Chapter

Managed Pressure Drilling and Cementing and Optimizing with Digital Solutions

Behzad Elahifar

Abstract

This manuscript provides a comprehensive examination of cutting-edge drilling technologies and their implications for the energy industry. Managed Pressure Drilling (MPD) and Controlled Mud Level (CML) are meticulously dissected, uncovering their techniques, equipment, and operational intricacies. Additionally, Managed Pressure Cementing (MPC) is explored, showcasing the ingenious application of MPD during cementing operations. The chapter then ventures into the realm of digitalization and automation, highlighting the role of Wired Drill Pipe as a conduit for high-speed data transmission, transforming drilling through real-time monitoring and decision-making. The convergence of digitalization and automation with MPD and CML systems is unveiled, elucidating how these technologies can create semi or fully automated systems that optimize drilling processes, enhance accuracy, and reduce nonproductive time (NPT). This manuscript invites readers on a journey into the frontier of drilling technology, where innovation knows no bounds, and the future of energy exploration and production is being reshaped.

Keywords: managed pressure drilling, controlled mud level, managed pressure cementing, pressurized mud cap drilling, controlled mud cap drilling, digitalization

1. Introduction

In the ever-evolving landscape of drilling operations, two pioneering technologies have risen to the forefront, promising enhanced control, efficiency, and safety: Managed Pressure Drilling (MPD) and Controlled Mud Level (CML). This chapter embarks on a comprehensive exploration of these groundbreaking techniques, their respective equipment, and operational intricacies, delving deep into the core principles that underpin their success. MPD, a transformative approach that manages wellbore pressure throughout the drilling process, is meticulously dissected to uncover its techniques and instrumentation, while CML, a novel method to manipulate mud levels in the riser, is unraveled to illuminate its unique operational strategies. Additionally, the chapter delves into the realm of MPC, an ingenious application of MPD during cementing operations to mitigate losses and ensure cement placement accuracy.

Furthermore, we venture into the digital frontier where automation and high-speed data transmission converge to revolutionize drilling. Wired drill pipes, acting as the neural pathways of this digitalization, enable seamless communication between downhole and surface, ushering in an era of real-time monitoring and decision-making. The marriage of digitalization and automation with MPD and CML systems forms the nucleus of our discussion, as we explore how these technologies can be harnessed synergistically to create semi or fully automated systems that optimize drilling processes, enhance accuracy, and ultimately reduce NPT. Join us on this journey through the cutting-edge realms of drilling technology, where innovation knows no bounds, and the future of energy exploration and production is being reshaped before our very eyes.

2. Managed pressure drilling

Managed Pressure Drilling (MPD) is a drilling approach born out of the need to combat the high costs associated with NPT caused by the precarious balance between pore pressure and fracture pressure during drilling operations both onshore and offshore drilling rigs.

MPD stands as an adaptable drilling technique deployed to regulate the annular pressure configuration within the wellbore. Its primary aims encompass defining the constraints of downhole pressure conditions and effectively orchestrating the hydraulic pressure profile surrounding the annulus. Implicit in this definition is the use of a single-phase drilling fluid treated to minimize flow friction losses.

Broadly speaking, Managed Pressure Drilling presents itself as a drilling approach that empowers precise oversight of wellbore pressure dynamics.

MPD is a broad concept encompassing various strategies and equipment designed to effectively control wellbore pressure. Its primary objectives are to prevent kicks, lost circulation, and differential pressure sticking, all with the aim of reducing the need for additional casing strings to reach the desired total depth.

This field of wellbore pressure management finds wide-ranging applications within the drilling industry, offering solutions to issues like:

1. Reducing lost circulation occurrences.

2. Preventing the sequence of lost circulation followed by a kick.

3. Minimizing NPT associated with pipe differentially stuck.

4. Enabling drilling operations with total lost returns.

5. Enhancing drilling speed.

The primary objective of MPD is to prevent the continuous inflow of formation fluids into the well [1]. Any unintended influx during operations is safely managed through suitable processes. Additionally, MPD employs a range of tools and techniques aimed at mitigating the risks and expenses linked to drilling wells with tight mud window. This is achieved through proactive management of the annular hydraulic pressure profile. MPD may encompass the control of various factors such as back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, hole geometry, or combinations thereof. MPD provides the advantage of swift response to observed pressure variations, facilitating dynamic control of annular pressures. This capability opens opportunities for drilling prospects that might otherwise be economically unfeasible.

3. Managed pressure drilling techniques

There exist four primary iterations of MPD, each tailored to address specific drilling hazards for which they have proven effective. Occasionally, multiple variations are combined for use on particularly challenging projects. This practice is anticipated to become more common as the technology gains acceptance among drilling decision-makers and as drilling prospects become progressively more intricate. The four key MPD variations, along with their sub-categories detailing their application areas and respective strengths, are as follows:

- Constant Bottom Hole Pressure (CBHP)
- Mud Cap Drilling (MCD)
    - Pressurized Mud Cap Drilling (PMCD)
    - Floating Mud Cap Drilling (FMCD)
- Dual Gradient Drilling (DGD)
    - Riser-less Mud Recovery (RMR)
- Return Flow Control (RFC)

3.1 Constant bottom hole pressure

Many challenges in drilling and wellbore stability arise from the considerable fluctuations in bottomhole pressure inherent in traditional drilling methods. These pressure variations serve as the root causes of numerous cost overruns in conventional land-drilling operations. These pressure spikes mainly occur during the start and stop of circulation for making drill string connections in jointed-pipe operations. They specifically result from changes in equivalent circulating density (ECD) or annulus friction pressure (AFP) when pumps are activated or deactivated. AFP contributes to bottomhole pressure during circulation but vanishes when circulation ceases [2].

Constant Bottom Hole Pressure (CBHP) is the term typically used to describe actions taken to correct or minimize the impact of circulating friction losses or ECD, with the aim of staying within the boundaries set by pore pressure and fracture pressure. To mitigate the effects of AFP or ECD, it's crucial to grasp the concept of backpressure (BP).

- *Conventional Drilling:*
    - (During Drilling) Bottom Hole Pressure (BHP) = Hydrostatic Head of Mud + AFP

- (During Connection) Bottom Hole Pressure (BHP) = Hydrostatic Head of Mud

- *Managed Pressure Drilling:*

    - (During Drilling) Bottom Hole Pressure (BHP) = Hydrostatic Head of Mud + AFP + BP

    - (During Connection) Bottom Hole Pressure (BHP) = Hydrostatic Head of Mud + New BP

In this approach, the objective is to closely follow the pore pressure line by employing a fluid density that is closer to balance than conventional practices. This strategy addresses challenges related to narrow margins between formation pore pressure and fracture gradient, particularly when drilling ahead. Surface annulus pressure remains nearly zero during drilling, but during shut-ins for jointed pipe connections, a few hundred psi of backpressure is required. The use of backpressure demonstrates the industry's ability to utilize less dense drilling mud.

Figure 1 provides a simplified depiction of how ECD or Annulus Friction Loss (AFL) can be compensated for. In theory, it's possible to offset a decreasing amount of AFL by simultaneously increasing Back Pressure (BP) when circulation stops, enabling control of Bottomhole Pressure (BHP).

Although the main objective of the Constant Bottomhole Pressure Method (CBHP) is to manage challenging pressure anomalies within the wellbore, the name might suggest controlling the bottomhole pressure at the well's base. Typically, lighter-than-usual drilling fluids are used, resulting in a statically underbalanced hydrostatic column. The utilization of less dense mud exemplifies one of the management strengths of MPD and highlights the application of this innovative concept.

MPD replaces the pressure exerted by static mud weight with dynamic friction pressure to maintain well control while preventing fluid losses. The technique aims to keep wellbore pressure within the range defined by the highest pressured formation's

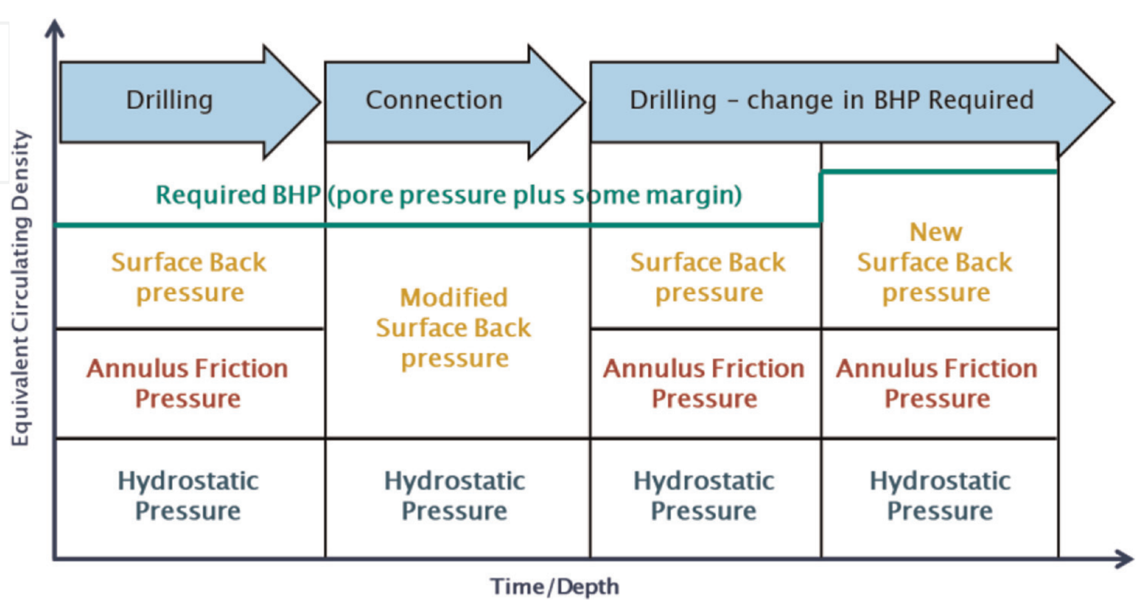

Figure 1.
ECD compensation during connection with MPD.

pore pressure and the weakest formation's fracture pressure. This is often achieved by using a mud weight with a hydrostatic gradient lower than required to balance the highest pore pressure, compensating for the difference through dynamic friction during circulation. While it sounds straightforward, this process can be quite complex.

