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Managed Pressure Drilling

The Solaris Prospect - HPHT Exploration well

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Summary

Managed Pressure Drilling is a drilling technique that evolves continuously. Complex drilling problems such as narrow mud-weight windows (narrow pressure margins), severe losses and deep water effects can be significantly reduced. The objectives of the MPD technology are to mitigate certain drilling challenges. Although this drilling technique has been proven to be efficient for several fields, proper candidate selection is essential. It is important to understand what MPD can accomplish as the technique do have associated risks that needs to be fully understood. Improper use of the technology leads to higher operational costs and possibly worsening of drilling issues.

Total E&P Norway is planning to drill an ultra HPHT well (Solaris) in 2015 located in the Central Graben area, an area with several drilling challenges such as narrow pressure margins, uncertainties, high temperature and high pressure. The Solaris well is a challenging well with many similarities to the Mandarin well drilled by BG. The objective is to securely drill through a narrow mud-weight window to the target depth. The goal of this Master Thesis is to define MPD risks and benefits and summarize all findings for the Solaris exploration well. A literature survey on MPD experience with focus on HPHT wells with narrow mud-weight window similar to the Solaris well will be performed, an MPD system is proposed for the Solaris well and risks and benefits of using an MPD system has been closely examined.

Based on current available information, literature review and simulation performed (comparing conventional drilling to MPD) it is likely that MPD is the better solution for the Solaris well. The well faces challenges such as a narrow mud-weight window and wellbore breathing issues, challenges that can be mitigated with MPD technology. As MPD do provide better control of the BHP pressure fluctuations are reduced. Target depth is more likely to be reached as the narrow pressure margins are drilled in a more controlled manner. Conventional drilling is possible for the Solaris well, however as uncertainty is present MPD do provide far better remedies and thereby increases the chance of reaching the target depth.

Further evaluation should be done before deciding whether to use MPD or not. Complex and detailed simulations are one solution, trying to reduce the uncertainty level.

Table of Contents

- 1 Introduction1
- 2 Managed Pressure Drilling (MPD)3
 - 2.1 Short history of the MPD development4
 - 2.2 Benefits of MPD.....6
 - 2.3 General MPD set-up and Equipment.....8
 - 2.3.1 PCD versus RCD9
 - 2.4 Different Managed Pressure Drilling Techniques.....13
 - 2.4.1 Constant Bottom Hole Pressure (CBHP)14
 - 2.4.2 Mud Cap Drilling (MCD).....16
 - 2.4.3 Dual Gradient Drilling (DGD)18
 - 2.4.4 Return Flow Control Drilling (RFCD) or HSE Method20
- 3 Weatherford’s MPD system21
 - 3.1 The Weatherford MPD circulation system27
- 4 Previous offshore MPD experience in the North Sea33
 - 4.1 The Mandarin East Well MPD experience33
 - 4.2 The Franklin-Elgin Field MPD experience36
 - 4.3 The Kvitebjørn Field MPD Experience40
- 5 The Solaris Well42
- 6 A Way to determine the applicability of MPD - Drillbench Simulation: Presmod47
 - 6.1 Input parameters.....48
 - 6.2 Results58
 - 6.2.1 Conventional Drilling Simulation58
 - 6.2.2 Managed Pressure Drilling Simulation61
- 7 Discussion.....64
- 8 Conclusion68
- Nomenclature70
- References.....73
- Appendix A – Figures.....78
- Appendix B – Tables80
- Appendix C – UBD vs MPD81
- Appendix D - Present DGD Technologies83
- Appendix E – MPD Tools84

| | |
|---|-----|
| Rotating Control Device (RCD) | 84 |
| RCD – Passive Systems | 85 |
| Rotating Annular Preventers – Active Systems | 86 |
| Rotating Control Devices on Risers | 87 |
| Chokes | 87 |
| Choke Gate – Power Choke SC Model..... | 87 |
| Sliding Plates – Swaco Super Choke | 87 |
| Shuttles – Swaco Auto Super Choke..... | 88 |
| Non-Return Valves | 89 |
| Basic Piston-type float..... | 89 |
| Hydrostatic Control Valve (HCV) | 90 |
| Inside BOP: Pump-Down Check Valve | 90 |
| Retrievable NRV or Check Valve..... | 91 |
| Down-Hole Annular Valves..... | 91 |
| Casing isolation valve (CIV)..... | 91 |
| Drilling Down-Hole Deployment Valve (DDV) | 92 |
| Quick Trip Valve (QTV) | 93 |
| ECD Reduction Tool | 93 |
| Disc (Friction) Pump | 93 |
| Coriolis Flow meter | 94 |
| Continuous Circulating System (CCS) | 94 |
| Appendix F – Further HPHT Considerations | 95 |
| HPHT Drilling Challenges | 96 |
| HPHT Cementing Challenges | 98 |
| HPHT Completion Challenges..... | 99 |
| Appendix G – Estimation of the Pressure Profile | 100 |
| Appendix H – Weighting agents | 101 |
| Appendix I – Heavy-Duty Jack-Up rig Maersk Gallant | 103 |
| Appendix J - Maersk Gallant potential MPD rig-up schematic..... | 108 |

1 Introduction

Drilling operations have always been challenging, wells are getting deeper, temperature and pressures are getting higher, and the industry is starting to focus on more remote and complex reservoirs such as in the arctic regions. Proper procedures for remedial actions are essential to keep drilling risks controlled and minimized. Managed Pressure Drilling (MPD) is a drilling process that enables accurate control of the wellbore pressure faster than by conventional methods. Pressure variations can thereby be reduced, influx and losses handled at an early stage thereby reducing the subsequent challenges, and wellbore stability can be improved. MPD allows for drilling into narrow pressure margins in a safer and more cost effective manner while mitigating drilling hazards and thereby reducing Non-Productive Time (NPT). MPD can be used for specific purposes such as drilling into depleted reservoirs, narrow Mud-Weight (MW) windows or into sections with massive losses where other drilling methods are inadequate. MPD is a drilling technique that helps make the otherwise un-drillable wells become drillable.

The MPD technology is still considered to be a relatively new technology, and is met with scepticism on several fronts. Despite this scepticism, the MPD technology is used more frequent for each day that passes. Whether this is due to the growing confidence and the following track record for this technology, or due to lack of other solutions is difficult to determine. However, the MPD technology is in continuous development.

Some of the challenges for this technology have been drilling from floaters and drilling of long wells. As of today both of these challenges has been more or less overcome, or can at least be said to have probable solutions (some proven successful). However, research is continuously performed on how to obtain safe and reliable pressure control when drilling from floaters or in Extended Reach Wells (ERD). The new ERD technology from ReelWell certainly opens for MPD possibilities for long wells. Other predominant focuses has been on developing MPD technology to be applicable for drilling in HPHT environments, which has been successfully accomplished in several fields all over the world. A lot of the MPD research today focuses on managing the pressure fluctuations when drilling in MPD mode. By reducing these pressure fluctuations, the MPD technology may reach new heights allowing even more troublesome targets to be reached.

Drilling in the North Sea is getting more challenging as many of the remaining reservoir targets are located in deeper environments with harsher conditions. As reservoirs keep getting deeper, pressure and temperatures keep getting higher. The MW windows get narrower, and may even completely

disappear in severely depleted reservoirs such as in the Franklin-Elgin field where depletion levels exceeded 600 bars.

Total E&P Norway is planning to drill a well called Solaris in 2015. This well is located in the Central Graben area in vicinity of the Mandarin East well. The aim is to use previous MPD field experience on offset MPD wells in the area to determine whether MPD is a plausible and preferable solution for the Solaris well. The Solaris well is predicted to be quite similar to the Mandarin well, which in few words means narrow pressure margins and ultra HPHT conditions. To determine whether MPD is a solution for the Solaris well the MPD technology, its benefits and challenges will be closely examined. Case studies on previous MPD field experience will be summarized, a specific MPD system provided by a leading MPD supplier will be presented and a simulation to examine whether MPD is even necessary to reach the target.

2 Managed Pressure Drilling (MPD)

MPD is defined by a subcommittee of the International Association of Drilling Contractors (IADC) as “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. The intention of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.”

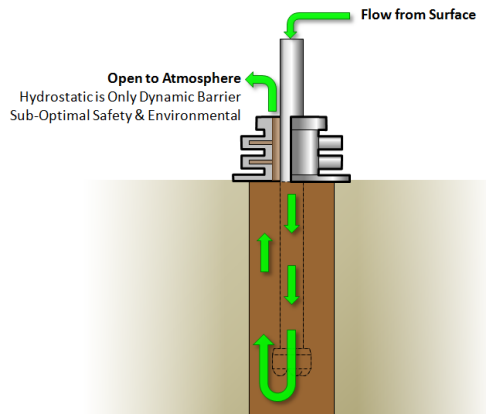


Figure 2: The conventional circulation loop: return flow open to atmosphere (Weatherford 2013)

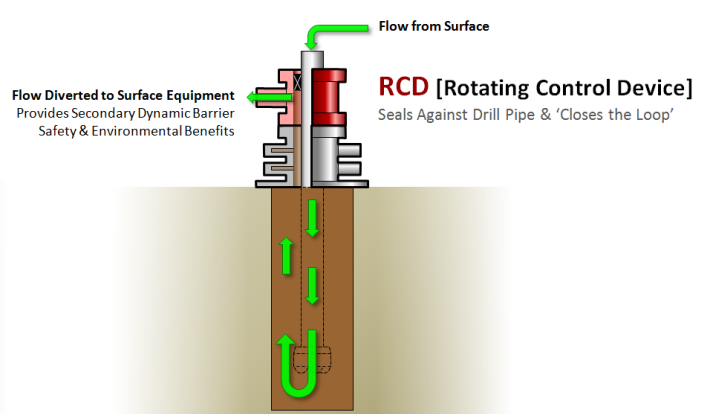


Figure 1: Closed loop circulation: the MPD and UBD approach (Weatherford 2013)

For a well open to atmosphere (conventional drilling) the BHP can be estimated as

$$BHP = MW + friction \quad \text{Eq. 1}$$

For a closed loop system, like for MPD and UBD, the return flow is diverted to surface equipment.

The BHP can then be estimated to

$$BHP = MW + friction + \textit{backpressure} \quad \text{Eq. 2}$$

In general, MPD is designed to mitigate various drilling problems and accessing reservoirs with complex pressure profiles. The intent is not to manage a continuous influx.

As reservoirs are depleted, the drilling window is significantly reduced, and can in extreme cases become negative. By closing the annulus and applying back pressure static mud weight can be reduced, even below the pore pressure. Overbalance is obtained by applying the ECD and dynamic back-pressure (Eck-Olsen, et al. 2012). Cuttings transport, prevention of influx and losses together

with keeping the drill string free are the primary tasks all throughout the life of the reservoir. As the reservoir is depleted these tasks gets more difficult to accomplish. Depletion level for a reservoir is difficult to predict. Designer mud can be used to strengthen the formation weakened by depletion. Additionally, particles can be added to create an effective filter cake preventing pressure communication and strengthening the borehole wall.

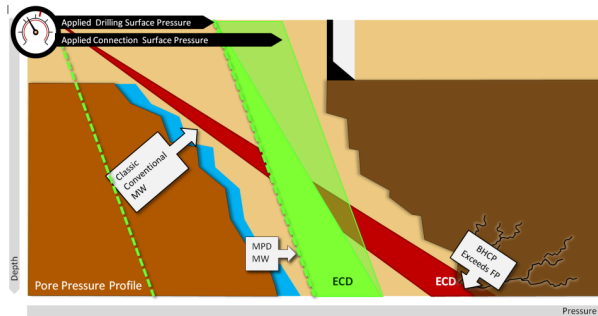


Figure 4: Conventional drilling - the addition of ECD causes the MW to exceed the wells fracture pressure (Weatherford 2013)

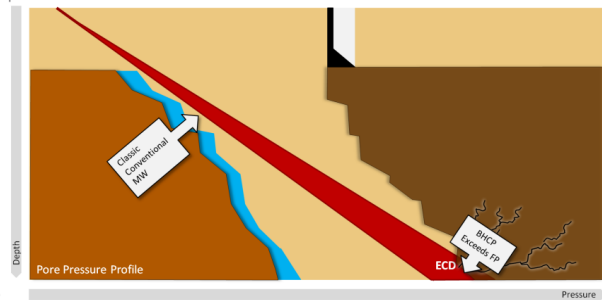


Figure 3: With MPD BHP can be manipulated by adding a surface back-pressure to make a conventional un-drillable well drillable (Weatherford 2013)

Further, IADC also separates MPD into two categories: Reactive and Proactive. The reactive MPD refers to having additional equipment rigged up on the conventional design to quickly react to unexpected pressure changes, whereas proactive MPD is designed to actively alter the annular pressure profile (Eck-Olsen, et al. 2012). This proactive, or “walk the line”, category provides the greatest benefit for both onshore and offshore operations, but it requires more thorough planning (Tercan 2010). The reactive category has been used on difficult wells for years, but as technology improves so does the use of the proactive technology.

2.1 Short history of the MPD development

Early in the 1800's spring pole drilling rig were utilized, but as the wells deepened pressure control became a problem as the wells were drilled with no pressure control. In the early stages the aim was to drill for salt, but as demand for kerosene and oil lamps evolved the focus became more on the oil itself. In the late 19th century, as internal combustion engines were made available, the demand for petroleum increased rapidly. In the late 1800's, early 1900's, things changed and modern era wells with some pressure control emerged. The use of rigs like the Spindle top helped guide the hydrocarbons up towards the surface creating environmental and safety challenges. Land owners and farmers protested as livestock and people died from the aftermath of the hydrocarbon spill. The industry now turned their focus to the use of weighted drilling fluids, developing overbalanced drilling.

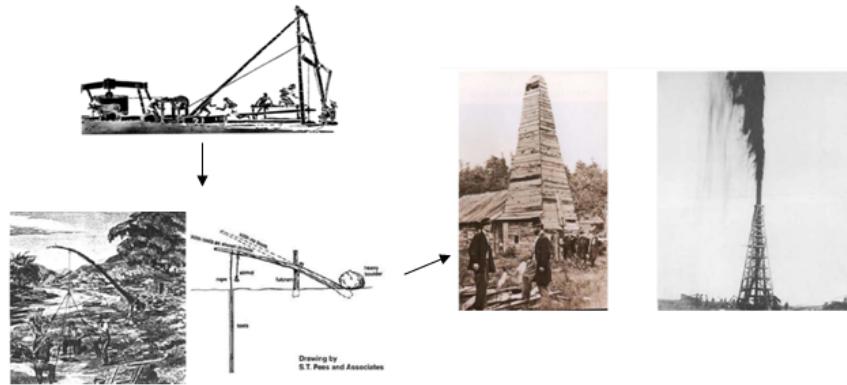


Figure 5: Development of drilling methods over the years (Eck-Olsen, et al. 2012). In the left upward corner the Chinese drilling process are shown. Below, the 1800's Spring pole drilling rig can be seen and on the rightmost side the new era wells are shown (from left to right): Drake Well (1859) and Spindle top Wells(1901).

The history of Managed Pressure drilling started decades ago. Three Abnormal Pressure symposiums (looking at the origin, extent and how to predict pressure profiles from available data) were formally introduced at Louisiana State University between the years of 1967 to 1972. These laid the foundation for many of the ideas for the technology known today as Managed Pressure Drilling (MPD). From the 1970's Equivalent Circulating Density (ECD) was used in well control practices. A major oil company in New Orleans also drilled with more or less continuous kicks to avoid lost returns and to increase drilling rate. During the 1970's to 1980's, horizontal drilling was accepted in the industry. "Drilling dry" or "drilling without returns", today referred to as Mud Cap Drilling (MCD), was common for years. In Venezuela 1980's, at the Hibernia field off Nova Scotia 1990's and later in Kazakhstan a more formalized version of MCD were tried. The drilling of thousands of high-pressure gas wells with total lost returns in Austin, Texas, in the 1990's led to the development of pressurized MCD (Eck-Olsen, et al. 2012). It was not until 2003 this technology was fully appreciated by the offshore industry (Tercan 2010).

As of today there is a few different focus areas when it comes to MPD systems. Some MPD systems focus on early kick detection (i.e. flow detection) while other focuses on pressure and correlation to the PWD. All MPD systems has both of these, the main difference is what they excel in. MPD is a new technology that continuously evolves. Research of how to reduce pressure variations during an MPD operation is on-going (SINTEF, IRIS). This research focuses on the currently un-drillable and how to make these targets drillable.

2.2 Benefits of MPD

MPD is normally a closed and pressurized circulating system, which facilitates precise management of wellbore pressure profile. In an open system the drilling fluids piping are open to atmospheric pressure, whilst for a closed system drilling fluids flow under pressure. The main benefit by utilizing MPD is the ability to control the pressure dynamically by manipulating the back pressure instead of the mud weight. This optimizes the drilling process by reducing the NPT, mitigating drilling hazards and enabling drilling in more complex areas. Adjustment of the choke enables a rapid change of BHP (in the manner of minutes compared to hours which is needed for conventional MW change), and thereby provides a safer way to control influxes and their subsequent bleed downs. Well control is maintained by using independent well barriers. For a typical MPD system the primary barrier will be a rotating BOP whereas the secondary barrier will be the BOP. Comparing this to conventional techniques where drilling fluid is used as primary barrier and BOP as secondary barrier, MPD is in general a more secure way of drilling in certain environments.

The aim of MPD is to drill as close the pore pressure as possible and thereby reduce the dynamic overbalance. A reduction in dynamic overbalance often help to increase the ROP, decrease surge and swab effects, reduce influx, and enhance well control (kicks, lost circulation). Lowering dynamic overbalance reduces the differential pressure in the well. As differential pressure is lowered, the force needed to break/cut rock is lowered increasing ROP. However, it is very important not to underestimate the significance of sufficient hole cleaning. Circulation rate is often lowered to reduce friction in the well. The combination of an increased ROP and reduced circulation rate may result in problems such as peak-off in the annulus, high torque and drag, and even worse stuck pipe, twists off and so on (Naduri, Medley and Schubert 2009).

Drilling hazards such as lost circulation, wellbore instability, kicks and differential sticking are issues that can often be mitigated by using MPD technology, leading to significant reduction in operational costs. MPD technology provides significantly improved flow measurements. The most common flow measurement device in today's market is the Coriolis flow meter. This device has a very high accuracy and provides early kick detection. As influxes are detected early they can be controlled at an early stage, opening for the possibility to safely control these volumes through the MPD system. As influxes can be handled without shutting in the well casing setting depths are often extended. Overall drilling with an MPD system can lead to significant cost savings and safety improvements in certain wells.

Ballooning, or wellbore breathing, is also a common problem when drilling, especially for an HPHT well. Parameters are steady as long as the drilling is on-going, but as soon as pumps are turned off

downhole pressure decrease (friction loss) and formation fluid “returns” into the well increasing the pit level. During drilling fluids are forced into the formation by the downhole pressure, but as soon as the downhole pressure decreased, fluids returns back into the well; causing wellbore breathing. MPD technology addresses this matter by applying back-pressure. When pumps are turned off, surface back-pressure is increased replacing the friction losses, resulting in little to no change in downhole pressure. Lowering of dynamic pressure in the well helps to minimize ballooning effects. Ballooning can be a confusing phenomenon, and is often misinterpreted as a flowing well or connection gas. If the inappropriate action is taken the problem often worsen and in worst case scenarios lead to lost circulation (Tirado, et al. 2011). Further, the use of NABM may lead to even further confusion due to its compressibility. Wellbore fingerprinting (real time data acquisition/ Pre-Emptive Information Gathering) helps to distinguish wellbore ballooning events to kick-loss situations (Naduri, Medley and Schubert 2009).

As defined, MPD manipulates the BHP by applying surface back-pressure. This means that it can be chosen to drill with either a static underbalanced mud or a static balanced mud, see Figure 3. Drilling with an underbalanced mud yields a larger operating window, meaning if something unexpected happens in the well the operating margins are larger. However, if dynamic overbalance is not maintained at all times the sudden overbalance may cause severe damage to the unprotected formation. Government regulations are also strict regarding underbalanced drilling.

MPD is expanding rapidly, and is used all around the world for many different reasons. However, it is important that MPD is used on proper candidates. Conventional drilling might be a better solution in some environments. Poor candidate selection is normally a result related to poor understanding of what the goal and objectives of MPD is. For instance, misunderstanding how the entire annulus is affected by maintaining a constant BHP (e.g. in horizontal wells). An incorrect understanding of what MPD can accomplish may thereby worsen the problem. Additionally, MPD equipment is expensive and will increase operational costs. MPD is in general a way to drill un-drillable wells with certain issues such as severely depleted reservoirs, highly fractured formations, extreme deep waters or narrow MW window. If the well does not have significant benefits from MPD, other techniques should be considered.

2.3 General MPD set-up and Equipment

A hydraulic model based on real time data controls the chokes that handle pressure variations. A combination of the MPD system and CCS complement each other yielding better BHP control. The CCS compensates for the large pressure variations during connections caused by the mud pump cycle; it improves the cuttings transport, reduces connection gas and borehole ballooning, and increases the hydraulic stability in the well.

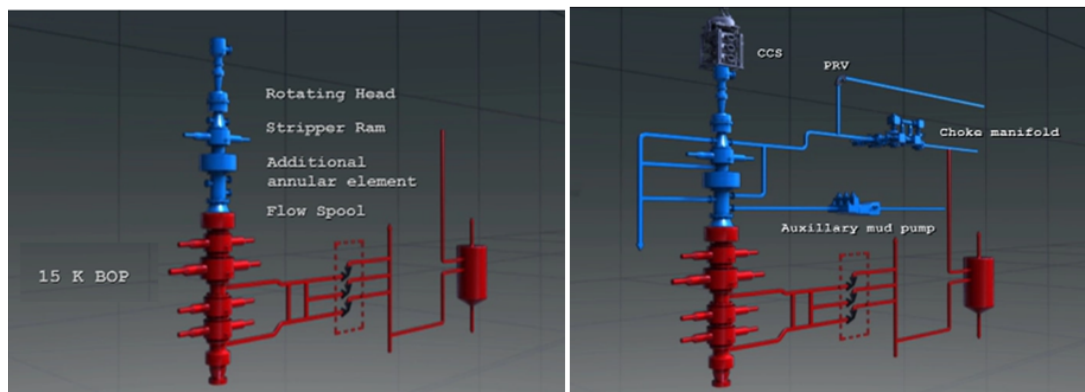


Figure 6: A typical MPD rig up schematic (Eck-Olsen, et al. 2012)

MPD operations require some additional equipment to that of a conventional drilling operation. The system is not designed for continuous influx and the rig up is fairly simple compared to a UBD rig up. If the well requires a closed-loop system a RCD (or PCD) must be installed. A choke skid is required to adjust the backpressure, an annular seal to provide the back pressure and a control system to adjust the choke itself. In addition, the use of a back pressure pump to adjust the pressure without circulation, a flow meter to detect kicks and losses and a Continuous Circulating System (CCS) to provide circulation during connections are recommended/optional equipment (Eck-Olsen, et al. 2012). MPD technology and equipment complements and enhance the capabilities of the existing conventional well control system. UBD on the other hand requires replacement of several elements.

The BOP, choke manifold and separator remain undisturbed as a flow spool, a stripper ram, an additional annular seal and a rotating head are placed on top, see Figure 6. The hydraulic model automatically adjusts the choke to compensate for pump rate and the effects of pipe rotation, temperature, swab and surge. The return flow is directed towards the MPD choke manifold and flow meter and then returned to the mud pit through conventional means. To provide smoother regulation of the flow and redundancy an auxiliary mud pump is connected to the flow spool. To prevent over pressurization in the event sudden shut in, a pressure relief valve is implemented. The CCS provides continuous circulation.

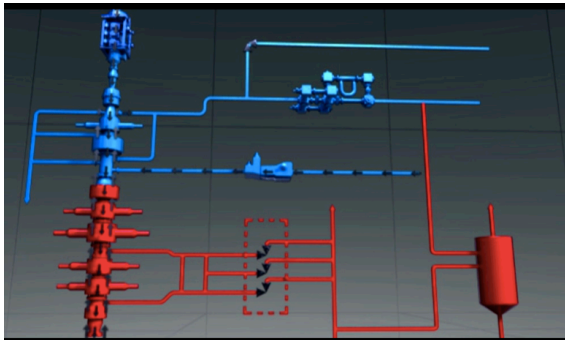


Figure 7: Primary flow path (Eck-Olsen, et al. 2012)

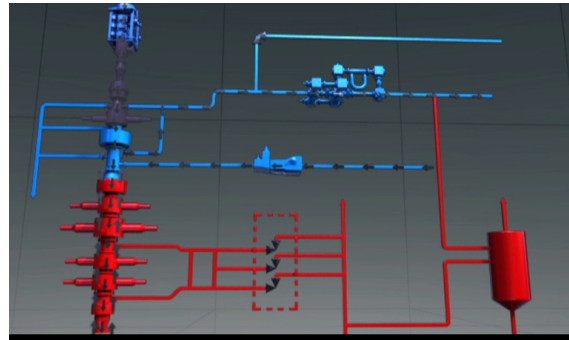


Figure 8: Secondary flow path (Eck-Olsen, et al. 2012)

The upper outlet on the flow spool is the primary flow path for the system. A secondary flow path is used when the rubber element in the rotating head needs to be changed. All well control incidents are handled by shutting down the MPD system and relying on the BOP well control system, see Figure 9 (Eck-Olsen, et al. 2012).

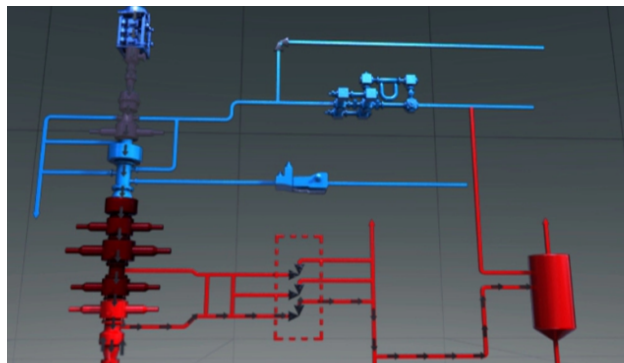


Figure 9: BOP well control system (Eck-Olsen, et al. 2012)

The fully automated choke control compensates for surge and swab effects when pulling out of the open hole. A Balanced Mud Pill (BMP) will be set at approximately 1000 m and the well is subsequently made into overbalance. This method is much gentler than the conventional well kill. The production liner, or casing, can now be run below the mud pill. The MPD mode is thereafter engaged and the well is displaced into full MPD mode. The liner/casing can be run to TD and then cemented in place while keeping a constant BHP.

2.3.1 PCD versus RCD

When drilling in MPD mode (closed loop system), an RCD or a PCD/RPCD must be installed. MPD operations do require the annulus to be sealed off when drilling, tripping and making connections. The Pressure Control Device (PCD) provides a seal against the DP, and can be used on operations on fixed platforms or land rigs. The Riser Pressure Control Device (RPCD) provides a closed loop system by isolating the riser annulus below the slip joint (Siem WIS 2013a). Similar to the conventional RCD, the PCD/RPCD is an annular seal that provides back pressure to the circulating system and works as

the first defense against influx/losses during critical well operations (Halliburton 2013a). The RCD/PCD/RPCD is not intended to replace the BOP, rather supplement it. The device is mounted on top of the BOP, and provide together with the choke and control system improved BHP control.

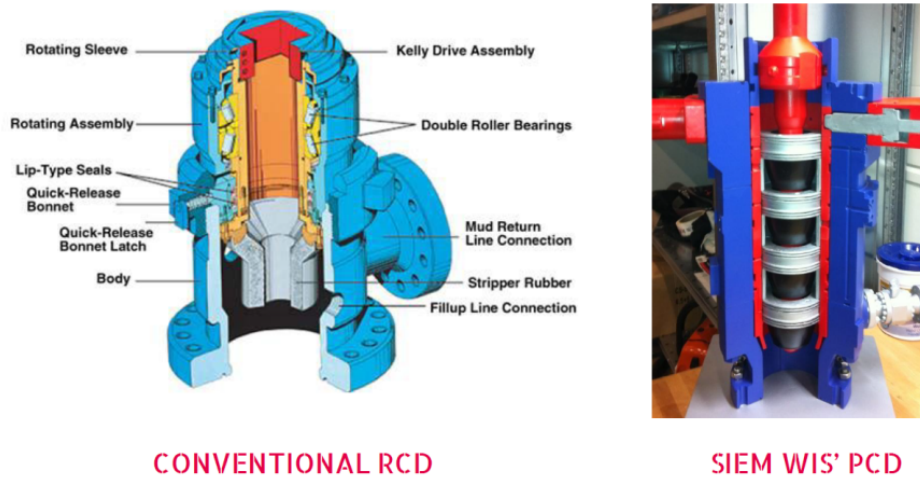


Figure 10: Sealing concept for the RCD (on the left) and the PCD (on the right) (Siem WIS 2013a)

The PCD sealing concept is passive, non-rotating seals. Pressure are continuously regulated and evenly distributed over all four seals. The seals themselves are continuously monitored and integrity logged (Siem WIS 2013a). When a seal wears, pressure monitors will indicate where the seal has lost integrity and proper manners will be taken. As the PCD normally have four seals, all acting independently, the seals do not have to be replaced if one seal fails. It is custom to replace the seals if two or more seals loses their integrity. The PCD can be customized to handle all ranges of dynamic and static pressures, depending on number of seals installed (Siem WIS 2013b).

Lubricant consumption of the PCD depends on drilling parameters and operations. 5-10 % of the equipments lubricant consumption is estimated to escape, entering the mud. The rest is collected in the gradient system and drained to a closed system (Siem WIS 2013a). Comprehensive testing has indicated that the lubricant do not react or alter the mud. So far it has been successfully tested in labs using WARP oil-based mud, on Ullrigg with a WBM and with a WARP mud on Gullfaks C. When using a PCD, the DP rotates on the grease instead of the rubber seals. For an RCD the rotation wears the rubber seals. As time goes by the rubber seals wear eventually leading to a slipping DP. RCD tests indicate that stripping can be performed for weeks as long as the pipe is non-rotating¹. However if the pipe rotates in a stationary “rotating-element” a new seal will wear and leaks occur within 10 hours.

¹ Personal e-mail correspondence with Henrik Sveinall, Product & Service Line Manager, Weatherford Norway

There are two PCD’s available on the market; the PCD 3000 and the PCD 5000. The technical data are shown in Appendix B – Tables: Table 3. The PCD 3000 was tested on Ullrigg in 2009 and on Gullfaks in 2010. Among the conclusions from the Gullfaks C project was:

- Safer and more planned change of seals
- Less spill on rig floor and BOP level
- Easier to rig up and down

The PCD 5000 is to be used on future projects such as Valemon and Gudrun, both HPHT field operated by Statoil. The system is planned to be used on 7 wells for the Valemon project and 2 wells on the Gudrun project (Siem WIS 2013a).

A normal RCD is limited by the pressure when RPM of the drill pipe increases. A PCD on the other hand, are not limited by the RPM, and thereby provide a wider operating window (Siem WIS 2013a).

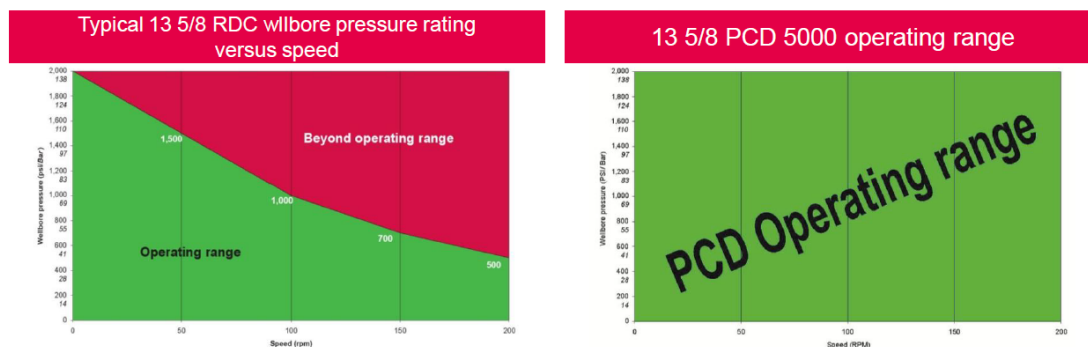


Figure 11: Typical operating range for RCD (on the left) and PCD (on the right). The graph shows the relationship between the pressure ratings versus speed of the drill pipe. The green area indicated the equipments operating range. (Siem WIS 2013a)

PCD is an active seal barrier system which can be used for both MPD and UBD operations targeting challenging wells such as Extended Reach Drilling (ERD) wells and HPHT wells. The PCD has been tested extensively for API 16 RCD standard (up to 80°C) with both OBM and WBM (Siem WIS 2013b).

Alignment of the device to the drill string is very important. A misalignment of just 2-5 cm results in an eccentric wear, leading to a possible leak. The RCD have a rotating element which leads to higher friction internal in the bearings over time. In addition, the design of the bearing prevent external cooling of the bearing leading to lower pressure ratings at high RPMs, see Figure 11. On the other hand, the RCD allows for immediate removal/replacement of all rotational elements if problems occur².

² Personal e-mail correspondence with Henrik Sveinall, Product & Service Line manager, Weatherford Norway

PCD is still quite new in the petroleum industry, meaning that the device lack extensive track records. The preliminary results are promising, thus its usage is increasing. However, it is important to remember that all wells are different. First of all, it must be considered whether the PCD are rated to handle an ultra HPHT well, and if so how extensively has it been tested. PCDs do have a higher overall pressure rating which can be seen on Figure 11 with the exception of the active RCDs (e.g. PCWD from NOV)³. As the PCD offers continuous monitoring of the sealing elements condition risks can be minimized, especially when drilling with a statically underbalanced MW. Both RCD and PCD require precise alignment, but the RCD however is more sensitive to alignment deviations as it has a rotating element. The PCD are a bigger piece of equipment, and require rig crew, which can be a huge obstacle for an already tight rig.

Another issue might be having large enough thru-bore ratings. Weatherford do have an 18 $\frac{3}{4}$ in, while the current PCD has 13 $\frac{3}{8}$ in.

PCDs in general are more expensive than RCDs. Most vendors will charge higher prices for single parts compared to buying a full MPD system. Mixing technologies often result in more expensive initial equipment costs. However, using the new technology may yield far better well results. A solution may be to offer long term contracts implementing several wells.

³ Personal e-mail correspondence with Christine Madsen, Segment Sales Manager MPD SCA, Mi SWACO

2.4 Different Managed Pressure Drilling Techniques

The IADC has agreed upon four variations of MPD, whereas each variation is captured within single and dual gradient. Single gradient is when a single fluid density is manipulated whilst dual gradient are the introduction and manipulation of two or more fluid densities. Changeable variables such as mud densities, trapped pressure and friction pressure can be manipulated by adjusting the RCD, the choke, the pump and/or wellbore and drill string geometry (Eck-Olsen, et al. 2012).

The four main MPD variations and providers are the following

- Constant Bottom Hole Pressure [Schlumberger, Weatherford, Halliburton]
- Mud Cap Drilling [Schlumberger, Weatherford, Halliburton]
- Dual Gradient (with and without a riser) [AGR, CleanDrill, ReelWell]
- Return Flow Control or HSE method

CBHP is a technique often used for severely depleted reservoirs and narrow MW windows, PMCD to mitigate extreme fluid losses, DGD for deepwater drilling and HSE for specific environmental and safety focus.

