without any noticeable results. He calls for a concrete plan from both the operators and the authorities to start a process of utilizing MPD technology on floaters on the NCS, and he promise that the rig industry will be ready for it. As seen here, different parties are taking interest in this technology also in Norway, but it might seem like there is a lack of will to work together and pull in the same direction. This is often the problem in the oil and gas industry, where you have both several different service companies with their own products and even more operators with their own objectives. So maybe the idea from the CEO of Odfjell Drilling with the authorities taking responsibility and sort of forcing the operators to work together to find a solution is the correct approach towards implementing MPD on floaters in Norway.

The first well drilled in Norway with Managed Pressure Drilling equipment and procedures might not be the undrillable well in the roughest conditions. It could be a "normal" well, a well perfectly good for conventional methods, but drilled using MPD to test and qualify equipment and procedures. To be safer, it could be drilled statically overbalanced during the summer season as the weather conditions are calmer at that time of year. This sort of well will be much safer than drilling a hard prospect, with narrow margins in statically underbalanced conditions during the winter season for instance. An aspect to think about is; you got to learn how to crawl before you can walk.

## 6.3 New Technology

Further development of the existing MPD equipment and methods are not the only thing the future will bring; new ways of drilling and applying MPD principles have been around for some years and there are still coming new technologies which will, as the producers say, be able to precisely control the bottomhole pressures while at the same time offer other benefits that conventional MPD methods cannot do. Below are some of the new technologies existing today presented, technologies with much of the same capabilities as conventional MPD systems.

### 6.3.1 Reelwell

Reelwell Drilling Method (RDM) is a quite new method to perform drilling, the idea was launched 8-9 years ago, which is based on riserless drilling and the use of a concentric (dual) drillstring. The idea behind the concept is to allow for drilling of extremely long wells, Extended Reach Drilling (ERD). Mud is circulated throughout the well in a closed loop, enabling pressure and mud flow to be dynamically controlled from surface and one of the benefits with this concept is its capability to precisely control and manage the bottomhole pressure, ie the same function as the CBHP variation of MPD.

The company have won several awards from OTC (Offshore Technology Conference) for their technology, eg for the actual Reelwell Drilling Method, Reelwell Telemetry System and Drilling Method Riserless.

The dual drillstring consist of a conventional 5" or 6 5/8" drillpipe, with an inner pipe specially designed for RDM. Mud is pumped down the annulus of the concentric drillstring, via a Top Drive Adaptor, passes through the nozzles in the bit and enters the well. Mud and cuttings is brought up outside the conventional BHA before it reaches a Flow Cross Over tool diverting mud and cuttings into the inner pipe, bringing the returns up to surface. Integrated with the Flow Cross Over tool is a Dual Float Valve, much similar to float valves used in conventional drill string except this one blocks both inflow and backflow when circulation stops. In combination with a RCD installed on top of the BOP, this will effectively close in the well and trap well pressure. The return flow coming up to surface through the inner pipe is controlled by a choke manifold adjusting return pressure, ie controlling the ECD. The choke manifold has much of the same function as the manifold system in conventional MPD systems. The setup of the equipment can be seen in Figure 6-4. As seen in the figure, there is no riser from the subsea equipment and up to surface, meaning it is a riserless system. A riser is not required as the cuttings are transported up through the inner pipe. Topside, there is a control system adjusting and measuring backpressure, pump rate and flow rates.

The MPD capabilities of the RDM have these benefits:

- Precise well pressure control enables operations in wells with narrow operational margins
- Pressure variations during pump start and stop is prevented through improved ECD control
- Significantly reduced drilling mud volume making influx and losses much easier to detect

These benefits listed here are the same as in conventional MPD operations, only the path leading there differentiates them. Compared to conventional MPD, and for that sake also UBD, operations, there is no pressurized equipment on surface, increasing safety for the rig crew. As there is a riserless system, the need for applying pressure in the riser is eliminated as all return and backpressure is contained inside the concentric drillstring. Eliminating the riser open up new markets for drilling rigs

in deepwater environment. Currently, only the huge 5<sup>th</sup> and 6<sup>th</sup> generation drilling rigs can be used in deepwater, due to the demands of handling the weight and tensioning of several thousand meters of riser. But eliminating the riser makes it possible to use smaller and much cheaper 3<sup>rd</sup> and 4<sup>th</sup> generation rigs in these environments. Looking at the rig market and not at least the rates of the big rigs, this is a huge benefit of the RDM riserless drilling.