The initial challenge lies in transitioning from static balance to dynamic (circulating) balance without losing returns or encountering a kick. This can be achieved by gradually reducing pump speed while simultaneously closing a surface choke to increase surface annular pressure. The goal is to reach a point where the formation experiences the exact pressure it encountered from ECD while circulating. It's important to note that bottomhole pressure remains constant at only one point in the annulus.

Various techniques have been employed to maintain constant bottomhole pressure during the transition from dynamic to static (or vice versa). These methods include:

- Hydraulic models have been utilized to calculate an annulus pressure schedule to follow while gradually reducing the pump rate.

- Computer-controlled chokes have been developed to automate the process of adhering to the required pressure schedule.

- Circulating loops have been constructed with dedicated pumps to ensure continuous surface circulation through a choke, facilitating precise control of annular surface pressure.

- In some instances, a conventional rig pump has been repurposed as a dedicated pump, offering the advantage of pump redundancy.

- Specialized equipment has been developed to sustain continuous circulation through the drill string during connections, effectively eliminating the need for a transition by preventing a static situation entirely.

With these methods, the well is typically never fully shut in, as any necessary surface pressure is imposed through a partially closed choke.

In addition to surface equipment, during drilling operations, influx is prevented by increasing annular friction pressure through pumping. During connections, drillers manage influx by applying back pressure or by trapping pressure within the wellbore. At the very least, a non-return valve (NRV) placed inside the drill string halts the flow of mud up the drill pipe towards the surface [3].

3.2 Mud cap drilling

3.2.1 Pressurized mud cap drilling

PMCD, which stands for Pressurized Mud Cap Drilling, is a technique employed for drilling while ensuring total loss returns. In PMCD, drilling takes place without returning fluids to the surface, and a full annular fluid column is maintained above the formation that receives injected fluid and drilled cuttings. Maintaining this annular fluid column necessitates the application of observable surface pressure to balance the downhole pressure.

PMCD not only addresses lost circulation issues but does so by utilizing two different drilling fluids. A heavy, viscous mud is pumped down the annular space on the backside to a certain height, forming a mud cap that acts as a barrier. Simultaneously, the driller employs a lighter, less damaging, and cost-effective fluid to drill into the weaker geological zones [3].

The driller pumps the lighter sacrificial fluid down the drill pipe. After circulating around the drill bit, this fluid, along with cuttings, is injected into a zone located above the last casing shoe, typically a weak zone. The heavy, viscous mud remains in the annulus, forming a mud cap above the weak zone. If necessary, the driller can apply backpressure to maintain control over annular pressure. This use of a lighter drilling fluid enhances the Rate of Penetration (ROP) due to increased hydraulic power and reduced chip hold-down.

The use of PMCD is contingent on experiencing total losses. These losses must be significant enough to accommodate all the fluids pumped down the drill string and the cuttings generated during drilling [4]. If circulation, even partial, is established, the mud cap would be circulated out of the well, rendering PMCD unsuitable, and the CBHP method would be the alternative.

Furthermore, unlike other methods, PMCD might be applied in situations where total loss scenarios are not encountered, but total losses can be induced by altering the wellbore pressure profile [4]. This variation is expected to be used in deepwater drilling, particularly when drilling through heavily depleted pay zones to reach deeper zones with virgin pressure. It enables safe drilling in cases where the depleted zone above the target can accept the sacrificial fluid and drilled cuttings. The mud cap, along with backpressure, directs the returns into the depleted zone above, the path of least resistance (**Figure 2**).

When the drill pipe is removed from the hole, a weighted mud slug can be pumped as a "pill" to balance bottomhole pressure, compensating for the loss of backpressure when the bottomhole assembly is out of the hole. The volume of mud required for this purpose depends largely on the hole's diameter and the proximity of fractures since returns are typically not seen at the surface [5].

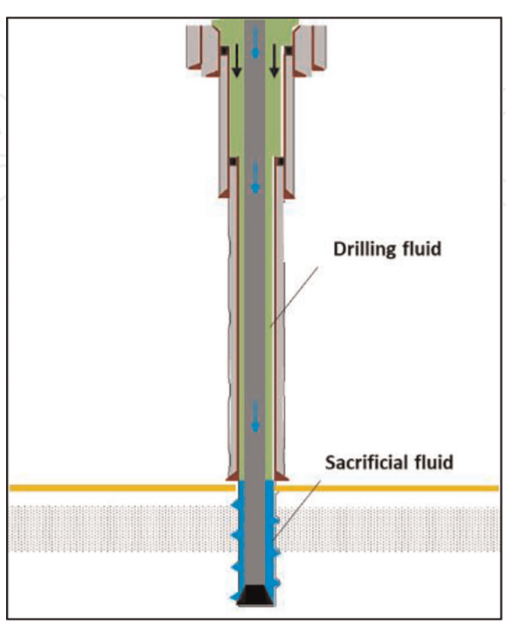

Figure 2.
Mud cap drilling.

3.2.2 Floating mud cap drilling

Floating Mud Cap Drilling (FMCD) is a specialized subset of the PMCD technique. It comes into play when it's challenging to design the annular fluid to provide surface pressure, resulting in a "floating" mud cap. In FMCD, a sacrificial fluid, typically water, is pumped down the drill pipe, like PMCD [5].

As drilling progresses and the well deepens, assuming increased formation pressure with depth, the high-density annular mud cap may lose its ability to contain bottomhole pressure independently. Over time and distance, an annular pressure differential of 200 to 300 psi, well below the pressure ratings for Rotating Control Device (RCD) tools, is not uncommon. As annular pressure rises, the fluid density of the mud cap is often increased to maintain pressure within acceptable limits. Surface pressure fluctuations serve to monitor three downhole conditions:

- Detection of gas migration to the annulus.
- Management of produced fluid injection back into the formation at specified rates and volumes.
- Handling of pore pressure increases by adjusting the annular hydrostatic fluid density to maintain surface pressure within a safe range.

Addressing potential fracture plugging issues, wherein if cuttings obstruct fractures, pressurized mud cap drilling may need to be halted in favor of conventional drilling operations.

However, monitoring of mud levels in the annulus is challenging, particularly when the formation pressure is below hydrostatic. In such cases, it's challenging to maintain the annulus full of fluid, and the fluid level in the well tends to reach an equilibrium point. This situation can make it difficult to monitor influx or gas migration. FMCD effectively means drilling blindly with limited annular pressure control [2].

New technologies such as wired drill pipe, which allows pressure monitoring along the drill string, could unlock additional FMCD capabilities and provide enhanced well control options. There are also considerations of using fluid technologies with lightweight solid additives like glass beads to facilitate mud cap operations when drilling in sub-hydrostatically pressured reservoirs.

3.3 Dual gradient drilling

Dual Gradient Drilling (DGD) is a term encompassing various strategies aimed at controlling up-hole annular pressure in the context of deepwater marine drilling. DG has found success primarily in offshore applications, where a significant portion of the overburden is comprised of water. Since this liquid overburden is less dense than the typical formation overburden, the drilling window is relatively narrow due to the limited margin between pore pressure and fracture pressure. The weak formation strength in deepwater conventional drilling often necessitates the use of multiple casing strings at shallow depths to prevent severe lost circulation when employing single-density drilling fluids.

To mitigate the impact of the deepwater overburden, the drilling system can be balanced by reducing mud density in the upper sections of the marine riser or by introducing sea water into the riser or dividing the system at the seabed into two parts.

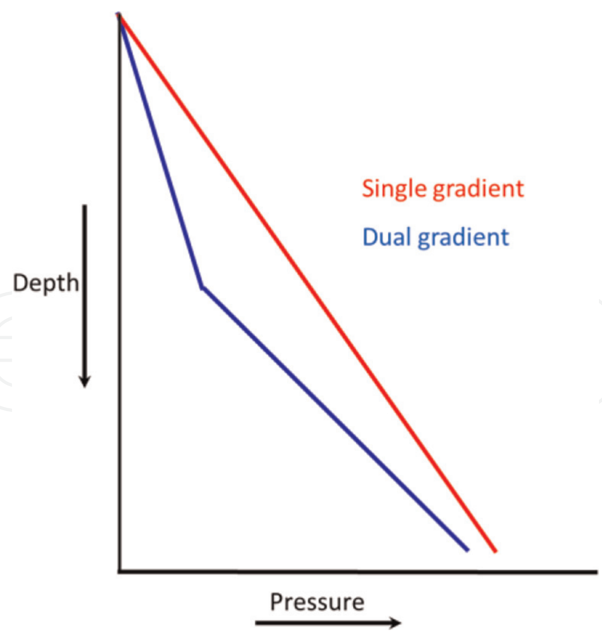

Figure 3.
Dual gradient drilling.