MPD techniques from floaters, or floating MODU, are emerging rapidly as the oil and gas industry are focusing toward this technology. CBHP MPD using a submerged RCD became available in 2010 and later in the riser less DGD system in 2012, Figure 12 and Table 1.

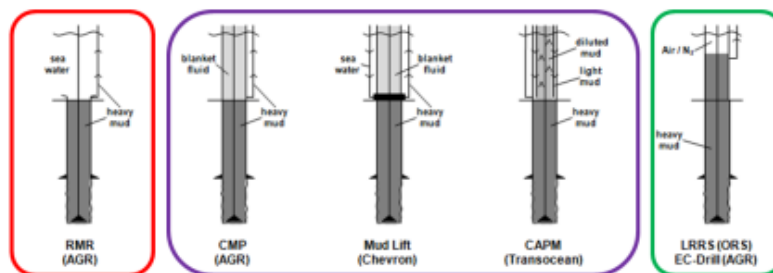


Figure 12: DGD systems concept (Total E&P 2011)

Table 1: DGD systems availability (Total E&P 2011)

| Technique | RMR | CMP | Mud Lift | CAPM | LRRS / EC-Drill |
|--------------------|---------------------|---------------------|--------------|---------------------|----------------------|
| Developer | | AGR | Chevron | Transocean | ORS / AGR |
| Status | Available | Awaiting field test | Under design | Awaiting field test | Awaiting field test |
| Riser | No | | | Yes | |
| Light gradient | Sea water | Blanket fluid | | Diluted mud | Air / N ₂ |
| Gradient interface | Sea bed | | | | 0-500m BRT |
| Max water depth | 800m (3-stage pump) | | N/A | | No |

2.4.1 Constant Bottom Hole Pressure (CBHP)

Constant Bottom Hole Pressure (CBHP) is a MPD method whereas the annular pressure is kept close to constant at a given depth. The method is based on maintaining control of the annular back pressure and has been successfully applied in several depleted reservoirs (Gravdal and Siahaan 2012). The objective for this method is to eliminate cycles of kicks/losses that are common in deep wells where fracture gradient are close to the pore pressure (Weatherford 2005-2010). The typical application for this technique is for cases where there are high uncertainties on the pressure limits, a narrow mud weight window with kicks/losses and high associated NPT, which is typical for depleted, fractured and high pressure reservoirs.

More specific, the BHP are bounded by the pore pressure and wellbore stability at one side and differential sticking, lost circulation and fracture pressure at the other side. It is important to be aware of how different parameters and operation influence pressure in the wellbore. Another important factor is surge and swab effects. The BHP relationship in an open circulating system can therefore be explained by the following equations

$$p_{pore} < p_{wellbore\ stability} < BHP < p_{diff.sticking} < p_{lost\ circulation} < p_{frac} \quad Eq. 3$$

$$BHP_{dynamic,open\ system} = ECD = p_{static} + p_{AFP} \quad Eq. 4$$

$$BHP_{dynamic,closed\ system} = p_{static} + p_{AFP} + p_{bp} \quad Eq. 5$$

To avoid fatigue caused by the pressure changes from turning the mud pump off and on (difference between static and dynamic pressure) in an open circulation system, a Continuous Circulating System (CCS) is used to maintain constant BHP (Rehm, et al. 2008). For a closed system the mud flows through a choke manifold designed to control the back pressure and maintain constant BHP when the mud pumps are turned off. The choke manifold increases the back pressure to compensate for frictional pressure losses when the mud pumps are turned off, thereby keeping the BHP constant (more precisely: within defined limits). A Rotating Control Device (RCD) acts as a primary pressure seal, providing a constant BHP to the MPD system. The RCD is located below the drill floor and above the annular BOP on the wellhead. The annulus back pressure is managed with a choke manifold connected to the RCD. To secure continuous flow through the MPD choke (including disconnection of top drive) a back pressure pump is installed (Gravdal and Siahaan 2012). A flow meter is also often

installed to provide early detection regarding influx and loss situations. MPD enables for both conventional circulation as well as for MPD circulation.

An automatic CBHP MPD system has several advantages compared to conventional drilling (Gravdal and Siahaan 2012)

- Pressure pulses is detected instantaneously
- The dynamic back pressure system responds extremely fast to adjust the pressure profile
- MPD system normally have improved set of sensors and measurements
- Real Time well simulation to feed the MPD system with reference back pressure

Unfortunately, the CBHP technique is often used improperly. The objective is to keep a constant BHP, but not necessarily at TD. The point of where constant BHP is maintained can be at the casing shoe where the risk is high for fractures, or any other point in the wellbore (Tirado, et al. 2011). More specifically, this point where the BHP is kept constant is more a physical depth where dynamic pressure and static pressure are equal, see. This point, often referred to as the anchor point, is often determined by the pressure profile. For cases with pressures diverging with depth, the anchor point is often set at the shoe. However, if the pressures are converging with depth the anchor point should be set at the bit (Tirado, et al. 2011).

Wellbore stability tends to be a very complex pressure as it is depending on several factors (magnitude and direction of maximum horizontal stress and relative well orientation, well inclination, fluid rheology, its density, porosity, permeability and so on). As drilling fluid is circulated the upper safety margin is reduced, creating difficulties particularly in depleted reservoirs whereas fracture gradients are reduced (Rehm, et al. 2008). MPD operations often allow for both conventional and MPD circulation, enabling the conventional circulation when a given influx limit is reached. Several factors need to be taken into account when changing circulation system, especially in the transition zone (light to moderate influx rate); operational limit for the back pressure choke manifold, operational limit for the choke valve itself and the pressure regime in the weakest section of the well (Gravdal and Siahaan 2012). CBHD is the preferred alternative as long as partial circulation is possible (Tercan 2010).

2.4.2 Mud Cap Drilling (MCD)

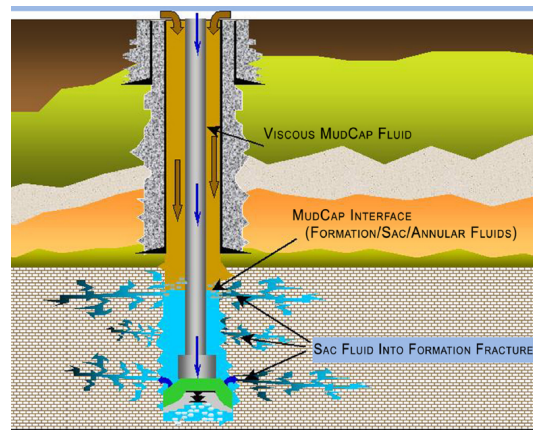


Figure 13: Pressurized Mud Cap Drilling schematic (Eck-Olsen, et al. 2012)

2.4.2.1 Pressurized Mud Cap Drilling (PMCD)

Pressurized Mud Cap Drilling (PMCD) is a drilling technique to mitigate extreme fluid losses commonly found in highly depleted and naturally fractured formations and associated NPT (Nesland, et al. 2012). This method is the first variation of the concept “heavy over light”. Mud cap drilling is employed when normal techniques have difficulties to maintain circulation. To prevent and control kicks and lost circulation while drilling in fractured or layered (different pressures) formations, drilling fluid together with water and cuttings are pumped into the wellbore and drill pipe (DP). Normal (floating) Mud Cap Drilling techniques allowed gas to migrate towards the surface, resulting in the possibility of undesirable sour gas releases. Another concern is the uncertainty of the fluid level in the wellbore as kicks are often sudden and powerful. For constantly monitoring the pressure at the surface, PMCD was developed (Rehm, et al. 2008).

PMCD is referred to as drilling without returns to the surface, and maintaining a full annular fluid column above a formation whereas fluids and cuttings are injected (Rehm, et al. 2008). When fractures are encountered and drilling fluid is lost, the annulus is closed using the RCD. Sacrificial fluid (light weight, e.g. seawater) is then pumped down the DP and a fluid cap is injected into the annulus or circulated in place by the casing. The fluid cap is balanced by the formation pressure and managing the surface pressure as the well is shut in, i.e. fluid cannot return up through the annulus. Heavy, viscous fluid remains in the annulus above the weak zone acting as a mud cap. Pressure and gas migration are quickly managed by applying surface pressure and by adding or removing the mud cap size (Nesland, et al. 2012). By pumping water or brine down the DP, drilling can be continued. Fluids will always follow the path of least resistance, which in this case will be to the previous fracture encountered. The injected sacrificial fluid carries away drill cuttings and produced fluids or gas, trapping the fluid and cuttings beneath the surface and thereby eliminating the need for

disposal. Dangerous gases do not reach the well site and the formation is often stabilized in many cases. Also, the reservoir conditions do not affect the fluid injection rate. Using PMCD thick, highly fractures and sour reservoirs previously thought to be un-drillable are now considered drillable.

PMCD reduces NPT associated with fluid losses and major gas influx, significantly reducing operational costs. Inexpensive fluids such as seawater are often used as sacrificial fluid, disposal expenses are close to eliminated as cuttings together with drilling fluid are injected into the fractures in the formation drilled. Risks are reduced and safety improved as the pipe can be tripped and rotated when fluid is pumped down the annulus (Nesland, et al. 2012). Reducing the requirements for annular fluids and allowing constant downhole monitoring opens for safely drilling of wells containing H₂S. For these reasons, PMCD is a good solution for cases where the loss of returns are high and gas kicks are experienced; situations that are common in highly fractured formations or vugular carbonate reservoirs. In terms of PMCD, high losses translate into high injectivity, i.e. an attribute.

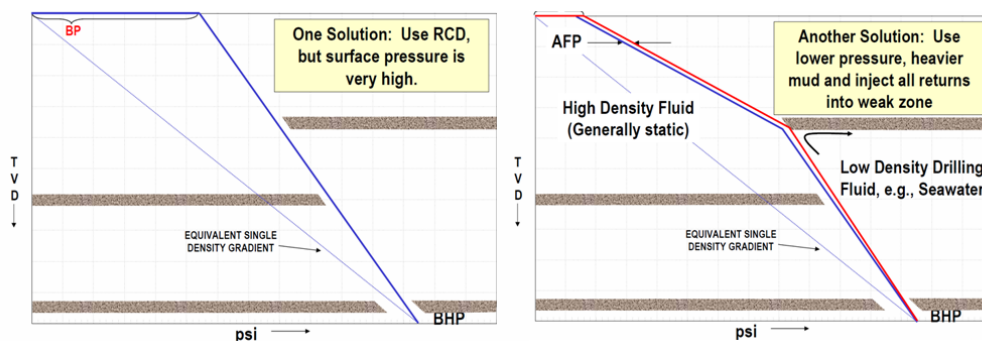


Figure 14: Two different solutions of Pressurized Mud cap Drilling (Eck-Olsen, et al. 2012)

2.4.2.2 Floating Mud Cap Drilling (FMCD)

The well is drilled with returns until circulation is lost, at this point drilling continues without returns. The annulus fluid level “floats” at a balance point in the well (lowest pressured fracture or vugs). To maintain vacuum in the well, fluids are pumped into the annulus when necessary (Rehm, et al. 2008). At low pressures, water is continuously pumped into the annulus for maintaining well control. FMCD is to drill “blindfolded”, meaning that annular well control are limited. Fluids must be pumped with a rate high enough to carry migrating gas and produced fluids back into the formation. Continuous injection is possible for cases where operational time is short or injected fluid supply is unlimited.

Rig-up for FMCD is simple, normally requiring only a pump and an RCD. For cases with high reservoir pressures, some upgrades must be made.

2.4.3 Dual Gradient Drilling (DGD)

Dual Gradient Drilling is an MPD technique that employs two different annulus fluid gradients to find a closer match to the natural pressure regime; one above the seabed, another beneath. This concept is the most applicable technology for deepwater drilling due to the heavy mud column in the marine riser can be eliminated by the use of a dual gradient system. The objective is to reduce formation damage and the related fluid losses when drilling deep formations with low-fracture gradients (eliminating mud density changes) (Weatherford 2005-2010).

Techniques to accomplish a dual gradient solution can be to inject a lower density fluid (often Nitrogen) by means of a parasite string for an onshore well or through the marine riser offshore (also referred to as dilution DGD system), or by actively pumping returns through return lines external to a seawater-filled riser (Gravdal and Siahaan 2012). Riser less drilling also helps to extend the deepwater capabilities. The objective is to adjust the BHP without having to change the base fluid, thus reducing number of interruptions for drilling ahead (Tercan 2010). DGD is primarily used in offshore applications where water poses a significant portion of the overburden. The intent of the dual gradient technology is to reduce the effect of deep water and thereby extend casing setting depths resulting in larger diameter completions, see Figure 15 and Figure 16 (Nesland, et al. 2012).

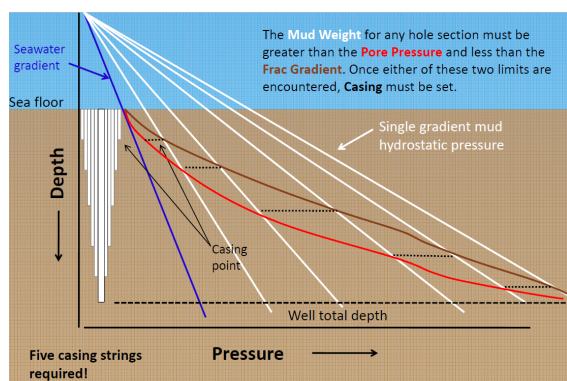


Figure 15: Casing/Mud program for a deepwater single gradient wells (Eck-Olsen, et al. 2012)

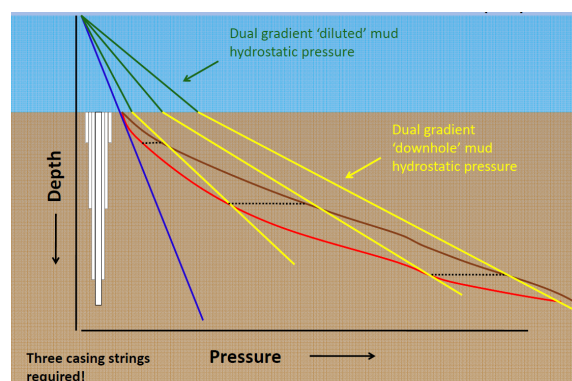


Figure 16: Casing/Mud program for a deepwater dual-gradient well (Eck-Olsen, et al. 2012)

Successful DGD increases drilling efficiency while significantly lowering mechanical risks and operational costs. Although promising results are indicated, operational experience as of today is very limited.

Methods for actively pumping fluid returns from the seafloor are “Pump and dump” (returns dumped at the seafloor) and “riser less mud returns” for drilling of the top hole sections (Figure 17 and Figure 18) whereas return through small diameter return lines via a mud-lift pump are used for drilling beyond the surface casing (Figure 19) (Rehm, et al. 2008). Adjusting the inlet pressure of the

seafloor pump to that of the hydrostatic pressure of seawater, dual-pressure gradient is imposed on the wellbore annulus.

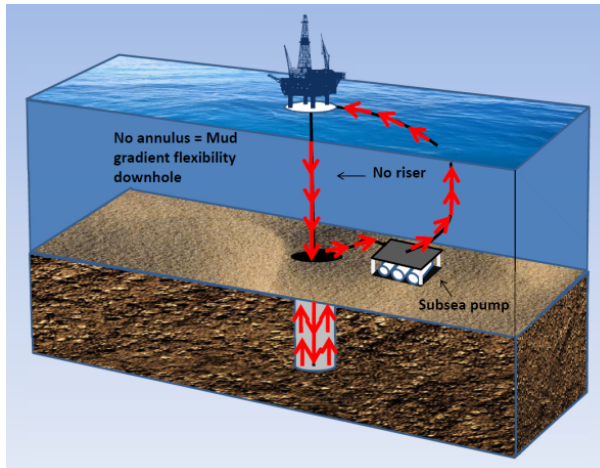


Figure 17: Riserless Mud Return (Eck-Olsen, et al. 2012)

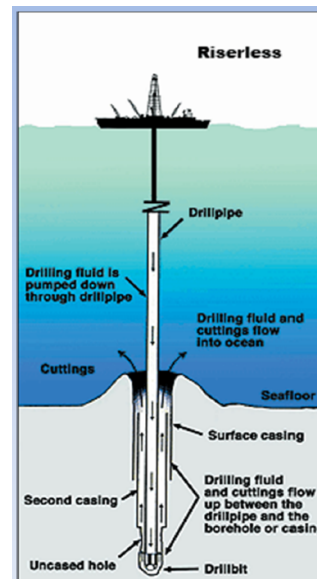


Figure 18: Riserless "Pump & Dump" (Eck-Olsen, et al. 2012)

Sacrificial fluid is used as the primary drilling fluid cleaning and cooling the bit in addition to lifting the cuttings for riser less "Pump and dump". The cuttings are pumped directly onto the seafloor, hence its name. Riser less Mud Recovery on the other hand allows for controlled handling and disposal of cuttings in addition to re-use of drilling fluid.

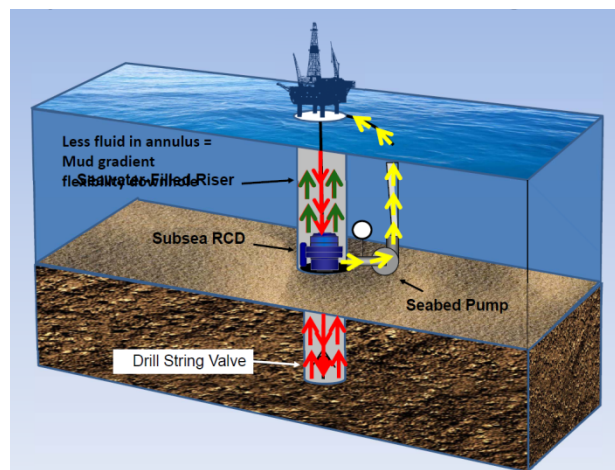


Figure 19: Subsea Mudlift Drilling (Eck-Olsen, et al. 2012)

For more specifics on current technology solutions for DGD see Appendix D - Present DGD Technologies.

2.4.4 Return Flow Control Drilling (RFCD) or HSE Method

Return through Flow Control (RFC) Drilling is a MPD method that reduces risks from drilling fluid, hazardous gases and well control incidents to the personnel and the environment. The objective of this method is to focus on HSE primarily. This method is specifically designed to enable drilling high-pressure, complex wells at reduced operational costs as it provides very accurate flow and pressure measurements and analysis (Micro-Flux Control Technology, RTD) (Rehm, et al. 2008). The system allows decisions to be made on actual data versus predicted data, resulting in safer operations.

To create a pressurized circulation system an RCD is placed above the conventional BOP. Drill string floats and a dedicated choke completes the closed pressurized system on the rig floor. Annular returns are diverted away from the rig to prevent spills onto the rig floor. This ensures for a more safely containment compared to conventional open-to-atmosphere mud return handling systems, thereby removing the risk of hazardous gases being released (Weatherford 2006). Gas returns are normally handled using a conventional degassing system. Depending on the expected gas return rates, some additional separation equipment may be required.

3 Weatherford's MPD system

Weatherford is one of the leading suppliers of MPD system solutions in today's market. The system has a good track record which is continuously expanding and raising its confidence within the industry. Further, the Weatherford MPD system has been tested and used successfully on the Maersk Gallant by ConocoPhillips in 2010. The following is an introduction to the Weatherford MPD system, followed by several examples of how the system can be used to optimize the drilling process. The schematic set-up shown in section 3.1 The Weatherford MPD circulation system is a set-up proposed for the Maersk Gallant rig for drilling of the Solaris well.

The Weatherford MPD system consists of an RCD placed on top of the BOP system and the Microflux Control system which is a combined manifold, Coriolis flow meter and control system (see Figure 20). The Microflux Control System patented algorithms use well data/inputs to decide what action to take.

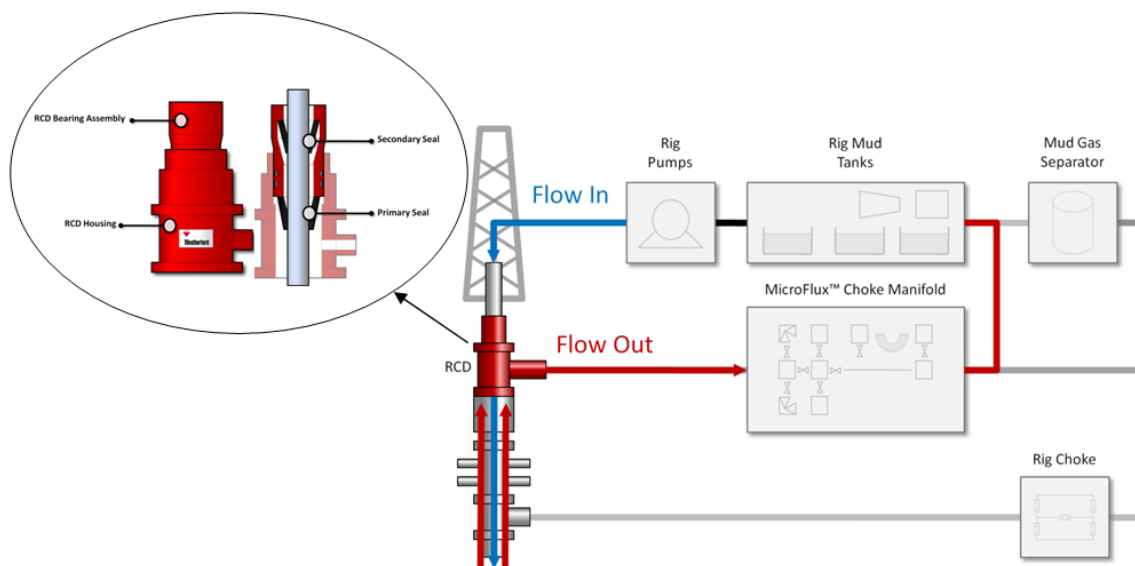


Figure 20: A simplified schematic of Weatherford's MPD system (Freely edited using figures from Weatherford 2013)

- The Coriolis flow meter is used for monitoring (kick detection), not to control the chokes. The accuracy is very high ($\pm 0.15\%$) as it measures the drilling fluid with cuttings (Weatherford 2013). The device is simple to use as it uses fluid density, mass flow and temperature to calculate the volumetric flow. However, correct installation is important to avoid gas/solid accumulation. Unfortunately, at high gas rates (multiphase flow) accuracy is significantly reduced. E.g. gas volumes of 25% will give strange readings (Weatherford 2013).

- The drilling chokes are a position control choke system consisting of Tungsten Carbide nose and seat which increases the in-service life. The chokes are available in 2in and 3in trims, whereas using two 3in SCB2 drilling is normal to allow for higher flow rates at a lower pressure drop (also allows larger cuttings to pass) (Weatherford 2013).

MPD controls wellbore pressure dynamically by manipulating the back-pressure. The closed loop system provides continuous information on the operational envelope and thereby helps to optimize the drilling process. MPD provides real-time well data, which helps to address wellbore issues at an early stage and thereby prevent them to escalate to more serious events.

The MPD system is equipped with an UPS (Uninterruptable Power Supply) which supplies the system with energy for a short while in the case of a rig blackout.

Defining whether the well is in balance comes down to total inflow versus total outflow. If the same volume flows into the well flows out, the well should be in balance. The operational envelope can thereby be determined by using the Weatherford Drilling Auto Control system.



Figure 21: Defining the lower end of the operational envelope. The red line shows flow out, the blue line flow in and the green line shows the current BHP. Additionally the specific amount mud lost or gained are shown in the lower left side of the control screen (Weatherford 2013)

When drilling in MPD mode, it is preferable to maintain a MW just above the pore pressure, and to do this it is important to establish the actual pore pressure in the well. Again, the well is defined as in balance if inflow equals outflow (Weatherford 2013). As seen on Figure 21 a reduction in pump rate

by 20 RPM lowers both inflow and outflow, after a short time the lines intersect again meaning the well is still in balance. It is observed that outflow changes more slowly than the inflow, which is natural as the mud has to go through the circulation system before reaching the Coriolis flow meter. As the pump rate is lowered a reduction of BHP occurs due to the loss of ECD in the well. The pump rate is then lowered stepwise until the well is out of balance (inflow \neq outflow).

When the pump rate is reduced to a stage where flow out of the well is larger than the flow in, the well is in underbalanced condition (BHP < Pore Pressure). The pump rate is then increased stepwise until the inflow and outflow again converges, see Figure 22. As the lines finally converge, the well is back in balance and pore pressure limit is established. The BHP where the well stabilized is the actual pore pressure at this depth.

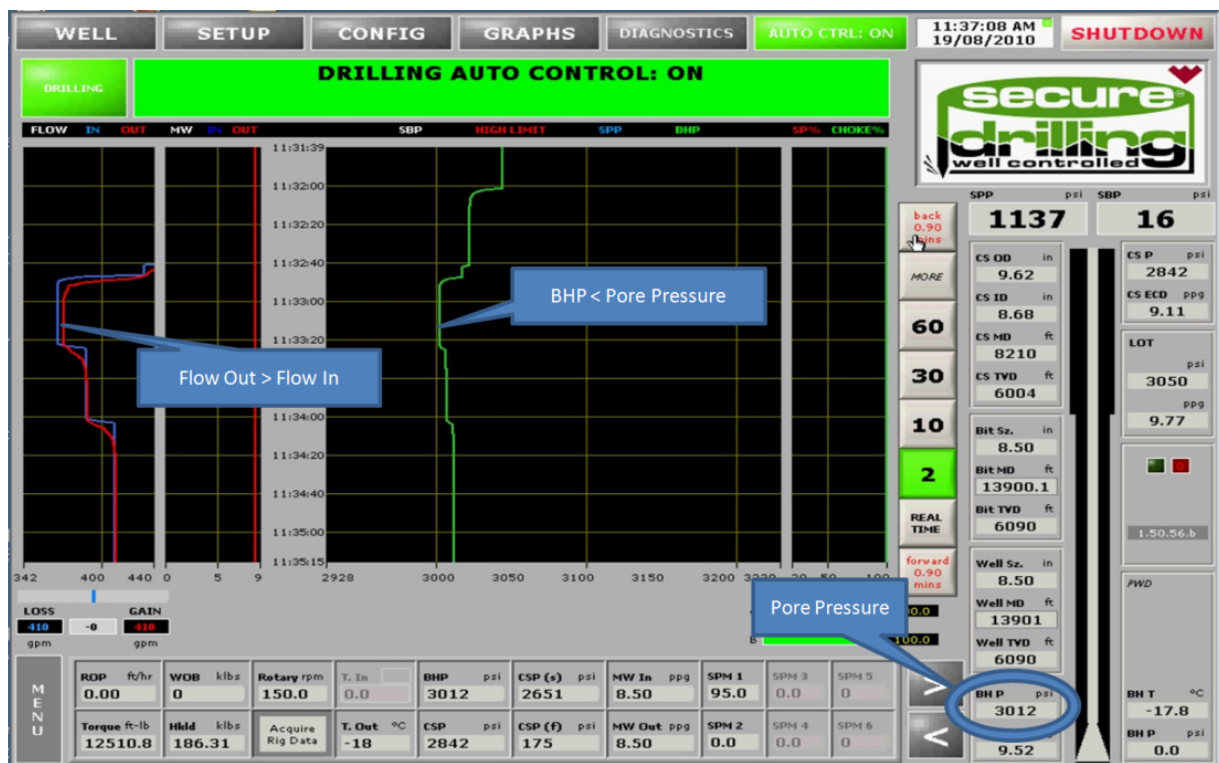


Figure 22: Defining the operational envelope limit. The blue line shows the flow into the well, the red flow out of the well while the green line indicates the current BHP. BHP can also be read in psi on the lower right side on the control screen (Weatherford 2013)

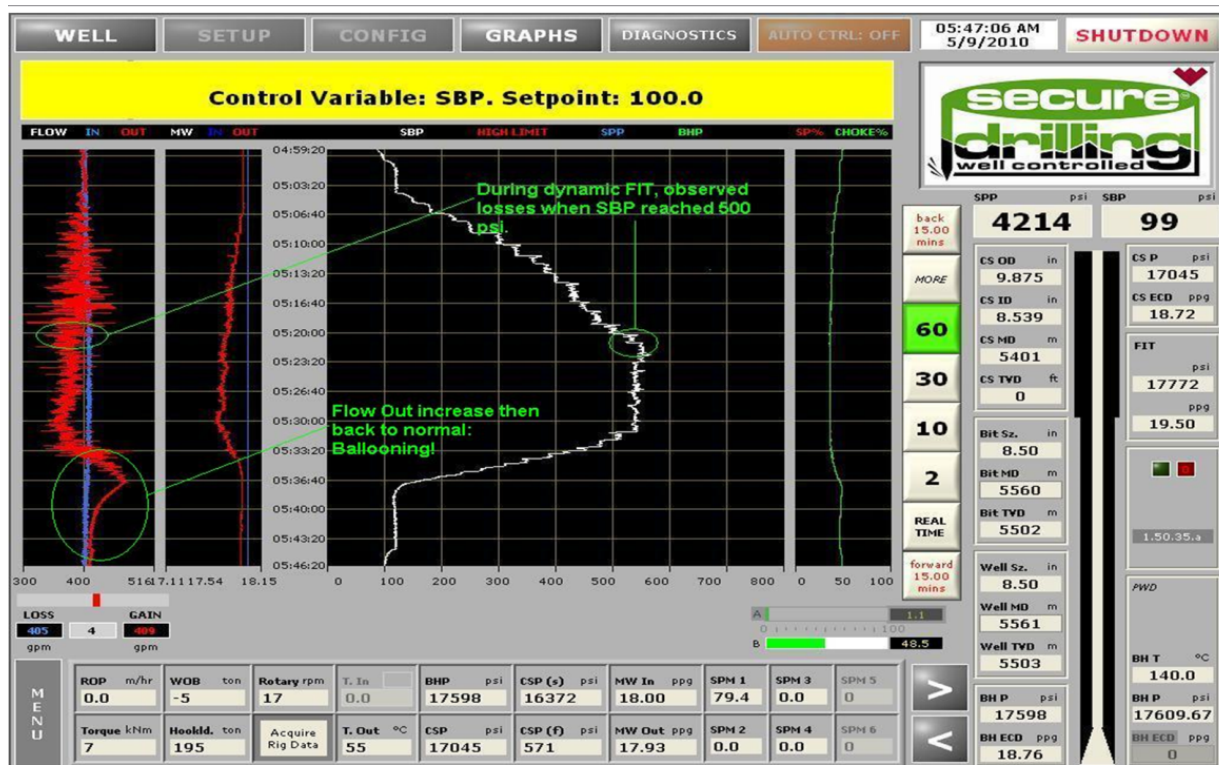


Figure 23: Defining the upper limit of the operational envelope (Weatherford 2013)

To determine the higher operational envelope limits the auto control are turned off while surface back pressure are applied. The following is an example of how the system works. As surface back-pressure is applied stepwise, flow in and flow out are monitored. When 500 psi surface back-pressure was applied, losses (outflow < inflow) were observed as the dynamic FIT was performed, see Figure 23. Surface back-pressure was then lowered causing flow out to increase. The flow out then exceeded flow in for a short while before the lines again converged. Due to the fact that the well stabilized after a short period indicated well ballooning. As the pressure was increased the well supercharged the formation. The following decrease in pressure resulted in formation fluids flowing back into the well. This is observed on the control screen as outflow is first lower than the inflow followed by a period of being higher before stabilizing.

MPD is efficient in influx detection. Putting the system back on auto control potential influxes can easily be detected. When influx enters the wellbore, the computer screen instantly shows flow out to be larger than the flow in, as an example see Figure 24. This influx is then counteracted by applying surface back pressure to the point where flow out does not exceed flow in. In this example, a back pressure of 146 psi was sufficient to handle and circulate a kick volume of 0.24 bbls. The kick volume helps to determine the wells condition, in this case a 0.65 ppg underbalanced well.

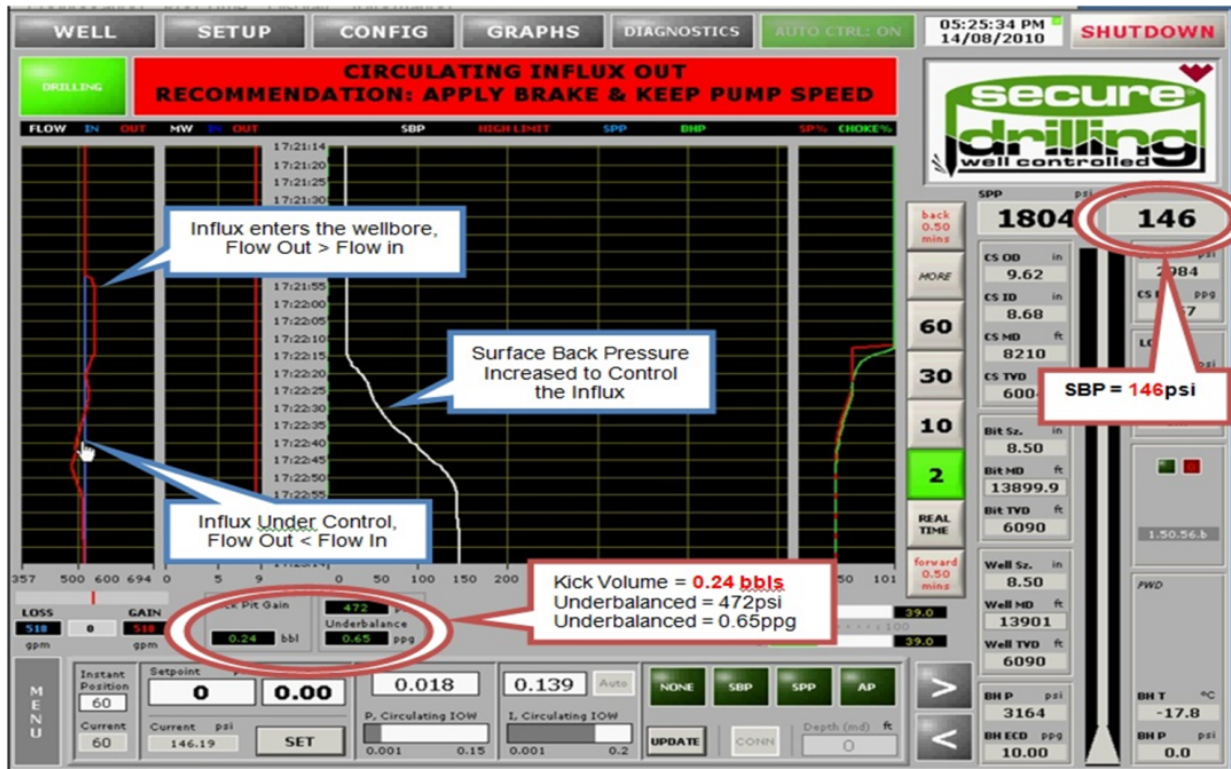


Figure 24: Above it can be seen how an influx together with the following action (adding backpressure) looks on the computer screen (Weatherford 2013)

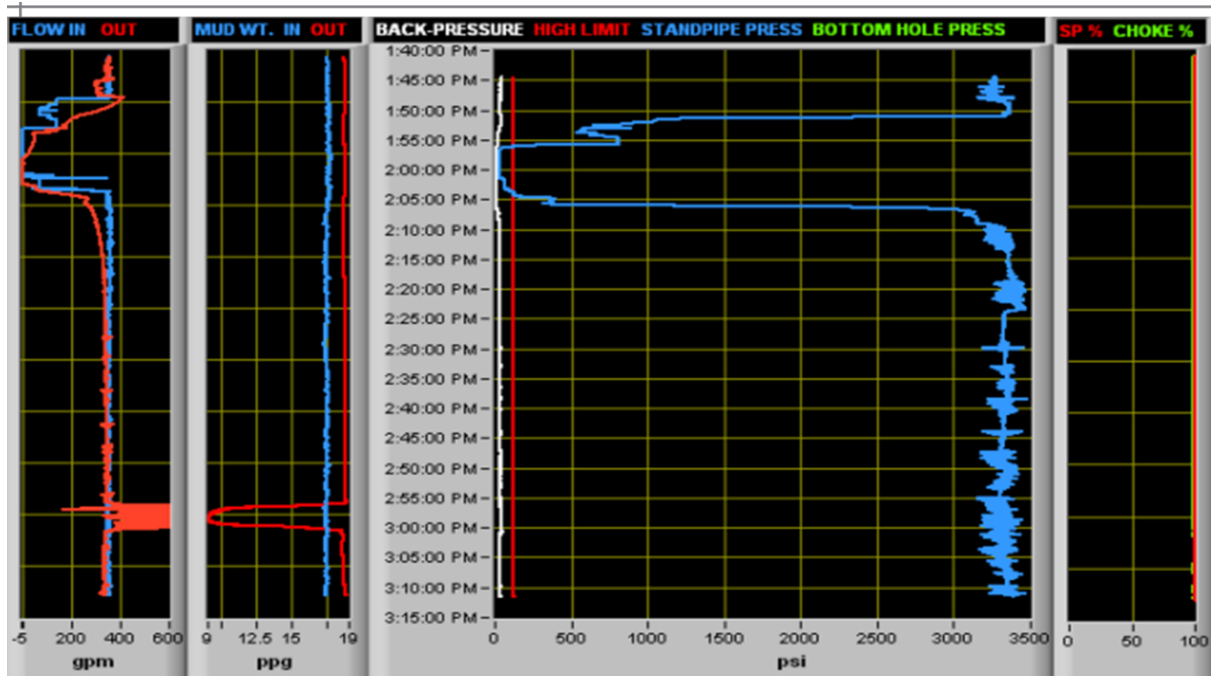


Figure 25: An example of how connection gas may look on the computer screen (Weatherford 2013)

The Weatherford MPD system provides early kick detection and accurate flow monitoring. Losses or gain less than ¼ bbl can easily be detected and monitored. The system thereby helps to determine whether the readings are caused to a flowing well, wellbore breathing issues or caused by connection gas. The following is an example of how to distinguish an abnormal flow reading detected by the system.