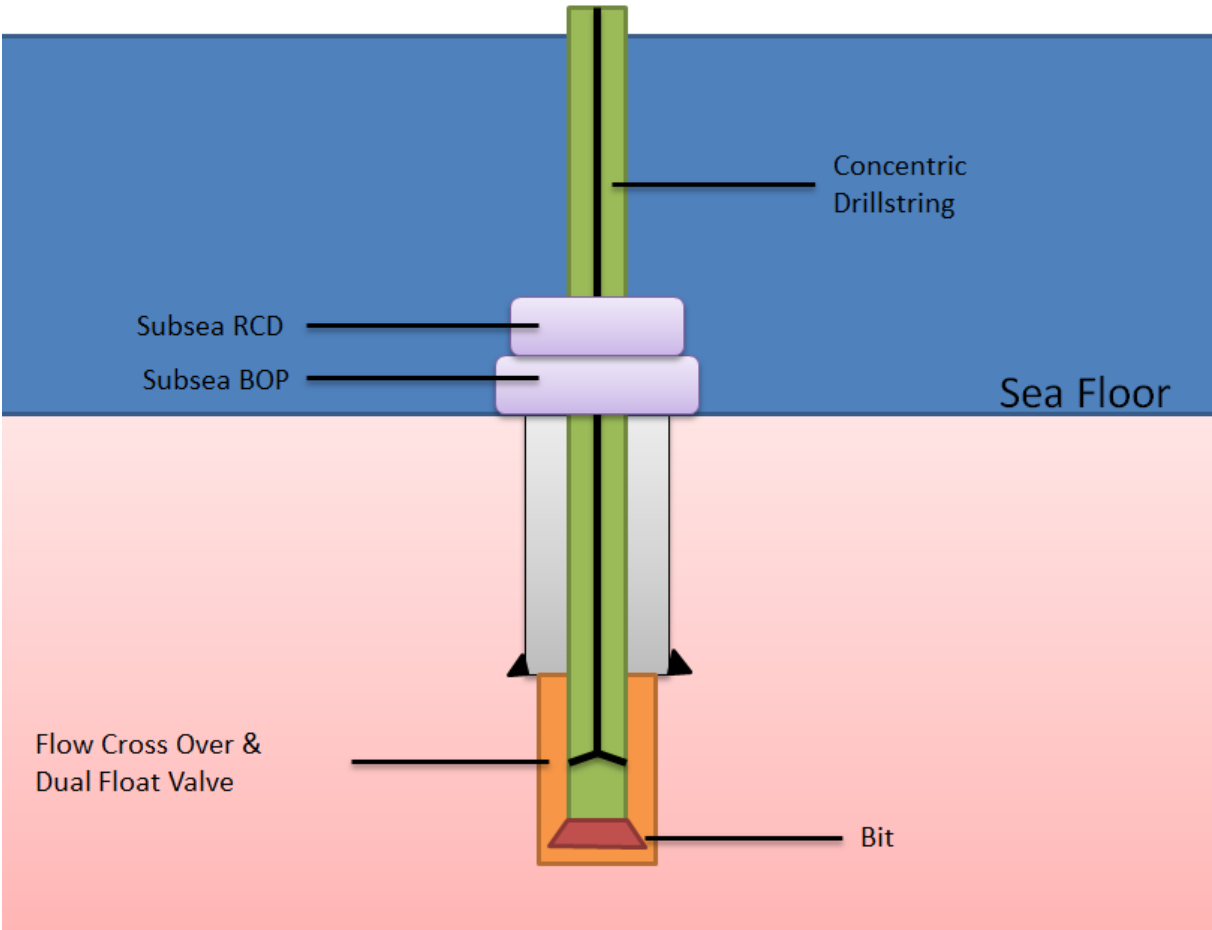


Figure 6-4 The basic setup of the RDM, describing everything below sea level

As ERD is one of the main drivers of the development of this technology, MPD capabilities are important to reach far out. Limitations for conventional drilling are about 10km horizontally out from the rig, while RDM will enable drilling up to 20km horizontally out of the rig. Well pressure must be kept between pore and fracture pressure along the whole horizontal length of the well, so precise pressure control is required. In conventional drilling, and in conventional MPD for that sake, ECD in the open hole section can limit the horizontal reach of the well. With RDM, the return flow is going up the inner pipe, and not up the wellbore annulus. This means that the pressure gradient in the horizontal part of the well will be static, as there will be no frictional pressure added to the pressure exerted on the wellbore wall. The high ECD due to annular friction pressure will be eliminated, and the pressure will not breach the fracture limitations. This is illustrated in Figure 6-5, where one can

see how horizontal reach of conventional drilling and conventional MPD is limited by the increasing dynamic pressure gradient present in the open hole section.