In the dual-gradient approach, the goal is to simulate the saltwater overburden with a less dense fluid. This can be achieved by injecting media with lower density, such as inert gas, plastic pellets, or glass beads, into the drilling fluid within the marine riser to adjust bottomhole pressure. Alternatively, the marine riser can be filled with saltwater while diverting and pumping mud and cuttings from the seabed floor to the surface. In this scenario, filling the drilling riser with seawater helps prevent collapse. The primary objective is not to decrease the Equivalent Mud Weight (EMW) or effective BHP to a point below formation pore pressure. Instead, the primary goal is typically to avoid excessive overbalance and surpassing the fracture gradient.

Figure 3 illustrates a comparison of pressure profiles between the dual gradient method and the conventional method. Particularly in deepwater drilling where fracture pressure is a significant concern, transitioning from conventional to dual gradient systems reduces the risk of fracturing weak zones under dynamic conditions [6].

Both methods involve altering fluid density near the mudline. By using two different fluids to create overall hydrostatic pressure in the wellbore, the fracture gradient is not exceeded, and formation breakdown is avoided. This prevents drilling operations from incurring NPT associated with lost circulation problems and the associated costs. This form of MPD can be implemented with or without a subsea RCD [3].

3.3.1 Riser-less mud recovery (RMR)

In the Pre-BOP section, implementing a DGD system can effectively address various operational challenges. Offshore drilling for the top-hole section often encounters difficulties such as soft and unconsolidated formations, shallow gas, and shallow water. Additionally, the use of seawater as a drilling mud can be less effective for hole cleaning and wellbore stability. Disposing of cuttings into the sea becomes an issue due to the absence of fluid return to the shakers, and cementing is challenging

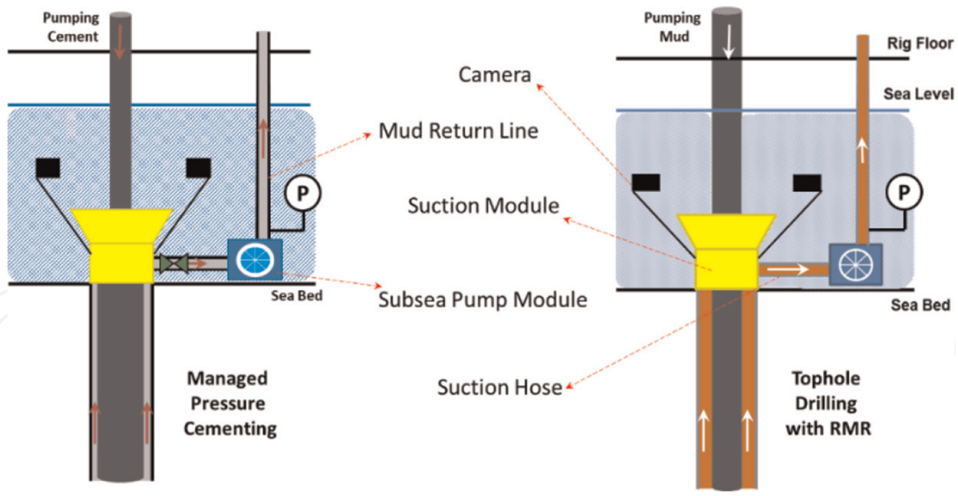

Figure 4.
Riser-less mud recovery system for top-hole drilling and cementing.

because of seawater mixing at the seabed and potential exposure of excess cement to the sea, among other concerns.

To overcome these challenges, the Riser-less Mud Recovery (RMR) system proves valuable. With RMR, engineered mud can be utilized, eliminating problems related to hole cleaning and instability. Mud and cuttings can circulate efficiently and be recovered without exposure to the sea on the shaker. Employing engineered mud circulation in the top-hole section contributes to the formation of a mud cake, enhancing wellbore stability and eliminating issues related to shallow gas during drilling.

Furthermore, cementing operations can be conducted within a closed system, enabling precise control of BHP. The closed system allows for accurate monitoring of cement volume, and when the cement reaches the seabed, it can be confirmed through pressure sensors in the return line. By adjusting and manipulating the speed of the Subsea Pump Module (SPM), BHP can be controlled with precision. This integrated approach addresses the challenges associated with drilling in the top-hole section and enhances overall operational efficiency and safety (**Figure 4**).

3.4 Return flow control

As we gear up to respond securely and efficiently to any unexpected downhole events, Return Flow Control (RFC) can be seen as a crucial aspect of the MPD approach, even though it does not directly manage annular pressure. RFC also serves the important purpose of diverting annular returns away from the rig floor to prevent any gas, especially hazardous gases like H_2S, from escaping onto the rig floor. This practice is primarily a safety measure [2].

In the event of an influx during drilling, trip gas, or connection gas spilling onto the rig floor, a safety protocol is activated. The flow line to the shakers is closed immediately, and the flow is redirected to the rig choke manifold, where the influx is safely controlled and circulated out of the wellbore. The utilization of an RCD negates the need for closing the Blowout Preventer (BOP), minimizing the potential for hydrocarbon release onto the drilling floor. It also allows for pipe movement while managing an influx or addressing gas-cut mud.

For RFC operations, two hydraulically operated valves are installed: one for the conventional flow line to the shakers and the other for the flow line to the rig choke manifold. This setup permits the handling of any influx through the rig choke manifold, while in regular operations, the conventional flow line is used for fluid circulation [7].

The primary objective of this approach is to conduct drilling with a closed annulus return system primarily for Health, Safety, and Environmental (HSE) reasons. For instance, during conventional production platform drilling operations with an open-to-atmosphere system, there may be a risk of explosive vapors escaping from drilled cuttings. This could trigger atmospheric monitors and potentially lead to automatic shutdowns of production in other areas of the platform. Other applications of this RFC variation include addressing toxicological concerns associated with drilling fluids emitting harmful vapors onto the rig floor, taking precautions in areas with shallow gas hazards, and drilling in populated regions. Typically, only an RCD is added to the drilling operation to implement this variation [6].

4. MPD operation

Drilling in MPD mode closely resembles conventional drilling in most aspects. The primary difference lies in the surface pressure (Surface Back Pressure or SBP), while all other procedures typically remain unchanged. In cases where a Coriolis Flow Meter is available, it enhances the detection of influxes or losses, and a new variable called Delta Flow (the difference between Flow Out and Flow In) is closely monitored.

Although the procedures in MPD are like conventional drilling, the meticulous control of pressures necessitates a more comprehensive monitoring of all parameters that could influence BHP. While drilling in MPD mode, particular attention must be paid to several key parameters, with some of the most crucial being:

- Standpipe Pressure trend can offer valuable insights into downhole events.
- Any increase or decrease in cuttings observed at the shakers may indicate variations in hole cleaning. Accumulation of cuttings in the annular space can significantly impact BHP.
- Parameters indicating influxes or losses:
    - Pit Volume Totalizer
    - Change in flow in and flow out
    - Rate of Penetration
- It's essential to remember that hydrostatic pressure is an important parameter that contribute significantly to the pressure applied at the bottom of the hole (mud weight).
- Changes in either of Mud Rheology and Flow Rate can affect annular friction losses, ultimately influencing BHP.

Additionally, it's important to consider any specific operations that require alterations in flow rates, such as monitoring slow circulating rates or conducting mud telemetry operations when using Measurement While Drilling (MWD) tools [8].

4.1 Connection with MPD system

During pipe connections, the flow rate undergoes significant changes, transitioning from drilling speed to zero or vice versa. This variation directly impacts the calculation of annular friction losses and, subsequently, the BHP. As previously discussed, it's essential to adjust the Surface Back Pressure to compensate for the loss of annular friction losses when the flow rate reaches zero. This is a necessary step to facilitate the breaking of pipe connections, allowing for the addition or removal of pipe sections to continue drilling operations.

Here's a summarized procedure for handling connections:

Drilling Phase: Drilling continues until the top of the stand reaches the rig floor level. All parameters are maintained at their drilling values during this phase. Circulation is actively maintained to prevent cuttings near the bottom of the hole from settling and potentially causing a pipe to become stuck.

Ramp Down: When the crew is ready to make the connection, the flow rate is gradually reduced in steps. Simultaneously, Surface Back Pressure is increased at each step to compensate for the loss of friction losses, ensuring a constant BHP. The ramp-down pressure follows a predetermined schedule, with Surface Back Pressure calculated for each step.

Connection: During this step, the drilling crew performs the actual pipe connection. Notably, in this closed system, pressure inside the drill string does not naturally bleed off. Thus, a bleed-off process must be executed before breaking the connection.

Ramp Up: After completing the connection, circulation is resumed, and the flow rate is gradually increased back to drilling values. This process reverses the ramp-down procedure (**Table 1**) [8].

