POLITECNICO DI TORINO
Department of Environment, Land and
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in Petroleum Engineering

Drilling with automated constant BHP (bottom hole pressure) by using CML (control mud level) system along wired drill pipe in narrow mud window

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ABSTRACT

Automation is not a new concept in the offshore oil and gas industry. However, the industry has not adopted full automation in order to focus on human-centric solutions.

Growing demand for deep-water and ultra-deep-water drilling requires more than conventional drilling approaches to pass through them safely and precisely. To address the challenges related to conventional drilling and the high percentage of non-productive time, many operators over the past decade have turned to one drilling method in particular: managed pressure drilling (MPD) in its many variations.

The effective and secure resolution of drilling challenges constitutes the domain of pressure drilling management, a set of techniques that aim to optimize the drilling process while minimizing costs. Controlled mud level (CML) drilling represents a subset of managed pressure drilling (MPD) methodologies that leverage a subsea pump to manage mud and cuttings ascent up a dedicated mud return line leading to the rig's mud-processing system. By controlling the speed of the pump, CML drilling facilitates the adjustment of the fluid level in the rig's marine riser, thus enhancing the safety, efficiency, and cost-effectiveness of drilling operations. The study led to the development of 'fully automated CML system-FACMLS' in offshore. FACMLS provides automated bottom hole pressure control by adjusting mud level in the riser at narrower mud windows.

Python language scripts have been generated to investigate the relationship between BHP generated by a mathematical model and PWD data. The script comparing real data with simulated data.

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NOMENCLATURES

Symbol	Definition
MPD	Managed Pressure Drilling
ROP	Rate of Penetration
WDP	Wired Drill Pipe
BHA	Bottom Hole Assembly
ECD	Equivalent Circulating Densities
ESD	Equivalent static density
TVD	True Vertical Depth
NPT	Non-Productive Time
CML	Control Mud Level system
FACMLS	Fully Automated CML systems
AOS	Automated operating system
NOV	National Oilwell Varco
MWD	Measurement While Drilling
LWD	Logging While Drilling
PWD	Pressure While Drilling
RPM	Revolutions Per Minute

PV	Plastic Viscosity
YP	Yield Value
SPP	Stand Pipe Pressure
MD	Measured Depth
TVD	True Vertical Depth
Incl	Inclination
Azm	Azimuth
Len	Length
OD	Outside Diameter
ID	Inside Diameter
DP	Drill Pipe
DC	Drill Collar
WDS	Wired Drilling String
MPD	Managed Pressure Drilling
UBD	Under Balance Drilling

INTRODUCTION

There are a lot of uncertainties related to deep water exploration wells. It is quite difficult to give an idea about pore and fracture pressure gradients specially below salt. It is important to know pore and fracture pressure gradients because they are used in the well construction process to design casing program, mud weights, etc.

Higher pore pressures than expected resulted in influxes, while lower fracture gradients resulted in mud losses. Furthermore, problems related to drilling, like losses and influxes may be the result of, for example, equipment failures or human error. MPD includes new measurements and improved kick detection capabilities, as well as a tool for quickly adjusting bottom hole pressure without replacing mud with different mud weight in a well. The main reason for implementing MPD technology was to improve wellbore stability while lowering the risk and cost associated with uncertain pressure gradients and a narrow pressure window.

Due to high number of strings, casing program for such wells are quite complex. Maintaining a conventional drilling program was seen as a significant benefit, as it means that if the MPD system fails, conventional drilling can be resumed at any time.

The main goal of this thesis is to educate others on how to integrate a CML MPD system onto an offshore drilling well and make a fully automated system to drill deeper by playing with the mud level in the riser with a subsea pump module (SPM) attached to the riser to control BHP. This system is not part of the well control, and the primary well barrier remains mud.[1]

CHAPTER 1

1.1 Description and Application of CML:

Understanding system functionality, and basic equipment is required to fully appreciate the CML integration process. When the rig mud pumps are turned off and there is a static condition in the well, the bottom hole pressure (BHP) is described using the following equation:

Equation 1

$$BHP=P_h$$

Where BHP is the bottom hole pressure and P_h is the hydrostatic pressure.
The system is dynamic when the rig mud pumps are turned on and the fluid in the well bore is circulating, and the BHP is described using the following equation:

Equation 2

$$BHP=P_h+P_{fric}$$

P_{fric} is frictional pressure drop due to fluid movement up in the annulus.
To drill a well successfully, the well bore pressure gradient must be between the pore and fracture pressure gradients.