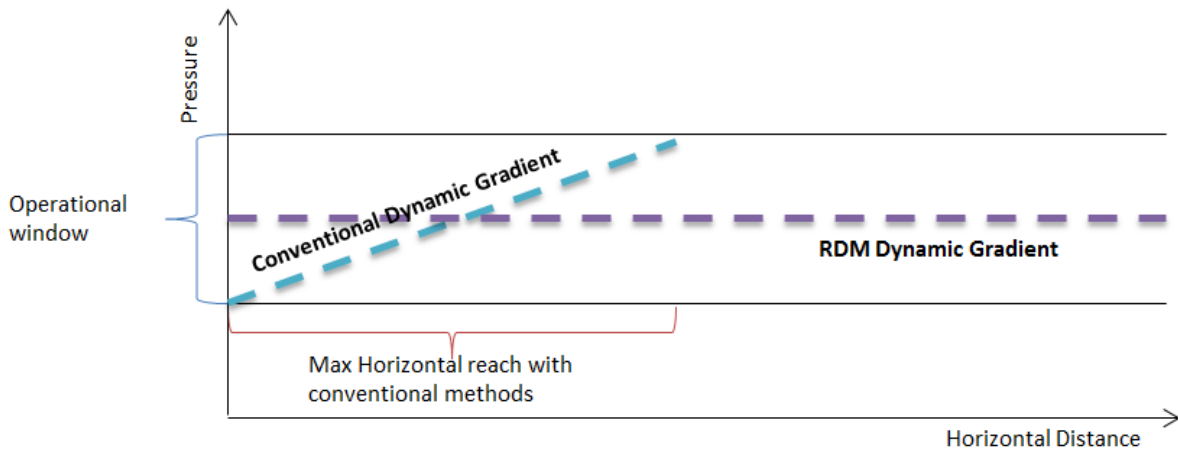


Figure 6-5 Illustration of the horizontal reach of RDM compared to conventional methods

Being able to drill long wells from one location can be more economical and also open up new areas for petroleum exploration. Instead of having several installations on a field, all the wells can be drilled from one location, decreasing building costs. And being able to drill extremely long wells makes it possible to drill in environmentally vulnerable areas from land rigs, not having to use an offshore vessel with its related risk of oil spills in marine environments. The company is involved in several ongoing projects with different operators to test the technology and further develop it. Together with BG Group and Petrobras, they are working on a project where the aim is to drill without a marine riser in water depth of 2000 meters outside Brazil with a 3<sup>rd</sup> generation drilling rig. In Saudi-Arabia, they are involved with the national state company Saudi Aramco in a huge drilling campaign. The last big project they are involved with are in Germany with the companies Total, Petrobras and RWE to drill 20km wells to offshore targets from an onshore location. Due to environmental concerns and UNESCO protected area, no offshore activity is allowed, so RDM might be the only solution for establishing petroleum activity in the area<sup>65</sup>.

This is a quite new technology, and the experience in field is limited up to date. There has been some field trials with good results, and the simulations are very promising, but there might still be a couple of years until this technology has matured enough, and eventually be commonly used from floating drilling units. An advantage with this system, compared to conventional MPD systems for floaters, is that it does not require any modifications to the upper marine riser assembly, as it is riserless technology. Due to this benefit, both time and money is saved in the planning phase. The project Reelwell is involved in with BG Group and Petrobras in Brazil with riserless deepwater drilling could open up new markets for this technology in the future enabling drilling of deepwater wells using older, cheaper rigs like 3<sup>rd</sup> generation drilling rigs. The availability of these rigs is higher, which again could lead to more wells being drilled in deeper water depths at a reduced cost. This type of riserless drilling could then potentially be a game changer in deepwater environments.

### 6.3.2 EC-Drill by AGR

Even though it's a DG method, it is worth mentioning due to its intended use in both deep and shallow water, with full MPD capabilities and enabling the operators to "drill the undrillable well", according to the manufacturer<sup>66</sup>.