After successfully completing the connection and restoring drilling circulation conditions, drilling operations resume. It is essential to continually monitor drilling

Step	Choke pressure (Psi)	Pump rate (gpm)	Pump pressure (psi)	BHP (psi)
Ramp down	20	196	2995	1566
Ramp down	113	183	2691	1611
Ramp down	155	170	2397	1608
Ramp down	155	155	2081	1566
Ramp up	347	85	1014	1590
Ramp up	347	71	931	1566
Ramp up	359	71	843	1578
Ramp up	413	0	0	1566

Table 1.
An example of typical MPD connection ramp down and ramp up.

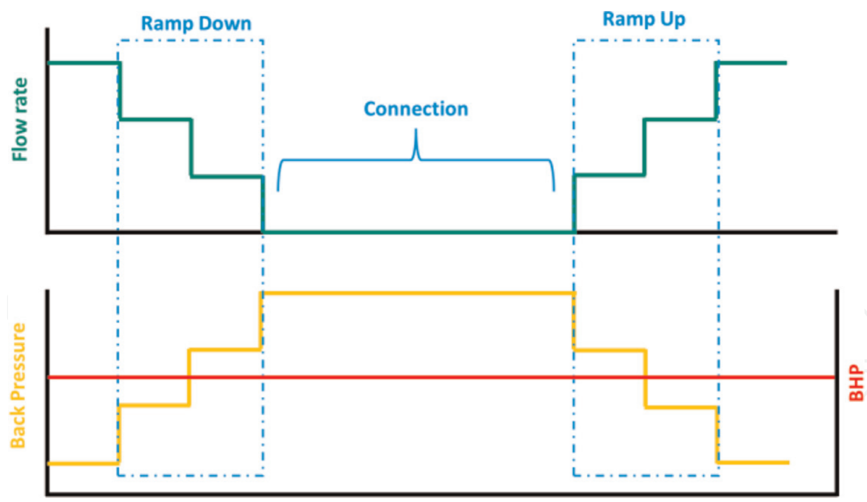

Figure 5.
Typical MPD connection illustration.

parameters to ensure they align with their pre-connection values. Significant variations in these parameters could indicate issues arising from the cessation of circulation.

Moreover, if, for any reason, the Surface Back Pressure did not synchronously adjust with the changes in flow rate (there might be a delay between the flow rate adjustment and the choke reaching the desired Surface Back Pressure value), it can lead to fluctuations in BHP. This situation could also introduce the presence of gas within the fluid stream.

Figure 5 is a visual representation illustrating the stages of a typical MPD connection procedure:

4.2 Rollover/rollback

In MPD operations where a positive Surface Back Pressure (SBP) value is consistently maintained, the process of tripping can be carried out with surface pressure applied. This is technically referred to as 'stripping.' However, it's important to note that stripping the pipe all the way to the surface is not feasible due to several limitations, which will be discussed in future training sessions.

One critical limitation to consider is the inability to pass the Bottom Hole Assembly (BHA) through the RCD. Consequently, at a certain point during the tripping process, it becomes necessary to completely release the Surface Back Pressure.

In situations where the Surface Back Pressure plays a vital role in maintaining well control, simply bleeding it off without considering the consequences is not an option. In such cases, the well must be transitioned to a higher density drilling fluid. This denser fluid creates a hydrostatic pressure significant enough to sustain well control without relying on Surface Back Pressure [8].

4.2.1 Rollover

Following is the procedure of rollover to ensures that the well remains stable and safe while tripping (**Figure 6**):

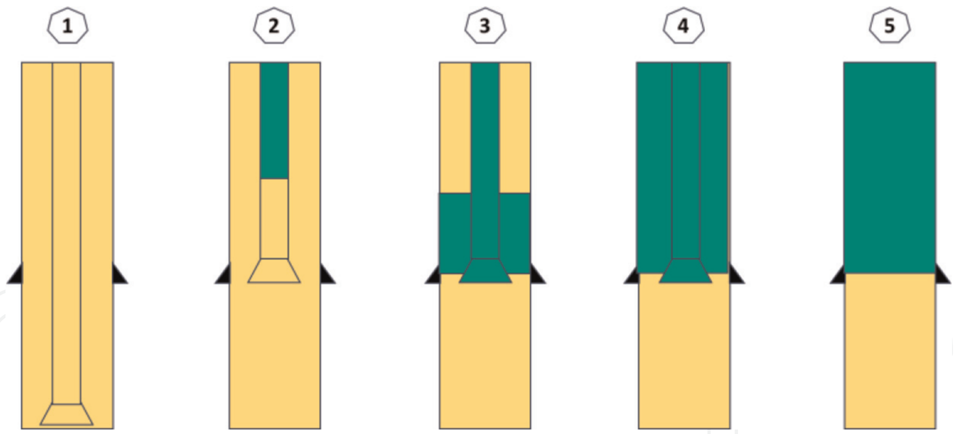

Figure 6.
Rollover steps in MPD tripping.

1. The rollover depth can either be at Total Depth (TD) or, more commonly, at the last casing shoe depth. If it's at the last casing shoe depth, the drill string needs to be stripped to that depth while maintaining SBP.

2. Position the bit at the rollover depth and pump the kill mud. While the mud is inside the drill string, refrain from making any system changes, as only events occurring in the annular section affect BHP. Expect a decrease in standpipe pressure as the heavier mud is easier to pump due to gravity assisting the process.

3. As the heavy mud enters the annulus, it impacts BHP, necessitating a gradual reduction in Surface Back Pressure to compensate for increased hydrostatic pressure. This reduction is done in steps, following a rollover schedule.

4. When heavy mud is observed on the surface returns, completely bleed-off Surface Back Pressure.

5. Halt the pumps and inspect the well. It should now be static, allowing the safe removal of the RCD bearing assembly. Proceed with the trip to the surface following conventional drilling procedures, closely monitoring tripping parameters to prevent excessive swab pressures [8].

4.2.2 Rollback

Here is the procedure for rollback (**Figure** 7).

1. Trip to the rollover depth using conventional tripping procedures, monitoring parameters to avoid surge pressures.

2. Position the bit at the rollover depth, install the RCD bearing assembly, and pump drilling mud (light). Maintain the system without changes as long as mud is in the drill string, keeping Surface Back Pressure as low as possible.

3. As drilling mud enters the annulus, gradually increase Surface Back Pressure to compensate for decreased hydrostatic pressure.

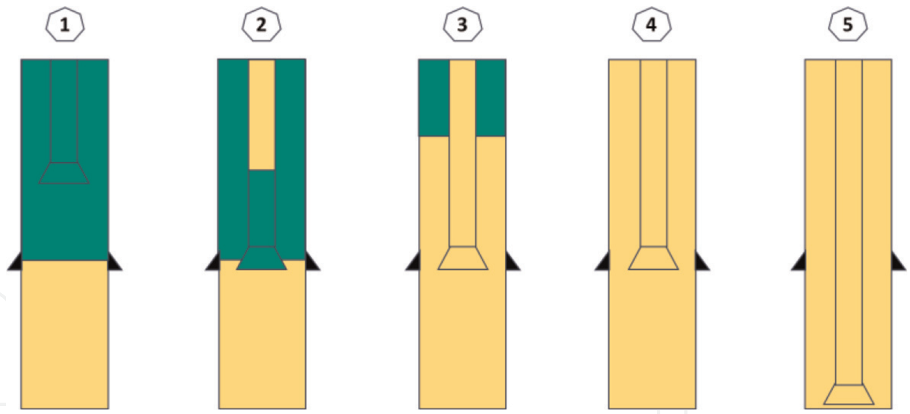

Figure 7.
Rollback steps in MPD tripping.

4. Once drilling mud returns to the surface, maximize Surface Back Pressure for the rollback operation.

5. Stop the pumps, apply extra pressure to account for friction losses, and check the static well. Resume drilling operations [8].

5. MPD equipment and layout

In drilling operations, the fluid circulation typically starts by drawing fluid from the mud tanks, which is then pumped through the rig pumps to add energy for return to the surface. From the mud pits, the fluid is transported via the standpipe line and surface drilling equipment before entering the drill string. Once it reaches the end of the drill string, the fluid exits through the bit and flows upwards within the annulus. It eventually returns to the surface through the BOP stack and is directed through a bell nipple, an open system exposed to the atmosphere. Subsequently, the fluid travels through a flow line, an atmospheric pipeline that is not designed to hold pressure. It proceeds to the solids control equipment, and then finally returns to the mud pits, thus completing the circulation cycle [9].

However, in MPD, the fluid follows a similar pathway but with some notable differences. Instead of the bell nipple, there's an RCD employed to create a sealed system around the drill pipe, so it established a closed system. From the RCD, the fluid is redirected to the MPD choke manifold through a specially designed primary line, rigorously tested to handle pressure. Conventional drilling rigs typically feature a choke manifold for well control, but MPD applications require an additional choke manifold, known as the MPD choke manifold, for continuous use in regulating surface pressure, serving as the primary method of pressure control in MPD. Downstream from the MPD choke manifold, another pipeline directs the fluid back to the shakers [8].

The backpressure MPD system has several essential equipment requirements, including (**Figure 8**).