On Figure 25 it can be seen that inflow suddenly decreases closely followed by a similar decrease in flow out. This change in flow lasts for a short while before stabilizing back to initial flow. A similar change can be seen in the BHP measurement as well. This suggests something other than a kick as outflow changes similarly as inflow. The well then stabilizes for a while before experiencing an increase in outflow. Looking more closely on Figure 25, in particular the MW for this event, a rapid decrease in MW can be seen indicating a gas bubble reaching surface as it only lasts for a short time before going back to normal conditions. This sequence; sudden drop in circulation followed by a gas bubble reaching the surface is a typical indication of connection gas. When a connection is made, the well experiences a brief influx to the drilling fluid. This influx is a direct result of the stopping of the mud pumps and thereby allowing gas to enter at the current depth. This effect can be reduced by using a CCS (Appendix E – MPD Tools).

The Maersk Gallant HDJU is a rig with MPD and HPHT experience. The Weatherford system has been used successfully on several occasions. A potential set-up of the Weatherford MPD system for the Maersk Gallant is shown in Appendix J - Maersk Gallant potential MPD rig-up schematic.

3.1 The Weatherford MPD circulation system

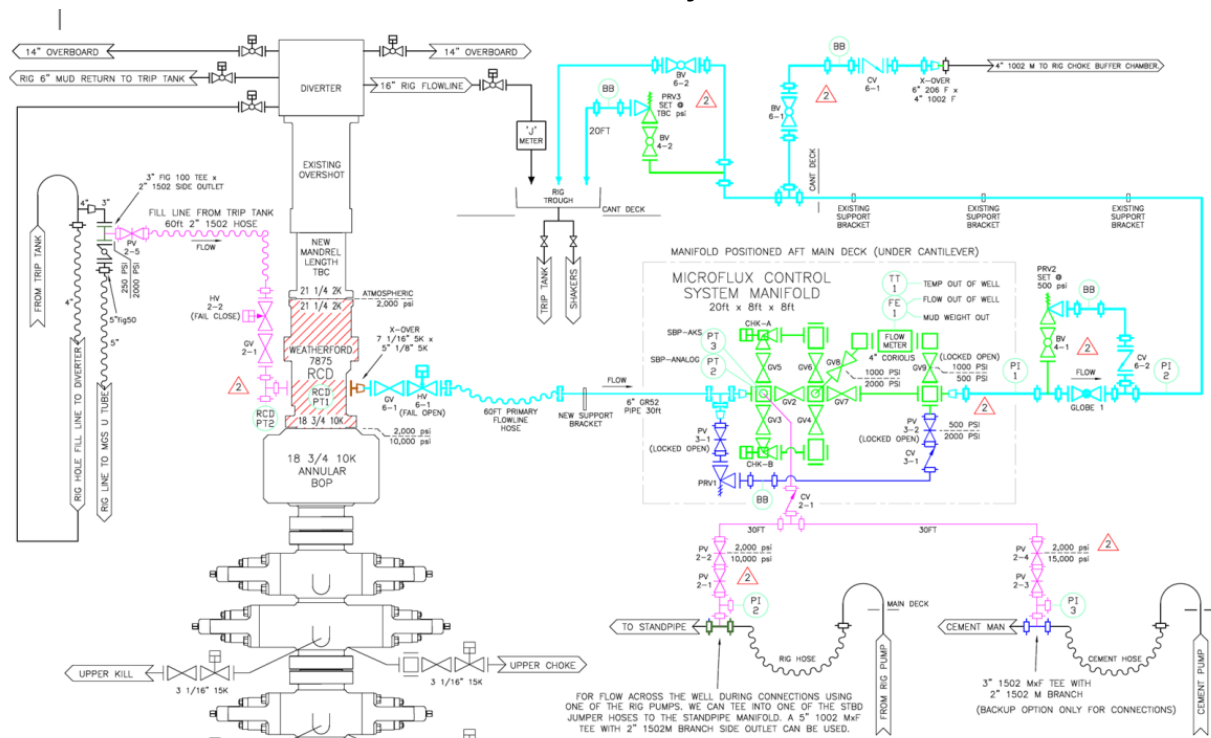


Figure 26: Schematic of a typical set up of the circulating system which enables for both conventional drilling and MPD (Weatherford 2013)

On Figure 26 a typical schematic of the Weatherford circulating system and its elements are shown. As mentioned in previous sections, the MPD system can be installed, but do not necessarily need to be engaged. Conventional drilling can be performed while having the MPD system installed, and alternating between these two can be done relatively easy as it was on the Kvitebjørn field.

The circulating system for a conventional system is fairly easy. As the mud returns to surface it flows through the return line and to the shaker, desander, desilter and degasser before reaching the mud tank. The drilling then passes through the suction line into the mud pumps where the drilling fluid is circulated. The drilling fluid is then pumped through the discharge line into the stand pipe through the rotary hose and swivel, into the Kelly and finally into the DP. The drilling fluid passes down the drill string, through RCD and BOP, and out the bit nozzles before it is circulated back up the annulus until it reaches the surface. On Figure 27 a typical schematic of how the circulation will be when drilling in conventional mode when an MPD system is installed. The green circles indicate open chokes or devices whereas the red indicates the closed chokes/devices.

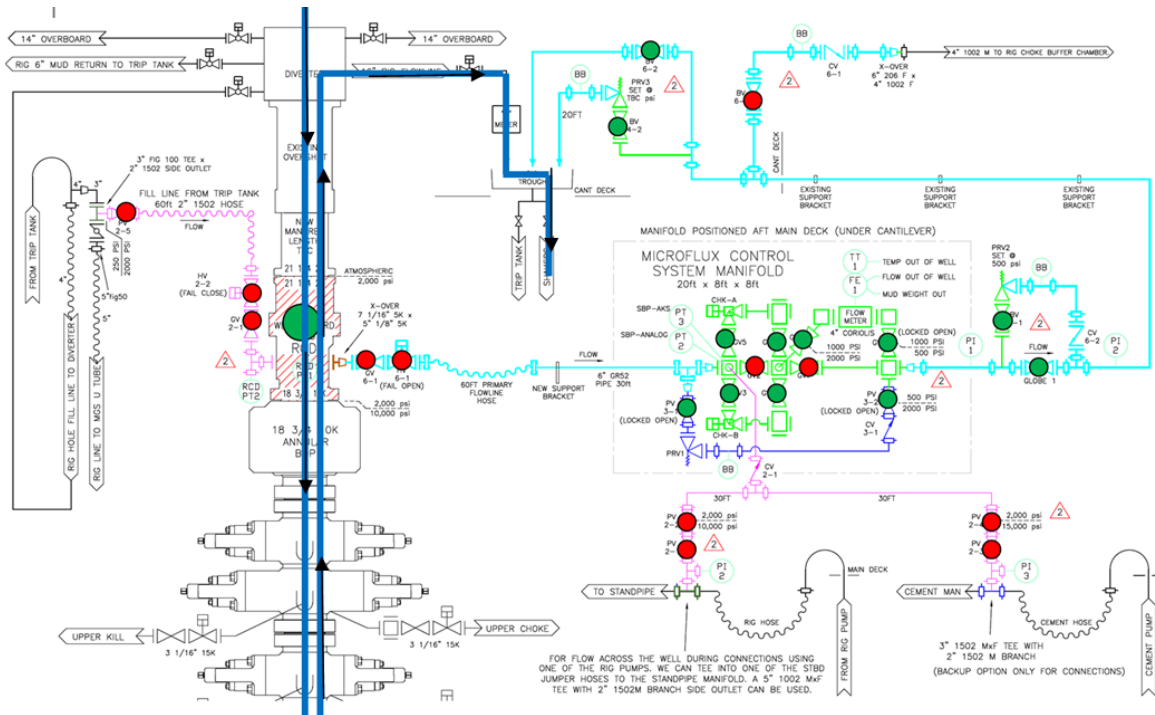


Figure 27: The circulation system when drilling in conventional mode when MPD equipment is also installed. The green circles indicate open path ways while the red indicate closed devices. (Freely edited from schematics provided by Weatherford (Weatherford 2013))

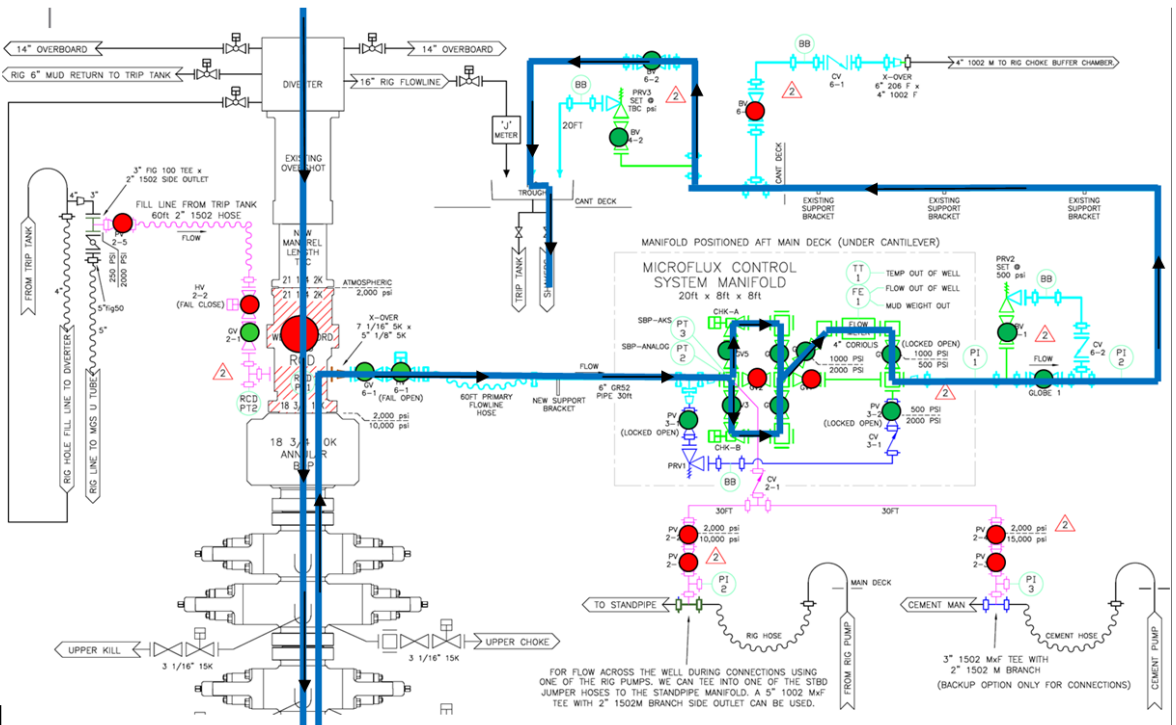


Figure 28: The circulation system when MPD is enabled (Freely edited from schematics provided by Weatherford (Weatherford 2013))

As MPD mode is engaged the circulation loop is closed, see Figure 28. The return flow is diverted at the RCD forcing the flow through the Microflux Control System Manifold. The Microflux provides accurate flow measurements and real time data (actual well data), yielding far better understanding of what is happening in the well compared to using predicted well data. The well is continuously monitored and will thereby provide crucial information much earlier than a conventional system would be able to. As the drilling fluid reached the Microflux it passes through an automated drilling choke manifold and a Coriolis flow meter which detects gain or losses at an early stage. The flow is controlled by the integrated control system which utilizes an advanced hydraulic model to calculate the actual well data. After passing through the Microflux control system manifold the flow is directed to the rig's shakers.

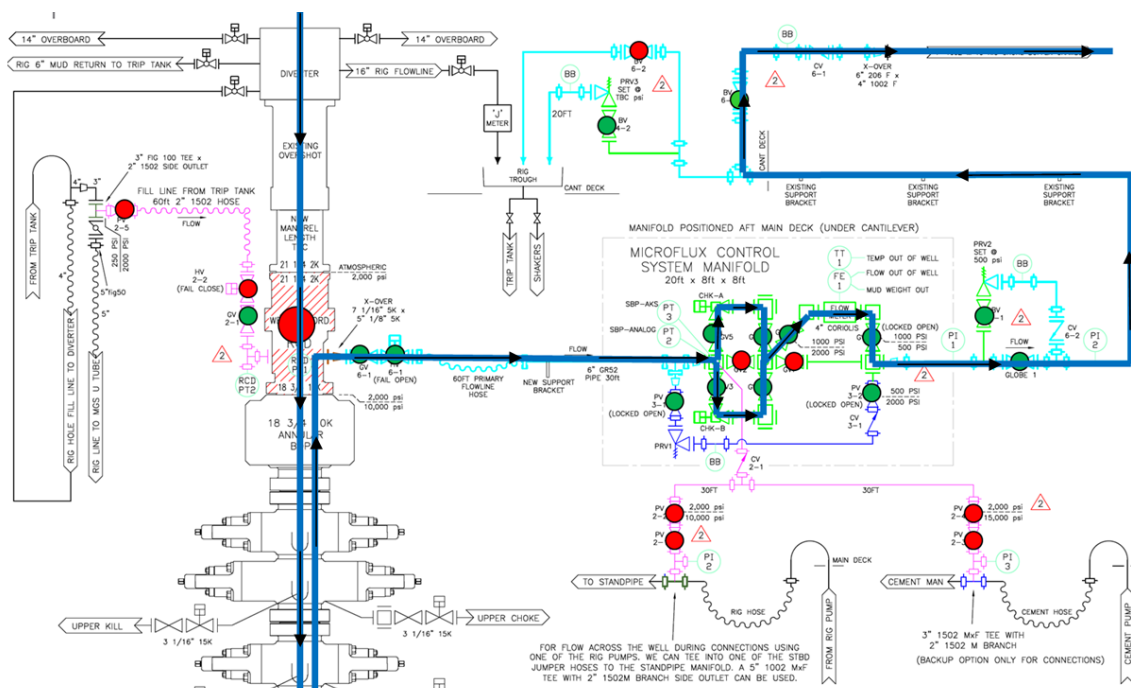


Figure 29: The circulation system for an MPD system experiencing high gas returns. The flow is diverted to mud-gas separators instead of going directly to the shakers and mud tanks. (Freely edited from schematics provided by Weatherford (Weatherford 2013))

When high gas return is detected in the flow, the flow needs to be diverted to a mud-gas separator. The flow still passes through the Microflux Control System Manifold, but instead of going through to the shakers and mud tanks it is diverted to a mud-gas separator, see Figure 29. A multiphase separator directs the free gas to external vents or flares located at safe distances from the rig, routes the liquid to degassers (removal of hazardous gasses) and pumps the solids to the shakers for removal. Coriolis flow meter is very sensitive to high gas volumes (yields strange readings; consistent density and corresponding frequency), the solution is very often to circulate until lower gas ratings are reached. Another way to deal with high gas volumes is to put pressure on the well to knock the gas volume down, but this is in general much more dangerous and expensive. As the flow meter

helps to detect influxes at an early stage, small kicks can be handled by circulating out through the MPD system instead of shutting in the well as in conventional well control. By being able to circulate out small kicks/influxes a lot of rig time is saved and thereby operational costs. When influx volume reaches a predetermined limit the well is handled by means of conventional well control.

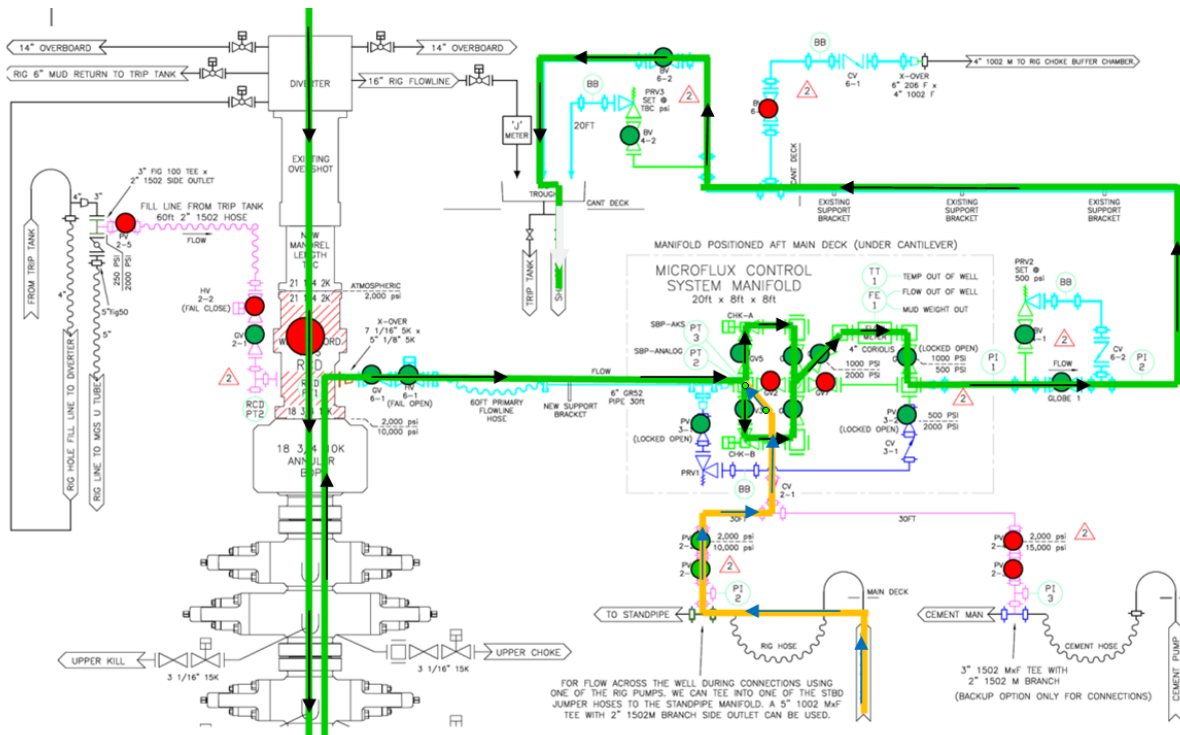


Figure 30: The circulation system as the back pressure pump is engaged subsequent to the mud pumps are turned off for making a DP connection (Freely edited from schematics provided by Weatherford (Weatherford 2013))

Another challenge is making a DP connection in MPD mode. As DP connections are quite frequent, significant BHP effects can be experienced. If these pressure fluctuations are not managed properly they can outweigh the benefits gained by MPD and in worst case scenario induce kicks. When a connection is made, mud pumps are turned off reducing frictional pressure and thereby maintaining the ECD. MPD manages this by applying surface pressure to account for the dynamic pressure loss in the well. A dedicated pump, referred to as a back-pressure pump, is connected to the annulus returns line upstream of the choke manifold. As mud pumps are turned off, back-pressure pumps are turned on to account for the drop in frictional pressure loss, see Figure 30 and Figure 31. As the pumps are turned on and off, pressure fluctuations occur. The MPD chokes will then try to counteract these fluctuations, a movement which may lead to wellbore breathing. If a compressible drilling fluid is utilized, such as for the Solaris well (NAMW), these problems may be more apparent (Johnson, et al. 2011).

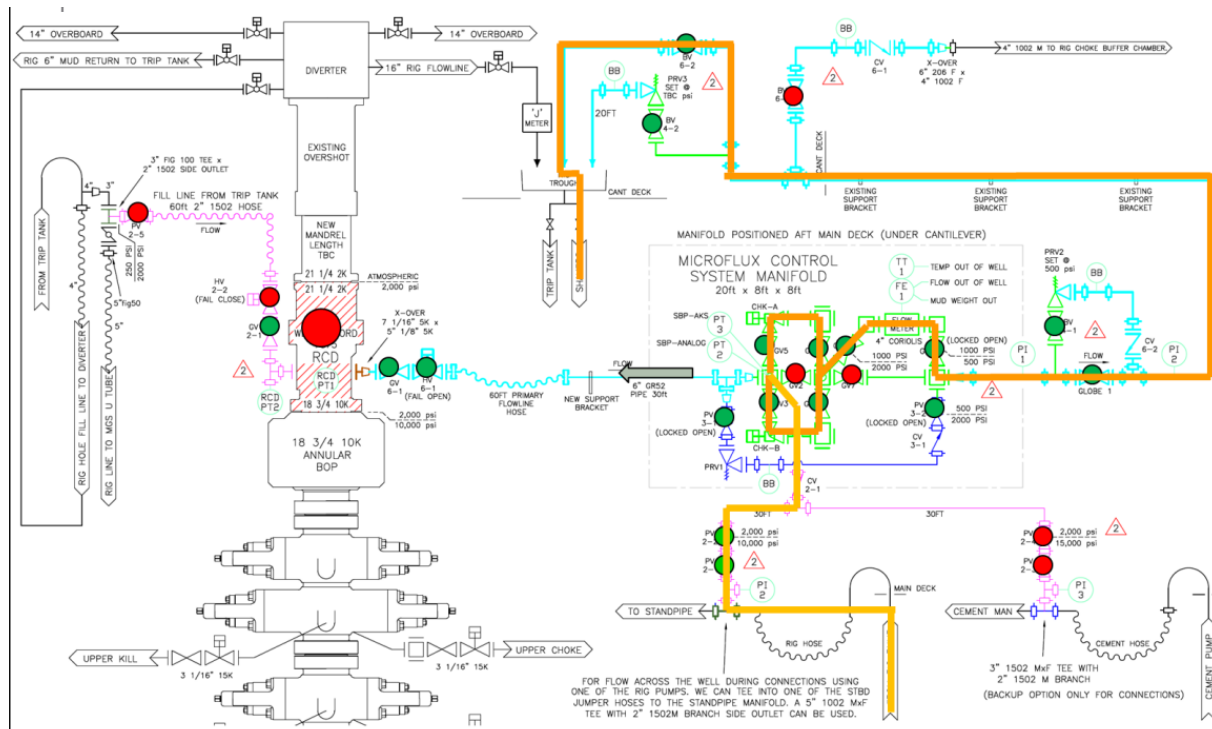


Figure 31: The circulation system as the back pressure pump counteracts the pressure loss from the mud pump being turned off (Freely edited from schematics provided by Weatherford (Weatherford 2013))

Ballooning is a challenge in many wells, and is typically observed in wells with narrow drilling margins. Even though drilling may be successful, the real challenge may be to trip out of the hole. Conventional tripping methods may not be sufficient, leading to possible abandonment with a subsequent sidetrack. By implementing MPD mode when tripping ballooning effects can be controlled and losses significantly reduced (Tirado, et al. 2011). All wells are different, meaning that one procedure does not fit all possible situations. While tripping the drill strings effective volume in the well must be compensated for, i.e. topping up the annulus when drill pipe is removed (or removal when pipe is tripped in), see Figure 32. When tripping in MPD mode backpressure is applied to compensate for possible surge or swab effects in addition to control wellbore breathing. If the well experiences ballooning and the mud stays in the formation for a longer period, there are risks of getting contaminated mud returns (gases/mud get diffused). The solution for wells having trouble with tripping can be to use spot weighted high viscosity pills to control the well statically (Tirado, et al. 2011).

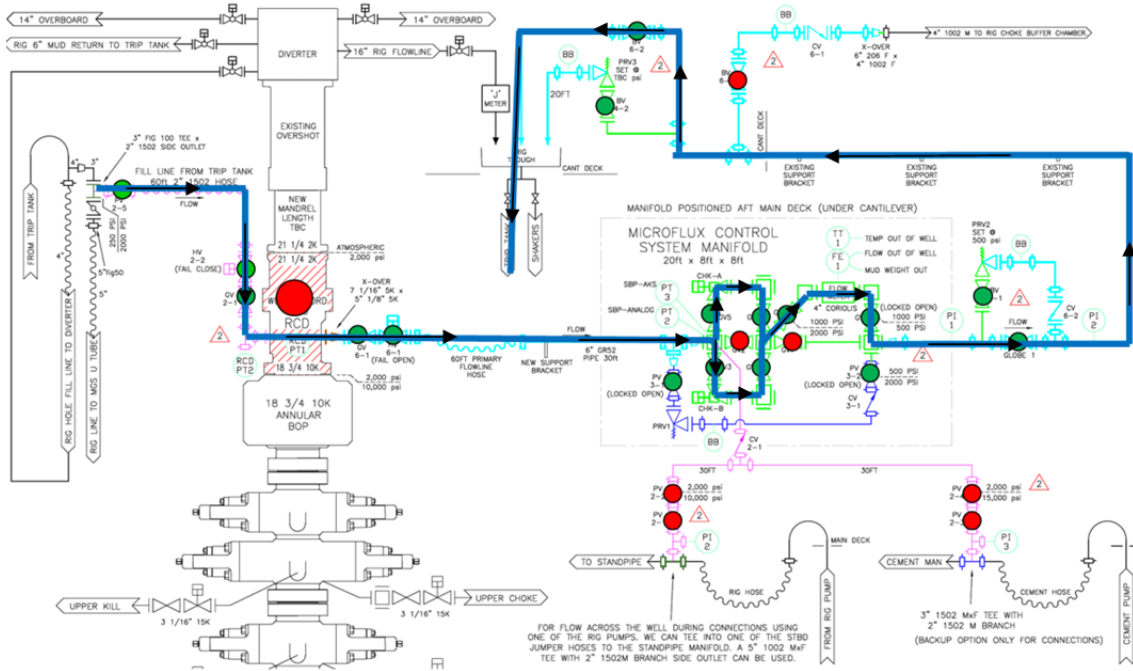


Figure 32: Tripping with RCD in place. The circulation shown above indicates the flow path for topping up or removing excess drilling fluid while tripping (Freely edited from schematics provided by Weatherford (Weatherford 2013))

4 Previous offshore MPD experience in the North Sea

4.1 The Mandarin East Well MPD experience

The extreme HPHT exploration well located on the Norwegian continental shelf North-West of the Ekofisk field in the North Sea was drilled using an MPD technology. The well reached TD with optimal hole size, but was unfortunately shown to be dry. Nevertheless, the drilling phase was successful yielding valuable data and experience for similar wells to be drilled. The Mandarin East exploration well was drilled using the Heavy Duty Jack-up rig “Rowan Gorilla VI” and is currently the most extreme well in regards to pressure (potential surface pressure close to 15 000 psi and BHP at the top of the reservoir close to 17000 psi) and temperature (close to 200°C) ever drilled in Norway (Naesheim, et al. 2011).

The primary reason for using MPD was the need to constantly keep the wellbore in an overbalanced condition through the narrow drilling window to provide early kick detection and to mitigate for wellbore breathing challenges. The location of the well was selected to optimize rig placement on the seabed (avoid legs punching through) and to avoid shallow gas having the Triassic Skagerrak Sandstones as primary targets. Water depth in the area is shallow, 70.4 m. Despite having offset well data available, the well was regarded to have unknown pressure and geology as this well was deeper than all offset wells (Naesheim, et al. 2011). To reach TD with optimal hole size (8 ½ in) it was key to place the 9 7/8 in production casing as close as possible to the reservoir due to the narrow drilling window of 0.4 ppg. Significant wellbore breathing challenges were also expected, making pore pressure and kick detection crucial for the drilling phase.

The 30 in conductor casing was cemented at 212 m MD RKB, the 20 in surface casing shoe at 1132 m, the 13 5/8 in intermediate casing at 4292 m (deepest and heaviest intermediate casing ever run in Norway) and the 10 3/4 · 9 7/8 in production casing shoe cemented at 5400 m. These were the deepest and heaviest (intermediate and production) casings ever run in Norway. The 8 ½ in section was successfully drilled in MPD mode to 5933 m (Naesheim, et al. 2011).

Prior to the Mandarin well, MPD operations performed in Norway normally utilize static underbalanced mud (annular friction and back pressure to control BHP). As this was not an option on the mandarin well, existing procedures needed to be modified as the rigs annular preventer and diverter was insufficient to accommodate the RCD (solved by cutting the mandrel off and re-welding to accommodate for the RCD). As an overbalanced wellbore was required, UBD techniques were not to be used at any stage, back pressure would only be used if an influx was detected (Naesheim, et al. 2011). One of the greatest challenges was to incorporate these new procedures into the existing

HPHT procedures in addition to having clear guidelines for when to use MPD and when to use the "standard" equipment, see Figure 64 Appendix A – .

The MPD system could not be rigged up before the 13 $\frac{5}{8}$ in intermediate casing had been run and cemented due to the limitations on variable deck load, space and required modifications on the rig. The MPD system itself consisted of computer controlled chokes, Coriolis flow meter and an intelligent control unit. The RCD (pressure rating at 200 rpm: 2000 psi static, 500 psi) connected to the BOP was a passive, self lubricating large bore type whereas pipe up to 6 $\frac{5}{8}$ in could pass. The RCD also had a removable bearing assembly which allowed for 18.69 in ID when removed. MPD equipment was connected to the RCD, rig choke manifold, trip tank and poor boy degasser using hard flexible pipes (Naesheim, et al. 2011). The MPD system also included various sensors for the flowlines, mud pits and so on. The top flange is tied back to the rigs bell nipple; see Figure 65, Appendix A – Figures.

Extensive flushing, pressure testing and fingerprinting program were carried out before drilling out of the 13 $\frac{5}{8}$ in casing. The lower part of the 12 $\frac{1}{2}$ in section (last 600 m) were drilled in MPD mode to familiarize the crews with the new procedures (Naesheim, et al. 2011). Another fingerprinting program was carried out prior to drilling out of the 10 $\frac{3}{4}$ · 9 $\frac{7}{8}$ in production casing (17.5 ppg OBM). A LOT to 19.5 ppg was obtained at 5407 m and drilling continued using 17.5 ppg mud weight. Background gas levels were moderate, at the start around 1 %. A gradual gas level increase (up to 5 %) were experienced in the interval 5555-5560 m, two flow checks were performed yielding negative results. Reaching 5562 m a sudden increase to 10 % gas was observed. As circulation yielded no significant decrease of gas levels, surface back pressure were stepwise added until the gas flow stopped at 350 psi which indicated a pore pressure of 18.5-18.6 ppg. The underbalanced state of the well was verified by opening the choke for a short time registering gas influx (Naesheim, et al. 2011). Mud weight was increased from 17.5 to 18 ppg in one circulation while the bit was kept stationary. An open hole LOT was performed to check for changes in formation integrity. The fracture gradient had been reduced to 19.1 ppg, yielding a pressure window of only 0.4 ppg (with 0.1 ppg safety margin). The mud was thereafter increased stepwise up to 18.6 ppg whilst maintaining ECD safely below the 19.0 ppg.

Some minor losses were observed in the sandy intervals. During connections ECD pressure were "locked in" to avoid wellbore breathing using the MPD equipment and chokes, thereby eliminating time needed to circulate the gas out of hole. The narrow pressure window did not allow for trip margin when pulling the BHA. This was solved by stripping put through the RCD with a back pressure of 19.0 ppg from TD to 1400m inside the production casing. For the remaining trip, a 20.0 ppg mud

cap pill were placed at 4000 m to provide necessary trip margin. The use of the MPD system together with this new way of tripping allowed for the 8 ½ in section to be drilled to TD (5932 m) which added significant value as it was very beneficial for the wireline logging, coring, fishing operations and DST (Naesheim, et al. 2011). This way of stripping proved to be much faster than the conventional technique.

The use of the MPD system on the Mandarin well yielded many operational advantages; accurate determination of pressures in the well without using wireline tools, flowlines preventing gas to escape every bottoms up at the bell nipple, locking of the ECD pressure elimination circulation time, time saving stripping technique and flow detection device accurately registering losses below ¼ bbl. Some of the lessons learned were the importance of large enough lines to avoid excessive back pressure, to minimize the off-center drill pipe to rotary table (could result in difficulties installing an RCD sleeve or bearing), tie the MPD flowlines to the rigs trip tank system to allowing circulation across the wellhead with RCD installed (another possibility is to tie the MPD return line from the choke manifold into the rigs flowline, thus eliminating the need for a line to the trip tank while allowing for flow detection if the MPD flow detection system should fail), and using a 2 in 5000 psi line from the rig stand to the choke manifold to accurately lock the ECD pressure during connections (Naesheim, et al. 2011).

The use of this MPD system on this well yielded total estimated savings of 10 days (7.5 MM\$) (Naesheim, et al. 2011).

4.2 The Franklin-Elgin Field MPD experience

The Franklin/Elgin field is a gas condensate field located in the Central Graben area on the UK continental shelf in the North Sea. The reservoirs lie at a depth of 5500 m (93 m water depth) with an initial reservoir pressure of 1150 bar and temperature of 200°C (Jezdimirovic, et al. 2012). The reservoirs are sandstones of late Jurassic age and contain significant levels of CO₂ (3.5 %) and H₂S (40 ppm) (Bergerot 2011).

The main reservoir is the Fulmar (also called Franklin) sands with initial reservoir pressure of 1100 bars and temperature of 190°C. This reservoir also shows good porosity and permeability allowing for good productivity, having up to 30 % and 1 Darcy respectively (Bergerot 2011). The fulmar reservoir can be divided into three main units; The C sands (poor characteristics: degraded permeability, vertical baffles), B sands (best properties, main production) and A sands (tight, may have good top layer). The Pentland reservoir lies underneath the Fulmar reservoir and has initial reservoir pressure of 1150 bars and 200°C, the reservoir quality is poor.