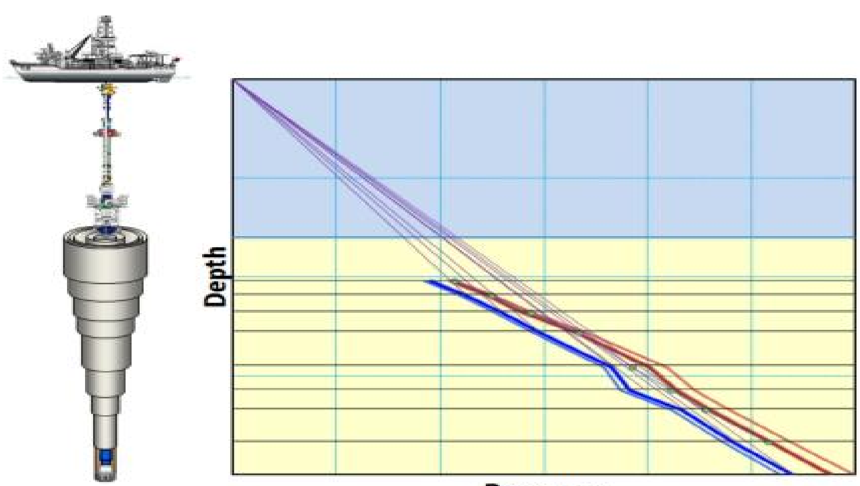


Figure 1 Wellbore Pressure

When the riser is full of drilling fluid and the pumps are turned off during CML operations, the system is statically balanced, and the BHP is between the pore and fracture pressure gradients. When the rig pumps are turned on and flow begins to flow up the annulus, friction from the flowing fluid raises the BHP.

ECD is composed of the hydrostatic pressure and the frictional pressure of the flowing fluid, as shown in the above equation. In Dynamic condition, CML controls BHP by lowering the fluid level in riser, which lowers the hydrostatic head enough to compensate for the annular friction portion of ECD. Similarly, in static condition, the CML system raises the fluid level in the riser, increasing the hydrostatic head to compensate for the lost frictional pressure drop. The change in height in the fluid column is proportional to the change in pressure seen by the wellbore due to friction. As a result, the BHP is kept almost constant, between pore and fracture pressure gradients in the drilling window.

Concerning the risk of equipment failure, if the CML system fails and the SPM stops pumping for any reason, the well bore will remain in a controlled state because the ECD is still applied to the well bore. In this case, the CML system would be isolated, and the driller would gradually reduce the rig mud pumps as the riser filled. The wellbore would lose ECD if the riser level was drawn down and the rig mud pumps abruptly stopped. The action taken would be determined by the amount of draw down in the riser. If the static well bore gradient at the lowered level remained inside the pore and fracture gradients, the only corrective action would be to restart the rig mud pumps as the CML system monitors the riser pressure. If an influx was caused by the static well bore gradient at the lower level, conventional well control methods would be applied.[2]

1.2 CML system Principles:

In CML, pressure sensors installed within the Modified Riser Joint (MRJ) measure the hydrostatic pressure of drilling fluids and pressure inside marine riser. An outlet from the marine riser beneath pressure sensors which is connected to a Subsea Pump Module (SPM) allows the annular fluid to be pumped back to the drilling rig via a dedicated Mud

Return Line (MRL). A control system measures the fluid level (hydrostatic head), and adjusts the SPM pump speed to maintain the riser fluid level at the desired depth and, as a result, increases or decreases the BHP.

In order to compensate for the highest pore pressure zone of the open hole formation capable of flowing, the annular pressure profile and hydrostatic pressure on the formation are kept high enough, while remaining low enough to reduce or eliminate losses to weaker zones. All of this is done by maintaining riser margin.