- The Rotating Control Device

- Choke manifold

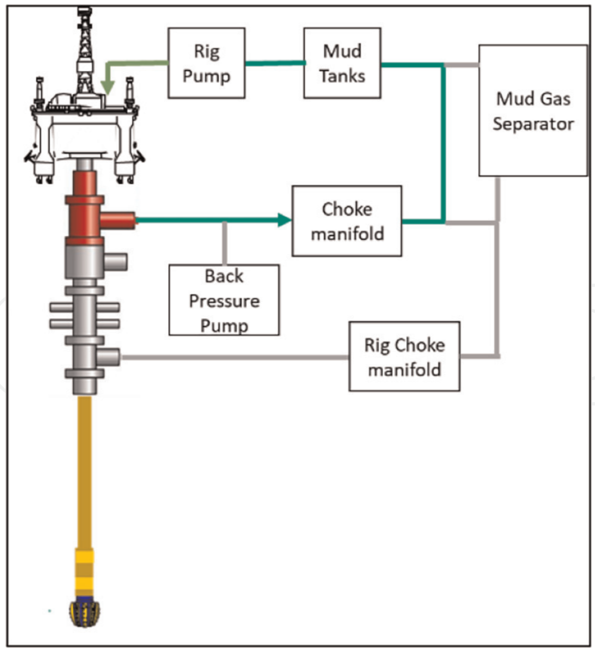

Figure 8.
MPD equipment set up.

- Backpressure pump
- Mud gas separator

The Rotating Control Device serves as a crucial pressure seal element positioned above the BOP and below the drill floor. Its primary function is to guide the annular flow and establish a closed-loop system. Meanwhile, the Choke manifold is employed to control well pressure, with its operation mode varying from manual to fully automated or semi-automated, depending on the situation. It can be used independently or in conjunction with the backpressure pump. Additionally, an integrated pressure management and hydraulic flow model can be integrated into the system, continuously updating flow parameters, and adjusting the choke opening in response to pressure variations. This hydraulic model also aids in early kick detection. In cases where a kick occurs, a mud gas separator can be utilized to separate fluids, even if the well remains unclosed and circulation continues [9].

6. Control mud level

Control Mud Level (CML) technology revolutionizes mud level management in the riser, serving as a Dual Gradient Drilling (DGD) solution designed primarily for post-BOP drilling operations. The key innovation involves a subsea pump integrated into a modified riser joint (MRJ), enabling precise control of mud levels within the riser's annular space. CML effectively eliminates the challenges associated with ECD and facilitates drilling with a nearly constant BHP. This groundbreaking technology can significantly influence well design, optimizing casing point placements. By eradicating the impact of circulating friction, it also allows for increased flow rates in horizontal sections and unstable formations, enhancing wellbore cleanliness. CML proves particularly invaluable when drilling through formations with a high potential for losses or layers at a heightened risk of influx.

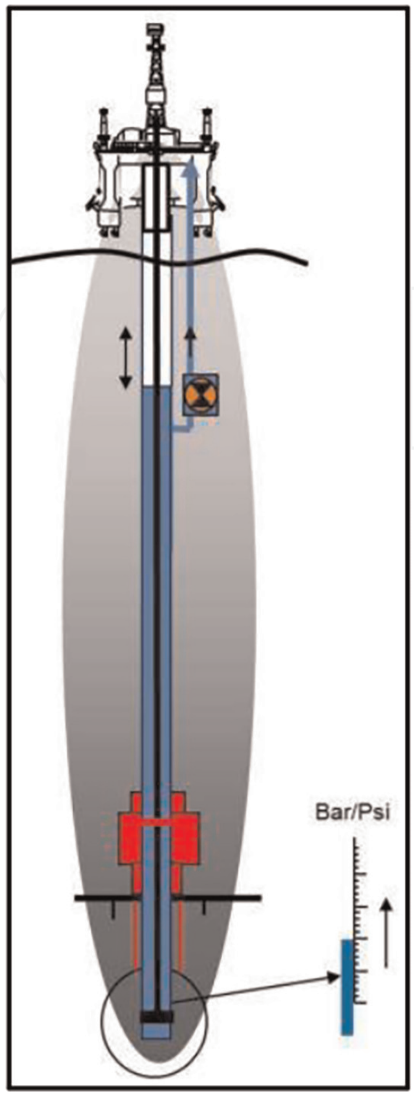

Figure 9.
CML system overview.

The EC-Drill technology represents a specialized CML method tailored for post-BOP drilling scenarios. This system employs a subsea pump installed on an MRJ to exert control over the mud level within the riser. By dynamically adjusting the mud level within the riser, the system compensates for fluctuations in hydrostatic and hydrodynamic pressures (ECD) encountered during drilling operations.

In stark contrast to conventional MPD systems that rely on an RCD to virtually extend the height of the mud column by applying back pressure, the CML system offers the distinct advantage of utilizing denser mud weight. Additionally, it provides the flexibility to lower the mud level within the riser, thus exerting precise control over BHP. Remarkably, CML system eliminates the need for an RCD [10].

The CML system comprises various components on both surface and subsea levels, including (**Figure 9**).

- Office Tool and Control container
- Umbilical Reel

- Top-fill pump
- Subsea pump module (SPM)
- Mud return line
- Modified Riser Joint (MRJ)

Within this system, the primary barrier consists of the drilling fluid (depicted in blue), while secondary barriers include subsea BOP, the wellhead, casing, and cement (depicted in red).

The Subsea Pump Module features three electrical pumps designed for efficiently handling the transfer of mud and drill cuttings at high rates. The SPM connects to a designated modified riser joint, directing the return flow into a dedicated Mud Return Line (MRL). For extended deployments, an improved solution involves integrating the MRL into the riser itself, enhancing both robustness and efficiency. This MRL integrates into the flowline upstream of the shaker box. Communication and electrical power to the SPM are facilitated by an umbilical line equipped with a winch, with the dedicated Control Container (CC) overseeing electrical power and communication. Operators and control systems are situated within a separate Office and Tool Container (OTC) located adjacent to the CC. The outlet from the riser is equipped with two isolation valves, enabling swift isolation of the CML system from the riser when necessary [10].

The SPM's placement on the drilling riser is meticulously selected based on mud weight and ECD reduction requirements, accounting for a margin to prevent pump cavitation. The number of pumps, their head, and power requirements are meticulously tailored to the task at hand. The relationship between the change in fluid column and BHP alteration adheres to the formula:

- (BHP during connection): P = Mud density x g (gravity constant) $\times$ (TVD-h_1)
- (BHP during drilling): P = Mud density x g (gravity constant) $\times$ (TVD-h_2) + AFP

Where P is the bottom hole pressure, ρ is the mud weight, g is the gravity constant, TVD is the true vertical depth of wellbore, h_1 and h_2 are the fluid column reduction in riser, and annulus friction pressure.

6.1 Effect of CML on BHP

The impact on well pressure (BHP), with the CML system is notable. When the SPM is mounted on the riser, the well's pressures become adjustable by varying the riser's level. This contrasts with traditional MPD methods where well pressure is typically controlled by selecting a Mud Weight (MW) lower than necessary and then introducing backpressure via a choke. With CML system, the technique is the opposite. A conventional overbalanced MW is chosen, and the riser level is reduced to attain the desired well pressure. This approach results in a less steep dynamic mud gradient, a characteristic dependent on the mud weight utilized (**Figure 10**) [11].

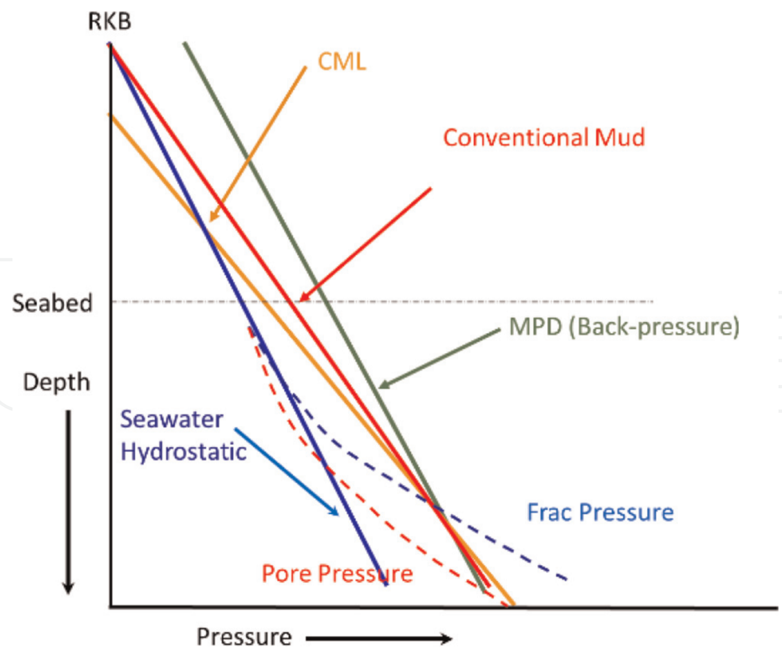

Figure 10.
Pressure gradients of different drilling system.