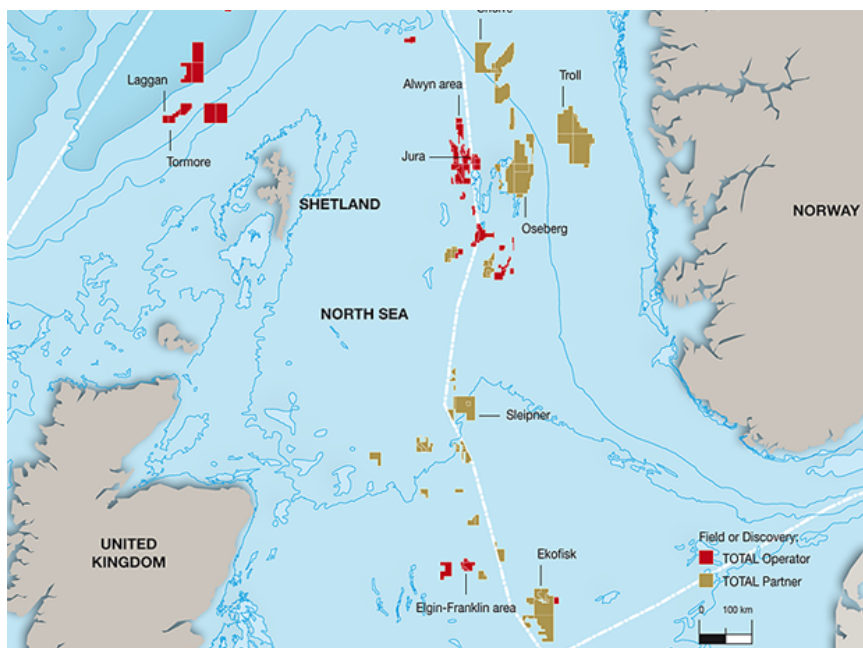


Figure 33: Location of the Elgin-Franklin field (Total E&P 2010)

The Elgin and Franklin fields were discovered 1991 and 1986 and put on stream 2001. At the time Elgin/Franklin was the largest HPHT development in the world (Festa 2009). The Franklin reservoir is located 6 km south-east of the Elgin reservoir. Glenelg (4 km step out, 1999) and West Franklin (3.8 km step out, 2003) were discovered using ERD techniques from the Elgin platform after the initial development, and were put in production 2006 and 2007 respectively. High step out wells in HPHT fields are challenging as the increased well angle affects fluid stability and thereby the ECD (Festa 2009). In 2008 a successful appraisal well was drilled in the West Franklin field. This ERD well (F9y)

yielded far better reservoir properties than the initial F8z well. The West Franklin field was proven to having an initial reservoir pressure of 1185 bars and temperatures up to 220°C in the Fulmar A sands (Jezdimirovic, et al. 2012).

Time of development is critical. Reservoir depletion causes the drilling window to shrink, i.e. the pressure range between the pore pressure and fracture pressure approach one another. Drilling becomes more difficult as depletion increases. The mud weight window may even disappear, which would be the case at Elgin-Franklin if depletion reached 100 bars (Festa 2009). The initial development plan was therefore to drill all wells during the first year, before a depletion level of 100 bars were expected to occur. When production started all wells but one was drilled, having the last well to be drilled at 90 bars depletion. Initial studies indicated that drilling after reaching a depletion level of 100 bars would be impossible.

Drilling of the F9 well on the Franklin field proved it possible to step by step bleed down the gas layers above the reservoir. The conclusion was that it was possible to obtain stability without raising the mud weight, a conclusion that triggered the possibility of using MPD on the Elgin field (Vastveit 2011). Drilling in depleted HPHT reservoir is difficult as the cap rock often is at virgin pressure while the mud window disappears in the transition zone between the cap rock and the reservoir (Festa 2009), see Figure 34. Having different reservoirs at different depletion levels in the same section complicates further infill drilling (Jezdimirovic, et al. 2012).

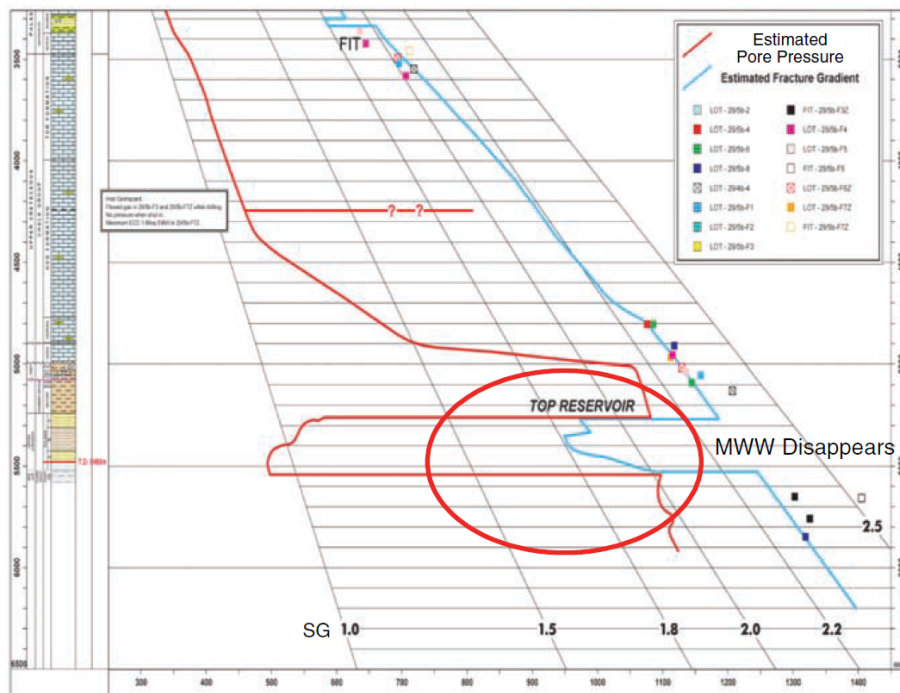


Figure 34: Mud weight window decreases to zero in at the cap rock-reservoir interface; high pressure cap rock following the low pressure reservoir (Bergerot 2011)

In 2007 an infill well was successfully drilled, completed and perforated in the Franklin field after a depletion of 660 bars. Prior to this achievement only a few infill drilling HPHT wells had been drilled, and none successful with depletion levels above 600 bars (Bergerot 2011). Following the success, two additional wells with depletion levels of approximately 800 bars were drilled successfully, both wells drilled using MPD technology.

The initial application of MPD was to determine and control the BHP while drilling, to determine the appropriate MW to balance the well through difficult formations, to control and bleed off gas layers above the reservoir and to evacuate influx at constant BHP (Vastveit 2011). The MPD system contributed to saving approximately 75 days of operational time (based on experience with conventional systems on offset wells).

The first well to be drilled in MPD mode faced severe depletion levels combined with an overlying cap rock at virgin pressure. The primary objects of the well was to enhance recovery from the Fulmar reservoir, prove the feasibility of drilling into highly deplete reservoirs and thereby calibrate the geomechanical model, and to acquire data to be used in simulation models (Corbier, et al. 2011). Prior to depletion previous wells had experienced gas layers bleeding into the well during drilling of the cap rock. How depletion affected this was unknown. The plan was therefore to use MPD to safely bleed of possible gas pockets in the cap rock and then to resume drilling in the reservoir using a low mud weight (Vastveit 2011). The Secure Drilling MPD system were installed prior to the 12 ¼ in section and utilized for the 12 ¼ in, 8 ½ in and 5 5/8 in sections while drilling and tripping (Corbier, et al. 2011)

The second well to be drilled in MPD mode faced similar challenges as the first MPD well. The primary object were to drill and complete an infill production well to produce the Fulmar B and C sands with perforations selected as close to Fulmar B as possible. The main purpose of using the MPD system was to control gas levels. By choking at surface and circulating gas through the mud gas separator the system opened for the possibility to bleed off high pressured gas layers in the well. By measuring the divergence flow downhole gas influx are detected, thus allowing for safe handling by circulating out the accumulated gas (Bouvet, et al. 2010). To avoid the difficulties encountered in the first MPD well (not sufficient gas bleed off) a higher FIT was performed. During the drilling of the reservoir MW was reduced due to early signs (high break-over torque at connections) of differential sticking. The Weatherford Secure Drilling MPD system was installed prior to drilling the 12 ¼ in section and used for all sections following the 12 ¼ in section.

Based on the Franklin-Elgin wells, the following is a summary of the main lessons learned related to MPD (Corbier, et al. 2011)

- Helped to control gas levels while drilling
- Helped avoid differential sticking (stuck pipe) while drilling
- Helped reduce losses in depleted reservoirs
- Helped to circulate out connection gas through the Mud-Gas separator
- Unable to sufficiently bleed off gas layers for the first MPD well which led to the need of a contingency scab liner followed by some minor issues getting the wellbore in full gauge
- Helped to bleed off the formation in the second MPD well (lessons learned from the first well)
- Helped to change BHP rapidly when needed
- Helped to reduce MW and thereby the ECD while drilling
- Total estimated operational savings of approximately 75 days

The Franklin-Elgin development has yielded success beyond expectations, particularly influenced by the discoveries on the satellites Glenelg and west Franklin. These discoveries have extended the life of the field from 22 to 32 years (Festa 2009).

4.3 The Kvitebjørn Field MPD Experience

The Kvitebjørn field is a gas/condensate field located in the eastern part of the Tampen area in the North Sea on the Norwegian continental shelf. The reservoir lies at a depth of approximately 4000 m TVD, water depth of 190 m and consists of Middle Jurassic sandstones of the Brent group (160-190 m) and lower Jurassic sandstones of the Cook formation (Berg, et al. 2009)(Syltøy, et al. 2008). The Reservoir is classified as a HPHT reservoir with reservoir temperature of 150°C and reservoir pressure of 770 bars (Eck-Olsen, et al. 2012). The Kvitebjørn platform (fully integrated steel jacket) was the first manned HPHT rig in the Norwegian shelf.



Figure 35: The location of the Kvitebjørn field (Statoil 2007)

Nine wells were drilled before MPD was introduced to the Kvitebjørn field. The last conventional well (34/11-A-2) encountered depletion of 140-170 bars together with massive losses. The mud used for drilling the A-2 well was very expensive resulting in huge costs when losses occurred (expensive designer mud). Prior to the A-2 well the platform produced at maximum capacity. As an attempt to reduce depletion production was reduced 50 % by December 2006, but as depletion approached 200 bars in May 2007 production was shut down (Syltøy, et al. 2008). Depletion of the reservoir made it impossible to continue to drill conventionally.

The strategy for further development was to combine technologies: MPD to provide control of downhole pressure profile, CCS to maintain constant ECD during connections and drilling fluid designed to improve the fracture gradient. The strategy is to keep the BHP above pore pressure, control the downhole pressure variations, bring the well into overbalance prior to any BHA handling during tripping operations and to let well control events be handled by the conventional BOP system (Eck-Olsen, et al. 2012). MPD technology utilizes an RCD to provide dynamic seal of the annulus, thereby diverting the return flow through a surface choke that controls the back pressure manipulating the downhole pressure profile. A hydraulic flow model was used to compute the required choke adjustments needed to compensate for significant variations in downhole pressure (temperature effects, pipe movement, rotation, torque, cuttings, etc.). The CCS helped to maintain

constant circulation, thereby providing control over the effect of varying downhole temperatures creating a hydraulic stability in the well (Syltøy, et al. 2008). Additionally, the drilling window can be increased by use of particles in the drilling mud (Eck-Olsen, et al. 2012). As a precaution MPD and CCS were utilized until level of depletion could be verified. Depletion levels of up to 170 bars were expected in some wells making conventional drilling impossible (unknown how the communication was between reservoir sections).

The installation of the MPD system started during the end of the 12 ¼ in section. The MPD BOP stack was hooked up to the choke manifold while the surface piping and software was installed. After the installations both the MPD system and the CCS was simultaneously tested and used for training of the crews. A conventional 15k BOP system was used to handle all well control events. Dual redundant chokes were installed to avoid corrosion in addition to pressure relief valves in the return flowline to protect the equipment (Syltøy, et al. 2008). The auxiliary pump provided full control over the annulus, providing continuous fluid flow to the choke and thereby maintaining the desired back pressure at all times regardless of the main pump operation.

HPHT procedures were implemented when drilling the 9 7/8 in casing shoe. The 9 7/8 in casing shoe and the entire 8 ½ in section was drilled in MPD mode until level of depletion could be verified. As the depletion levels got verified drilling continued in MPD mode for the severely depletion sections and conventional mode for sections with low depletion (low enough to drill conventionally). Several wells were drilled using MPD as the first MPD well was considered to be a success. MPD was used on 6 wells in total on the Kvitebjørn field, most considered as successful.

Based on the Kvitebjørn wells, the following is a summary of the main lessons learned related to MPD

- Helped reduce losses in depleted reservoirs
- Helped verify depletion levels and thereby also reservoir communication
- Helped verify formation depths
- Helped to stay within the narrow MW window
- NPT due to commissioning and testing of the system in addition to some minor tool failures (CCS had to be rigged down and up)
- MPD control possible for fishing operations
- Plugging of the wellbore due to reduced circulation rate (particle addition should be compromised with ECD for proper cleaning)

5 The Solaris Prospect

The Solaris well is an Ultra HPHT exploration well expected to be drilled in 2015 by Total E&P Norway. The reservoir is classified as ultra HPHT with temperature close to 200°C and an absolute maximum expected WHP close to 15 000 psi. Jurassic fault block which is a part of the larger structure known as the Mandarin structure (drilled by BG in 2010) is the target. This structure is located in the eastern Central Graben area with at shallow water depth of 70 m close to the border between the UK and Norway. The Solaris well is planned to be a vertical well with the Upper Jurassic reservoirs of Oxfordian age (also known as the Ula formation) as the main objective lying at 5650 m MD, the target depth (TD) for the well is 6000 m MD (Total E&P 2013a). Based on the depth of the target together with the maturity of the source rock, it is expected to be a gas-condensate reservoir. This correlates to the Elgin-Franklin field which is producing from the same reservoirs. Levels of H₂O and CO₂ are expected to be low based on reference wells and regional knowledge.

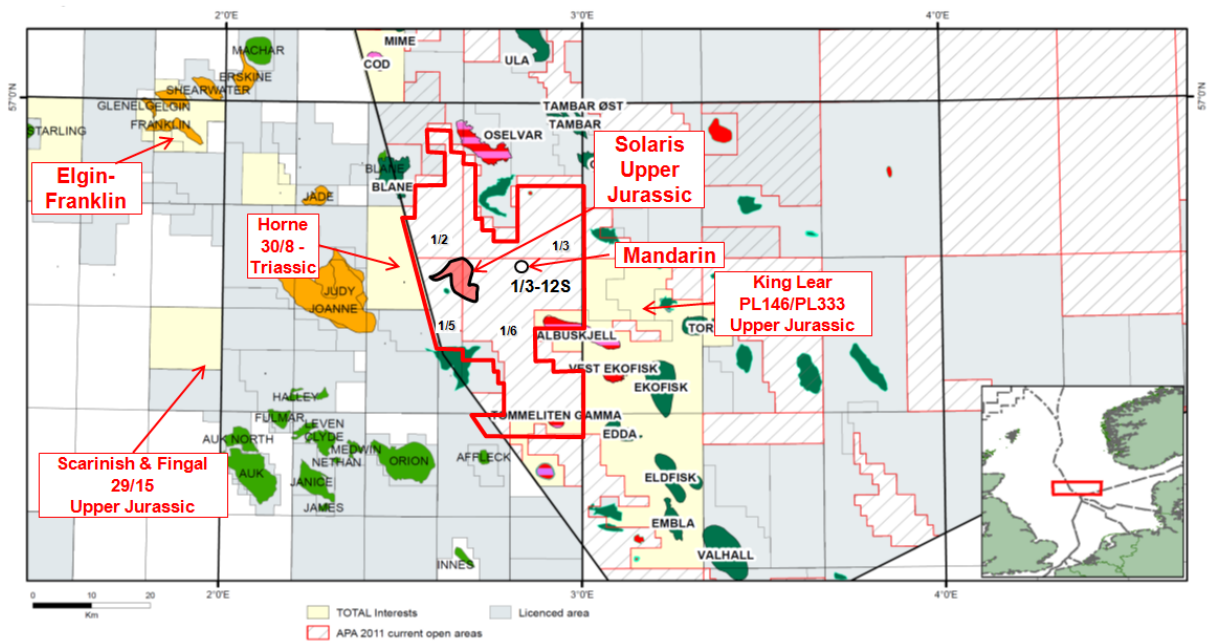


Figure 36: Location of the Solaris well (Total E&P 2013a)

There are many offset wells in the area that have been used to estimate (and lowered the level of uncertainty of) the well characteristics and pressure profiles. An overview of the most important reference wells is shown in Appendix B. The main uncertainties are reservoir conditions, probability of taking a kick and the operational procedures to detect and stabilize the kick safely, and in worst case scenarios the performance of well barrier components themselves (Total E&P 2013c). Based on offset wells, the pressure regime for the well has been estimated. The most likely case and the commitment case are shown in Figure 37 (more specifics can be found in Appendix G – Estimation of

the Pressure Profile). As the figure indicates, the main issue is the narrow MW window in the deeper section of the well. For the commitment case (i.e. the case of which an operator can commit to as being plausible) the apparent MW window is 0.14 sg. The most likely case on the other hand has a MW window of 0.25 sg.

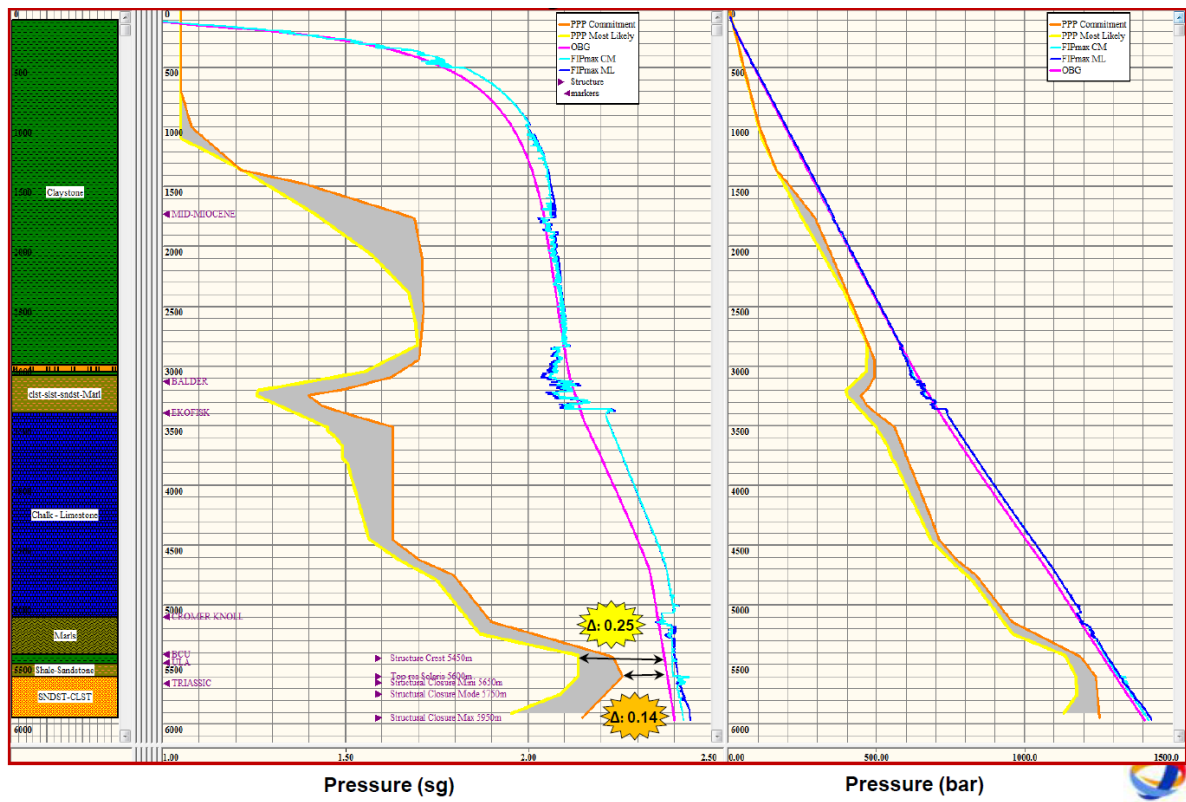


Figure 37: The Solaris well pore pressure prediction Most Likely case (yellow line) vs. Commitment case (orange line) (Total E&P 2013a)

There are many risks associated with drilling an Ultra HPHT well. The casing design must be designed to handle the maximum expected wellhead pressure with safety factors, the mud needs to be properly adapted to the HPHT conditions to prevent losses and an extensive contingency plan must be prepared. It is also important to follow strict tripping procedures to minimize swab and surge effects. Many uncertainties regarding rheological properties, compressibility, heat expansion, and reservoir and wellbore volume arise when drilling in an HPHT environment. Equipment is also affected by high temperatures, whereas most equipment can handle temperatures up to 400°F (205°C). As the experience of drilling in HPHT environments increase, so do the technical research and equipment advancements. A brief summary on HPHT challenges can be found in Appendix F – Further HPHT Considerations.

The casing design for Solaris covers both the most likely- and the commitment case, with the maximum fracture initiation pressure (FIPmax). Having a high FIP yields an extra challenge for casing design as it may lead to high internal casing loads. The Solaris base case design is shown in Figure 39

whilst the contingency design is shown in Figure 38. The plan is to set the conductor casing at 115 m MD RKB, followed by the surface casing set between 1050-1150 m MD RKB. A 9 7/8 in pilot hole will be drilled for shallow gas exploration, before drilling and setting of the 14in×13 3/8 in casing at 4100 m MD RKB can commence. Then at 5300-5400 m MD RKB the 10 3/4 in×9 7/8 in casing will be set. The contingency design on Figure 38 shows the casing designs if trouble arises while drilling (basically shows the additional casing setting points): liner at 1700 m MD RKB if shallow gas is detected or insufficient kick tolerance to drill as planned, liner at 4500 m MD RKB and at 5430 m MD RKB if previous casing is set shallow or there is insufficient kick tolerance to drill as planned. The contingency design requires slim connections.

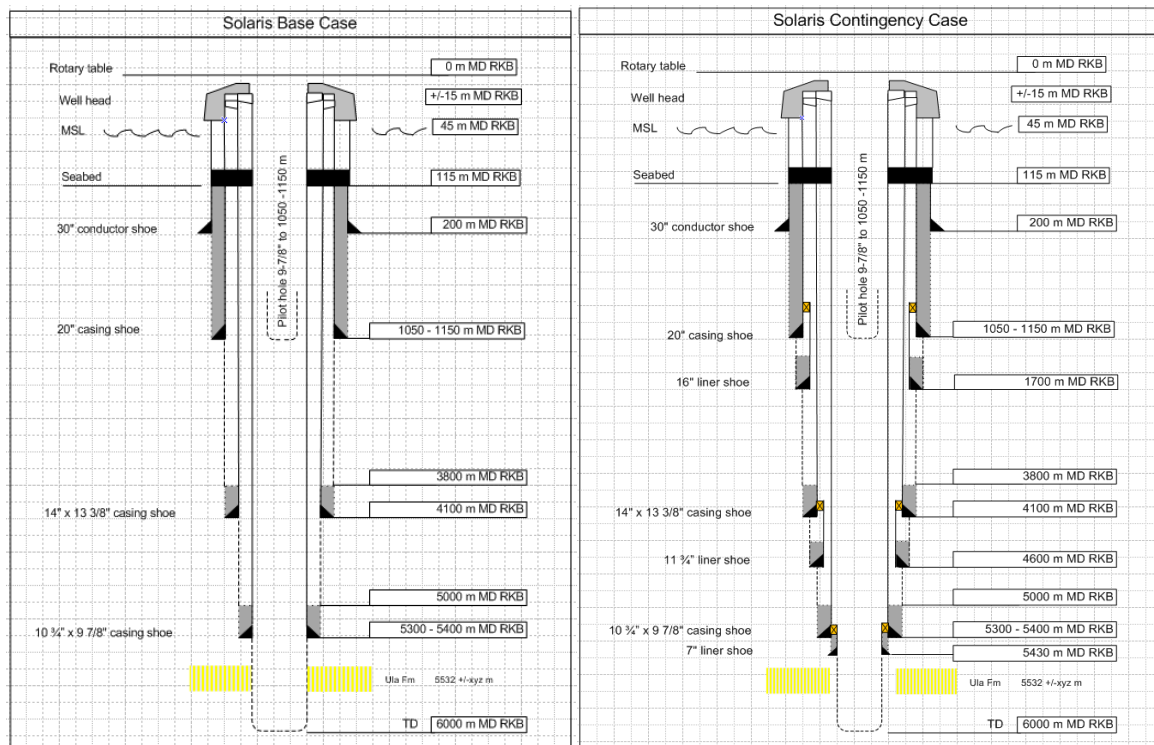


Figure 39: Casing Design for the Solaris well (Total E&P 2013a) Figure 38: Contingency design for the Solaris well (Total E&P 2013a)

As for the Mandarin well (case very similar to the Solaris prospect) the main reason for using an MPD system is to keep the wellbore in constant overbalance while drilling through the narrow MW window. Wellbore breathing challenges are expected as this is an ultra HPHT well, meaning that pore pressure and kick detection is crucial for the drilling phase. An MPD system provides the possibility to continuously identify the actual pore pressure and fracture gradient while drilling (see section 3 Weatherford's MPD system), thereby providing data which helps the driller stay within the narrow pressure margins. Wellbore breathing issues can also be minimized by "locking in" the ECD pressure during connections. This is done by manipulating the MPD chokes to keep a constant BHP and thereby eliminating the need to circulate the gas out of the wellbore. Maintaining control over the

ECD is crucial when drilling through narrow pressure margins, even small fluctuations may cause the MW to exceed the pressure limits as pressure margins may be underestimated.

The well needs to be kept in constant overbalance while drilling through the narrow MW window, preferably with a static overbalanced mud. If this shows not to be plausible static underbalanced mud can be considered, however this also incorporates new safety risks. As the objective will be to keep the well in constant overbalance, back-pressure will only be applied (or increased) when influx is detected in the well. When drilling in MPD mode, suppliers often recommend applying a minor back-pressure to help minimize pressure fluctuations while drilling⁴.

The use of a Non-aqueous based mud (NABM) is beneficial when drilling in HPHT environments due to its thermal and lubricant capabilities. Barite sag is a common problem in HPHT wells, especially for deviated wells (for more specifications see Appendix F – Further HPHT Considerations). The Solaris well is planned to be a vertical well, meaning that sagging is not likely to be a major issue. As the well has a narrow MW window combined with high pressure and temperature, it requires a relatively high MW (which in general worsens sagging issues). As of today, there are a few options: Micromax (Magnesium Oxide particles) weighting agent and WARP (barite particles) weighting agent. Both weighting agents being micronized particles normally delivered as slurries (Mi SWACO 2013a), particle distribution for common weighting agents is shown in Figure 40. As the Micromax weighting agent has a higher density than the WARP weighting agent, a higher MW can usually be obtained with a lower viscosity. Another challenge is the need to form a filter cake. Ultra fine particles will not be able to block the pores, meaning that they cannot form a filter cake. A solution commonly used is to mix these ultra fine particles with some larger particles (e.g. API barite). More information about Micromax and WARP can be found in Appendix H – Weighting agents.

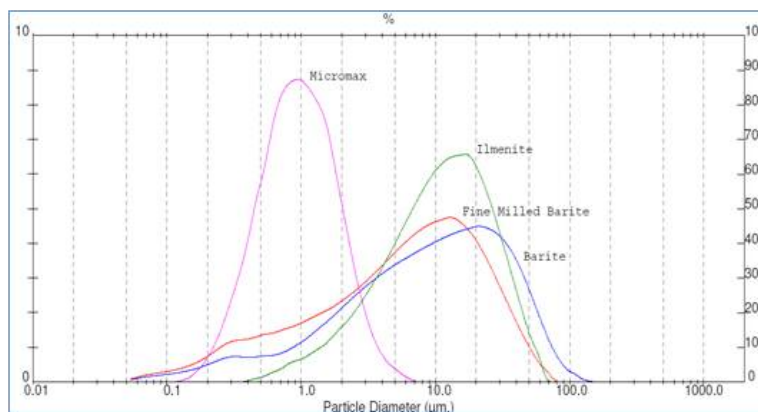


Figure 40: Particle distribution for common weighting agents used by Baker Hughes⁵

⁴ Personal communication and e-mail correspondence with Christine Madsen, Segment Sales manager MPD SCA, Mi SWACO Norway.

⁵ Personal communication and e-mail correspondence with Eirik Jøntvedt, Sr. Fluid Engineer, Total E&P Norway

The Solaris well has many similarities to the wells mentioned in the MPD case studies in the North Sea (section 4 Previous offshore MPD experience in the North Sea): large uncertainties regarding the pressure profile, a narrow MW window and unknown level of depletion (communication between reservoir sections). Many reference wells are available, which gives sufficient data to provide a probable pressure profile. The narrow MW window makes conventional drilling impossible, or at least improbable. MPD opens for drilling while controlling the wellbore pressure dynamically and thereby optimize the drilling process while NPT is significantly reduced. NPT for HPHT wells such as the Solaris is initially set to 30 %, which is a huge part of total operational costs. As for the mandarin well, the Kvitebjørn and the Franklin/Elgin field NPT was reduced significantly on the MPD wells compared to conventionally drilled wells. MPD also provide mitigations for several drilling challenges which have proven to be successful for several wells similar to Solaris. MPD provide continuous and accurate data on pressures and ECD without using wireline tools, which is a huge asset when drilling through narrow MW windows. The objective of MPD is to eliminate cycles of losses/kicks and the associated NPT.

For the Solaris prospect a 15k BOP system will be used. The rig selected to be used on this well is the Heavy-duty Jack-up (HDJU) rig Maersk Gallant. The Maersk Gallant is a very stable drilling platform suitable for sensitive HPHT wells (rig specifications can be found in Appendix I – Heavy-Duty Jack-Up rig Maersk Gallant). This type of rig can handle harsh environments needed for drilling in harsh conditions such as the North Sea. The crew on Maersk Gallant is familiar with HPHT- and MPD procedures, but nonetheless frequent drills should be performed to keep the crew up to speed and familiar with the correct practices for all scenarios. A comprehensive blowout contingency plan should be among these scenarios. The Maersk Gallant is equipped with a 15k BOP system and do have a sufficient tank and pump capacity for the Solaris prospect.

6 A Way to determine the applicability of MPD - Drillbench Simulation: Presmod

Drillbench is an advanced software used to design and evaluate drilling operations. The software focuses on different challenges encountered in drilling operations by compiling individual applications (tailored for specific tasks) that are based on the same design basis.

Presmod is one of the applications in Drillbench which focuses on drilling hydraulics and modelling of wellbore pressure and temperatures during all phases of the drilling operation. Presmod offers an exact evaluation of how operational conditions and fluid properties influence pressure and temperature in the well. Important parameters such as pressure, temperature depended fluid properties, thermo physical properties, detailed geometry description and operational effects are included. The Presmod application is a valuable tool for operations with narrow pressure margins typical for HPHT wells, deepwater wells, ERD wells and for depleted reservoirs where temperature effects are extremely important. Presmod can be used for selecting fluid systems, the development of operational procedures to ensure objectives without exceeding the wells pressure limits, interpret and correlate PWD readings, provide temperature information needed for the downhole electronics, and calculate ECD, ESD, thermal expansion effects and temperature profiles.

This software is a good way to help determine whether a well can be drilled conventionally, or if it is beneficial to use other drilling techniques. By simulating the different techniques at hand, visual and specific challenges are examined more closely. How the ECD is directly affected by connections, and which parameters worsens the effect can be determined. Also, by activating the RCH and the choke to the simulation, back pressure can be applied and thereby MPD can be simulated. As both conventional drilling techniques and MPD can be simulated, these can then be compared for determining the best possible solution for a well.

6.1 Input parameters

The first step is to create a file and to define the project description. The purpose is to describe the main purpose and key parameters to easily identify which case is simulated.

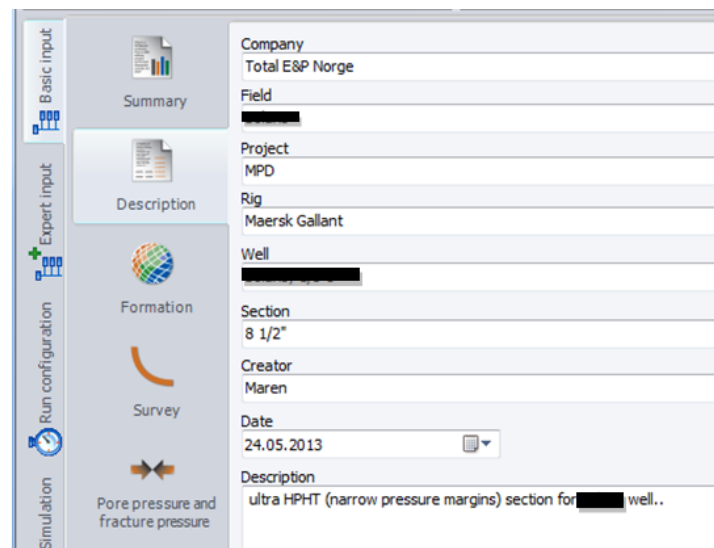


Figure 41: Description window of the case to be simulated (Drillbench - Presmod 2011)

The next step is the formation inputs. This is in general information about the environment where the well is to be drilled. Surface temperature must be specified and will be the starting point of the geothermal gradient, and is for this case chosen to be set at 15°C. All depths entered into Presmod are in reference to RKB. For the formation inputs an air gap of 48 m was put as the top layer having a geothermal gradient of zero, while layer two is the sea water having a negative gradient of -0.05 as cold water normally sinks due to its higher density. The fact that water is heaviest at 4°C can be disregarded as the water depth for this particular well is shallow (effect is minor and can therefore be neglected). The third layer implemented is the formation layer. The geothermal gradient chosen for the formation is $0.033 \frac{^{\circ}\text{C}}{\text{m}}$ as this correlates to close offset wells. Geothermal gradient varies from location to location, but is normally in the range of $0.025\text{-}0.035 \frac{^{\circ}\text{C}}{\text{m}}$. If it is indicated that the formation consists of two or more geothermal gradients several layers should be selected and specified, but for this case one geothermal gradient is sufficient. For each layer thermo physical properties can be specified by activating the customized fields, or set to default values. For this well these values are set to default.