EC-drill is a new concept developed by AGR<sup>67</sup>, which includes a subsea pump module mounted via a special riser joint on the marine riser at a predetermined height, see Figure 6-6. The system is initially designed for deepwater applications, but could as well be used for shallower water depths. In addition to floating units, it is also intended to be used on jack-ups if required. The principle of the system is that the riser-mounted pump allows for adjustment of mud level in the riser, while bringing the returns up to the rig via a flexible return line to surface. When the system is in use the top of the riser is filled with air, so the riser becomes a dual-gradient system. Adjusting the mud level in the riser affects the bottomhole pressure since it lowers the hydrostatic pressure and affects the frictional pressure drop in annulus. The level of mud inside the riser is adjusted continuously through the subsea pump controlled by an automatic control system utilizing advanced data acquisition from PWD-tools, sensors and the control system.

The system promise to be able to maintain a near constant BHP through the use of a Dynamic Mud Level Control system, enabling drilling in depleted reservoirs and narrow operational windows, precise pressure control aiding in HPHT drilling and a good flexibility to switch to conventional drilling and vice versa at any time if necessary. Experience from the first wells drilled is that the system is good for adjusting and increasing ROP<sup>68</sup>, where ROP increases when mud level in riser is reduced. Much of the same good early kick/loss detection as conventional MPD systems can provide is also promised in this system, which is good for reducing NPT. The safety aspects and operational limitations are maintained by allowing for the use of riser margin by using heavier mud than possible in conventional MPD operations. An advantage with this system is that the top riser components; telescopic joint, tensioner system etc., doesn't need to be modified, unlike the RCD based systems. As a result, the weather capabilities of the rig is maintained, and the operations are not limited by heave motions, except from surge and swab during eg connections which all operations from floaters to some degree struggle with.

As this is a relatively new system, the field experience gained so far is limited. Wells have been drilled outside Cuba<sup>67</sup>, in deep water, and from a fixed platform in Caspian Sea<sup>34</sup>, so the overall experience is limited, but there are joint-industry projects taking place now which intent is to take the technology further. The operations performed up to date with this system has been with specially designed equipment for the specific rig used in the operation, and so far there are no standardized equipment which is plug-and-play on any rig. So it will probably still be a couple of years before this system is ready to be implemented on any rig, at any location. Comparing this system to conventional MPD systems currently in use and being used for 6-7 years already, there are uncertainties with EC-Drill as it does not have any long track record to refer to and new equipment and systems might not be as reliable as the systems been in use for several years. But in some years, it could be a realistic alternative to conventional MPD systems, at least in deeper waters.