6.2 Effect of CML on well design

The implications for well design are profound. The CML system's unique capabilities, combining a gentler dynamic mud gradient with the flexibility to adapt to unforeseen formation pressures, can enable the drilling of longer sections. This optimization extends to casing point placements, offering more flexibility in designing wells. Additionally, the capacity to enhance circulation rates for improved hole cleaning may eliminate the need for employing hole openers in deepwater settings. This simplification of the BHA contributes to reduced downtime risks. The benefits of dual-gradient drilling and the mud density gradient slope are most prominent in the upper well sections, while the ability to maintain high circulation rates finds its greatest utility in the lower regions of the well. In formations prone to weakness, traditional methods necessitate reduced circulation rates to prevent losses, putting hole cleaning at risk and increasing the potential for pack-offs. CML system, however, permits the maintenance of full circulation rates [10–12].

The accompanying **Figure 11** depicts a typical well and illustrates the mud weight window that dictates the need for multiple casing strings. Due to the common uncertainty surrounding pore and fracturing pressure, planning for additional casing is often essential. In such cases, this can result in the installation of 7 or 8 strings after the BOP is installed.

Figure 12 portrays the same well as in **Figure 11**, but this time with the CML system. Manipulating the mud level in riser represents a practical enhancement of the existing CML equipment. Change in the slope of mud gradient (with low mud level in riser) will help to fit BHP inside mud window. This will lead to set the TD (casing points) deeper which will ending up eliminating number of casing points in the planning phase. It's worth noting that in this scenario, filling the riser without fracturing the shoe would require the qualification and implementation of new well control methods [11].

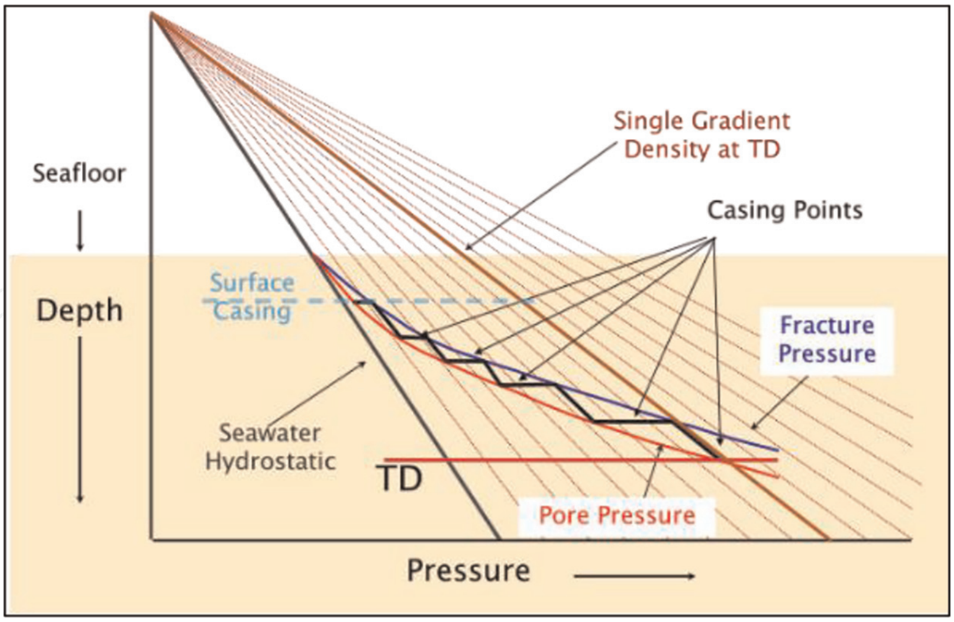

Figure 11.
Conventional casing points determination.

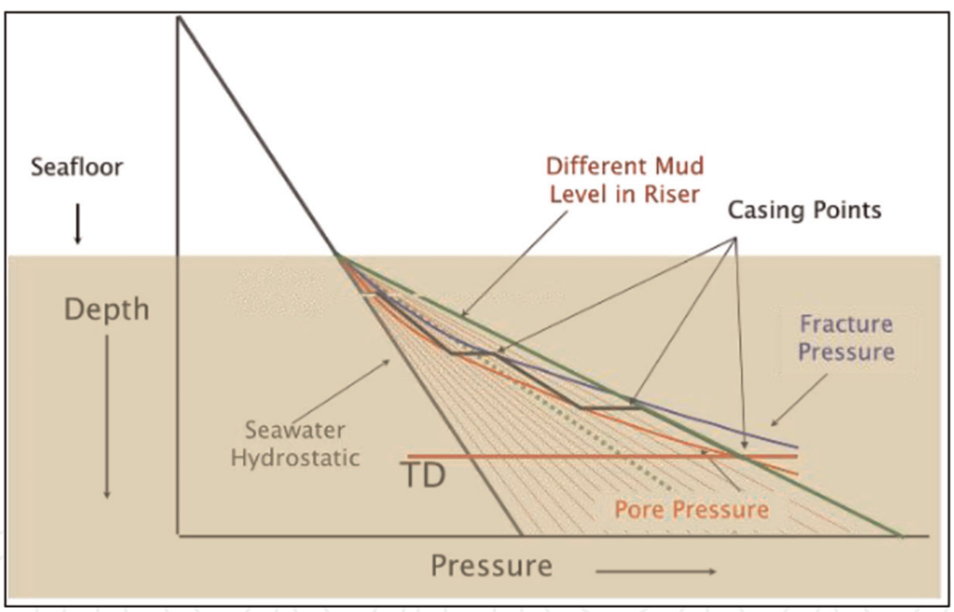

Figure 12.
Casing point determination by CML.

7. Advantages of the CML system

The implementation of the CML system on offshore wells offers several significant advantages, enhancing well design and operational efficiency while minimizing NPT and cost.

Early Kick Detection: The CML system demonstrates superior kick detection capabilities compared to conventional Early Kick Detection (EKD) systems. It can identify kicks at an earlier stage based on real-time data, enhancing well safety.

No Rig Heave Limitation: Unlike some other systems, the CML system operates without being limited by rig heave. It can effectively detect influxes, contributing to safer drilling operations.

Extended Reach and Horizontal Drilling: The CML system proves valuable in extended reach drilling and long horizontal sections. By adjusting the mud level in the riser to compensate for increased friction pressure loss, it enables the drilling of longer horizontal sections.

Narrow Mud Window Drilling: CML's ability to manipulate the mud level in the riser allows for precise control of BHP within narrow mud weight windows.

Loss Prevention: The CML system significantly reduces losses by lowering the mud level in the riser and thereby reducing bottom hole pressure. This approach has led to a remarkable 70% reduction in losses.

Managed Pressure Cementing (MPC): The CML system has facilitated successful MPC operations by manipulating fluid levels in the riser, BHP can be controlled effectively during cementing operations, preventing losses.

Hole Cleaning: With the CML system, there's no need to reduce flow rates to compensate for friction pressure losses. It automatically compensates for increased friction pressure, allowing for higher flow rates. This not only reduces hole-cleaning issues but also maintains efficient drilling operations.

In summary, the CML system, presents a range of advantages in offshore drilling, encompassing improved safety, efficiency, loss prevention, and the ability to handle complex drilling scenarios [10–12].

7.1 Early kick detection (EKD) with CML system

In traditional rig site practices, the detection of influxes or losses primarily relies on monitoring mud pit levels and return flow rates. The rig crew typically uses these parameters in combination to identify any potential influxes while drilling or tripping. However, the CML system introduces a more sophisticated approach by augmenting these traditional indicators with the monitoring of two critical parameters: hydrostatic pressure in the riser and the speed of the SPM.

Hydrostatic Pressure Monitoring: Pressure sensors positioned at the same level as the SPM installation point (pump outlet) continuously measure the hydrostatic pressure within the riser. An influx (extra volume) into the well causes a noticeable increase in riser pressure because the mud level within the riser rises in response to the additional volume.

SPM Speed Monitoring: To maintain a constant mud level within the riser, the CML system keeps the speed of the SPM constant. Consequently, any influx is detected as an increase in riser pressure because the mud level in the riser rises with the extra volume. However, if the riser pressure remains constant during drilling (indicating a fixed mud level in the riser), any influx is detected through an increase in the speed of the subsea pump module. As the SPM endeavors to maintain the mud level in the riser at a fixed pressure, it must work faster when it encounters extra volume. This dual monitoring approach places the CML system at the forefront of early kick detection.

To effectively detect losses or influxes with the CML system during operations, it is imperative to monitor the following parameters:

- Speed of the pump (SPM speed).
- Hydrostatic pressure within the riser (mud level in the riser above the SPM inlet).
- Flow rates into and out of the well.

During drilling operations in the Gulf of Mexico (GOM), ten kick drills were meticulously conducted to validate the system's efficacy. These drills unveiled a distinctive pattern: the initial indicators were a rise in riser pressure and an increase in SPM speed, promptly detected and recorded. The second indicator, the return flow, followed 48 seconds later. This represents a notable improvement over conventional drilling practices where flow out typically provides a faster response compared to monitoring the gain or loss from the active pit [10, 11].

When operating CML system while drilling, there are repeatable events in operations, such as connections, that detecting influxes or losses can be challenging due to the dynamic nature of the parameters. Therefore, the system employs a baseline established from recorded connection data (fingerprint) from before the operation. This baseline aids in identifying any deviations from the established connection procedure, enhancing early kick detection capabilities.

7.2 Extending horizontal section with CML system

Horizontal drilling, particularly the extension of horizontal sections, benefits significantly from the implementation of the CML system. This technology offers a means to push the boundaries of horizontal drilling, which conventionally faces limitations due to ECD restrictions.