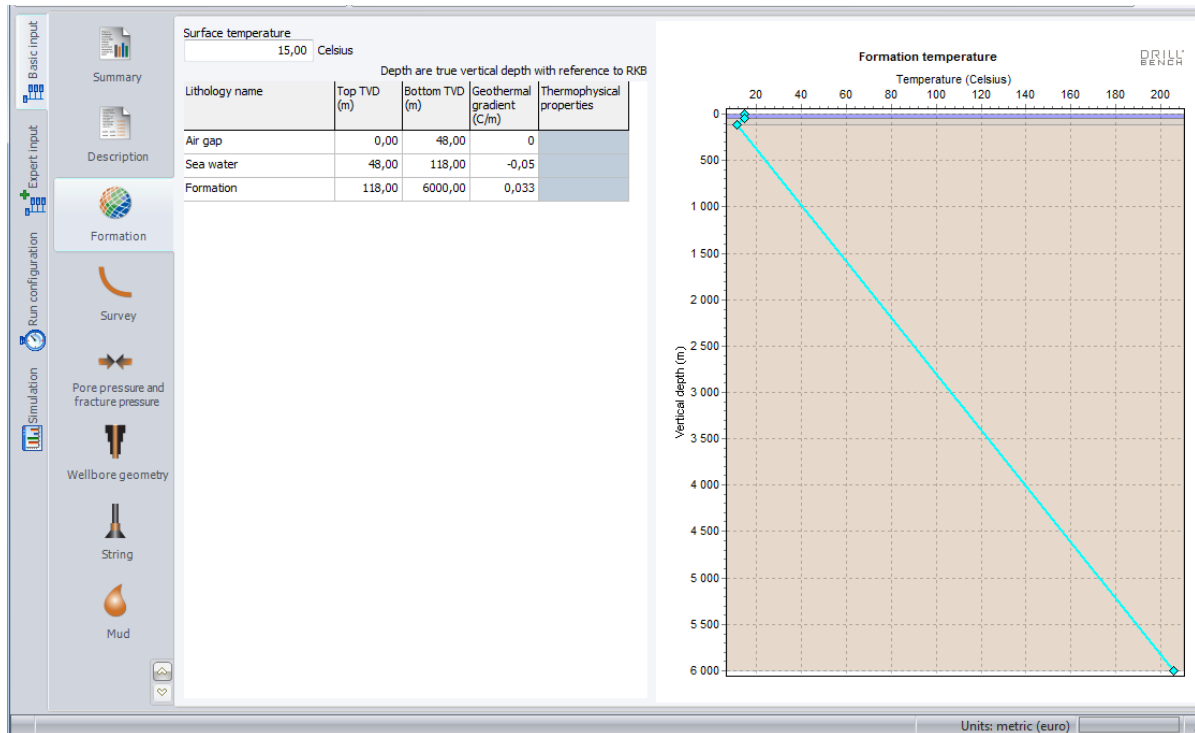


Figure 42: The formation inputs with specified layers depths, geothermal gradients and an illustrative graph (Drillbench - Presmod 2011).

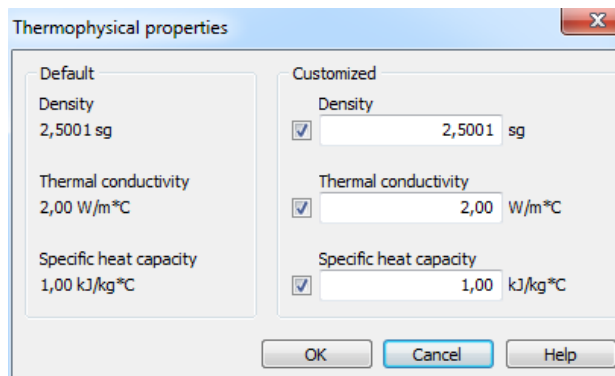


Figure 43: Thermo physical properties can be set to default or be specified by customizing these values (Drillbench - Presmod 2011)

The Presmod application uses the minimum curvature method to calculate TVD from measured depth, inclination and azimuth. Inclination is defined the vertical plane whilst the azimuth in the horizontal plane, see

The minimum curvature method is an extension of the balanced tangential method. Instead of assuming the wellpath to be two straight line segments, it assumes the wellpath to be a circular arc.

This modification is implemented to the survey equations as a factor F based on bending (also known as the dog-leg angle, ϕ) between the two survey stations.

$$\phi = \cos^{-1}[\cos\alpha_1 \cos\alpha_2 + \sin\alpha_1 \sin\alpha_2 \cos(\beta_2 - \beta_1)] \quad \text{Eq. 6}$$

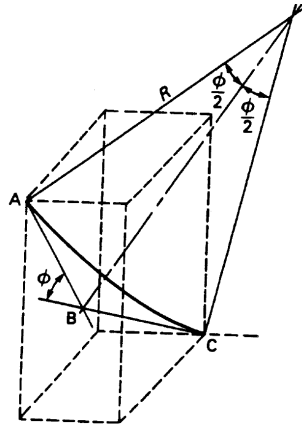


Figure 44: Minimum Curvature model

The factor F can be calculated from basic geometry rules as

$$F = \frac{AB + BC}{arc AC} = \frac{2}{\phi} \left(\frac{180}{\pi} \right) \tan \left(\frac{\pi}{2} \right) \quad \text{Eq. 7}$$

This yields following survey calculation equations

$$\Delta V = F \frac{L}{2} (\cos\alpha_1 + \cos\alpha_2) \quad \text{Eq. 8}$$

$$\Delta N = F \frac{L}{2} (\cos\alpha_1 \cos\beta_1 + \cos\alpha_2 \cos\beta_2) \quad \text{Eq. 9}$$

$$\Delta E = F \frac{L}{2} (\cos\alpha_1 \sin\beta_1 + \cos\alpha_2 \sin\beta_2) \quad \text{Eq. 10}$$

The minimum curvature method is the most accepted method worldwide for survey calculations. The angle between two points is given as the average angle between the points. The Presmod application can handle horizontal sections, but angles higher than 100° is not recommended. The survey plot can be previewed in 3D.

As the well to be simulated is a vertical well both inclination and azimuth is set to zero. While drilling it is important to check whether or not the well is following the planned well path as deviations may cause large problems especially in regards to nearby wells and narrow pressure margins.

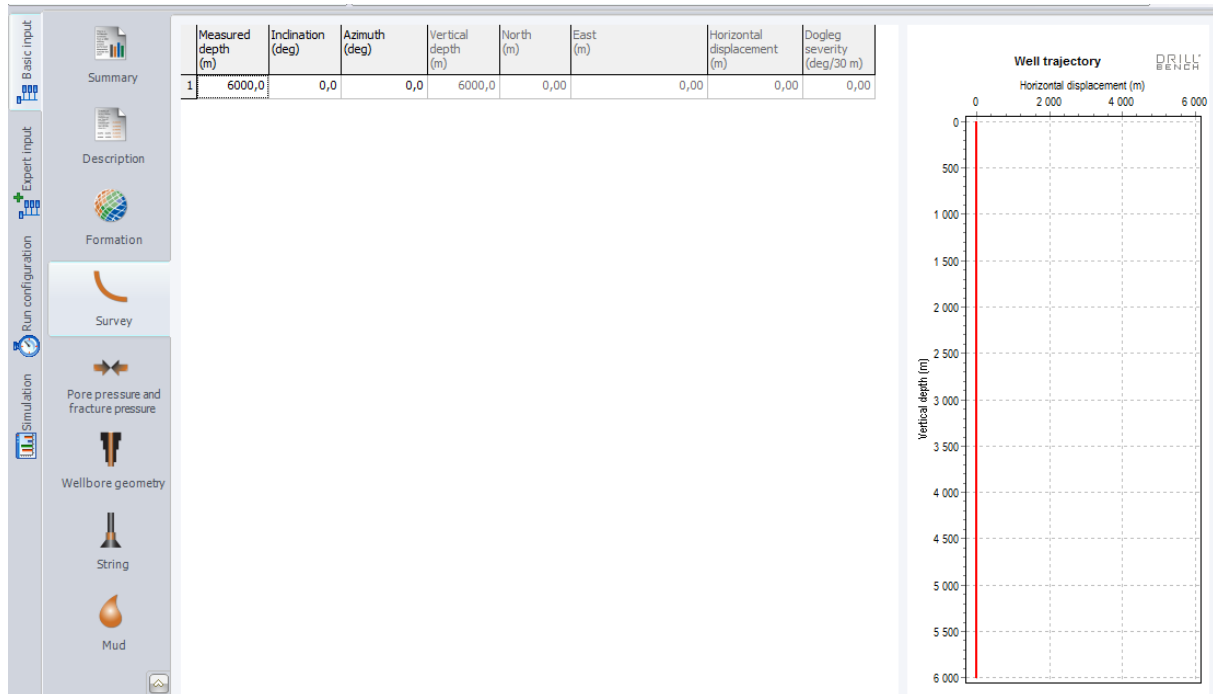


Figure 45: Survey inputs and well trajectory (Drillbench - Presmod 2011)

The next step is to input pore pressure with corresponding fracture pressure at various depth in the well. These data will later be used for ECD and pressure references. Either pressure or pressure gradients can be implemented whereas the corresponding value will be automatically calculated. The upper table specifies the pore pressure data whilst the lower specifies the fracture pressure data. Figure 46 below shows the expected pressure profile for the well in this simulation.

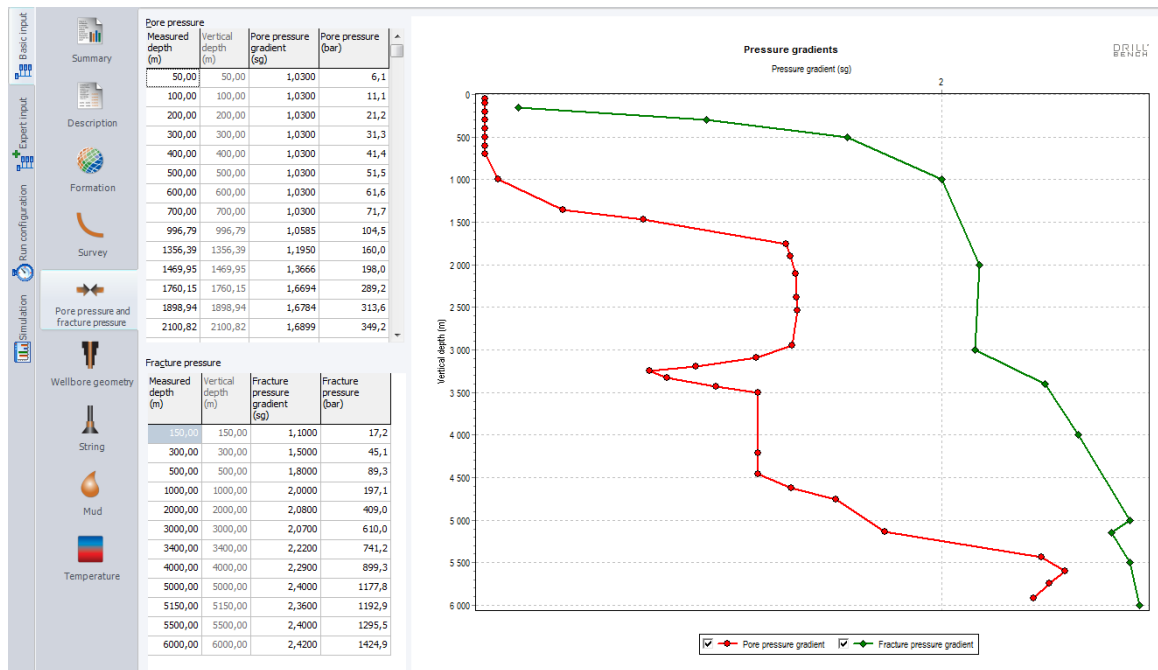


Figure 46: Specification of pore pressures with the corresponding fracture pressures at various depths. The upper table shows the pore pressures whilst the lower table shows the fracture pressures (Drillbench - Presmod 2011)

Some believe that the more points are added into an expected pressure profile the more accurate the plot will be. The expected well data are usually estimations, meaning that they may all deviate from the actual well data. The goal is to catch the wells main characteristics and probable pressure margins.

The next input parameters are the Riser and Casing data for the well. The riser is specified according to its dimensions and length. For casing inputs it is normal to include all casings together with surrounding materials. If the dynamic temperature model is not used the innermost casings and liners are sufficient (hole diameter, top of cement and material above cement is excluded). Figure 47 shows the riser and casing/liner program for the well simulation. The dynamic temperature model is used for this simulation. For the casing/liner input hanger depth (starting point of the casing/liner) is specified in the first column, setting depth (actual casing setting depth or cross-over point) in the second, inner diameter (if casing is selected from the library this is taken from the library data) in the third, outer diameter (bit size) in the fourth, top of the cement in the fifth and material above the cement in the sixth. As for the materials above the cement: if cemented to the seabed there will still be a seawater column above. Thermo physical properties can be specified or set to default.

Riser

| Name | Length (m) | Inner diameter (cm) | Outer diameter (cm) | Thermophysical properties |
|--------|------------|---------------------|---------------------|---------------------------|
| 13 5/8 | 15,0 | 31,8 | 34,6 | |

Casing / Liner

Depths are measured depth with reference to RKB

| Name | Hanger depth (m) | Setting depth (m) | Inner diameter (cm) | Outer diameter (cm) | Hole diameter (cm) | Top of cement (m) | Material above cement | Thermophysical properties |
|---------------------------|------------------|-------------------|---------------------|---------------------|--------------------|-------------------|-----------------------|---------------------------|
| 30" X-52 309.7 lbs/ft | 15,0 | 200,0 | 71,1 | 76,2 | 91,4 | 115,00 | Sea water | |
| 20" Q125 94 lbs/ft | 15,0 | 1150,0 | 48,6 | 50,8 | 66 | 115,00 | Sea water | |
| 13 3/8" Q125 80.70 lbs/ft | 15,0 | 4100,0 | 31 | 34 | 44,5 | 3800,00 | OBM example#1 | |
| 9,875 | 15,0 | 5400,0 | 21,9 | 25,1 | 31,1 | 5000,00 | OBM example#1 | |

Figure 47: Riser and Casing/liner specifications (Drillbench - Presmod 2011)

When drill string details are entered it can be chosen to use tool joint calculations. If tool joints calculation is chosen the average stand length must be specified, see Figure 49. Components can also be chosen and then manually modified if necessary. After manually specifying a component, it can be stored in the library for later simulations. The different drill string components can be found in the library or manually specified. The table includes the entire BHA from the bit and up. The bit itself is specified separately either by choosing from the library or manually adjusting the properties. The flow area through the nozzles can be defined either as total flow area or by entering each nozzle diameter, see Figure 48. Extra nozzles can be added if desired.

Bit data

Bit
Bit 8 1/2 pdc

Bit / Open hole diameter
21,6 cm

Area definition method
Total flow area

Total nozzle area
0,00045 m2

| Nozzle diameter (cm) |
|----------------------|
| 1 1,2 |
| 2 1,2 |
| 3 1,2 |
| 4 1,2 |

Figure 48: Bit configuration (Drillbench - Presmod 2011)

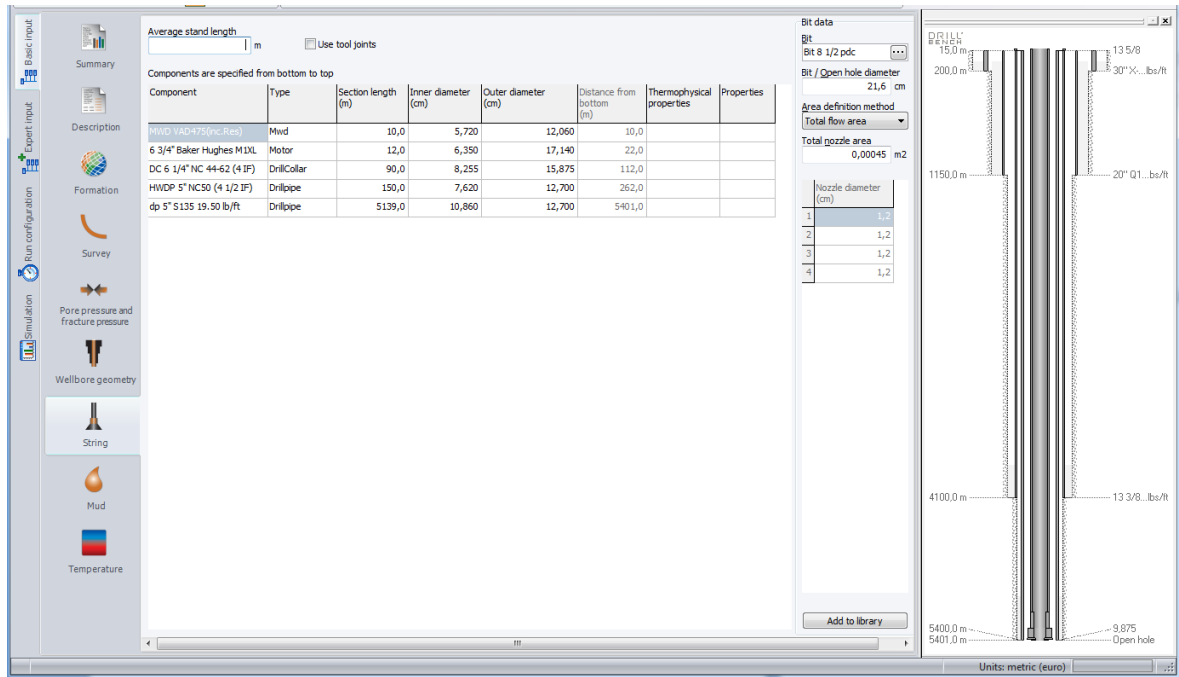


Figure 49: Drill string specifications together with a schematic of the well (Drillbench - Presmod 2011)

Then drilling mud must be implemented. The mud can be chosen from the library or specified at wish. To create a new fluid component density, PVT, thermo physical properties and rheology needs to be specified. The component input densities is as follows: 0.82 sg base oil density, 1 sg water density and 4.5 sg solids density. The mud is set at 2.26 sg which is the limit of the pore pressure for the well simulated. The density is in reference to a temperature of 40°C. Further, the oil-water ratio is $\frac{85}{15}$ (5.67).

For this well the density correlation PVT model was chosen. These correlations are based on experimental work on different oil samples. The different models are the Standing model which was developed for Californian oils, the Glassø model which was developed for North Sea oils and the Sorelle model which was developed specifically for HPHT conditions. A fourth option is to enter specific experiment data on a spreadsheet function. For this simulation the Sorelle model was chosen as the simulation will be of an ultra HPHT well. The water density model chosen for the simulation is the Kemp-Thomas model which is formulated for brines compensating for ionic interactions. Wight fraction of the salts is set to be 20 % CaCl₂.

| Temperature (Celsius) | Pressure (bar) | 600 RPM (Pa) | 300 RPM (Pa) | 200 RPM (Pa) | 100 RPM (Pa) | 60 RPM (Pa) | 30 RPM (Pa) | 6 RPM (Pa) | 3 RPM (Pa) |
|-----------------------|----------------|--------------|--------------|--------------|--------------|-------------|-------------|------------|------------|
| 50,00 | 1,0 | 54 | 31 | 23 | 13 | | | 3 | 3 |

Figure 50: Fann Table(Drillbench - Presmod 2011)

Further, three rheology models are available: Power law, Bingham and Robertson-Stiff. The Robertson-Stiff model ($\tau = A(\dot{\gamma} + C)^B$) is the recommended model for most cases (Drillbench - Presmod 2011). Pressure and temperature dependent rheology data is entered into the Fann reading table, where at least three Fann readings are recommended, see Figure 50.

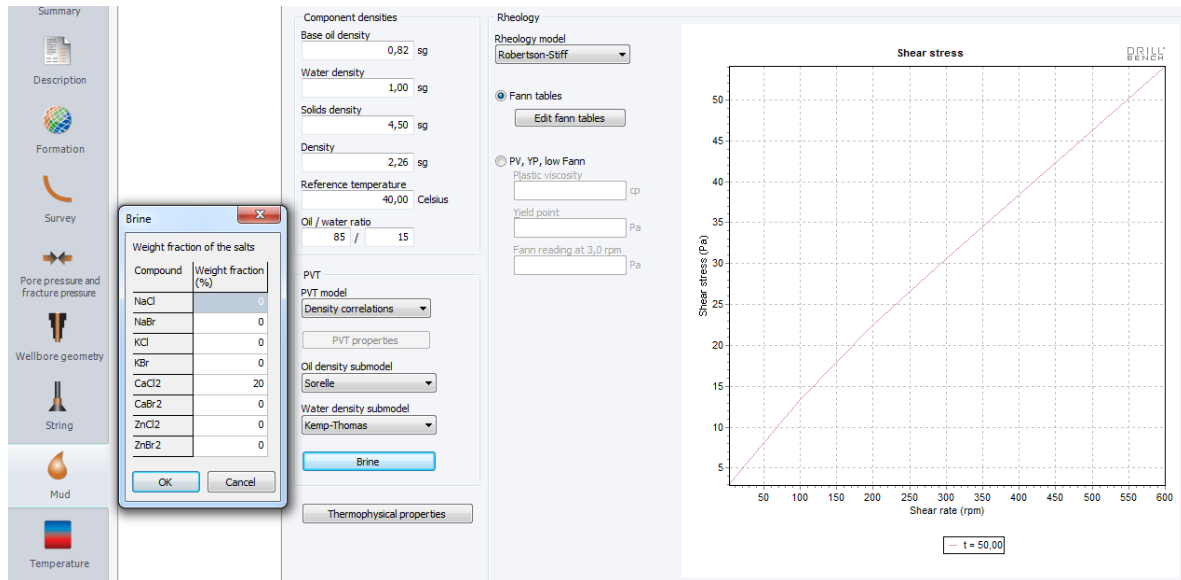


Figure 51: Mud specifications (Drillbench - Presmod 2011)

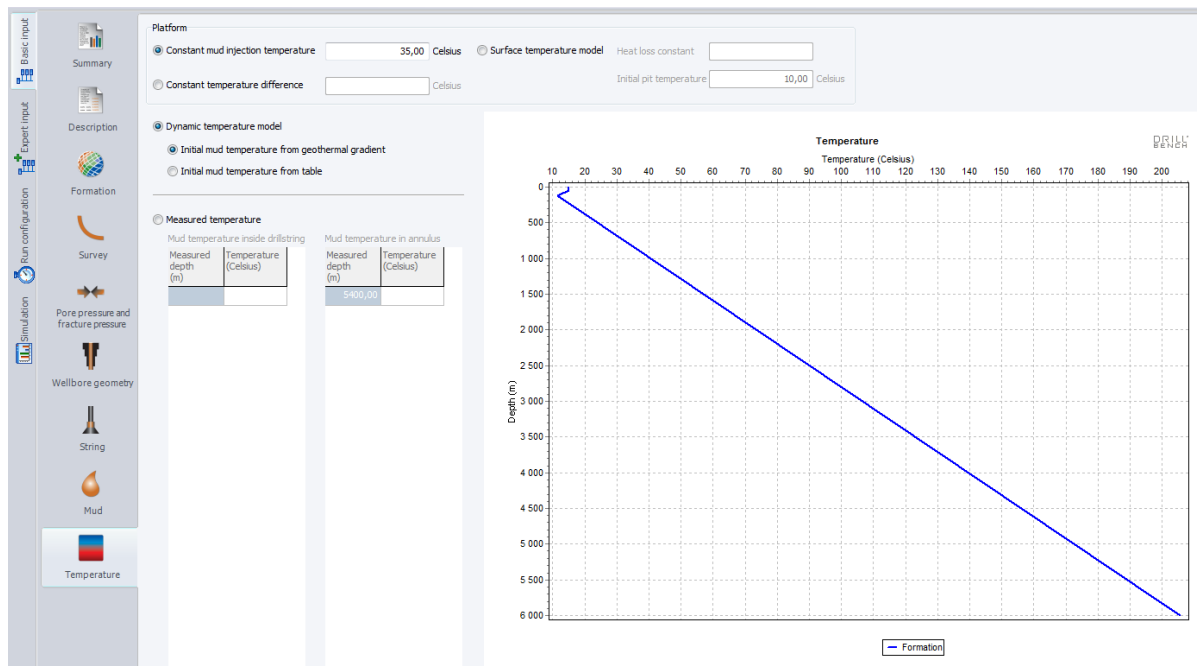


Figure 52: The temperature inputs (Drillbench - Presmod 2011)

The next step is then to specify the temperature of the injected mud. This is only used for when the dynamic temperature model is chosen. The injected mud can be specified as constant if the temperature will remain the same under the entire simulation or as a constant temperature difference of the outlet temperature. Another option is to specify the initial pit tank temperature and

its heat loss constant. For the simulation of this well the dynamic temperature model is chosen, see Figure 52. This model calculates heat transfer and temperature dynamically along grid cells in both radial and flow direction.

The final “short summary” can then be found fairly easy at all times during the simulation process which is very helpful if several cases are run at the same time, see Figure 53.

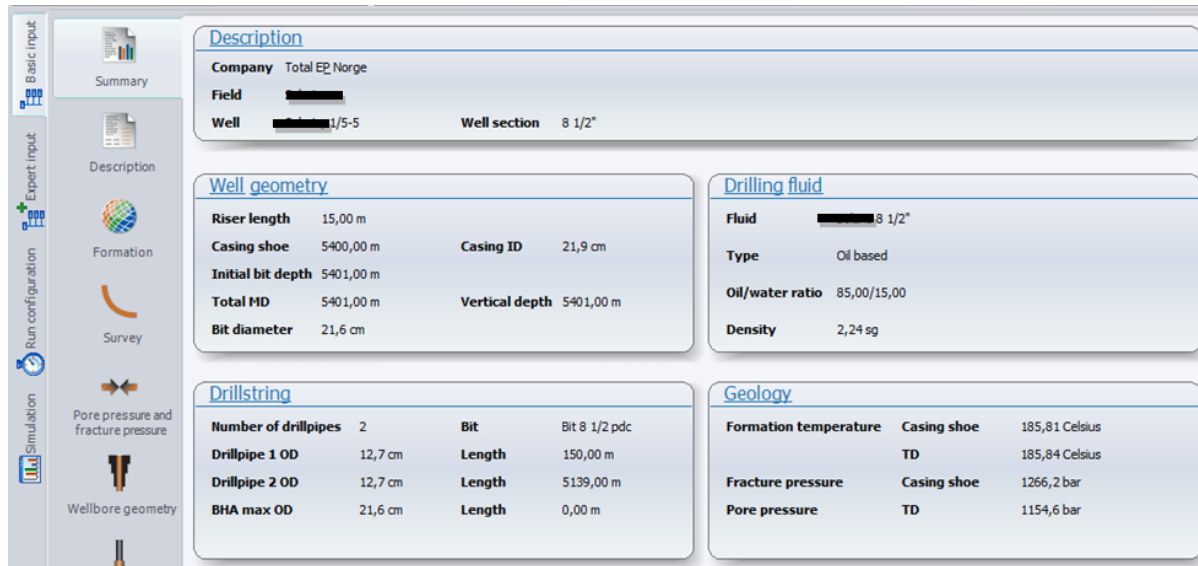


Figure 53: A summary of the simulation to be run (Drillbench - Presmod 2011)

The software also allows for eccentricity input. However, as this is a vertical well eccentricity effects can be neglected. Conventional drilling simulations can now be performed. To implement an MPD simulation a Rotating Control Head and choke are specified into the simulation. The goal is then to compare these results and hopefully be able to do a recommendation based on the achieved simulation results.

If the surface piping between the pump and wellhead has a considerable pressure loss the pressure loss must be entered into the program, see Figure 55. Further, information about the rotating control head (RCH) and choke must be entered. As can be seen on Figure 54 inner diameter and the minimum required time to fully close the choke must be specified (surface pipe length is automatically added by the simulator). For the case simulated the chokes ID is set to 10.2 cm and a minimum closing time of 0.02 minutes. When the RCH is in use and specified, a working pressure for the separator must be set. For this case the separator working pressure is set to 10.3 bars.

The software also allows for eccentricity input. However, as this is a vertical well eccentricity effects can be neglected.

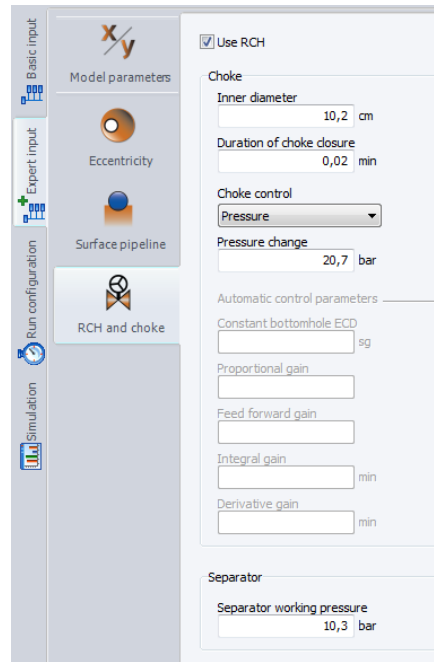


Figure 54: Specifying the RCH inputs, Choke control input and separator working pressure

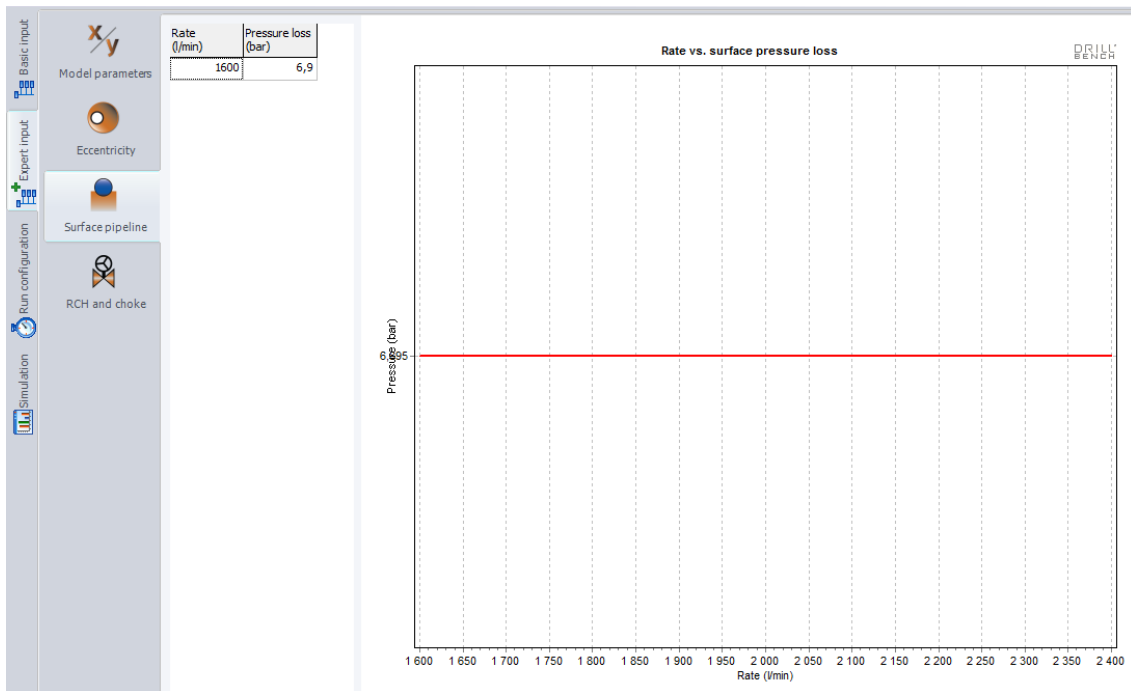


Figure 55: Surface piping and the corresponding pressure loss specified

When running a simulation, it can be divided into specific sequences of constant operational conditions known as batch configuration. By specifying certain time periods a set of operational conditions are kept constant until a new batch is run. After all batch configurations are run, the conditions specified at the simulation itself become active.

| | Duration (min) | Accumulated time (min) | Pump rate (l/min) | Choke opening (%) | Fluid | Fluid density (sg) | Inlet temperature (Celsius) | Rotation velocity (rpm) | Torque (Nm) | Rate of penetration (m/hr) | Riser booster pump rate (l/min) | Bit depth (m) |
|---|----------------|------------------------|-------------------|-------------------|----------------|--------------------|-----------------------------|-------------------------|-------------|----------------------------|---------------------------------|---------------|
| 1 | 30,00 | 30,00 | 1200 | 50 | Solaris 8 1/2" | 2,24 | 35,00 | 80,0 | 10,00 | 60,0 | 0 | 5431,0 |
| 2 | 60,00 | 90,00 | 1200 | 50 | Solaris 8 1/2" | 2,24 | 38,00 | 120,0 | 10,00 | 60,0 | 0 | 5491,0 |
| 3 | 120,00 | 210,00 | 1200 | 100 | Solaris 8 1/2" | 2,24 | 40,00 | 120,0 | 10,00 | 60,0 | 0 | 5611,0 |

Figure 56: an example of batch configuration inputs (Drillbench - Presmod 2011)

The batch configuration can be applied for both conventional and MPD/UBD drilling. If conventional drilling is simulated the RCH and choke are not specified, meaning that this column in the batch configuration becomes inactive.

The Drillbench software also allow for surge and swab simulations in addition to cementing simulations. However, this paper will focus on drilling of the 8 ½ in section through the narrow MW window.

6.2 Results

The main objective for this simulation is to simulate conventional drilling compared to MPD when drilling through the narrow MW window. The simulation is based on keeping a constant ROP of 5, constant torque of 10 kNm and a constant rpm of 100. To account for pressure fluctuations during connections a batch configuration system is set up. The batch configurations account for 6 hour drilling combined with a 30 minute connection time throughout the drilling of the 8 ½ in section.

The initial MW was set to 2.26 sg which is the expected pore pressure. It is preferable to reduce the dynamic overbalance as much as possible. Lowering of dynamic pressure reduces the differential pressure in the well and thereby helps to increase the ROP and reduce surge and swab effects in the well.

6.2.1 Conventional Drilling Simulation

The biggest challenge for conventional drilling is managing the ECD pressure. At every connection, rotation is stopped and pumps are turned off. This results in a pressure drop as the mud becomes static for a short period. The batch configuration set-up for the initial case with a MW of 2.26 and pump rate of 600 l/min is shown in Figure 57. As this is a simulation of conventional drilling the RCH and choke are disabled.

| | Duration (min) | Accumulated time (min) | Pump rate (l/min) | Choke opening (%) | Fluid | Fluid density (sg) | Inlet temperature (Celsius) | Rotation velocity (rpm) | Torque (Nm) | Rate of penetration (m/hr) | Riser booster pump rate (l/min) | Bit depth (m) |
|----|----------------|------------------------|-------------------|-------------------|----------------|--------------------|-----------------------------|-------------------------|-------------|----------------------------|---------------------------------|---------------|
| 1 | 360,00 | 360,00 | 600 | 50 | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5431,0 |
| 2 | 30,00 | 390,00 | 0 | 50 | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5431,0 |
| 3 | 360,00 | 750,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5461,0 |
| 4 | 30,00 | 780,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5461,0 |
| 5 | 360,00 | 1140,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5491,0 |
| 6 | 30,00 | 1170,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5491,0 |
| 7 | 360,00 | 1530,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5521,0 |
| 8 | 30,00 | 1560,00 | 0 | 100 | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5521,0 |
| 9 | 360,00 | 1920,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5551,0 |
| 10 | 30,00 | 1950,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5551,0 |
| 11 | 360,00 | 2310,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5581,0 |
| 12 | 30,00 | 2340,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5581,0 |
| 13 | 360,00 | 2700,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5611,0 |
| 14 | 30,00 | 2730,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5611,0 |
| 15 | 360,00 | 3090,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5641,0 |
| 16 | 30,00 | 3120,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5641,0 |
| 17 | 360,00 | 3480,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5671,0 |
| 18 | 30,00 | 3510,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5671,0 |
| 19 | 360,00 | 3870,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5701,0 |
| 20 | 30,00 | 3900,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5701,0 |
| 21 | 360,00 | 4260,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5731,0 |
| 22 | 30,00 | 4290,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5731,0 |
| 23 | 360,00 | 4650,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5761,0 |
| 24 | 30,00 | 4680,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5761,0 |
| 25 | 360,00 | 5040,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5791,0 |
| 26 | 30,00 | 5070,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5791,0 |
| 27 | 360,00 | 5430,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5821,0 |
| 28 | 30,00 | 5460,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5821,0 |
| 29 | 360,00 | 5820,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5851,0 |
| 30 | 30,00 | 5850,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5851,0 |
| 31 | 360,00 | 6210,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5881,0 |
| 32 | 30,00 | 6240,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5881,0 |
| 33 | 360,00 | 6600,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5911,0 |
| 34 | 30,00 | 6630,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5911,0 |
| 35 | 360,00 | 6990,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5941,0 |
| 36 | 30,00 | 7020,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5941,0 |
| 37 | 360,00 | 7380,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5971,0 |
| 38 | 30,00 | 7410,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5971,0 |
| 39 | 360,00 | 7770,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6001,0 |
| 40 | 30,00 | 7800,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6001,0 |
| 41 | 360,00 | 8160,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6031,0 |
| 42 | 30,00 | 8190,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6031,0 |
| 43 | 360,00 | 8550,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6061,0 |
| 44 | 30,00 | 8580,00 | 0 | | Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6061,0 |
| 45 | 360,00 | 8940,00 | 600 | | Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6091,0 |

Figure 57: Batch configuration implementing the effects on ECD due to connection time

As the simulation shows in Figure 58, a MW of 2.26 is not sufficient to keep the well in constant overbalance during connections. As the pressure drops in the well, it reaches a dangerous level below the pore pressure limit. Having the well in underbalanced condition causes influx followed by a kick, and in worst cases a blow out. Leading the well towards this situation leaves little choice of remedy; the well most often has to be shut in. However, an increase in the static MW to 2.28 sg helps to balance the well. In conventional drilling pressure fluctuations due to connections needs to be taken into account, effectively meaning that the operational pressure window significantly decreases.