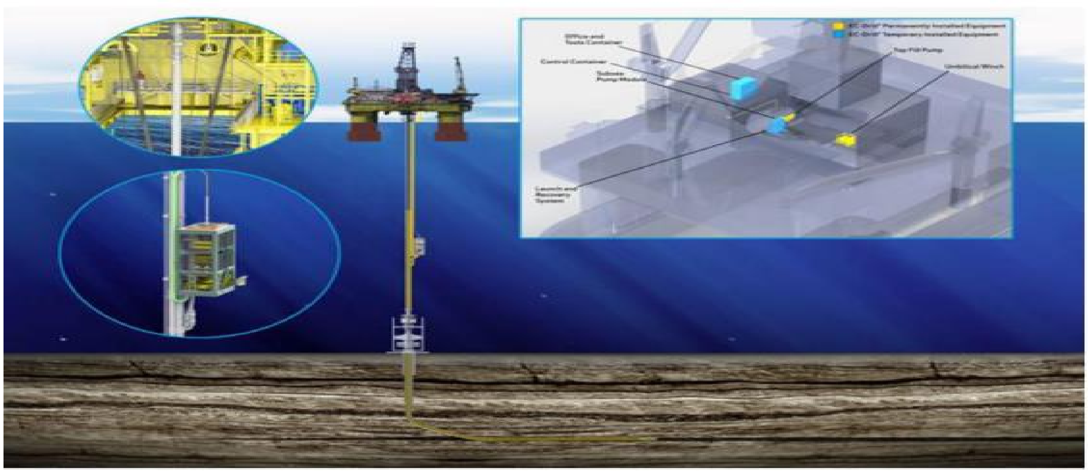


Figure 2 CML system concept

1.3 Configuration, Cost and Schedule of CML:

Figure 3 depicts a typical CML system as well as the scope separation between the CML provider and the Rig Contractor. The CML system is a standard product offering that does not require re-engineering in order to be installed on the rig.

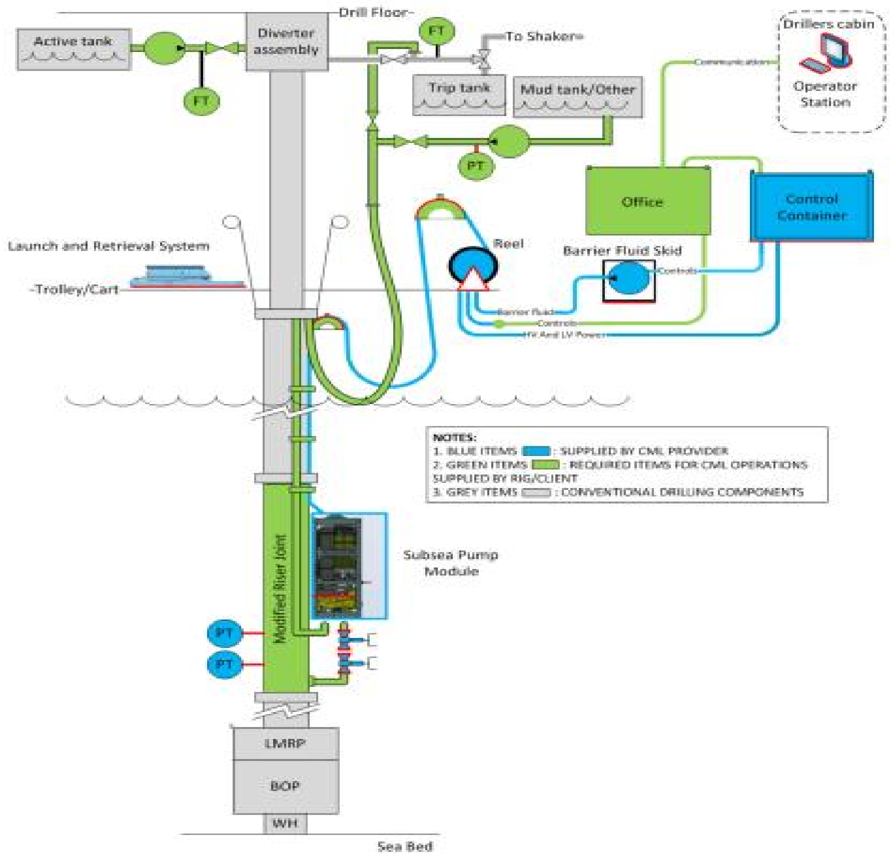


Figure 3 Overview of CML system

- Tool container
- 2 x diesel electric generators on the main deck.
- Backflush pump for testing and flushing the MRL.
- Office Tool Container
- Control Container
- Remote panel screens (GUI) on drill floor.