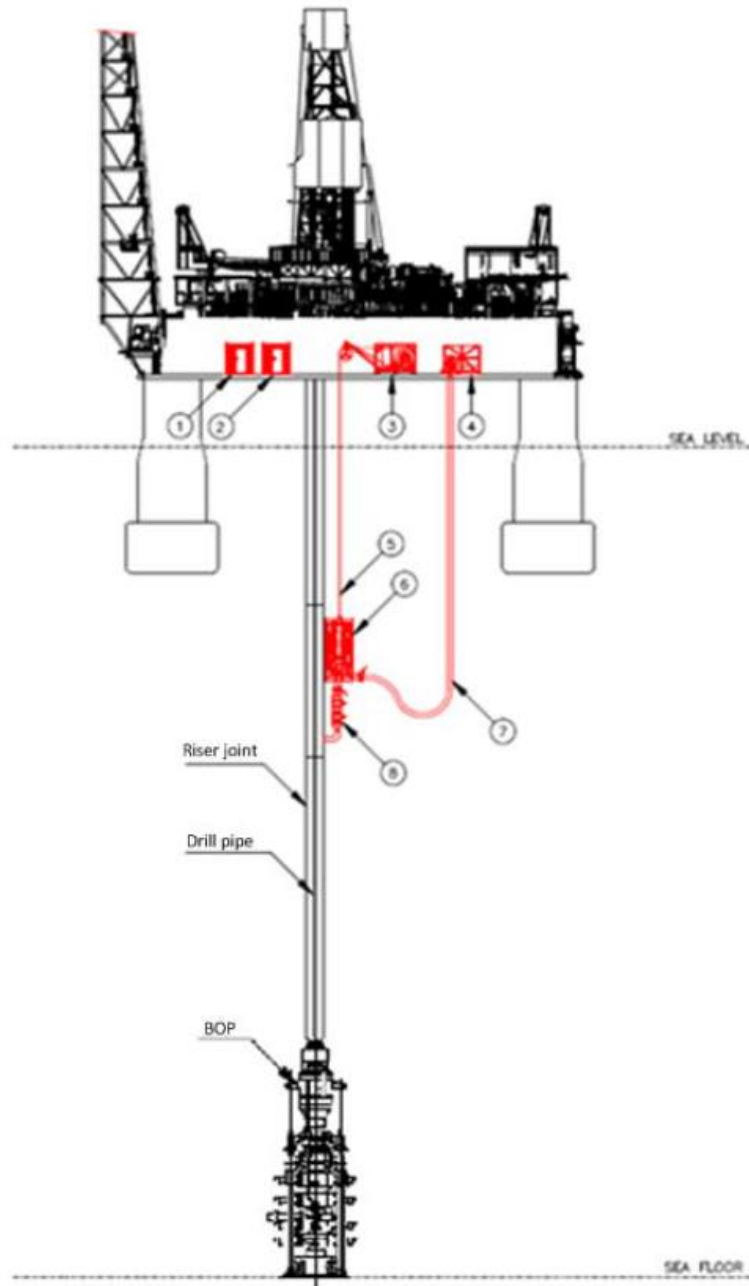


Figure 6-6 EC-Drill system with the mud pump mounted on the marine riser<sup>68</sup>

## 6.4 Discussion

Looking at what is described in this chapter, it is clear that there is a lot of activity going on in the industry these days, with new operators starting to utilize MPD, rig owners starting to embrace MPD and new variations of MPD technology are coming. The future of MPD from floaters looks bright, with many involved parties taking interest in bringing the technology into the future both by using existing technology and principles and by enhancing and developing new equipment and methods.

## 7 Case Study BG Group

Due to positive experiences with MPD from fixed installations, BG Group is involved in planning of future MPD operations from floaters, both operations operated by themselves and partner operated fields.

Important criteria for BG Group when choosing MPD for drilling a well are:

- Operational window (PP/FP)
- Geology
- HPHT
- Offset well experience
- Economy

To evaluate BG Groups future use of MPD technology from floaters, the Roxy Well in Block 63/16 in China has been chosen. The information presented here is based on internal planning material and documents, and discussions with Lead Well Engineer, Developments & Operations, Marco Meirich in BG Group

The location in the South China Sea is seen in Figure 7-1, is BG Group operated block 63/16, in water depth of 100-180m with multiple gas prospects and leads. The geothermal gradient in the area is considered high with a gradient of  $4.1^{\circ}\text{C}/100\text{m}$  assuming a seabed temperature of  $5^{\circ}\text{C}$ . Several wells have been drilled in the neighboring blocks, so offset well data from wells penetrating the same formation targets are available. Based on the classification of the offset wells from the same area, most of them are either high, or extreme pressure wells, or some even extreme pressure-ultra temperature wells. The prospects found in block 63/16 are almost certainly HPHT, might even be extreme, and the well will be planned as a HPHT-well to be drilled with MPD.