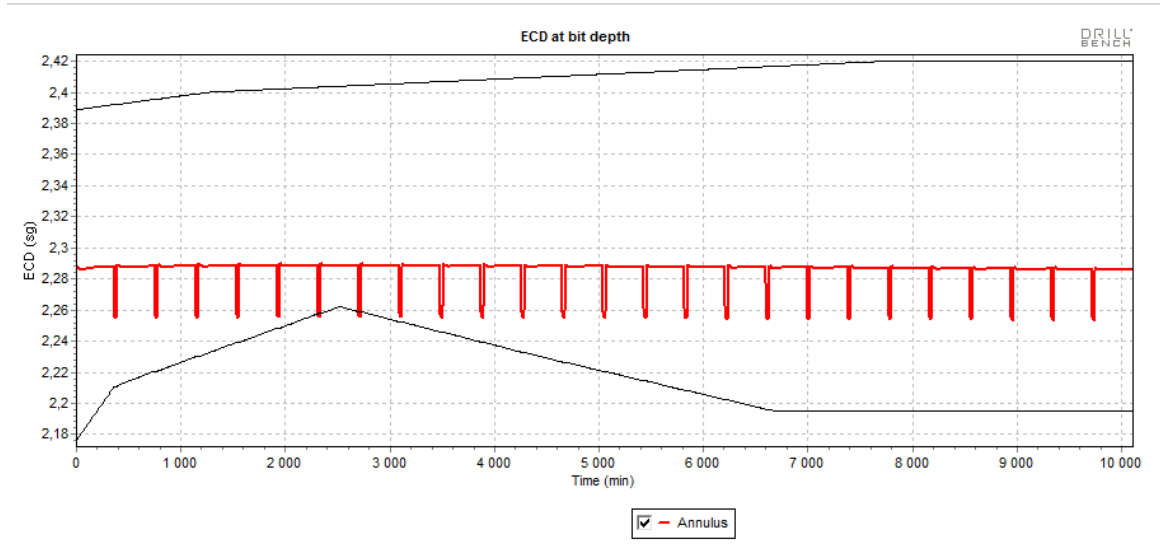


Figure 58: The graph shows the ECD in the annulus versus time. The black lines on the graph indicate the fracture gradient on the top and the pore pressure on the bottom. As seen on the graph, the effective MW drops below the pore pressure creating a dangerous situation for the well. The static MW used for this particular simulation was 2.26 sg (Drillbench - Presmod 2011).

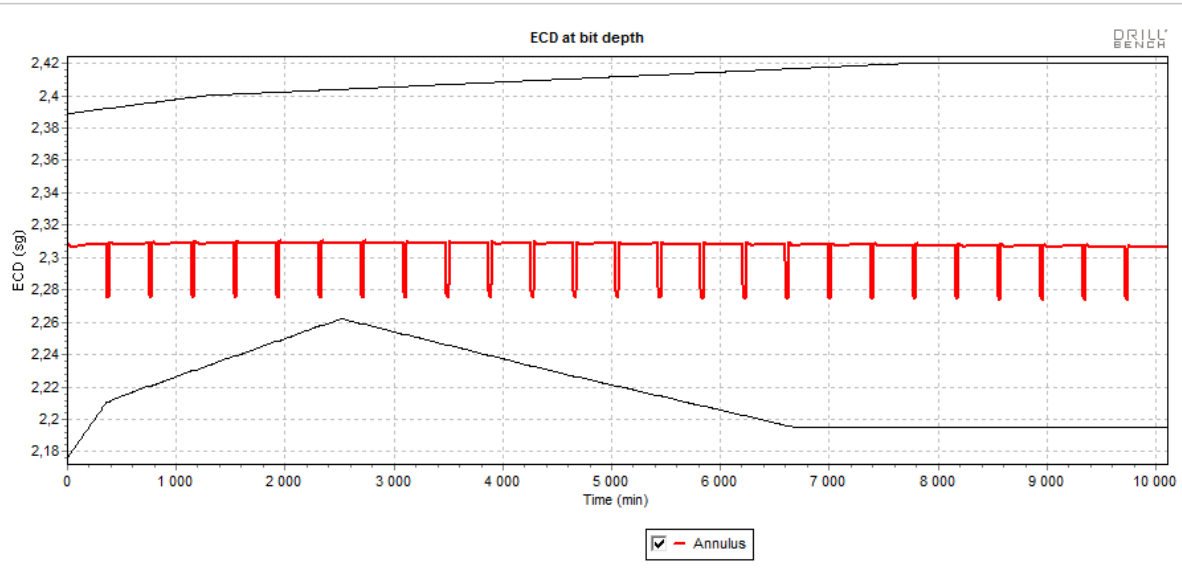


Figure 59: The graph shows ECD in the annulus versus time. The black lines on the graph indicate the fracture gradient on the top and the pore pressure on the bottom. The static MW in this simulation is 2.28 sg. This indicates the possibility to drill through the narrow margins conventionally (Drillbench - Presmod 2011)

The simulation was mentioned done with a pump rate of 600 m/l. To compare, a simulation was done at a higher pump rate of 1000 m/l, and at 1600 m/l. As seen on Figure 60 the pressure fluctuations are even higher, which means that the operational window has increased even more. To be able to balance the well with a higher pump rate, the static MW must be increased even more: 2.29 sg and 2.3 sg respectively.

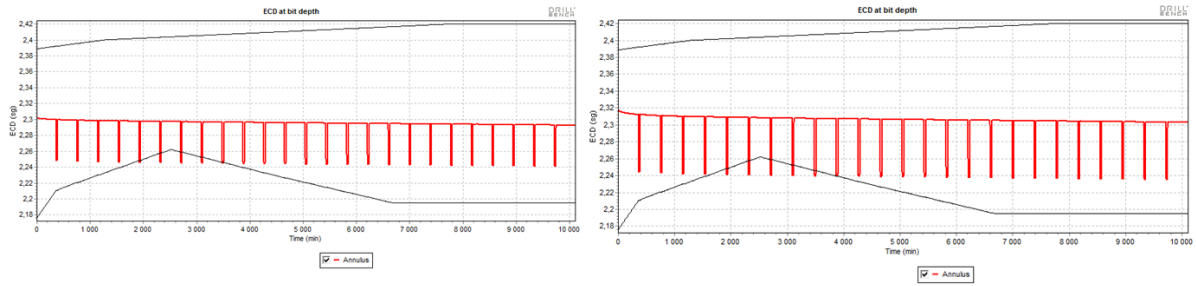


Figure 60: The above graphs show the ECD in the annulus versus time. On the left side is a simulation done with a pump rate of 1000 m³/l whilst on the right side the simulation was done at 1600 l/min. As can be seen, the pressure fluctuations increase with pump rate (Drillbench - Presmod 2011)

6.2.2 Managed Pressure Drilling Simulation

MPD is a drilling technique that manipulates the wellbore pressure by applying back pressure. This can easily be done by adjusting the choke. Applying surface—back pressure to counteract pressure fluctuations helps to minimize these and thereby widens the operational window. How these pressure fluctuations are minimized can be seen on Figure 61.

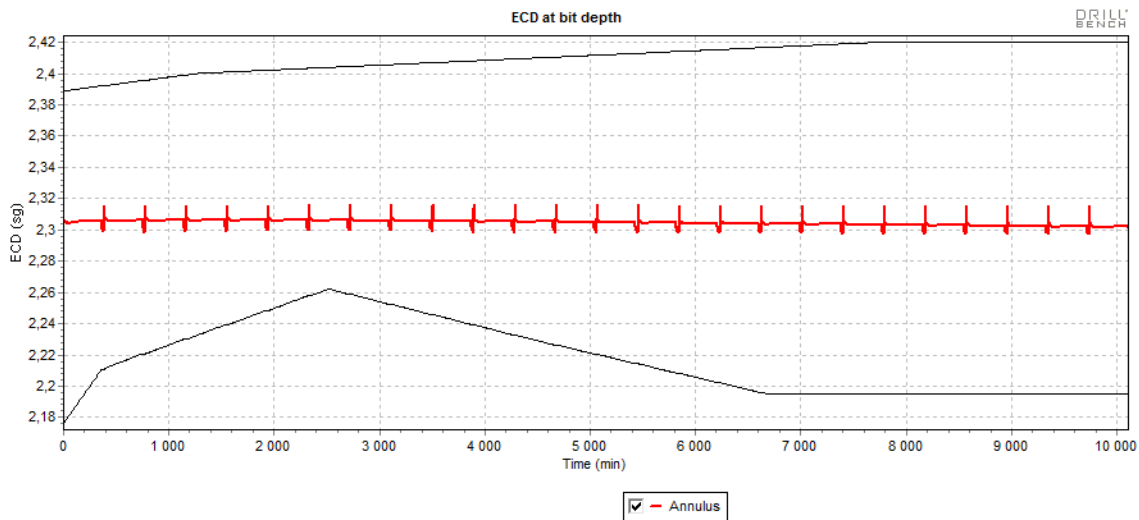


Figure 61: The graph shows the ECD in the annulus versus time. The static MW is 2.26 sg, and back pressure is applied during connections to minimize the pressure effects (Drillbench - Presmod 2011)

The batch configuration is a bit more detailed for a MPD system (choke opening must be specified), and is shown in Figure 62. The batch configuration is the one used for the simulation whereas choke adjustments during drilling is made.

| Duration (min) | Accumulated time (min) | Pump rate (l/min) | Choke opening (%) | Fluid | Fluid density (sg) | Inlet temperature (Celsius) | Rotation velocity (rpm) | Torque (Nm) | Rate of penetration (m/hr) | Riser booster pump rate (l/min) | Bit depth (m) | Descri |
|----------------|------------------------|-------------------|-------------------|--------------------|--------------------|-----------------------------|-------------------------|-------------|----------------------------|---------------------------------|---------------|--------|
| 12 | 30,00 | 2340,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5581,0 | |
| 13 | 360,00 | 2700,00 | 600 | 20 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5611,0 | |
| 14 | 30,00 | 2730,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5611,0 | |
| 15 | 360,00 | 3090,00 | 600 | 20 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5641,0 | |
| 16 | 30,00 | 3120,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5641,0 | |
| 17 | 360,00 | 3480,00 | 600 | 50 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5671,0 | |
| 18 | 30,00 | 3510,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5671,0 | |
| 19 | 360,00 | 3870,00 | 600 | 50 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5701,0 | |
| 20 | 30,00 | 3900,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5701,0 | |
| 21 | 360,00 | 4260,00 | 600 | 50 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5731,0 | |
| 22 | 30,00 | 4290,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5731,0 | |
| 23 | 360,00 | 4650,00 | 600 | 70 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5761,0 | |
| 24 | 30,00 | 4680,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5761,0 | |
| 25 | 360,00 | 5040,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5791,0 | |
| 26 | 30,00 | 5070,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5791,0 | |
| 27 | 360,00 | 5430,00 | 600 | 15 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5821,0 | |
| 28 | 30,00 | 5460,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5821,0 | |
| 29 | 360,00 | 5820,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5851,0 | |
| 30 | 30,00 | 5850,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5851,0 | |
| 31 | 360,00 | 6210,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5881,0 | |
| 32 | 30,00 | 6240,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5881,0 | |
| 33 | 360,00 | 6600,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5911,0 | |
| 34 | 30,00 | 6630,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5911,0 | |
| 35 | 360,00 | 6990,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5941,0 | |
| 36 | 30,00 | 7020,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5941,0 | |
| 37 | 360,00 | 7380,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 5971,0 | |
| 38 | 30,00 | 7410,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 5971,0 | |
| 39 | 360,00 | 7770,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6001,0 | |
| 40 | 30,00 | 7800,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6001,0 | |
| 41 | 360,00 | 8160,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6031,0 | |
| 42 | 30,00 | 8190,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6031,0 | |
| 43 | 360,00 | 8550,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6061,0 | |
| 44 | 30,00 | 8580,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6061,0 | |
| 45 | 360,00 | 8940,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6091,0 | |
| 46 | 30,00 | 8970,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6091,0 | |
| 47 | 360,00 | 9330,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6121,0 | |
| 48 | 30,00 | 9360,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6121,0 | |
| 49 | 360,00 | 9720,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6151,0 | |
| 50 | 30,00 | 9750,00 | 0 | 1,6 Solaris 8 1/2" | 2,26 | 35,00 | 0,0 | 0,00 | 0,0 | 0 | 6151,0 | |
| 51 | 360,00 | 10110,00 | 600 | 100 Solaris 8 1/2" | 2,26 | 35,00 | 100,0 | 10000,00 | 5,0 | 0 | 6181,0 | |

Figure 62: The batch configuration for the MPD simulation base case (Drillbench - Presmod 2011)

As mentioned, MPD provides a safer way to control the wellbore. The downhole pressure can easily be altered by adjusting the choke, see Figure 63.

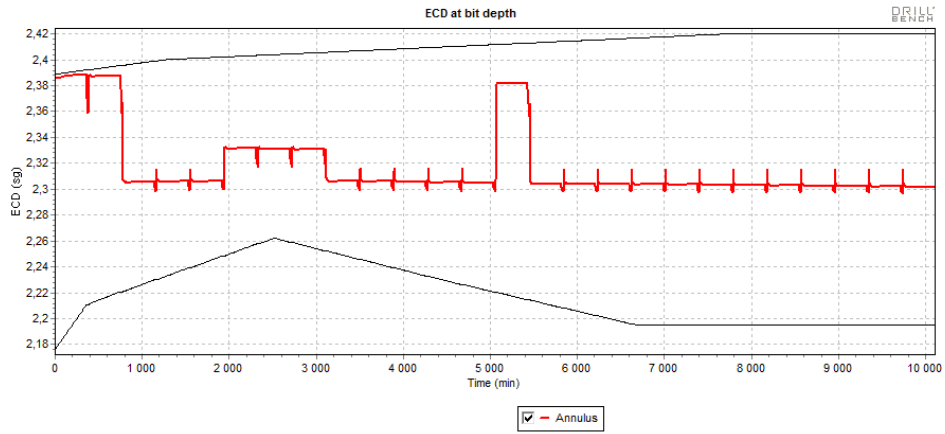


Figure 63: The graph shows the ECD in the annulus versus time. The static MW is 2.26 sg, and back pressure is applied during connections to minimize the pressure effects. During the simulation adjustments were made to the choke to indicate how easily downhole pressure changes can be made when drilling in MPD mode (Drillbench - Presmod 2011)

7 Discussion

MPD is a closed and pressurized circulation system (drilling technique) that provides precise control of the wellbore pressure profile by manipulating back-pressure instead of the MW. The intent of MPD is not to manage influx, but rather to avoid and mitigate various drilling hazards such as differential sticking, reservoir depletion, losses/influx, pressure fluctuations and wellbore stability. As MPD manipulates the BHP by applying surface back-pressure a larger operating window is provided, resulting in lower risks when drilling into challenging formations.

MPD was developed to meet challenges of wells that were previously considered to be un-drillable, and provide a new way of thinking for future wells. The idea of MPD started decades ago; in the 1970's ECD was used as well control and in the 1980's drilling without returns (today known as PMCD) became common. A more formalized way of MCD was developed followed by pressurized MCD in the 1990's. Today we have several different MPD techniques and systems. Some focuses on early kick detection while others focus on pressure monitoring. However, all MPD techniques have different ways of reaching previously considered un-reachable targets.

MPD provide the unique possibility to accurately control the pressure dynamically by adjusting a choke. BHP can then be rapidly changed in minutes rather than hours providing a safer way to control influxes and their subsequent bleed offs. The objective of MPD is to drill with a MW as close to the pore pressure as possible to reduce the dynamic overbalance. By minimizing the dynamic overbalance surge and swab effects are reduced, ROP increased and well control is enhanced as differential pressure in the well is lowered. However, it is important to provide sufficient hole cleaning as increased ROP combined with reduced circulation rate is an unfortunate combination in regards wellbore plugging, and torque and drag forces. As MPD reduces pressure fluctuations in the well, wellbore breathing issues are reduced. Fingerprinting of the well also contributes to determine whether an influx is a wellbore breathing issue, a flowing well or the occurrence of connection gas. MPD provide accurate flow measurements, and thereby early kick detection (influxes smaller than $\frac{1}{4}$ bbl can be detected by the Coriolis flow meter). Small influxes can thereby be managed at an early stage through the MPD system. As influxes can be handled without shutting in the well also help to extend the casing setting depths.

MPD is more expensive than conventional drilling as it requires more equipment. The drilling process is optimized as NPT is reduced resulting in operational cost savings in some environments. However, a good candidate selection is crucial. The benefits gained by MPD need to outweigh the costs of the extra equipment needed. Unfortunately, poor understanding of what MPD can accomplish have led to many wells being drilled under wrong pretences.

According to the IADC, there are four variations of MPD: CBHP, PMCD, DGD and HSE method. CBHP is a method based on keeping the BHP constant and thereby eliminating cycles of kicks and losses. The typical application for CBHP is depleted (narrow MW window), fractured and high pressure reservoirs. This MPD technique is often referred to as the preferable method and therefore also the most commonly used. The selection of anchor point is crucial in many cases to whether the well is a success or not. PMCD is a method to mitigate extreme fluid losses commonly found in highly depleted and naturally fractures formations. This method is often employed when other techniques have difficulties maintaining constant circulation, a method often referred to as drilling without returns. DGD is a method primarily used for deepwater drilling. The drilling technique employs two fluid gradients, one above the seabed and another below. The intent is to reduce the effect of the deep water and thereby reduce casing setting depths. The HSE method focuses on HSE primarily reducing risks from drilling fluid, hazardous gases and well control to personnel and environment.

One of the leading suppliers of MPD systems is Weatherford. The Weatherford MPD system consists of an RCD placed on top of the BOP system and the Microflux control system which is a combined manifold, flow meter and control system. The system controls the wellbore pressure dynamically by manipulation of surface back-pressure. The system provides real time data in addition to accurate flow measurements, and is thereby able to provide determination of the operational envelope and quick detection of influxes or losses. The circulation system provides a safer way to manage small influxes and drilling with constant BHP. The Weatherford MPD system has been used successfully on the Maesk Gallant previously, which is beneficial to the crew and system set-up.

The Solaris well is located in the Central Graben area close to several offset wells with similar challenges; all facing narrow operational windows.

- The Mandarin well is a well very similar to the Solaris well. The well is an ultra HPHT well with a challenging narrow MW window. The main reason for implementing MPD was to navigate through the narrow MW window, provide early kick detection and to mitigate the expected wellbore breathing effects. Despite many offset wells prior to drilling of the well, the well had high uncertainties regarding the pressure profile as no offset well had been drilled as deep. Use of the MPD system provided accurate pressure determination, the ability to “lock in” the ECD pressure eliminating circulation time, accurate flow detection and significant NPT reduction.
- The Franklin-Elgin field is an HPHT reservoir facing severe depletion. As the depletion level up to 800 bars the MW window had disappeared, making conventional drilling impossible. MPD was seen as the only viable option. The main purpose of the MPD system was to control gas

levels as previous wells had experienced gas bleed off when drilling into the cap rock. The use of MPD was considered to be very successful as it helped to control the gas levels while drilling, helped reduce losses in the depleted reservoirs, helped to avoid differential sticking while drilling, helped to bleed off the formation and helped to rapidly change the BHP when needed. The MPD system was estimated to help save approximately 75 days of operational time.

- The Kvitebjørn field is another HPHT field facing problems related to depletion. The level of depletion made conventional drilling impossible, and the focus shifted towards MPD. The main reasons for applying MPD was the severe depletion combined with massive losses. A CCS together with the MPD system was used until well conditions could be verified. The use of MPD on the Kvitebjørn wells helped to reduce losses, helped verify depletion level and formation depths, and helped to navigate within the narrow MW window. The MPD operations were considered to be successful as more wells have been planned to drill in MPD mode.

The Solaris well is an ultra HPHT well with many similarities to the close offset well the Mandarin East well. The main challenge is the narrow MW window in the deeper section of the well together with wellbore breathing issues related to the downhole environment typical for HPHT wells. To be able to drill through the narrow MW window determination of the actual pressure limits is essential. If the estimated pressure limits prove to be underestimated, the risk is high for problems such as fracturing the casing shoe (or formation) or ending up in an underbalanced situation. If drilling is performed in MPD mode, the operational window is larger and actions can be taken immediately by applying surface back-pressure and not necessarily result in the shut in of the well. Drilling of narrow MW window in conventional mode is difficult, especially if the operation does not go as planned. The mitigations while drilling conventional is very limited. MPD on the other hand provide early kick detection which often reduce the influx volume which again results in less damage to the well itself. Another benefit of using an MPD system is the “locking” of the ECD during connections, which reduces pressure fluctuations which may be crucial in areas with narrow MW window.

To be able to confirm whether MPD is the proper solution for the Solaris well further research and extensive simulations should be performed. The most important goal will be to accurately determine the pressure profile, reduce possible uncertainties and accurately determine pressure fluctuations (and thereby their weakness in regards to drilling in narrow margins) for the different drilling technologies. Before deciding whether to use MPD for the Solaris well benefits of the MPD versus the extra operational costs must be considered. The benefits must outweigh the risks (both economical and operational).

The Drillbench simulation Software is a great way of simulating different well challenges, such as drilling through narrow pressure margins. By simulating both conventional drilling and MPD, the benefits and challenges became more apparent. Conventional drilling is possible in theory. However, the operational window is very small as the pressure fluctuations are quite large (created during connections), a higher MW is required to stay in constant overbalance at all times. If the estimations are off, problems can easily develop and escalate. MPD on the other hand minimizes pressure fluctuations which yields a far wider operational window. Additionally, this technology also provides far better remedies if the drilling process faces trouble while drilling.

8 Conclusion

- MPD is a drilling technique that helps to mitigate several drilling hazards, thereby reducing the associated NPT resulting in operational cost savings. However, this is only the result if a good candidate selection has been performed. The benefits of MPD must outweigh the extra operational cost.
- MPD is a technology that is continuously being developed, a technology with an exponential growth within the industry. As its usage is growing, so does unfortunately the improper usage.
- As of today four variations of MPD is defined; CBHP typically used for depleted reservoirs with narrow MW windows, PMCD typically used for highly naturally fractured formations experiencing massive losses, DGD typically used for deepwater drilling and the HSE method focusing on reducing risks to personnel and environment. CBHP is usually the preferred alternative, and therefore as of today the most used method.
- The Weatherford MPD system is a good example of how drilling in difficult formations can be met by providing accurate data on the operational envelope, early kick detection and accurate flow measurements which helps to distinguish wellbore breathing problems from connection gas or a flowing well.
- There are several case studies that have benefited greatly from the use of MPD technology. Both the Franklin-Elgin field and Kvitebjørn field faced severe depletion levels which made the drilling window shrink or disappear, making conventional drilling impossible. MPD helped to reduce losses, helped to confirm the pressure profile, helped to control gas in the well and bleed off the formation. The main issue on the Mandarin field was the narrow MW window and wellbore breathing issues. MPD helped to navigate through the narrow MW window of only 0.4 ppg in addition as wellbore breathing was minimized. NPT was reduced significantly in all three case studies, resulting in large cost savings for these wells.
- The Solaris well has many similarities to the Mandarin well, Franklin-Elgin field and Kvitebjørn field. The main challenge is the narrow MW window and wellbore breathing challenges. MPD can provide a safer way of drilling as it helps to control the wellbore pressure while minimizing pressure fluctuations (reduces wellbore breathing). ECD can be “locked in” during connections, early kick detection is provided and the pressure profile can be accurately verified. If problems regarding to wellbore pressure limits are encountered when drilling in conventional mode, the possibilities are slim compared to MPD.

- Whether MPD is the solution for Solaris is still too early to say. However, based on currently available information it is more likely to be the better option as the well faces challenges of narrow pressure margins. As MPD do provide better control of the BHP, it is more likely that MPD will help guide the well safely through the narrow MW window without causing other issues such as wellbore breathing. As uncertainty always is present, MPD has far better remedies than conventional drilling in regards to reaching TD.
- Simulations clearly identify the benefits of using MPD prior to conventional drilling. Pressure fluctuations are minimized, operational window is larger and wellbore pressure can easily be adjusted if needed during drilling. The simulation also indicates that conventional drilling is possible. However, the operational window is very limited and small uncertainties in pressure estimations can easily have severe consequences. MPD offers a safer way of controlling the BHP, as back pressure easily can be manipulated. The probability of reaching TD with MPD looks far better than when conventional drilling is used.

Nomenclature

| Symbol | | Unit, Field (SI) |
|---------------------------------|--|-------------------------|
| P_{pore} | pore pressure | psi (Pa) |
| $P_{\text{wellbore stability}}$ | pressure at where the wellbore becomes unstable | psi (Pa) |
| $P_{\text{diff. sticking}}$ | pressure at where differential sticking occurs | psi (Pa) |
| $P_{\text{lost circulation}}$ | pressure at where lost circulation occur | psi (Pa) |
| p_{frac} | fracture pressure | psi (Pa) |
| P_{static} | static hydrostatic pressure (pumps off) | psi (Pa) |
| P_{AFP} | annulus frictional pressure from the circulating fluid | psi (Pa) |
| P_{bp} | surface back pressure applied to the annulus | psi (Pa) |

Subscripts

| Abbreviation | | Unit, Field (SI) |
|---------------------|--------------------------------------|-------------------------|
| BHA | Bottom Hole Assembly | - |
| BHM | Bull Head Margin | - |
| BHP | Bottom Hole Pressure | psi (Pa) |
| BMP | Balanced Mud Pill | - |
| BOP | Blow Out Preventer | - |
| CBHP | Constant Bottom Hole Pressure | psi (Pa) |
| CCS | Continuous Circulating System | - |
| CO ₂ | Carbondioxide | - |
| Cs | Caesium | - |
| DC | Drill Collar | - |
| DGD | Dual Gradient Drilling | - |
| DP | Drill Pipe | - |
| DST | Drill Stem Test | - |
| ECD | Equivalent Circulating Density | - |
| eHPHT | extreme HPHT (see HPHT abbreviation) | - |

| | | |
|--------------------------------|---|--|
| ERD | Extended Reach Drilling | - |
| FIT | Formation Integrity Test | - |
| FMCD | Floating Mud Cap Drilling | - |
| Fo | Formate | - |
| HCD | Hydrostatic Control Valve | - |
| HDJU | Heavy-Duty Jack-Up | - |
| HPHT | High-Pressure-High-Temperature | - |
| HSE | Health, Safety and Environment | - |
| H ₂ S | Hydrogen Sulphide | - |
| IADC | International Association of Drilling Contractors | - |
| ID | Internal/inside Diameter | in (m) |
| K | Potassium | - |
| LCM | Lost Circulation Material | - |
| LOT | Leak Off Test | - |
| LTOBM | Low Toxicity Oil Based Mud | - |
| MCD | Mud Cap Drilling | - |
| MD | Measured Depth | - |
| MEWH | Maximum Expected Wellhead Pressure | psi (Pa) |
| Mn ₃ O ₄ | Maganese tetraoxide | - |
| MPD | Managed Pressure Drilling | - |
| MW | Mud Weight | - |
| NABM | Non- Aqueous Based Mud | - |
| NPT | Non Productive Time | - |
| OBM | Oil-Based Mud | - |
| OD | Outside Diameter | in (m) |
| P&A | Plug and Abandon | - |
| PMCD | Pressurized Mud Cap Drilling | - |
| PP | Pressure Prediction | - |
| ppg | pounds per gallon | $\frac{\text{lb}}{\text{gal}} \left(\frac{\text{kg}}{\text{l}} \right)$ |

| | | |
|------|------------------------------|----------|
| PPP | Pressure Profile Prediction | - |
| PRV | Pressure Release Valve | - |
| RBOP | Rotating Blow Out Preventer | - |
| RCD | Rotating Control Device | - |
| RFCD | Return Flow Control Drilling | - |
| RKB | Rotary Kelly Bushing | - |
| ROP | Rate Of Penetration | - |
| RTD | Real Time Data | - |
| Sg | specific gravity | - |
| SVT | Step Volume Test | - |
| TD | Target Depth | - |
| TVD | True Vertical Depth | - |
| UBD | Under-Balanced Drilling | - |
| WBM | Water-Based Mud | - |
| WOB | Weight On Bit | lbf (kg) |

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Appendix A – Figures

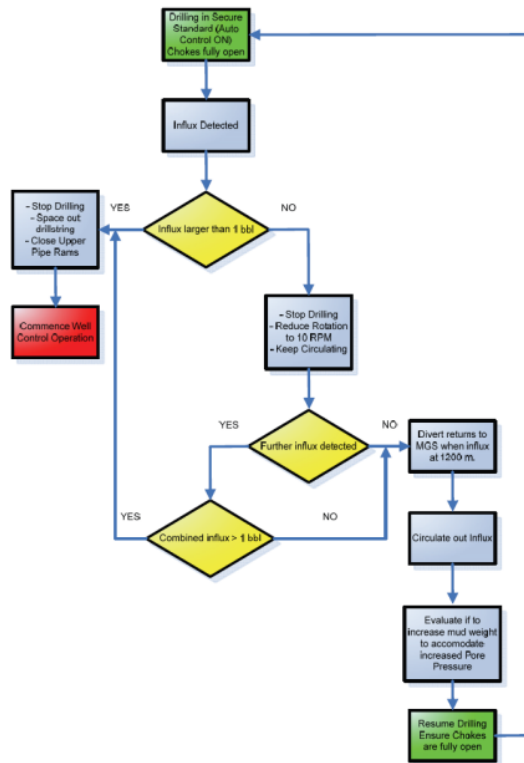


Figure 64: Procedure decision tree for the mandarin East well (Naesheim, et al. 2011)

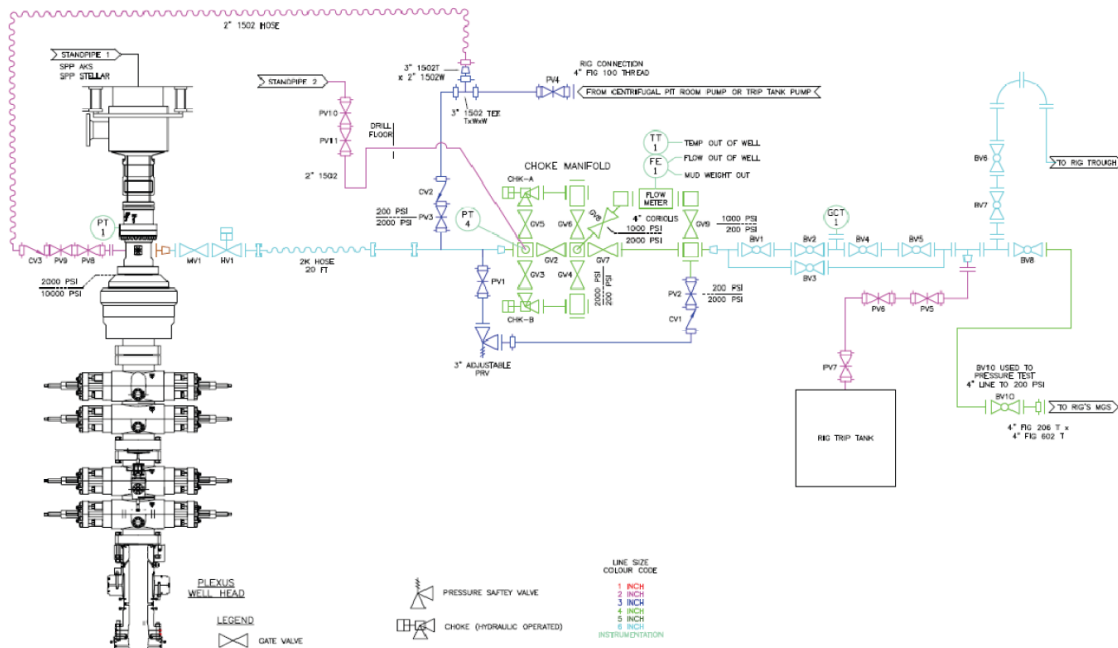


Figure 65: Final MPD rig up for the Mandarin East well (Naesheim, et al. 2011)

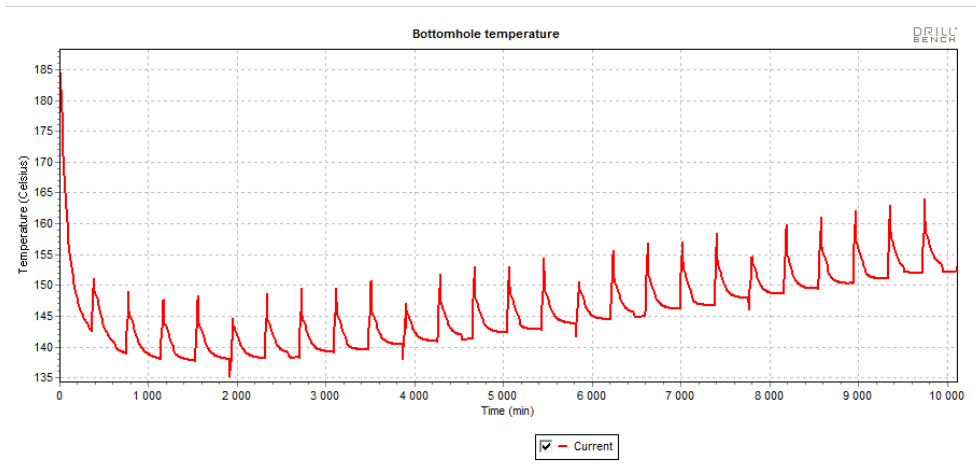


Figure 66: Bottom hole temperature plotted against drilling time with a pump rate of 600 l/m (Drillbench - Presmod 2011)