With a standardized design and prior project experience, the current delivery time estimate from contract execution to the start of drilling operations is between 6 and 9 months, with efforts underway to reduce this further.

The pre-operational costs of implementing a CML system vary greatly depending on the needs of operators and plant builders. There are different categories of costs, some that are consistent from project to project, and others that vary widely between implementations.[2]

1.4 EC-Drill Equipment:

The following is a list of required equipment for CML operation:

- (LARS) SPM launch and recovery system
- (SPM) Subsea pump module
- (MRJ) Modified riser joint
- Umbilical Winch with umbilical
- (MRL) Mud return line
- Topside MRL flow meter
- Top-fill pump
- The CML controls system

SPM launch and recovery system:

The SPM was deployed and recovered from the riser using the Launch and Recovery System. Skidding jacks were used to secure the LARS to the BOP elevator. To reduce further movement caused by heave, the LARS can be moved laterally and unlatched to float.[3,4,5]

Figure 4 LARS system

Subsea Pump Module:

The subsea pump module is a serial 3-stage pump based on existing (RMR) systems, allowing the individual pumps to be electrically isolated depending on their discharge requirements. The module is made up of three 3300 kW motors, each with a 20-inch disc pump and a pressure rating of 50 bar. The SPM weighs 13 tons and is housed in a stainless steel and duplex structure.[3,4,5]

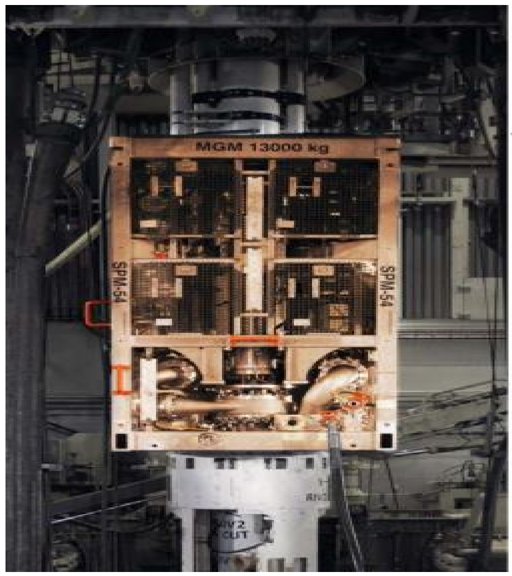


Figure 5 SPM

Modified Riser Joint and Subsea Valves:

One of the rig's existing slick riser joints was used to create the Modified Riser Joint. To dock the SPM onto the riser and provide an inlet to the SPM, modifications were required. Docking plates, six-inch Pin connectors, and four pressure sensors are included with the MRJ. In addition, the modified riser joint houses the subsea riser isolation valves and pressure sensors required for CML operations.[3,4,5]

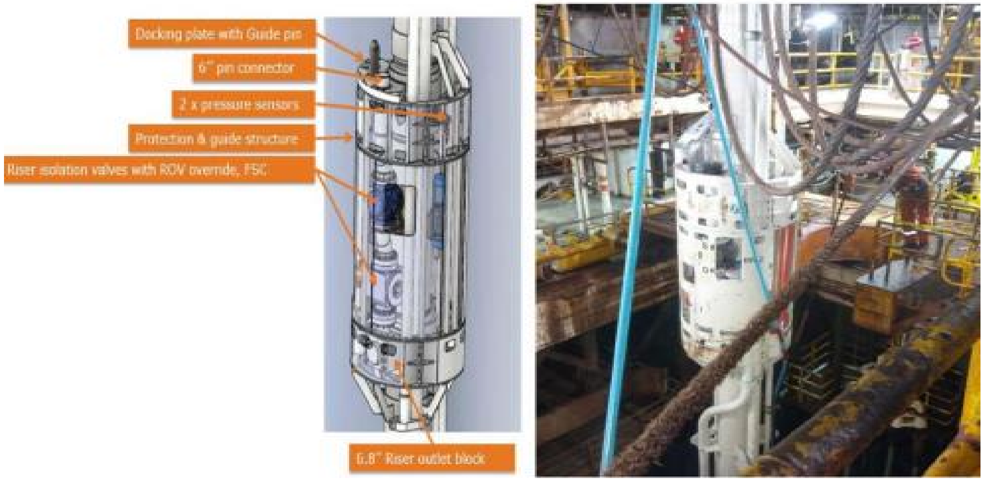


Figure 6 Modified Riser Joints and Subsea Valves

Umbilical Winch and Umbilical Cable:

The electrical and fiber optic lines that connect to the SPM are housed in the umbilical cable. The umbilical cable is cut while the SPM is docked on the LARS in the moon pool for initial system testing. The umbilical winch is located on the starboard aft of the rig, and the umbilical cable had to be hauled under the rig by the keel.[3,4,5]

Figure 7 Umbilical Winch and Umbilical Cable

Mud Return Line:

The mud return line was originally made up of 10-20 m collapsible rubber hose with 1/4" turn subsea connections. To support the load of the hoses, each hose link has a secure shackle with wire cable installed. To reduce wear, several sections of the MRL hose (closer to the surface) were covered with an additional rubber protector. Once connected to the SPM, the hose spacing was adjusted to allow the connection points to be lowered sufficiently below the splash zone. The MRL was integrated into a hard line on the marine drilling riser after several operations.[3,4,5]

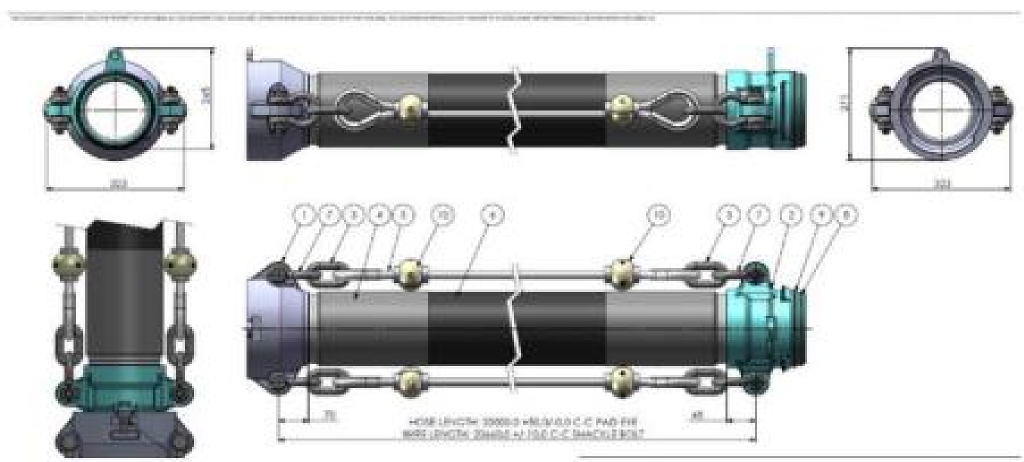


Figure 8 MRL

Top Side MRL and Flow Meter:

The mud return line was connected to a support frame on the starboard aft side of the rig at the surface, on top side flow meter and deck, additional surface hoses were connected.[3,4,5]

Figure 9 TSMRL

1.5 Drilling control system integration:

The CML system includes a stand-alone control system with multiple operating modes:

1. Fixed riser level mode
2. Fixed return flow or fixed pump speed mode
3. Manual mode, in which the operator manually adjusts the pump speed.

If a combination of input signals is validated outside of valid boundary conditions, several built-in ASD (Automatic Shut Down) sequences are initiated. When set to fixed riser level mode, the system operates automatically. The CML is also fully integrated into the drilling control system on the rig.

The CML system is installed with an operator station in the rig's I/O (Integrated n Operations) room. During CML operation, one operator observes the control system. The drilling control system of the rig could be modified to include all CML valves, sensors, and top fill pump operation. All valves are controlled remotely. The system operates automatically, with the option of shutting it down from the driller's chair if necessary. The driller's chair is used to transition from CML operations to conventional operations.