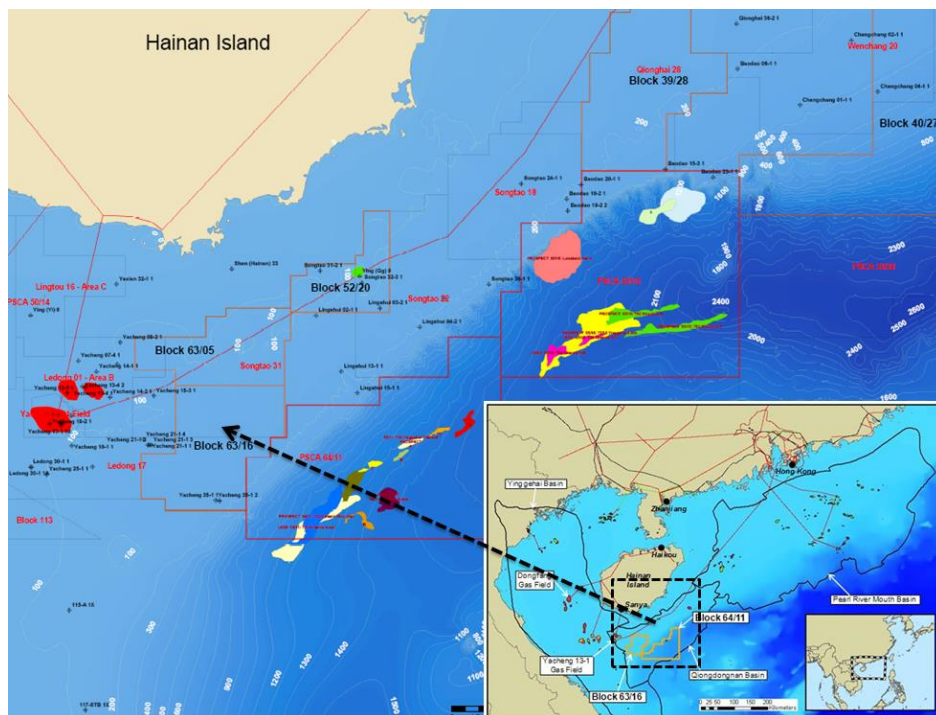


Figure 7-1 Location of the Roxy well in the South China Sea

Experience from the offset wells is that they have spent very long time to reach target because of challenging drilling conditions causing a low ROP. None of the previously drilled wells in the area have been drilled with MPD. The best offset wells to compare with are listed below:

- 21-1-1: Did not reach targets, entered HPHT zone and P&A'ed due to well control issues.
- 21-1-2: Reached targets, however could not manage the well control events (gains/losses) and it was decided to P&A the well.
- 21-1-4: Reached both targets, but faced gain/losses in 8 ½" hole section and had to P&A'ed.

BG Group has identified some targets, and the most interesting is named Roxy and is classified as a HPHT target. This well is planned to be spudded late-2014, and the preplanning and engineering work is currently running.

**Table 1 Well info Roxy 63/16 China**

Planned total depth	5,250mMD with 18.5ppg PP below 4,550mMD
Water depth	137m
Max reservoir pressure	14,263psi @ 4,500mTVD
Max expected surface pressure @ 4,500mTVD	12,787psi (with 0.1psi/ft dry gas)
H <sub>2</sub> S	No

The well is to be drilled with an anchored semi-submersible rig with MPD and continuous circulation technology for the reservoir section categorized as HPHT.

### **7.1 Why choose MPD for this well?**

Based on the experience gained from other operators on offset wells, and the internal reviews of the prospect, MPD seem to be the best option to be able to drill the well safely, on time and at a reasonable cost. It has proven to be very challenging to drill with conventional methods due to the rapid, huge increase in pore pressure in the interesting area of the prospect. And problematic seismic images have not helped establish a clear picture of the downhole conditions, so the boundaries and pressure distribution between the formation layers are uncertain. Based on these facts, MPD is a clear choice due to its capabilities to assess and determine boundaries during the operations. Pore pressure can be determined when influxes are detected or by lowering MW and backpressure until influx is detected. Dynamic FIT and LOT can be performed to determine the upper boundaries of the formations being drilled through. This will help to be able to navigate through the uncertain formations and be able to set the casings as deep as possible and at the correct place.

One aspect BG is definitively certain about is that the prospect is high pressure and high temperature. With good experience of using MPD to drill HPHT wells from jack-ups, BG looks at MPD as a safety feature in HPHT operations. Detecting influxes are often hard in HPHT wells as influxes often dissolves in oil based drilling mud, influxes can be misinterpreted as temperature effects on the mud and influxes can be thought to be ballooning effects. Proper planning and modeling of temperature effects and surge and swab effect in the operation, in combination with the capabilities of a MPD system to measure flow in and flow out of the well to determine what is actual influxes down to a size of ¼ of a barrel are extremely valuable in a HPHT operation. It can enable the operator to take the correct action towards any event, both safer and more time efficient. So having the capability to assess and determine the formation conditions as the operation proceeds and the

capability of early kick detection are the main reasons for choosing the MPD approach to drill this well. Continuous circulation equipment is thought to be used on this project, based on previous experience with this method in BG and the good track record for this system, enabling a continuous feed of bottomhole data and circulation of mud to avoid degeneration of the mud.

## 7.2 Formation Conditions

The pore and fracture predictions that exist today are presented in Figure 7-2 and they are based on data from offset wells. The planned MW presented in the plot is based on predicted geological model and MW used in relevant offset wells. As off today the planning of the well, ie casing design and mud weights are done according to these predictions. But there are uncertainties in these predictions, uncertainties that must be sorted out before proceeding to the final well design. The main challenge is to identify the correct lithology around 4400-4500m, where it seems to be a tight seal capping the high pressure below, even though the reflection of the 2D seismic is poor. It is important to identify the thickness and quality of this sealing formation to be able to set the 9 7/8" casing in it and have good integrity before drilling into the high pressure zone below. The operational margins of the formations are quite good down to the HPHT zone starting at approximately 4450m, where the margins are approximately 1.0 ppg (0.12sg), making operations much harder. Subsurface personnel are currently working on processing 3D seismic to get a better understanding of the subsurface conditions.