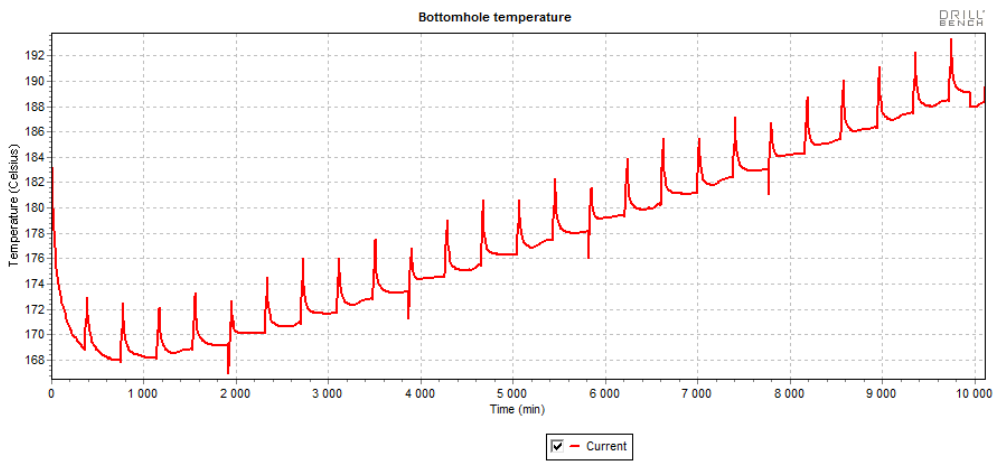


Figure 67: Bottom hole temperature plotted against drilling time with a pump rate of 1000 l/m (Drillbench - Presmod 2011)

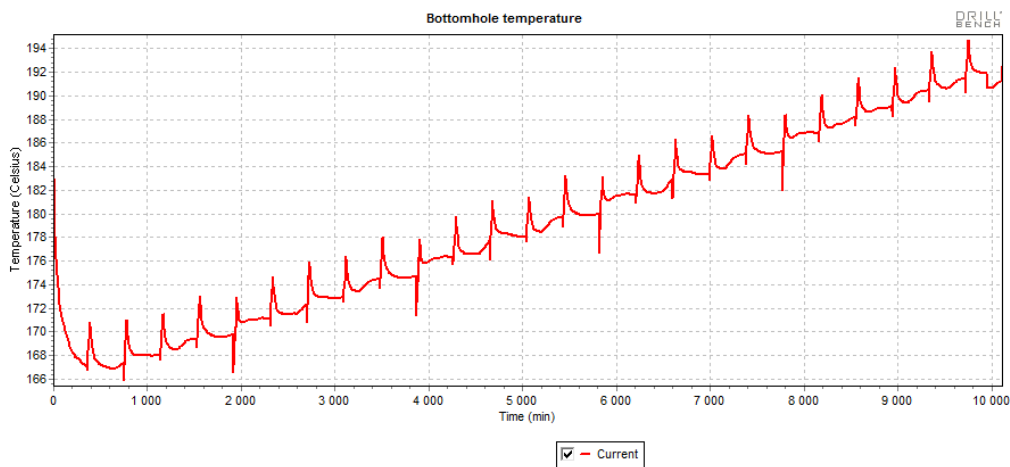


Figure 68: Bottom hole temperature plotted against drilling time with a pump rate of 1200 l/m (Drillbench - Presmod 2011)

Appendix B – Tables

Table 2: Some of the most important reference wells used to calculate and evaluate PPP (Total E&P 2013a)

| No | Well Name | WD | Pshale | | Markers | LOT | FIT | MW | WellTD | FWR | DDR |
|----|------------------|----|--------|-----------|---------|-----|-----|----|------------------|-----|-----|
| | | | Actual | Prognosis | | | | | | | |
| 1 | Jackdaw 30/2-6 | | | | | | | | Triassic | | |
| 2 | Calloway 30/8-3 | | | | | | | | Triassic | | |
| 3 | Albuskjell 1/6-4 | | | | | | | | Upper cretaceous | | |
| 4 | Mandarin 1/3-12S | | | | | | | | Triassic | | |
| 5 | Albuskjell 1/6-3 | | | | | | | | Paleocene | | |
| 6 | Albuskjell 1/6-6 | | | | | | | | Triassic | | |
| 7 | King Lear 2/4-21 | | | | | | | | Triassic | | |

Table 3: PCD 3000 and PCD 5000 Technical data (Siem WIS 2013)

Mechanical:

| | |
|-----------------------|----------------------------------|
| PCD 3000 Body Rating: | 3000psi |
| PCD 5000 Body Rating: | 5000psi |
| ID both systems: | 13 ⁵ / ₈ " |

Seal performance (PCD 3000 and 5000):

| | |
|----------------------------|---------|
| Static seal rating: | 3000psi |
| PCD's Dynamic seal rating: | 2000psi |
| Nominal RPM: | 150 |
| Max RPM: | 200 |

Control system:

Automated PLS based system
 Suitable for fully automated control and
 integration to other systems

18 ³/₄" system option :

The PCD design can be supplied as a 18 ³/₄" ID

Appendix C – UBD vs MPD

Wells drilled today are more complex and challenging than wells drilled earlier as most of the “easy wells” have already been developed. Conventional drilling may be incapable to drill certain wells due to narrow operational windows, geological complexity and unexpected events. The industry needed to explore and develop alternative methods such as UBD and MPD for further development of depleted and complex reservoirs.

MPD technology changes wellbore pressure rapidly by means of conventional techniques available. MPD require accurate pressure control to avoid influx and at the same time stay within a narrow pressure window. UBD in the other hand is basically intentionally drilling below the pore pressure, intentionally producing while drilling. Advantages of UBD are typically higher ROP, reduced risk of formation fracturing, differential sticking and skin damage.

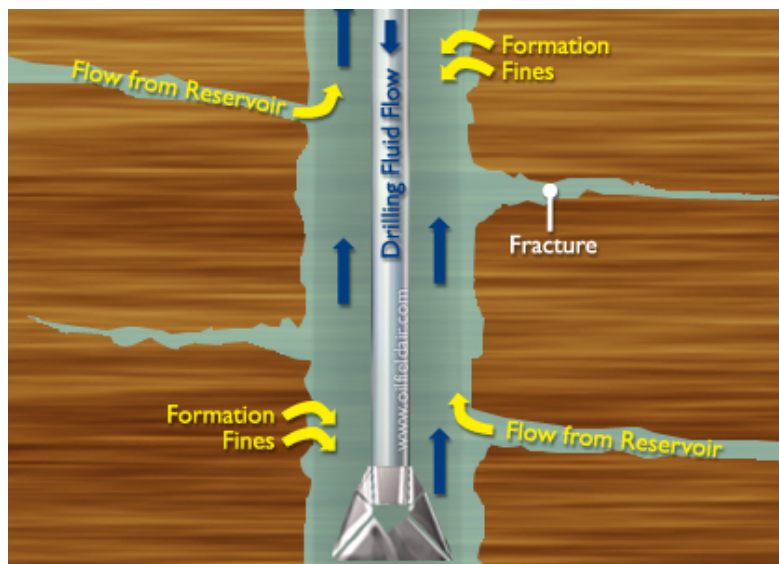


Figure 69: Underbalanced Drilling (Rigzone 2013)

When drilling underbalanced the hydrostatic head is lower than the formation pressure, i.e. the drilling fluid do not act as a well barrier and formation fluids are thereby allowed to flow continuously into the wellbore during operations. In UBD it the intent is to manage influx continuously and bring the formation fluids to the surface, thereby no near wellbore damage occur and losses are avoided. Differential sticking issues are eliminated as no mud cake forms. Drilling fluids used in UBD are relatively light, thereby increasing the ROP as well reducing wear on bit. It is easier to detect and characterize reservoir zones when using UBD, and thereby often enhances recovery and production (Eck-Olsen, et al. 2012). Poorly planned UBD operations may on the other hand result in some disadvantages. Low wellbore pressure may result in an instable wellbore, MWD might not be possible due to high concentration of compressible fluids and failure to maintain continuous underbalanced pressure. As no filter cake is present when drilling underbalanced, any

sudden overbalance pulse may cause severe damage to the unprotected formation (more severe than for conventional drilling).

MPD is designed to maintain a wellbore pressure slightly above the formation pressure, more of a “walk the line” method, whereas UBD ensures the wellbore pressure to be kept beneath the formation pressure allowing for influx into the wellbore. The primary objectives of MPD are to mitigate drilling hazards and optimizing drilling efficiency by reducing the NPT (Tercan 2010), meaning drilling hazards are reduced not eliminated. UBD offers both solutions to drilling related problems as well as reservoir related challenges. For operations where wellbore instability is an issue, high H₂S content causes safety concerns or government regulations prohibit certain procedures, MPD is often considered the preferable method. The two major disadvantages for UBD is the increase operational costs as additional equipment is needed and the possible consequences for not keeping the well at underbalanced condition at all times.

Appendix D - Present DGD Technologies

DGD techniques are quite often associated with challenges of deepwater drilling from floaters. Examples of such technologies are the CMP and the EC-drill technologies by AGR (low-annulus level return), and the Ocean Riser System technology. The CMP focuses on dual gradient configuration to compensate for deep water pressure gradient (**Error! Reference source not found.**), whereas EC-drill and Ocean Riser can, but not necessarily, be in hydrostatic condition mono gradient drilling solution providing downhole pressure control using the annulus level solution during circulation which results in a temporary dual gradient system(**Error! Reference source not found.**) (Gravdal and Siahan 2012). Both solutions have a mud-lift pump connected to the marine riser that extracts the drilling fluid and a booster pump to inject the drilling fluid at the connection point, and a high accuracy pressure sensor inside the marine riser close to the extraction point to determine level of interface between the drilling fluid and blanket fluids (CMP) or air (EC-drill) (Gravdal and Siahaan 2012). Targeted reference pressure is maintained by steering the lift pump by the use of a Proportional-Integral-Derivative (PID) controller. The interface level decreases results in reduction of downhole pressure when the lift pump is pumping faster than the circulation rate. On the other hand, for raising the interface level, pumps must pump slower than the circulation rate. When pumps are stopped, or running at low speed, booster pumps can assist in raising the interface level.

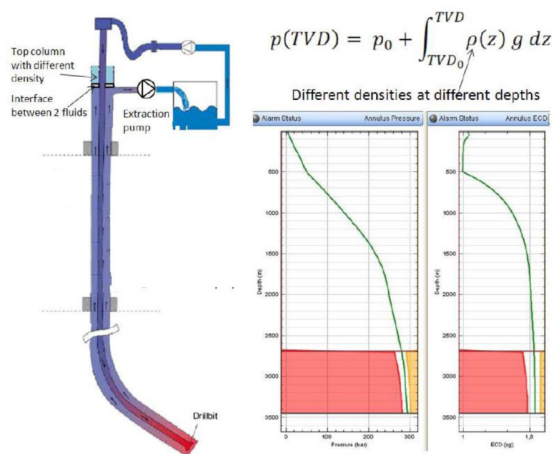


Figure 71 The CMP dual gradient MPD solution by AGR (Gravdal and Siahaan 2012)

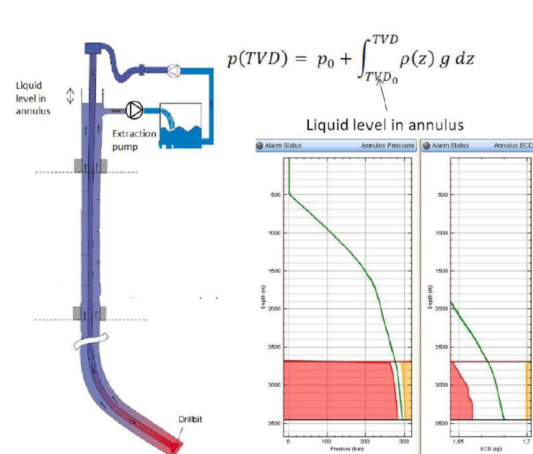


Figure 70: The EC-drill MPD solution: a low annulus level solution by AGR (Gravdal and Siahaan 2012)

Appendix E – MPD Tools

As MPD technology and equipment complements existing conventional systems standard rig equipment (BOP stack, surface DP valves etc.) is not included in this section. Equipment common to all MPD systems on the other hand will be defined in this section.

Rotating Control Device (RCD)

A Rotational Control Device (RCD) is an annular seal providing back pressure to the circulation system. All MPD techniques require the annulus to be packed off when drilling, tripping and making connections. The RCD is a vital piece of the well control equipment as it is the first defence against influx/escape of formation fluids during critical well operations (Halliburton 2013a). An annular preventer or a pipe ram can pack off the annulus temporarily, but the industry depends on the RCD to limit the rotational wear while drilling (Rehm, et al. 2008). The RCD is not intended to be a replacement for the BOP, but rather a supplement adding more flexibility to the operation.

As of today there are two basic systems in use: the passive Rotating Control Device and the active Rotating Annular Preventer. The passive system is the most common system used as of today. High-pressurized RCDs account for more than 90 % of RCDs used in MPD operations if all low-pressurized RCD used in air drilling is excluded (Rehm, et al. 2008). All high-pressure systems are equipped with rig floor gauges, alarms, controls and a surface hydraulic unit to circulate oil for cooling (additional for active systems: a separate system for closure). In most cases active intervention when wellbore pressure changes are not necessary (Rehm, et al. 2008).

RCD typically operates with static pressure up to 5000 psi and dynamic pressure up to 2500 psi (Rehm, et al. 2008). Most high-pressure rotating systems utilize oil for lubrication of bearing and heat transfer that are generated by the pressurized rotation. Snubbing force created by the grip of the packer on the DP as recorded WOB is lower than the actual WOB. This weight reduction is normally in the range of 2 – 5 tons and is therefore normally only an issue when very light bits or milling weights are required (Rehm, et al. 2008).

There are several types of RCDs available on the market. The different types address the various challenges such as heave on floating rigs, high/low pressure reservoirs and so on. Installation of RCD on floating rigs needs to incorporate flexible flow lines to compensate for the relative movement between the rig and the riser.

RCD – Passive Systems

The RCD is basically a rotating packer that pushes an annular seal element against the moving pipe forming a seal at zero-pressure conditions. The element is exposed to the wellbore pressure which provides further sealing.



Figure 72: RCD (Rehm, et al. 2008)

Weatherford’s High-pressure RCD uses dual elements whereas the upper acts as backup against seal leak due to wear of the lower element. The lower element is the primary seal as it deals with the pressure differential and thereby experiences about 60 % of the wear (Rehm, et al. 2008). The two seal elements are positioned in a way that one element always is sealing, and thereby preventing leakage during e.g. passing of tool joints.

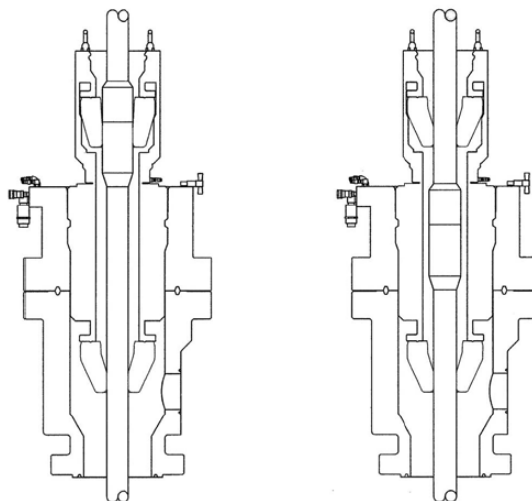


Figure 73: Dual annular seal elements in a high-pressure RCD (Rehm, et al. 2008)

Most passive RCD failures occur at low pressures and results in leakage around the pipe or drill collars. Packers wear over time, as a certain limit is reached they will no longer be able to provide sufficient seal at low pressures (Rehm, et al. 2008). A leak of seal element is normally seen on the drill floor during trips or connections, but can also often be seen on pressure tests.

Rotating Annular Preventers – Active Systems

The rotating annular preventer is an active system that hydraulically activates the annular packer. The difference from the passive system is that it has an air chamber behind the rubber element to compensate for the rubber wear (Eck-Olsen, et al. 2012).

The classic example is the Varco Shaffer Pressure-Control-While-Drilling (PCWD™), see Figure 75. This system is not actuated by well pressure, but of a ram that forces the element against the spherical head, packing off the pipe. A dual hydraulic system is used whereas the basic system operates the opening/closing mechanism of the preventer while the secondary system cools and lubricates the bearing pack (Rehm, et al. 2008). The packer replacement frequency is similar to that of conventional annular preventers. The system itself is highly automated, and limits the required action to opening and closing the packer. The packer pressure can be controlled automatically or manually from the control panel.

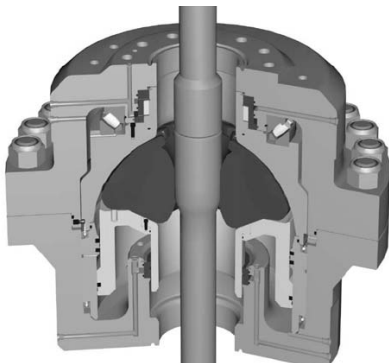


Figure 75: Cross section of a Varco Shaffer PCWD (Rehm, et al. 2008)

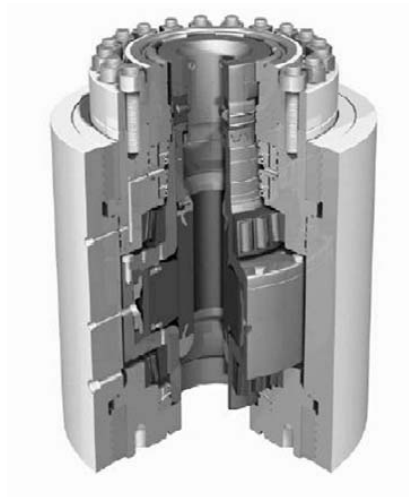


Figure 74: Cross section of an RBOP (Rehm, et al. 2008)

Other active rotating annular preventers include the Rotating Blow-Out Preventer (RBOP), see Figure 74. The RBOP system squeezes the packer against the pipe by using a pressurized diaphragm (Rehm, et al. 2008).

Rotating Control Devices on Risers

To de-energize pressured sand stringers in the top section of a well a rotating element placed on top of the diverter was developed. This allowed for pipe movement during gas flows and thus drilling through these stringers. The operational requirements for the rotating diverter device is the low-pressure riser slip joint to be locked and closed, in addition to pressurized seals (Rehm, et al. 2008).

A modification of the RCD is the riser cap. The riser cap can be used for PMCD as well as for other MPD operations where the pressure regimes are relatively low.

Chokes

During MPD operations chokes are used constantly, resulting in the need for a separate choke system other than the well control system. MPD chokes can be divided into three main categories; choke gates, sliding plates and shuttles (Rehm, et al. 2008). There are several providers of drilling chokes for well killing and high-pressure drilling operations, whereas the MI Swaco chokes are briefly described as an example in this section.

Choke Gate – Power Choke SC Model

The cylinder shaped Power Choke SC restricts the flow by moving towards a seat. The choke closes as it sets onto the seat. To help the operation to run more smoothly, the trim is pressure balanced. The choke operation itself is driven by an air-operated hydraulic pump normally driven by a hydraulic motor (1200-1300 stops/starts per hour) with an electric motor as backup (Rehm, et al. 2008). The Power Choke SC control panel are equipped with stroke counters, pressure gauges (hydraulic pump, annular, DP), a choke position indicator, a pump speed controller and a control handle.

Chokes are available for operating pressure of 10K, 15K and 20K psi, and MPD choke sizes of 2-in and 3-in. Failure of the Power Choke SC system is very rare, most often related to difficulties with proper sealing or damage to the hydraulic system (Rehm, et al. 2008). As the system is driven by a worm drive operating system, the last fixed position will show the mode where the failure occurred.

The back pressure is controlled automatically by a computer control system that is based upon data interpreted by a software system (Rehm, et al. 2008).

Sliding Plates – Swaco Super Choke

The Swaco Super Choke consist of two thick plates (heavy duty diamond lapped tungsten carbide) with half-moon shaped orifices, whereas the front plate is fixed and the rear plate rotates opening or closing, i.e. restricting the fluid flow (Rehm, et al. 2008). These chokes are effective for applications in well conditions such as H₂S and abrasive fluids.

The seal itself is not affected by pressure drops or surge, well pressure actually improves the seal. An overlap of 17° ensures full despite wear caused by repeated exposure to abrasive fluid flow (MI SWACO 2012).

The system can be operated in three ways: normally by air, manually by a hydraulic pump located on the remote control skid as redundancy for lost air or manually with a bar on the indicator head as redundancy for severed hydraulic lines (MI SWACO 2012). The control panel are equipped with pump stroke counters, pressure gauges (hydraulic pump, annular, DP) and a needle valve to control the pump speed. Chokes are available in 2-in sizes and 10K, 15K and 20K psi operating pressures (Rehm, et al. 2008). System failure is rare and in general related to sealing difficulties, and damage to the air- or hydraulic system.

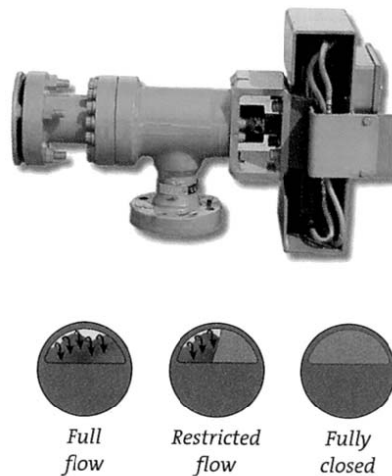


Figure 76: MI Swaco Super Choke with choke plates functionality schematic.

Shuttles – Swaco Auto Super Choke

The design of the Auto Choke is very different from the Super choke; the sliding shuttle is directly operated by the hydraulic pressure (Rehm, et al. 2008). The Auto Choke provides automatic, precise pressure control, technology applicable to both UBD and MPD operations. The main feature of the Auto Choke is that it regulates casing pressure automatically (MI SWACO 2010).

The shuttle is connected to a dynamic trim sleeve which controls the fluid flow (adjusting the position of the trim relative to the static trim). The shuttle assembly (metal-to-Teflon seal) will in the event of an increase in annulus pressure or decrease in hydraulic set point pressure move further away from the static trim to allow more fluid to flow, and thereby equalizing the pressure in the well (MI SWACO 2012). The shuttle assembly will move closer to the static trim to decrease the fluid flow to mitigate for a decreasing casing pressure or increasing set point pressure. Set point pressure is adjusted by a regulator and applied on the backside of the shuttle assembly (rapid response)

whereas annulus pressure is applied on the front side(MI SWACO 2012), meaning that the choke movement are directly control by the hydraulic pressure balance. In other words, the Auto Choke automatically adjusts fluid flow to regulate casing and DP pressures.

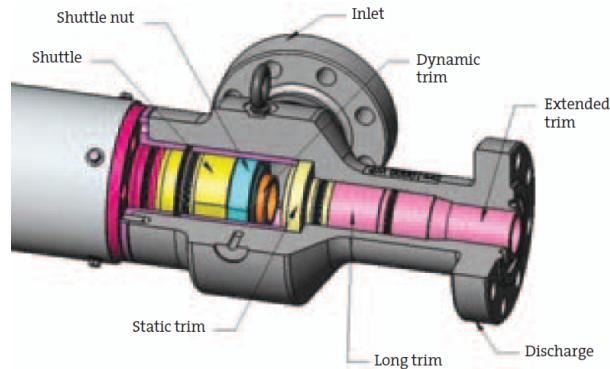


Figure 77: Schematic of the Auto Super Choke(MI SWACO 2010)

The Auto Choke are normally operated with an air hydraulic pump, but can alternatively be operated manually using a hydraulic pump. The control panel is equipped with set point indicator and control, pump stroke counters, pressure gauges (annular, DP) and hydraulic pump (Rehm, et al. 2008). The Auto Choke is available for 10K and 15K psi operating pressures. Failure is rare, and is most often related to sealing on pressure tests. Another important characteristic is that the choke goes to open position in the event of cut hydraulic lines (Rehm, et al. 2008).

Non-Return Valves

The DP non-return valve (NRV) is an essential part of the MPD operation as backpressure is often required. Originally it was named float, but as NRV is a more descriptive term for the one-way valve it became the primary descriptor(Rehm, et al. 2008). NRV ensures that the fluid flows in the right direction whereas pressure conditions may cause reversed flow. The pressure drop over the NRV is relatively large and needs to be taken into account when designing the well(Grundfos 2013).

Basic Piston-type float

The piston NRV is driven by a simple piston that is closed by a spring. Pressure forces from the circulating drilling fluid forces the valve to open. As the pumps are shut off, the valve closes. The piston NRV rarely fails, and is known to be a reliable and robust NRV. Failure of a piston NRV is normally caused by lack of maintenance or having too high volume pumping of abrasive fluids(Rehm, et al. 2008). The valve is normally placed in a sub above the bit. Additionally, it is becoming more normal to use dual NRVs in critical wells.

The type-G Baker Float has been the most common remedy for backflow problems. The downside of this tool is that the float blocks back pressure or shut-in DP pressure, in addition to blocking the DP for wireline. These limitations are minimized by placing the NRV close to the bit (reducing need for passing wireline) and slowly increasing pump pressure (Rehm, et al. 2008).

Hydrostatic Control Valve (HCV)

The HCV is a subsea version of the bit float valve used on DGD. This valve avoids the U-tube effect by holding a column of drilling fluid in the pipe. An NRV valve can also be placed near the bit to prevent backflow and plugging. The HCV is longer than the type-G float, and therefore the spring needs to be calibrated for holding the piston closed against the pressure from the drilling fluid in the riser.

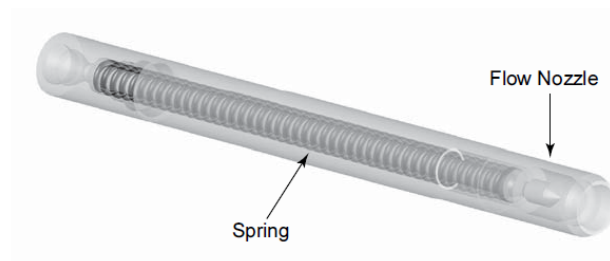


Figure 78: HCV valve (Rehm, et al. 2008)

Inside BOP: Pump-Down Check Valve

This tool is of the piston float generation, i.e. an older tool. This technology was used when there were objections to the use of NRV due to the chance of increasing lost circulation. The inside BOP is designed as a pump down tool acting as a check valve against upward flow and is seated in a sub above the BHA (Rehm, et al. 2008). The tool requires a sub inside the drill string and inside clearance to run. The sub is normally placed above the BHA or DC, and is non-retrievable after run. The inside BOP is essentially designed to control or prevent backflow when the top drive or Kelly is disconnected from the DP.

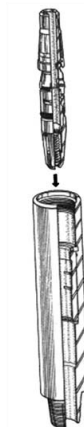


Figure 79: Inside BOP NRV (Rehm, et al. 2008)

Retrievable NRV or Check Valve

An improvement of the inside BOP is the retrievable NRV. These can be pulled out without tripping to the surface. There are two versions: the wireline retrievable dart-valve system and the flapper-type NRV which leaves an opening for balls or wireline passage through the valve (Rehm, et al. 2008).

Weatherford's WR-NRV flapper style drill-float valve is designed to manage backpressure in the drill string. Tripping is eliminated as the tool can be moved on wireline, and thereby enhancing the safety and operational efficiency. The WR-NRV prevents pressure from entering the drill string above. Safety is enhanced as the valve bleeds off when making/breaking connections. Time associated with bleeding of pressure of the entire drill string, as needed for fixed valves near the bit, is eliminated due to having multiple valves (intervals of 500ft) to enable incremental bleed or re-pressurization (Weatherford 2012a). This technology allows for quick recovery by wireline, enabling valve replacement without killing the well in addition to allow fishing operations to reach the BHA, which is not possible for fixed valve configurations.



Figure 80: Weatherford Gateway WR-NRV (Weatherford 2012a)

Down-Hole Annular Valves

Maintaining control of the BHP is difficult in MPD, especially when tripping. Trips can be managed by using casing isolation valve, stripping, snubbing or killing the well, all of which may cause technical and NPT problems (and thereby cost). Downhole valves allows for tripping without killing the well (Tercan 2010).

Casing isolation valve (CIV)

The pipe is stripped up into the casing until the bit is above the CIV, the valve is then closed (trapping pressure below) allowing the trip to continue without stripping or killing the well (Rehm, et al. 2008). The valve needs to be placed as deep as practically possible due to gas migration and to limit the pressure build up below the valve. Placing the valve deep also limits the stripping distance. The constraints are the need for a larger casing to allow the retraction of bit, differential pressure limits (typically 4000 psi) and directional drilling tools such as extreme bent housings that may damage the face of the valve.

Drilling Down-Hole Deployment Valve (DDV)

DDV is a CIV that is run as an integral part of the casing, which allows for installation in standard casing programs, set above a formation of interest. The DDV is operated from the surface by an umbilical (two hydraulic control lines run externally) leaving a small footprint of a hydraulic control unit (Rehm, et al. 2008). By avoiding the need for snub and well kill, the operation becomes safer, formation damage is minimized and emissions are significantly reduced (Weatherford 2012b).

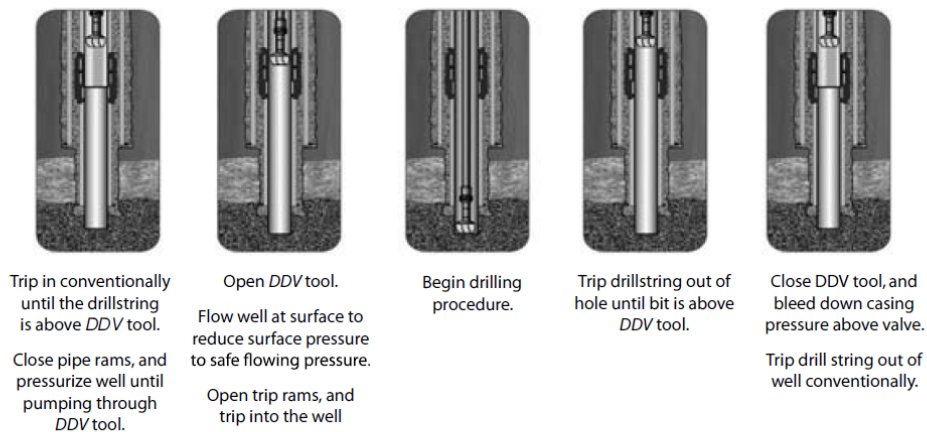


Figure 81: DDV trip sequence (Rehm, et al. 2008)

The valve lands on a matched metal seat to provide the seal containing reservoir fluids, thus preventing pressure at the surface (Weatherford 2012b). The DDV system is easily integrated into conventional casing program. The curved flapper fits against the outer casing string with the flapper in a locked open position allowing for full wellbore access. The tool is then a part of the casing and run into the well. The casing can be run in, drilled and cemented in place conventionally as the flapper is fully protected (mandrel seal with debris barrier). When tripping out of hole the pipe is stripped out until the bit is above the DDV valve, the flapper is then closed isolating the pressure below the valve (hydraulic pressure on the “close” line). The pressure above the valve is bleed, and conventional tripping is then feasible, see Figure 81 (Rehm, et al. 2008). Tripping in, the pipe is run to the valve (just above) and pipe rams are closed. The well is then re-pressurized to equalize with the pressure below the valve, hydraulic pressure is applied to the “open” line. The DDV is not a pressure equalizer, but functions as a power opening/closing device (pressure must be equalized before utilizing the device).

The advantages of using DDV are many. Conventional tripping is feasible since the well pressure below DDV is isolated, the tripping time is significantly reduced, the surface footprint is minimal and

no mud changes are required. This system allows for long and complex BHA where sealing of annulus poses a challenge. It can also be used for completion operations (Weatherford 2012b). As the DDV contain elastomeric seals that may deteriorate over time, it should not be used on long-term bases such as for production. Pressure limits must also be considered (Rehm, et al. 2008).

Quick Trip Valve (QTV)

The QTV is Halliburton's version of the CIV. It is run as an integral part of the casing string, but do not require a larger casing string as the DDV does (Rehm, et al. 2008). The downside is that in open position the ID is somewhat restricted. Pressure around the valve must be equalized for the valve to be open. The QTV tool isolates the reservoir while tripping by establishing a mechanical barrier and thereby eliminating the need for killing the well. Operating costs during drilling and completion is significantly reduced as tripping time is less and many wellbore issues are avoided (Halliburton 2013b). This tool has no depth limit.

ECD Reduction Tool

An ECD Reduction Tool is designed to adjust the hydrostatic head to obtain the desired well pressure. The tools objective is to reduce pressure loss due to friction, i.e. minimizing the difference between static and dynamic downhole pressure. The tool has many applications including narrow drilling windows, casing setting depths, wellbore instability, depleted reservoirs and ERD wells (Bern, Armagost and Bansal 2004). The ECD Reduction Tool is essentially a downhole turbine pump that reduces the ECD by creating a dual gradient in the annulus (Rehm, et al. 2008). The tool reduces the annulus pressure instead of imposing a pressure. Additionally, the U-tube effect is avoided as the system creates a dual gradient.

The advantages of this tool is that it does not require rig modifications, constant well pressure is maintained, MWD mud pulse signals are unaffected and wire-line operations are possible. Some of the challenges on the other hand are experienced when running and pulling the tool and maintaining sufficient hole cleaning.

Disc (Friction) Pump

The pump has a number of parallel plates which creates pumping action when spinning. The disc pump is more efficient than a centrifugal pump, particularly for high-viscosity fluids. The AGR subsea pump is a modified high-head disc pump that can pump cuttings and gas-cut mud.

Coriolis Flow meter

The Coriolis flow meter provides supplementary data while using automated pressure control systems and plays an important role in flow measurement for some MPD operations. The measurement principle is based on the Coriolis Effect: “The deflection of moving objects when they are viewed in a rotating reference frame”. The Coriolis meter measure the deflection for a flowing mass in a tube.

The Coriolis flow meter is very accurate compared to other flow meters as it measures drilling fluids containing cuttings. It can measure and calculate mass and volumetric flow in addition to the density and temperature of the flow (Rehm, et al. 2008). It is important to install the device correctly to avoid gas/solid accumulation. The measurements are not affected by external forces, but the effect of high flow rates and thus the risk of erosion should not be disregarded (Tercan 2010).

Continuous Circulating System (CCS)

The objective for the CCS is to maintain ECD at a constant level, i.e. avoid BHP changes and minimise pressure spikes associated with making connections. The CCS allows for continuous circulation during connections, which potentially increases the drilling efficiency for operations where maintaining constant pressures are essential, such as for depleted reservoirs (NOV 2012). Using the CCS will thereby reduce connection time resulting in a more stable wellbore and improve hole cleaning (Rehm, et al. 2008). The use of the CCS has proven to be successful in several challenging situations such as for depleted reservoirs, HPHT wells and wells with difficult and narrow drilling windows. A stable and uninterrupted circulation (ECD control) reduces fluid invasion and formation damage (NOV 2012). Additionally, this technology can be applied for closed-hole circulation (with rotating BOP) drilling to reduce formation damage or with an open annulus mud return.