The CML system enables the extension of horizontal sections beyond the typical stopping point imposed by ECD limits. By strategically lowering the mud level in the riser, the adverse effects of ECD can be mitigated and brought below the critical ECD limit. Consequently, drilling operations can continue, and the horizontal section can be significantly extended, surpassing what is achievable with conventional drilling methods.

Moreover, the CML system introduces the flexibility to increase the flow rate for enhanced cuttings removal and improved hole cleaning within the horizontal section. This is a valuable advantage as it ensures efficient wellbore cleaning in these challenging drilling environments. Additionally, the system can effectively compensate for any extra friction pressure loss that might arise due to the higher flow rate. This

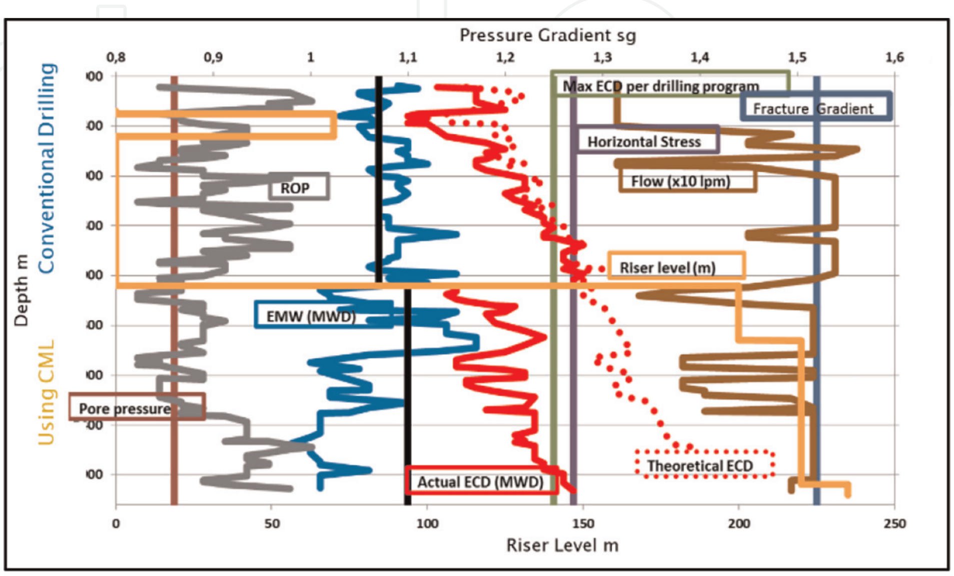

Figure 13.
Extending horizontal section by using CML system.

capability is accomplished by strategically lowering the mud level in the riser, demonstrating the adaptability and versatility of the CML technology.

To vividly illustrate the effectiveness of the CML system in extending horizontal well sections, this section provides a comparative analysis of a drilling operation conducted with and without CML. In **Figure 13** data from a North Sea well's horizontal section is presented. In the initial segment of the section, the CML system remained dormant. Consequently, the Actual ECD soared to its maximum threshold, halting conventional drilling operations. To resume drilling, the ECD needed reduction, prompting the activation of the CML system. The mud level was deftly adjusted to 200 meters (as indicated by the orange line), resulting in a remarkable drop in ECD from 1.28 sg to 1.12 sg. Subsequently, an additional 2000 meters were successfully drilled with the lowered riser level, maintaining ECD within permissible limits. Without the intervention of the CML system, this extended section of the well would have remained unattainable.

8. Managed pressure cementing (MPC)

Managed Pressure Cementing (MPC) utilizing the CML system is a comprehensive approach to controlling wellbore pressure during the critical phases of pumping and displacing cement. This technique is instrumental in preventing losses and ensuring the proper placement of cement in the wellbore.

MPC's core objective is to manage the pressure gradient within the wellbore effectively. This entails using the SPM to manipulate the pressure conditions within the well, ensuring that the pressure stays within the desired range during the cement displacement process. This control over wellbore pressure is crucial for cementing operations, as it helps prevent issues such as lost circulation and ensures that the cement is delivered precisely where it is intended.

The MPC process involves the use of a step-down table to guide the cementing operation (**Table 2**). This table outlines the desired pressure values at the wellhead throughout the operation. It consists of several columns, with the first column indicating the volume of cement returned. The second and third columns specify the desired pressure values at the wellhead in pounds per square inch (psi) and bar, respectively.

Here's a step-by-step description of the MPC process:

Start SPM and Maintain Low Riser Level: The MPC process begins with the activation of the SPM. Initially, a low riser level is maintained.

Volume returned from start of pumping spacer (bbl)	Pressure (psi)
0–840	761
880	757
920	753
960	748
1000	744
1040	740
1080	735

Table 2.
MPC Step down table.

Standby Phase: During this phase, the system remains in standby mode while keeping a constant riser level. The goal is to maintain this level until the cement exits the drill pipe. The detection of this phase is achieved by monitoring the increase in standpipe pressure.
Pressure Reduction Strategy: As the cement progresses up the annulus, a systematic pressure reduction strategy is employed. For every 15-psi increase in standpipe pressure, the riser pressure is reduced by 10 psi. This strategy is designed to compensate for increase in standpipe pressure. Consequently, it provides an estimated 80% compensation for the corresponding increase in hydrostatic pressure downhole.

This approach ensures that wellbore pressure remains within the specified parameters throughout the cementing operation, preventing potential issues and facilitating successful cement placement in the wellbore. The MPC process with the CML system enhances the overall safety and effectiveness of cementing operations, particularly in challenging well environments.

9. Controlled mud cap drilling (CMCD)

Having a CML system onboard also enables the use of Controlled Mud Cap Drilling (CMCD) as a contingency measure in case of total mud losses. CMCD is a technique where mud cap fluid is introduced into the wellbore to control pressure, especially in zones where total losses are encountered. CMCD is introduced as a response to spontaneous reactions during drilling into zones where total mud losses occur. It's a drilling technique with no returns to the surface, meaning that drilling fluid and cuttings are lost to the formation. In CMCD, the key control parameters are the amount of viscous mud cap fluid injected into the annulus from the top-fill pump at the surface and the riser booster pump. These parameters are adjusted using the Subsea Pump Module (SPM) (**Figure 14**) [12].

To prevent gas from entering the wellbore, the minimum required injection rate of mud cap fluid into the annulus must be greater than the gas migration rate. Gas ingress into the wellbore is not tolerated. The injection rate of mud cap fluid is

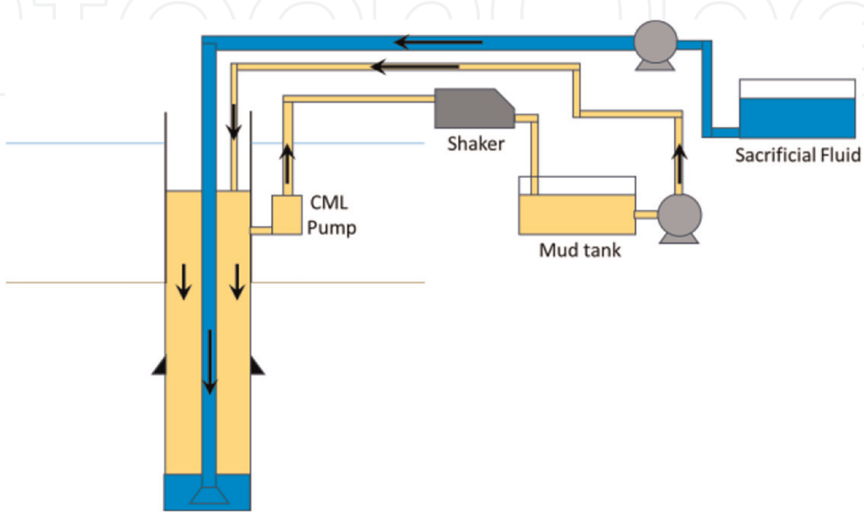

Figure 14.
CMCD overview.

adjusted using the SPM, and it's determined based on the mud cap fluid level in the riser, friction pressure due to the injection rate, and formation injectivity. Unlike traditional drilling techniques where bottom hole pressure is controlled, CMCD cannot control bottom hole pressure effectively. This is because the drilling fluid and cuttings are lost to the void space, leading to a constant bottom hole pressure on top of the loss zone. CMCD is a valuable technique in situations where total mud losses are encountered, and conventional drilling methods are no longer effective. It allows for some level of control over pressure and wellbore stability in challenging drilling environments.

10. MDP vs. CML

Here is a **Table 3** comparing MPD and CM) systems, highlighting their respective advantages and disadvantages:

Please note that the advantages and disadvantages listed here are general and can vary depending on specific drilling conditions, equipment, and operational practices. Both MPD and CML systems have their merits and are valuable tools in the oil and gas industry, with their effectiveness depending on the context in which they are applied.