### Roxy-1, China, wellbore stability predictions

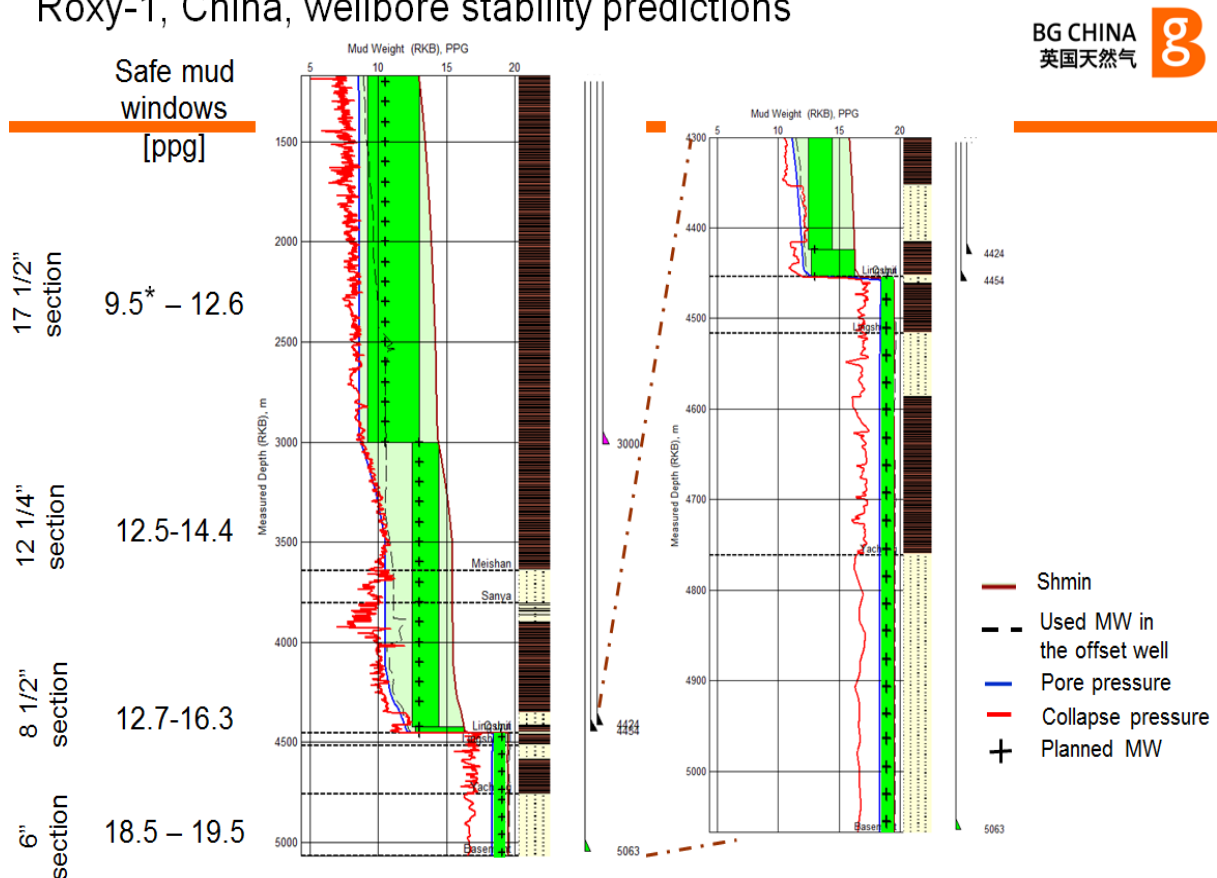


Figure 7-2 Wellbore stability predictions. Courtesy of BG Group

### 7.3 Well Design

The sections described in Figure 7-2, are for one of the offset wells, where the 8 ½" section had to be aborted, a casing set and continued to TD with a 6" hole.