Some of the benefit this technique provides is the ability to mitigate unexpected influx and ballooning effects in the wellbore. CCS enables wells to be drilled to their target depths in a safe and efficient drilling operation. The CCS does not require changes to DP or additional equipment as all tool joint connections occurs inside a pressure vessel consisting of BOP components (NOV 2012). A possible disadvantage is the higher risk of formation washout at the connection point.

Appendix F – Further HPHT Considerations

The Deepwater Horizon blowout April 20th 2010 that resulted in loss of 11 workers has forced the oil and gas industry to focus more intensively on safety challenges and risks. New standards, such as regulations and API procedures have been set. HPHT wells will continue to push the limits of existing technology in order to meet the future energy demand.

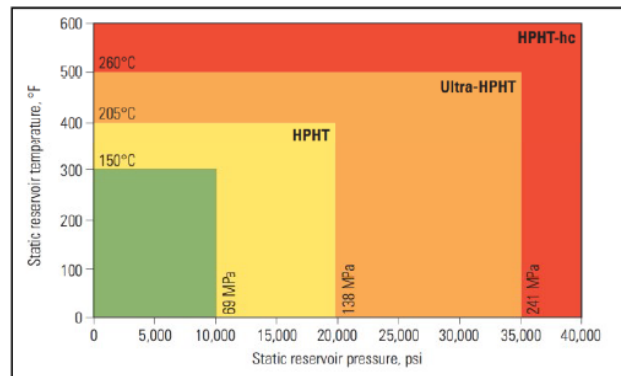


Figure 82: HPHT tiers (Shadravan and Amani 2012)

Drilling a HPHT environment is more prone to operational problems such as lost circulation, stuck pipe and well control issues. The commonly accepted definition of HPHT reservoir is pressure that exceeds 10 000 psi (690 bar) and temperatures exceeding 300°F (150°C). Further classification (tiers) of HPHT reservoirs has also been developed to help identify operating environments, technology that is available, safety issues and so on. HPHT reservoirs are divided into three tiers based upon initial pressure and temperature. Tier I (HPHT) is referred to as pressure between 10 000 psi to 20 000 psi and/or temperatures of 300°F to 400°F, tier II (ultra HPHT) as pressure between 20 000 psi to 30 000 psi and/or temperature between 400°F to 500°F, and tier III (extreme HPHT) for pressures between 30 000 psi to 40 000 psi and/or temperatures of 500°F to 600°F (Shadravan and Amani 2012). The Kristin field is a HPHT reservoir with 13 200 psi and 350°F. The definition of HPHT varies geographically as regulations differ. Norway defines a reservoir to be HPHT if the pressure or the temperature exceeds the HPHT definition, while other countries require for both temperature and pressure to exceed these limits.

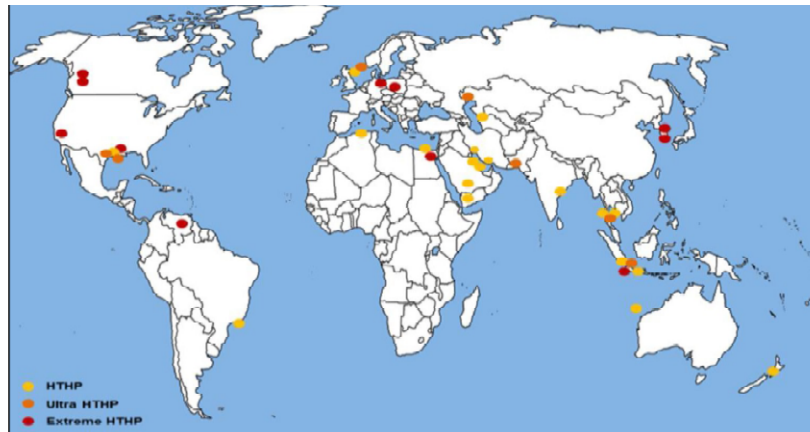


Figure 83: Locations on different classifications of the HPHT reservoirs in the world (Shadravan and Amani 2012)

Other well known HPHT reservoirs are the Elgin-Franklin fields with reservoir temperatures of 387°F and pressure of 16 750 psi, and the Morvin subsea field with temperatures of 333°F and pressure up to 12 154 psi. In addition to having HPHT environment, other issues such as depleted reservoirs raises its complexity.

HPHT Drilling Challenges

When drilling in HPHT environments there are several uncertainty factors such as the wellbore volume, drilling fluid rheological properties, high pressure, high temperature, compressibility and heat expansion. To understand the wellbore and its behaviour it is important to address and deal with these issues.

High temperatures affect tool readings. Most wireline tools can handle up to 425°F (some up to 450°F) and battery technology (mercury) up to 400°F for MWD applications, indicating that the tool accuracy significantly drops with temperature (Shadravan and Amani 2012). Standard seals used for DST are normally recommended up to 400°F, exceeding this limit they should be considered as a function on several factors such as pressure regime, fluids present and exposure time. The use of mechanical equipment is often avoided as it requires extra equipment to be operational, e.g. mechanical packers needing slip joints, safety joints and jars (Salguero, Almanza and Haddad 2011). Another challenge is data acquisition. Electronic gauges are suitable for temperatures up to 400°F, exceeding this mechanical gauges yield the most accurate result. Mechanical gauges are recommended as back up due to the fact that temperature predictions may be off or flowing temperature may be higher than the initial reservoir temperature. Real-Time Data-acquisition systems are also sensitive to temperature, often reliable up to 350°F. Permanent-gauges technology has been suggested as they measure the capillary tubing to calculate real-time pressure. These

gauges could provide readings in extreme environments, but may also lead to other complications and additional costs (Salguero, Almanza and Haddad 2011).

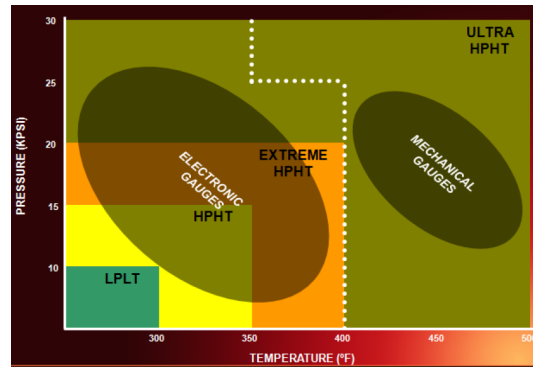


Figure 84: Operating envelope for gauges: electronic vs. Mechanical (Salguero, Almanza and Haddad 2011)

In regard to well control there are also challenges as fluid loss may occur due to lithology and geopressure, mud being forced into the formation causing ballooning (supercharging the formation) whereas a relief of pressure allows mud to flow back into the well possibly giving the appearance of a kick, and the occurrence of H₂S in OBM.

Fingerprinting is a method whereas real time data is used to determine the downhole environment. The objective is to compare real time data to previously obtained data to quickly detect influx. For precise results communication between posts are essential. Non-Productive Time (NPT) during operation may be caused by stuck pipe and twist offs, additional trip time due to tool failure or bit trips, and decision making due to lack of sufficient HPHT experience (Shadravan and Amani 2012).

OBM is more effective than WBM in directional HPHT wells due to its thermal stability and lubricant capabilities. On the other hand, static/dynamic barite sag is known to be a common safety and operational problem in HPHT wells. Weighting material such as barite may start to slowly segregate due to gravity effects and lack of sufficient circulation. This process is accelerated for deviated wells. The weighting material (barite) accumulates on the low side of the well, and will start to slide down the wellbore for inclinations above 30° (Skalle, et al. 1999). Sagging can lead to several drilling and completion problems, amongst these are density variations leading to pressure control problems, high torque and drag due to thick and tight particle/barite beds, stuck pipe, wellbore plugging and in some cases lost circulation.

Investigations and testing have been performed with several new surfactant types for use in drilling fluids (Aphron colloidal gas, asphaltic petroleum fluids). The primary objective is to maintain fluid properties throughout the wellbore, thereby being capable to determine carrying capacity (hole cleaning), frictional pressure drop, pump pressure and ECD. A solution may be to use Caesium

format, a particle free brine system. A Caesium format system allows for low ECD and quick kick detection, but is on the other hand very expensive and does not address fluid losses very well, i.e. can have losses 10 times higher than for an OBM. Experience with this system showed OBM to be a better option for high angle wells (Shadravan and Amani 2012). For challenging and complex HPHT wells OBM is normally used due to its thermal stability. Chemicals in drilling fluids become unstable at higher temperatures, and degradation starts. Normal drilling fluid is stable up to 400°F, but recent developments have shown to be stable up to 600°F and 40 000 psi (Shadravan and Amani 2012).

HPHT Cementing Challenges

Physical and chemical behaviour of cement materials depend greatly on temperature and pressure, thereby complicating the cementing operations when drilling in HPHT environments. Cement slurries consist of a mixture of water, cement and additives that controls density, setting time and strength.

A cementing operation has three risk phases, the immediate whereas the cement is pumped and displaced, the short-term risk whereas the cement has set until it starts to gain compressive strength, and the long-term risk whereas the cement starts to mature (Nesland, et al. 2012). The largest challenge is the transition between phases where the cement is between liquid and solid, acting as neither. Cement integrity is essential, particularly during the production phase. Most challenges are connected to the narrow pressure margins and tight annulus. The main objective for the cement is to provide a continuous impermeable seal to prevent influx of reservoir fluids. One of the most important factors for achieving a good primary cementing job, especially for HPHT wells, is the displacement of drilling fluid. Not properly displaced, the drilling fluid may cause channels or pockets that may lead to inter-zonal communication and possible erosion of casing. Effective displacement aids such as spacers and flushes enhance the removal of gelled mud and thereby creating an improved cement bond (Shadravan and Amani 2012).

HPHT wells are exposed to high temperature variations which affect casing and formation causing expansion and contraction resulting in cracks in cement that has set. Shallow gas and/or water in deepwater cementing operation is a great challenge as it may cause excessive washouts and subsequent losses resulting in an insufficient cement seal (Nesland, et al. 2012). Burnt Magnesium Oxide (MgO) can be added to provide an increase in shear bond strength and thus provide expansion curing up to temperatures of 550°F (Shadravan and Amani 2012).

Gas migration however is considered to be the most critical issue (25 % of cement job failures) as it leads to the formation of gas channels in the cement forming a flow path for formation fluids into the well. Zero gel time can be long when controlling gas migration, but transition time should be as short as possible, preferably less than 30 minutes (Shadravan and Amani 2012).

Portland cement that experiences temperatures exceeding 230°F to 248°F undergoes strength retrogression caused by formation of large di-calcium silicate hydrate resulting in an increase in permeability. To mitigate this problem silica flour or silica sand is added (ranging from 30 % to 100 %, whereas 30-40 % is normal) as it alters the reaction with cement and water to produce Xonolite instead of Tobermorite, which is stronger and thereby results in cement with lower permeability (Shadravan and Amani 2012). High temperatures also significantly reduce thickening time of the cement slurry. Another issue in deep wellbores are the small annuli.

HPHT Completion Challenges

HPHT environment are challenging as it affects all aspects of drilling, cementing and completion processes. Such extreme conditions affect the metallurgy, the stability and the endurance of downhole tools. High concentrations of acidic gases such as H₂S or CO₂ may cause severe cracking and weight-loss situations.

Developing completion fluids that can withstand HPHT environments in addition to possible sour environments is challenging, as every case is different. Fluid rheology, equipment endurance, perforating explosive charges limits, seal technology and electronics are all affected by high temperatures and high pressures. Newly developed techniques which allows for wells to flow at higher rates without damaging the near wellbore area raises both productivity and wellhead temperatures (liquid is a more effective temperature carrier than gas).

Appendix G – Estimation of the Pressure Profile

ConocoPhillips performed an advanced pore pressure evaluation by studying reference wells to define shale pressures. Due to some limitations for the Eaton method (smectite rich claystones: i.e. specific parameters are needed, not applicable in certain formations, only reliable in pure shale formations), shale pressures were also predicted by comparing results from the pseudo sonic to reference wells. The pseudo sonic results were consistent with reference wells, but yielded some uncertainty below the base-cretaceous unconformity due to lateral anisotropy. The final pressure profiles were a mix of several methods to obtain the most likely scenario.

Looking at Figure 37, the Pressure Profile Prediction is shown, the most likely case in yellow and the commitment case in orange. There are some deviations between the two cases, starting with the shale pressure ramp in the shallow section of the well. For the commitment case it has been adjusted based on the Solaris pseudo dynamic test and adjusted 0.05 sg below the MW used on Albuskjell (1/6-4 well). The pore pressure estimation was adjusted additionally at 1750 m TVD to 1.69 sg based on kick experienced on the 30/13-3 well. For the interval between 1750-2950 m TVD, the pressure profile was estimated to have a slight increase compared to the most likely case. This was primarily based on the Solaris Pseudo dynamic test and shale pressure experienced on the 1/6-4 well, and then adjusted with MW used on the 1/6-4 well. From 2950 m TVD pore pressure drops to 1.39 sg at 3220 m TVD. This drop is indicated by the shale pressure drop experienced on the 1/6-4 well together with the Balder pressure measured on well 30/8-2. For the commitment case, the Balder formation pressure are set slightly above the measurement made on the 30/8-2 well. The pore pressure estimation for the interval 3500-5200 m TVD are based on MW used on the Mandarin well in addition to regional MW used, setting the commitment case 0.05 sg below. Shale pressure ramp at the base-Cretaceous unconformity follows which are based on shale pressure experienced in offset wells adjusted with MW. Further, based on the water and gas influx experienced on the Mandarin well, pressure for the commitment case are set to 2.23 sg, and 2.26 sg for the reservoir pressure at 5600 m TVD.

The fracture gradient prediction is in general based on data from reference wells in the area, using FIT/LOT, calibrated stress models and lithology corrections

Appendix H – Weighting agents

There are several proposed solutions for reaching a high MW on the market. Among these are Ceasium formate system (see section **Error! Reference source not found. Error! Reference source not found.**), the Micromax system from Elkem (Elkem Materials 2013) and the WARP system from MI Swaco (Mi SWACO 2013a).

- Micromax** is an inert weighting agent which provides superior flow properties. The weighting agent is characterized by its dark-red color, colloidal particle size and spherical shape⁶. This system can easily be weighted up to 2.64 sg, which is more than enough for the Solaris well. Micromax is a self-stabilizing densifier which consists of more than 90 % Manganese Oxide (Mn_3O_4 , additive density of approximately 4.8 sg), and is classified as an environmentally safe additive. The weighting agent consisting of microfine particles (d50 of 0.5 micron), see Figure 86 and Figure 85. Micromax provides good lubricity, lowers plastic viscosity and yield point, which are preferable for HPHT wells. Micromax was used to drill a HPHT well in the UK North Sea having ECD management trouble as bottom hole temperature was close to 210°C The well was successfully drilled using a 2.24 sg LTOBM (Micromax weighted). A 1.43 sg LTOBM completion and packer fluid was also used successfully on another project also located in the North Sea to avoid sagging, and to optimize productivity and well stability.

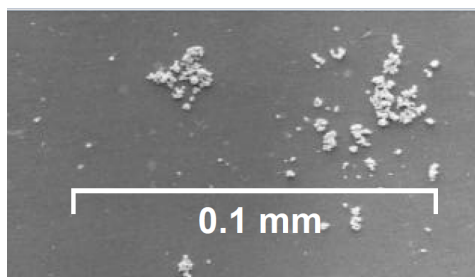


Figure 86: Micromax particles (Elkem Materials 2013)

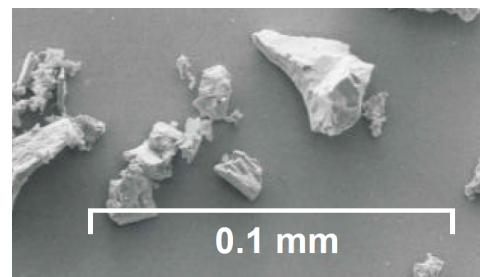


Figure 85: API Barite particles (Elkem Materials 2013)

- The **WARP** additive technology is another micronized weighting material system. WARP is based on Barite ($BaSO_4$) and has a density of approximately 4.2 sg. The particle size of the WARP additives is 2 microns. WARP have shown to reduce barite sag, lower plastic viscosity and yield point, and providing improved filtration system thereby reducing the risk of differential sticking. WARP additives are also coated with product to reduce friction between particles and thereby lower the viscosity of the fluid. In theory, the WARPs own weight can

⁶ Personal communication and e-mail correspondence with Eirik Jøntvedt, Sr. Fluid Engineer, Total E&P Norway

be achieved, but a limit is normally set at 2.4-2.5 sg as viscosity at this point will be too high. WARP additive exists in both slurry and dry form. The WARP fluid technology system has been used successfully on several projects in the North Sea. For instance, the WARP technology was used offshore in the North Sea on a vertical HPHT well. The main focus for the well was settling stability at 210°C and the high density mud required (2.07 – 2.14 sg). The well was successful having no indications of settling throughout the well, even in static conditions as the well had a failure to the top drive which took about 10 days to repair.

The main advantage of using micronized additive materials is based on its ability to hold a stable MW in the well, i.e. reduce the solids settlement velocity. Uncontrolled solid settlement can lead to poor well control and risk for kicks/blowouts. Particle size is directly related to the particle settling velocity (Stokes Law). In addition to extending particle settling velocity other parameters such as viscosity, emulsion and filtrate loss are optimized. Muds containing micronized heavy weight additives are therefore often used in HPHT wells. The higher an additive's density, the lower amount is needed to reach a given density. However, this does not take into account other parameters such as friction, settlement potential (sagging), filtration properties, viscosity and so on. The weight additives themselves are not affected by a HPHT environment, but other components (composition, physical parameters etc.) in the mud can.

Appendix I – Heavy-Duty Jack-Up rig Maersk Gallant

TYPE

MSC CJ62-120S, Ultra harsh environment jack-up drilling rig

BUILT

Far East Livingston Shipbuilding (FELS), 1993

CLASS

Lloyd's Register of Shipping

FLAG

Denmark

The **MÆRSK GALLANT** is one of the ultra harsh environment jack-ups in Maersk Drilling's fleet.

The rig is designed for year-round operation in the North Sea, in water depths up to 120 m (394 ft) with an available leg length below hull of 148.5 m (487 ft). The water depth capability can be increased to 125 m (410 ft) through installation of spudcan extensions. The rig is fully equipped for high pressure/high temperature drilling (HP/HT).

The **MÆRSK GALLANT** has been working in the North Sea since its commissioning in 1993.

The main features of the **MÆRSK GALLANT** include:

- 120–125 m water depth year-round in the North Sea
- Fully equipped for HP/HT operations
- 63 ft cantilever reach
- Skid-off feature
- 5,000 bbl dual mud system with dedicated oilbase storage tanks
- Driller's cabin, fully enclosed, touchscreen and joystick controls
- Computerised drilling systems
- 18 ¾" 15,000 psi BOP system
- Automated pipe handling system
- Automated and dust-free chemical mixing system
- Unmanned engine room
- Cuttings slurryfication and reinjection system

MAIN PARTICULARS

| DIMENSIONS | IMPERIAL | METRIC |
|---|----------------|------------------|
| Length overall | 257 ft | 78.2 m |
| Width overall | 296 ft | 90.3 m |
| Depth | 35.5 ft | 10.8 m |
| Length of legs | 575 ft | 175.2 m |
| Cantilever - max. reach: aft of stern to each side of centerline | 63 ft 15 ft | 19.5 m 4.57 m |
| Draught | 19.4 ft | 5.9 m |

| WEATHER/DESIGN CRITERIA | IMPERIAL | METRIC |
|-------------------------|-----------|----------|
| Water depth | 394 ft | 120 m |
| Wind speed | 87 knots | 45 m/sec |
| Penetration | 16.4 ft | 5 m |
| Wave height | 98.4 ft | 30 m |
| Current (surface) | 1.9 knots | 1 m/sec |
| Air gap | 68.8 ft | 21 m |

| PARTICULARS | IMPERIAL | METRIC |
|---------------------------------|------------------------|--------------------------|
| Rated drilling depth | 25,000 ft | 7,620 m |
| Hook load static w/top drive | 1,650,000 lb | 750,000 kg |
| Rotary load | 1,650,000 lb | 750,000 kg |
| Setback load | 850,000 lb | 385,560 kg |
| Variable load (incl. hook load) | 5,000 t | 5,000 t |
| Derrick, beam leg type | 160 ft x 40 ft x 40 ft | 48.8 m x 12.2 m x 12.2 m |
| Jacking speed | 1.15 ft/min | 0.35 m/min |
| Drill water | 14,045 bbl | 2,233 m ³ |
| Fuel oil | 4,240 bbl | 676 m ³ |
| Nontoxic oil | 1,700 bbl | 270 m ³ |
| Brine | 1,700 bbl | 270 m ³ |
| Potable water | 1,880 bbl | 300 m ³ |
| Liquid mud | 5,035 bbl | 800 m ³ |
| Bulk cement | 5,600 ft ³ | 160 m ³ |
| Bulk mud | 9,100 ft ³ | 260 m ³ |
| Slurryfication tank | 1,880 bbl | 300 m ³ |
| Accommodation | 100 persons | 100 persons |

DRAWWORKS

Continental Emsco C-3 Type II, 3,000 hp.

TRAVELLING EQUIPMENT

Continental Emsco RA 60-7-750 travelling block, 680 MT capacity.

TOP DRIVE AND PIPE HANDLING

Varco TDS-6S with pipe handler and block retract system.
 Varco PHM-3 pipe racking system with automatic fingerboards.
 Varco AR3200 integrated iron roughneck.
 Varco fully interlocked zone management system (ZMS).

ROTARY TABLE

Continental Emsco T4950-65 driven by Rexroth Mr-3600 hydraulic motor. Opening 49 1/2°.

MUD PUMPS

Three Continental Emsco FC-2200, 2,200 hp, rated for 7,500 psi.

CEMENTING EQUIPMENT

Halliburton HCS-25D 15,000 psi wp. On free placement agreement.

WELL CONTROL EQUIPMENT

NL Shaffer 18 3/4" 15,000 psi NXT BOP consisting of one annular + one double ram preventer + one single ram preventer.
 Vetco Gray diverter system type KFDJ 500 psi.

MUD RETURN SYSTEM

Four Rigtech VSM 300 shale shakers, high performance linear motion. Swaco Geolograph degasser horizontal type. Two Swaco centrifuges and one Smedvig IPR cascade desilter. The rig is equipped with an Expro ultrasound slurryfication unit, a holding tank and an Expro injection pump. The pump is an electrical driven triplex pump with its own power supply.

DRIVE PIPE SUPPORT DECK

Hinged deck for conductor support 50 ft aft of transom. For sizes 30° to 36°.

TENSIONER SYSTEM

Conductor tensioning system consisting of 4 x 60 t hydraulic cylinders.
 BOP handling system consisting of 4 x 45 t air-powered chain type trolley cranes.

DRILLING INSTRUMENTATION

HITEC/ABB 1000 drilling instrumentation with multi-parameter and alarm settings.

POWER SUPPLY

Five Caterpillar 3516 DITA air-start diesel driven engines. Continuous output 1,545 hp at 1,200 RPM, maximum output 1,615 hp. Each diesel engine driving one LeRoy Somer LSA 52L9/6P. Output 1,260 kW, 1,800 KVA, 600 volts, 60 Hz.

SCR SYSTEM

ABB SCR system.

CRANES

Two Liebherr BOS 50/1100 cranes, 42.7 m (140 ft) 50 t capacity and whip 1 x 8 t and 1 x 11 t.
 One Liebherr BOS 34/930 crane, 42.7 m (140 ft) 34 t capacity and whip 5 t.

HELICOPTER DECK

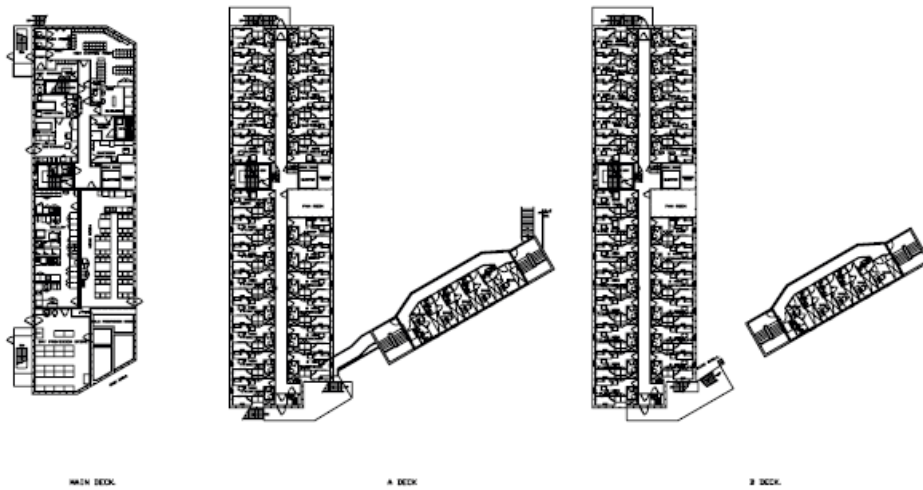
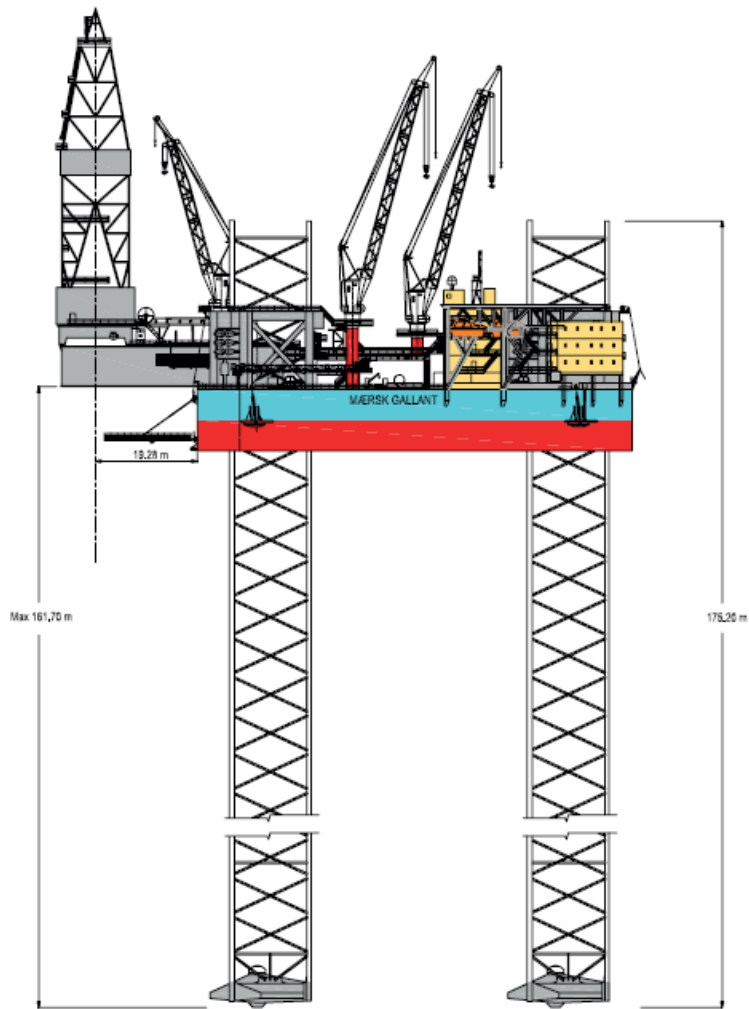
22.5 m (74 ft) diameter helicopter deck suitable for Sikorsky S-61N helicopter.

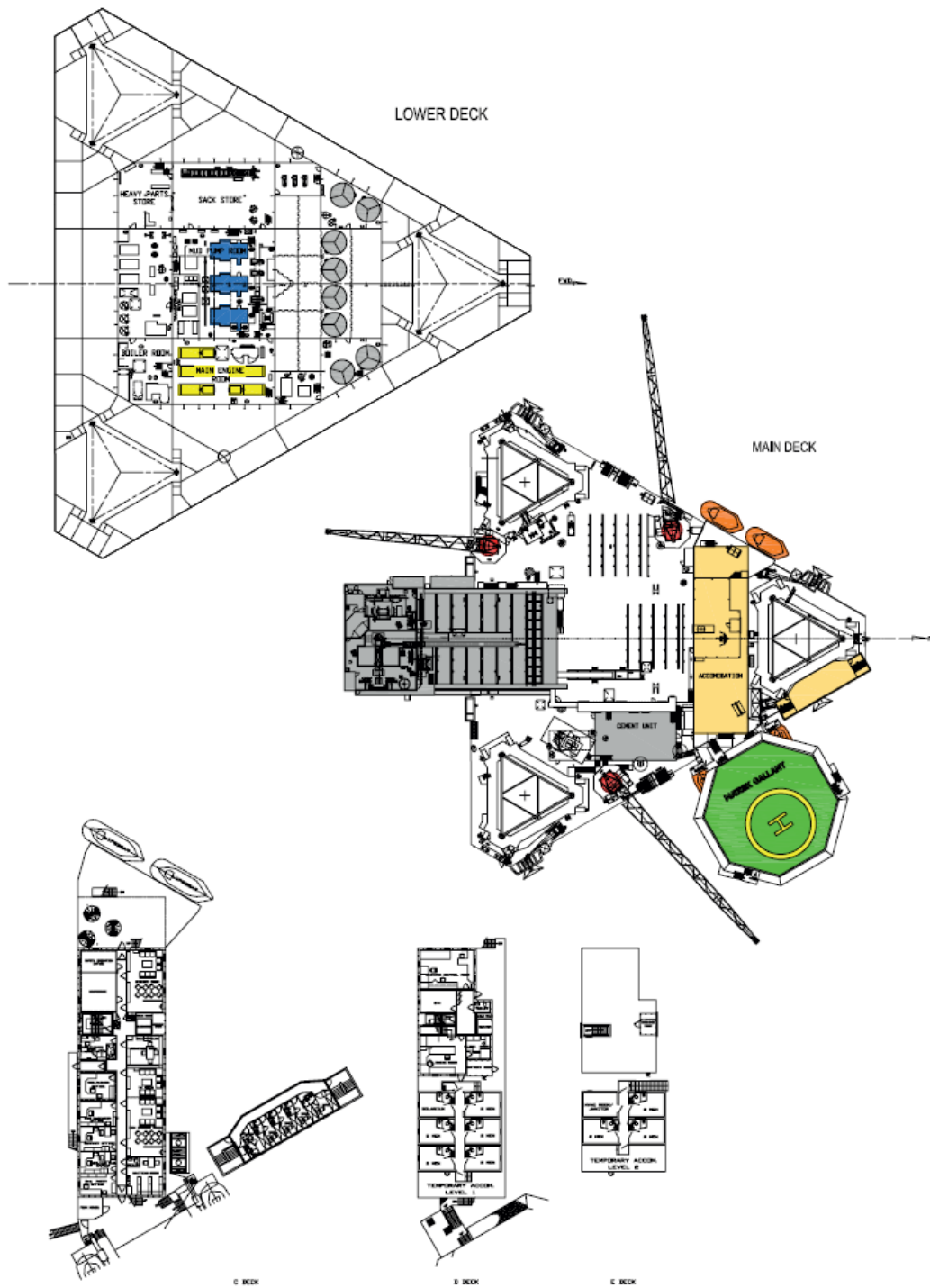
SAFETY EQUIPMENT

Lifesaving and fire fighting equipment in accordance with Danish Maritime Authority, U.K. DOE/DOT and Norwegian regulations, draft of IMO MODU code 1989. The rig holds a vessel specific safety case which has been approved by HSE UK.

ACCOMMODATION

100 persons in two-man rooms with full facilities. ■





Appendix J - Maersk Gallant potential MPD rig-up schematic

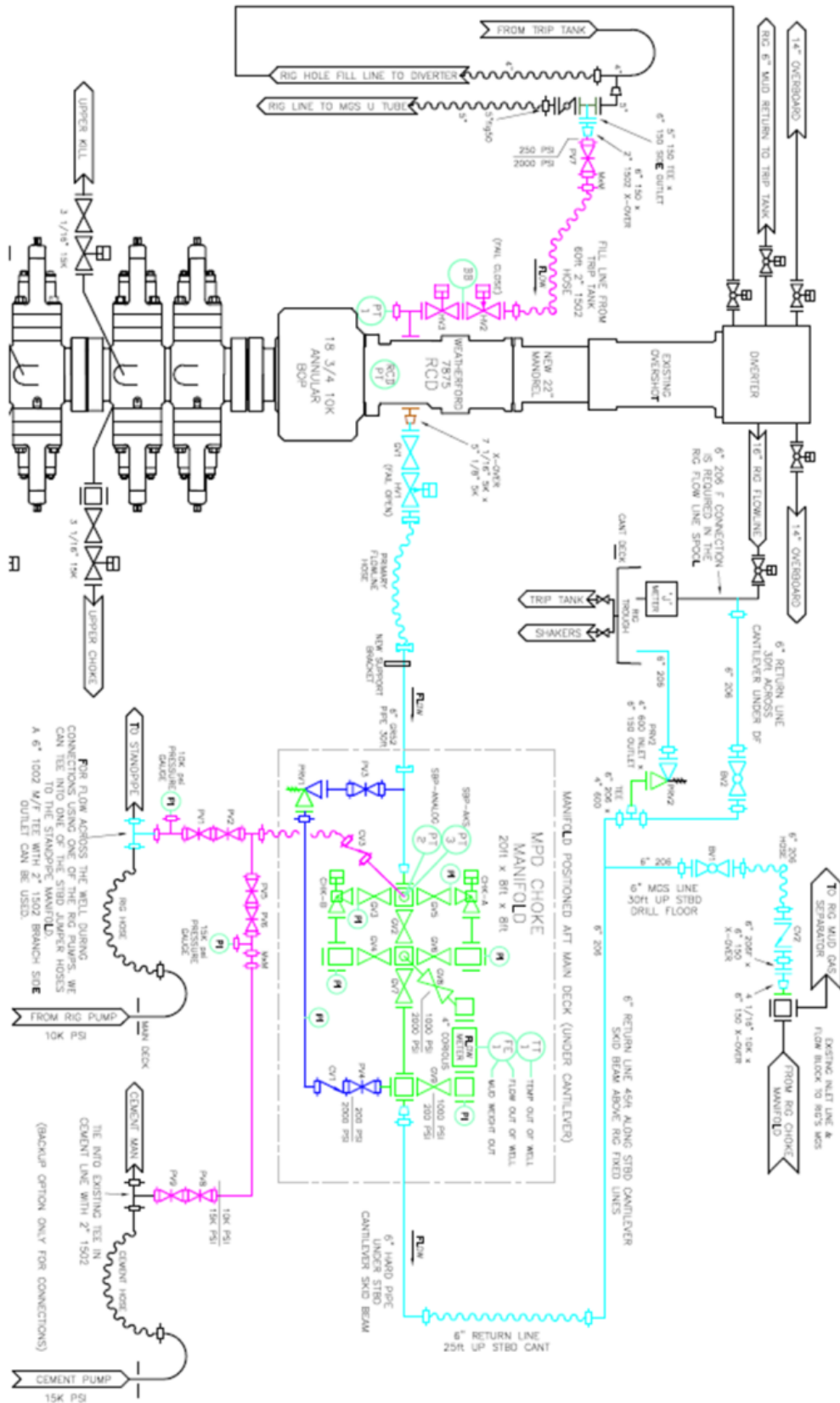


Figure 87: Weatherford MPD set-up for the Maersk Gallant HDJU rig (Total E&P 2013c)