Aspect	MPD	CML
Primary Objective	Controlling BHP and ECD by adjusting surface backpressure.	Controlling BHP and ECD by manipulating mud level in the riser.
Application	Both onshore and offshore	Just offshore
Pre job installation time	Weeks to months	Days to weeks
Effect on Well Design	MPD may have minimal impact on well design.	CML may impact well design positively by optimizing casing points
Operational system	Pressurized closed system	Open to atmosphere system
Well control scenario	Involved	Not involved
Affecting operational sequence	Controlled ROP due to RCD	Flexible ROP due to open system
Kick and Loss Detection	Conventional MPD systems rely on pit-level monitoring.	CML systems can detect kicks earlier with riser-level monitoring.
Total loss curing system	PMCD	CMCD
Switching to conventional drilling	Not possible in short time	Instantly
Tripping time	More time needed (roll back and roll over)	Less time included (lowering or increasing mud level in riser)
High gas cut in mud during drilling	Safe drilling (closed system)	Need to isolate and apply well control (open system)
Cost comparison	More expensive	Less expensive

Table 3.
Comparing MPD vs. CML.

11. Digitalization and automation of MPD and CML

Digitalization and automation are transforming the drilling industry by ushering in a new era of efficiency, precision, and safety. At the heart of this transformation is the utilization of advanced tools like wired drill pipes and high-speed data transmission systems that establish seamless communication between downhole operations and the surface. These technologies enable real-time data collection, analysis, and decision-making, which is paramount for enhancing drilling operations [13].

The core value of digitalization tools, such as wired drill pipes, lies in their ability to provide operators with a continuous stream of downhole data. This real-time data can include critical information about wellbore conditions, pressure differentials, and formation analysis. By transmitting this data quickly and reliably to the surface, drilling operators can make immediate adjustments to drilling parameters, thereby optimizing drilling processes and minimizing NPT.

Furthermore, digitalization and automation go hand in hand in revolutionizing drilling operations. These technologies enable the development of semi or fully automated systems for drilling processes like MPD and CML. With automation, key drilling parameters can be controlled and adjusted in real time based on the data received from downhole sensors and models. This ensures that drilling remains within specified pressure windows and wellbore stability limits, reducing the risk of issues like kicks and losses. Ultimately, the integration of digitalization and automation enhances the operational sequence, making it more accurate and significantly increasing drilling speed while simultaneously reducing NPT.

Incorporating MPD and CML systems into the digitalization process is the next logical step. By digitizing the operation of these systems, operators can leverage real-time data to make precise adjustments to drilling conditions, pressure levels, and fluid dynamics. This can lead to semi or fully automated MPD and CML operations, where the systems respond autonomously to wellbore changes and operator-defined parameters. As a result, these systems can optimize drilling processes more effectively, maintain wellbore integrity, and enhance drilling safety, all while contributing to a significant reduction in NPT. The synergy of digitalization and automation holds immense promise for the drilling industry, paving the way for more efficient, cost-effective, and environmentally friendly drilling practices.

A fully automated CML system aims to maintain constant BHP throughout drilling operations, including connections. This is achieved through real-time pressure monitoring with technologies such as Pressure While Drilling (PWD) or Along String Measurement (ASM) positioned behind the drill bit. To achieve this, a hydraulic model is established, allowing calculations to determine the required mud level adjustments based on the input BHP data, ensuring precise and continuous control of well pressures and ECD (**Figure 15**).

This level of full automation, ensuring constant BHP during drilling and connections, can also be applied effectively in MPD systems, offering enhanced well control and operational efficiency for the drilling industry (**Figure 16**).

In summary, the integration of digitalization and automation into both CML and MPD systems represents a transformative leap in the drilling industry. With real-time data transmission, wired drill pipes, and advanced sensors, these systems can now maintain constant bottom hole pressure, optimize drilling parameters, and swiftly respond to downhole conditions, significantly reducing NPT. Whether pursuing a fully automated CML system, an MPD solution, or a combined approach, these

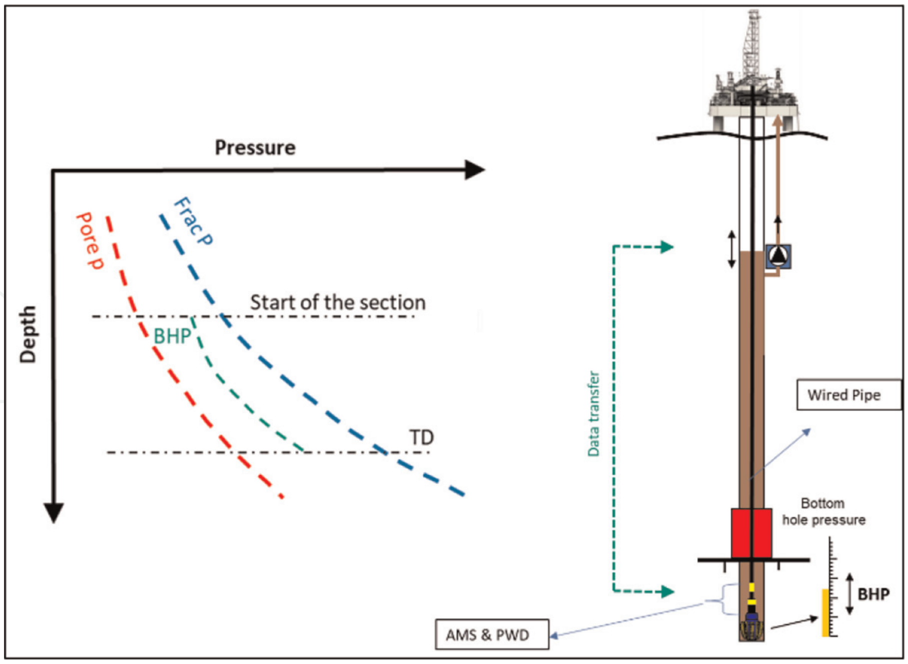

Figure 15.
Automated CML system.

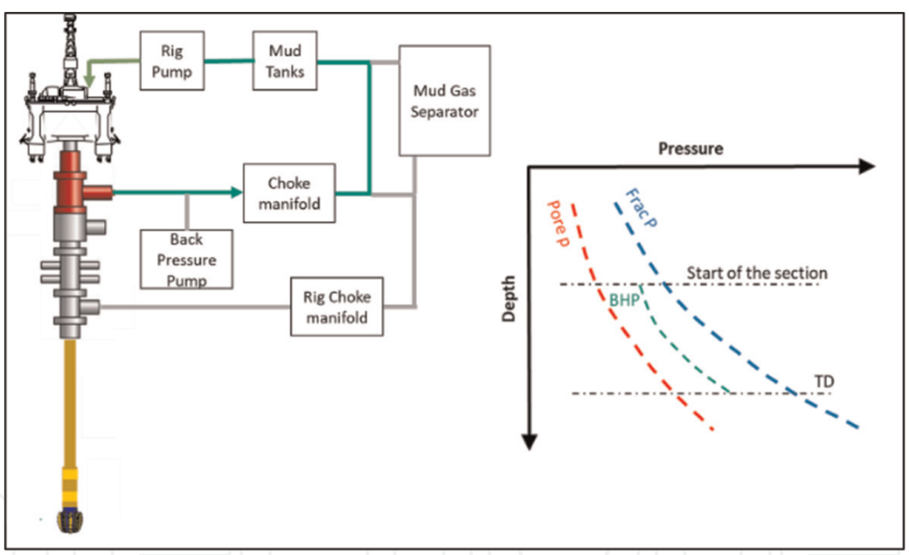

Figure 16.
Automated MPD system.

advancements hold the promise of safer, more efficient drilling operations, providing greater control and precision to the energy sector.

12. Conclusion

In conclusion, this chapter has delved into the intricate world of drilling technology, encompassing MPD, CML, and MPC. We've explored their techniques, equipment, and operational nuances. Furthermore, we have illuminated the transformative potential of digitalization and automation, facilitated by Wired Drill Pipe, in conjunction with MPD and CML systems. This convergence promises to usher in a new era of drilling, characterized by enhanced precision, reduced NPT, and optimized operational sequences. The fusion of cutting-edge technology and time-tested drilling methods beckons a future where energy exploration and production are more efficient, economical, and sustainable than ever before.

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Nomenclature

MPD	Managed Pressure Drilling
CML	Controlled Mud Level
MPC	Managed Pressure Cementing
NPT	Non-productive Time
CBHP	Constant Bottom Hole Pressure
MCD	Mud Cap Drilling
PMCD	Pressurized Mud Cap Drilling
FMCD	Floating Mud Cap Drilling
DGD	Dual Gradient Drilling
RFC	Return Flow Control
AFP	Annular Friction Pressure
ECD	Equivalent Circulating Density
BP	Back Pressure
AFL	Annulus Friction Loss
BHP	Bottom Hole Pressure
NRV	Non-Return Valve
ROP	Rate of Penetration
RCD	Rotating Control Device
EMW	Equivalent Mud Weight
BOP	Blow out Preventer
HSE	Health Safety Environment
MWD	Measurement While drilling
SBP	Surface Back Pressure
BHA	Bottom Hole Assembly
TD	Total Depth
MRJ	Modified Riser Joint
SPM	Subsea Pump Module
MRL	Mud Return Line
CC	Control Container
OTC	Office Tool Container
TVD	True Vertical Depth
MW	Mud Weight
GOM	Gulf of Mexico
CMCD	Controlled Mud Cap Drilling
ASM	Along String Measurement
PWD	Pressure While Drilling
RMR	Riser-Less Mud Recovery

Author details

Behzad Elahifar
Department of Geoscience and Petroleum, Norwegian University of Science and Technology (NTNU), Trondheim, Norway

*Address all correspondence to: behzad.elahifar@ntnu.no

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