The base case well design for the Roxy well is; 36" X 20" X 13 3/8"x13 5/8" X 9 7/8"x10 ¾", ie drilling to TD with an 8 ½" bit after setting the 9 7/8" casing as close to the high pressure reservoir zone as possible. The contingency well design is much the same as for the offset well; 36" X 20" X 13 3/8"x13 5/8" X 9 7/8"x10 ¾" X 7 5/8", ie drilling to TD with a 6" hole. The contingency plan is for the case if it is not possible to drill and set the 9 7/8" casing in the difficult formation layer at 4400-450m. The 9 7/8" casing will then have to be set prior to entering the uncertain layers, then drill through it with a 8 ½" bit, set a 7 5/8" liner before drilling through the last high pressure zone with a 6" bit down to TD.

MPD is planned to be used from the 12 ¼" section and down to TD, and BG is hoping that MPD will help them drill through the uncertain layers and being able to stick to the base case well design plan. However, if they are forced to change to the contingency plan, it will not be a huge loss. As the well is not going to be tested, just run a full LWD, wireline logging program and conventional coring without any well testing, the requirements to having a big hole size is not present, so a 6" hole to TD is enough. The well is not planned to be used later, for any eventual development purposes, so it will be plugged and abandoned after the planned data evaluation.

Regarding mud weight design, at least the 12 ¼" section is planned to be drilled in statically overbalanced conditions, as the margins there allows it. But in the 8 ½" section, the margins are narrower and statically underbalanced conditions might be chosen, but it depends on the evaluations by the subsurface crews. As it is a floater, a riser margin is common to include in the MW calculations, and for this well, as the water depth is shallow riser margin will be applied at least for the 12 ¼" section where the margins are good. In case any losses occur, the riser margin will have to be reconsidered. The last section will have to be evaluated later if it is possible to apply a riser margin as the operational window is narrower. If riser margin is not possible to maintain, an exemption can be applied for making it possible to continue operation without riser margin.

In case the unwanted, an uncontrolled blowout would occur, drilling a relief well is possible with any conventional rig available. As there have been drilled several wells in the area previously without MPD, it is proven that it is possible to drill a well with conventional methods too. The availability of floaters with MPD capability is limited, so having the opportunity to drill relief wells conventionally is an advantage.

### 7.4 Discussion

This prospect is a typical prospect well suited for MPD operation from a floater when you look at the status and the maturity of the technology today. According to Don Hannegan in Weatherford, this is a typical MPD candidate as it follows the principle of: "wells where offsets have experienced the types of drilling-related nonproductive time, mud loss excesses and/or well control scenarios that MPD has proven to be capable of addressing safely and effectively"<sup>45</sup>.

The prospect is drillable with conventional methods, it's not *undrillable*, however MPD is chosen based on its capabilities as a safety feature with early kick detection in HPHT environment and due to the uncertain formation conditions which the MPD system can help identify. These capabilities will also help keep the operation on time, reducing NPT and most likely reduce the operational expenditures seen in other wells drilled in the same area.

The area of the prospect is not defined as harsh environments, neither deepwater nor rough weather conditions; so much of the operational aspects and procedures from conventional operations can be maintained. That means one can have a riser margin throughout much of the operations and the heave conditions are quite calm so operational limitations would not be exceeded and the standard equipment on the market can be used, equipment that is already been tested and proved to work in similar conditions. According to the information and data existing today, this seems like a good prospect to use MPD and planned and executed correctly it would most likely be a successful operation.

## **8 Conclusion**

The main challenges for MPD from floaters are to mitigate and compensate for the temperature effect on the fluid properties caused by high formation temperatures and often long riser sections in low seawater temperature, which affects the density of the fluid and thus the effective bottomhole pressure. In addition, in rough weather conditions surge and swab effects often require an automatic control system capable of predicting and handling these effects. Regarding riser margin, this is challenging with the existing technology and equipment, and will have to be evaluated individually for each project.

These specific challenges for MPD from floaters should be included and analyzed when evaluating such a MPD operation. However, the proven benefits of performing MPD enabling more secure pressure control during the drilling operation and earlier detection of influx and losses suggests that MPD from floaters should be evaluated with these risk reduction properties in mind. The risks for bad weather conditions and possibilities of riser disconnect should also be included in such a risk analysis.

The status as of today is that MPD is in use on floaters and the existing technology is also ready to be implemented in many new geological regions right now and in the forthcoming years. Further improvement and development of this technology could open up new regions for MPD in the near future, even in rougher weather conditions.

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