If measurements show excessively high values, the gas sensors installed on the riser's top are set to warn and alarm. To address any increased risk with the CML system, common operating procedures and contingencies have been developed.[4]

1.6 CML well planning:

ECD limits are defined during the well planning phase for specific intervals in the reservoir section(s) to limit the bottom hole pressure acting on the wellbore. These ECD limits are determined by mapping nearby lost circulation incidents and estimating formation strength.

Based on simulations, a riser level reduction plan is developed with the ECD limitations in place. To reduce the wear on the subsea pump, the riser level is not reduced any further than necessary. The riser level reduction strategy can be modified based on the actual ECD values measured during drilling.

The ECD varies significantly with ROP, clay content in the drilled formation, and Q, but the ECD profile is generally quite predictable, allowing the riser reduction plan to be carried out as planned.[6]

1.7 CML experiences:

The following encounters are detailed:

- BHP reduction
- Volume control
- Subsea pump module erosion
- Managing loss incidents with a lower riser level
- Gas in riser measurements
- Use of slugs[6]

CHAPTER 2

2.1 History of Wired Drill Pipe:

Since 2006, wired drill pipe (WDP) has been in commercial use. After approximately 150 wells of experience, an engineering team used the lessons learned to change and upgrade some of the features.
Because of those lessons and updates, a second version of wired drill pipe was released in 2015.[7]

The following are the lessons learned from WDP Version 1:

- The WDP connections were found to be responsible for the majority of the reliability-related incidents (Edward et al. 2013), (Lawrence et al. 2009), and (see Veeningen et al. 2012a). Drill pipe stands falling onto their secondary shoulder while being handled on the rig floor, stabbing issues, and over torque issues all contributed to connection damage. Furthermore, it was discovered that the WDP version one connection was difficult and costly to maintain on-site.
- Downhole circuitry failures could be the second most common cause of WDP telemetry interruption. Furthermore, the WDP network diagnostic capability was discovered to be deficient.
- On some aggressive mud operations, stress corrosion cracking of the armored coax was observed.

As a result of the aforementioned field experience, several improvements have been made to the basic Version 1 design of the wired drill string telemetry components, resulting in the WDP Version 2 wired drill pipe system.
Version 2 has been a significant improvement, with a focus on lower total cost of ownership and increased reliability.
The following are the most significant changes made to wired drill pipe version 2:

- Reusable and field-replaceable inductive coils
- Proud box-end inductive coils provide superior signal transfer by maintaining coil contact.
- Recessed inductive coils in drill pipe pin ends
- A built-in battery controller allows for more efficient use of battery packs.
- Increased the corrosion resistance of armored coaxial cable by using Inconel 825.
- The WDP Version 1 coil was installed in the center of the pins shoulder (as shown in Figures below).

Figure 10 left side WDP1 and Right side WDP2

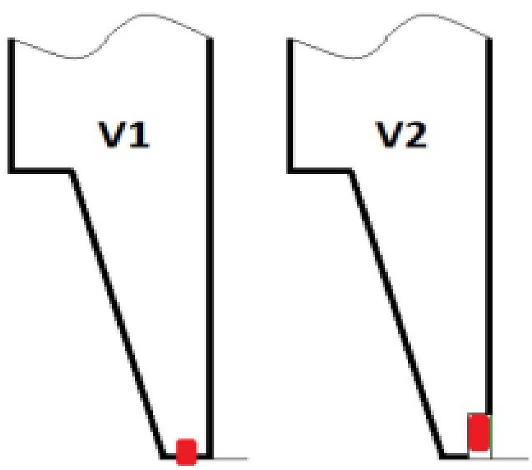


Figure 11 WDP1 and WDP2 with coil placement

In Figure 11, the coil placement on both Version 1 and Version 2 designs is highlighted in red. You can clearly see how the Version 1 coil was prone to flaring, whereas the Version 2 coil is unaffected by PIN deformations.[6]

2.2 The Basic WDP Network System

Wired drill pipe has been successful implemented for more than a decade in oil and gas offshore and onshore operations.
WDP creates high-speed bi-directional communication around 57.600 Bps, allowing for instantaneous downhole data transmission.
The basic components of such a high-speed WDP network are briefly described and illustrated in the diagram below:

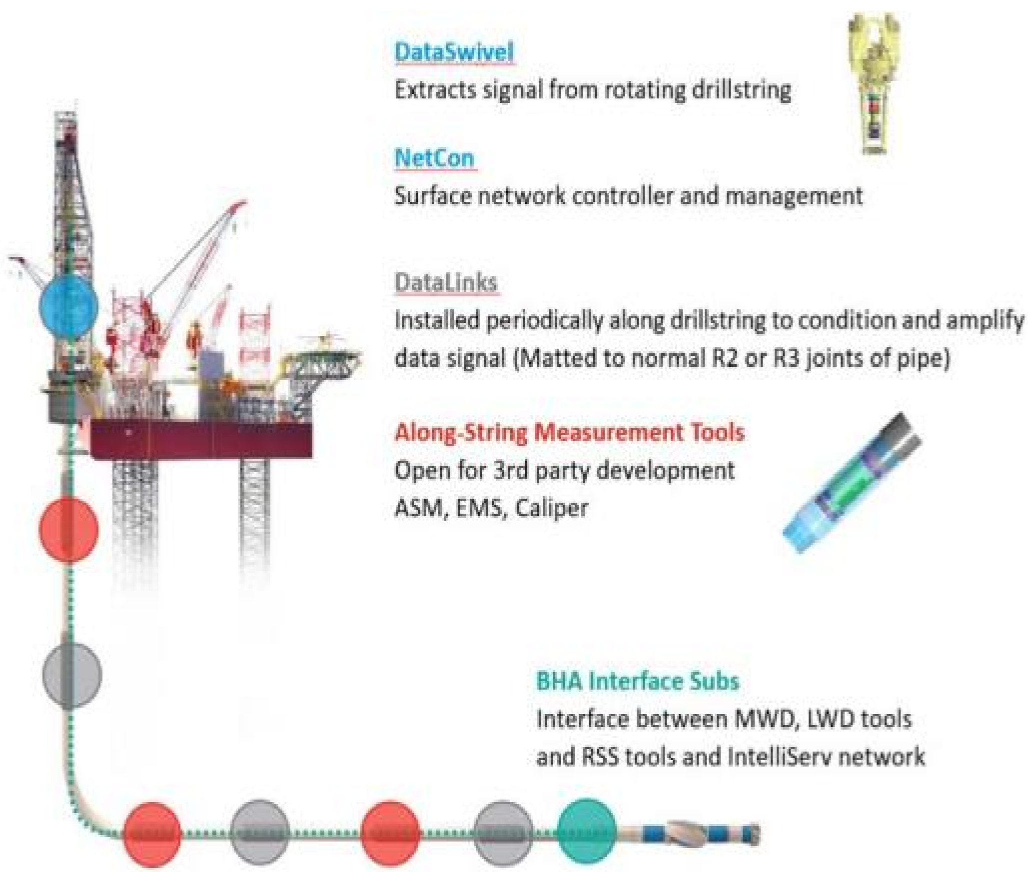
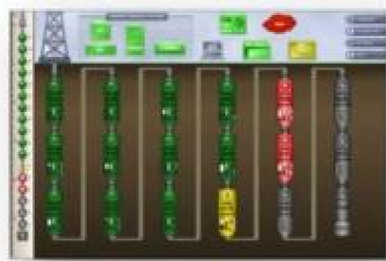


Figure 12 High speed WDP components

Double-shouldered drill pipe is "wired" with inductive coils and outfitted with armored coaxial cable. It is now available in a variety of sizes and configurations (4′ - 6 5/8′).

The Net Con (network Controller) allows for simple network maintenance and control from the surface. It has the following features: touch screen interface, graphical intuitive display automated diagnostic and repair



Armored data cables are attached to tool joints and together with coils and data links form a high speed telemetry network.
Corrosion and damage resistance is provided by armored material.

- High-strength Inconel exterior
- Corrosion-resistant
- Compatible with cesium formate liquid

Both the pin and box ends have inductive coils.
At a lower cost, new coil designs provide robustness, durability, and reduced susceptibility to damage.

- Reusable and Removable
- impact resistant and over torque
- Maintenance costs reduced by over 50%

Datalink units clean and amplify signals, which improves network performance and reliability. The most recent advancements in this technology include:

- Battery management improvements
- Electronics and structural improvements
- Rigorous shock, vibration and thermal certifications[12,13,14,15,16]

2.3 System Functionality and Integrity:

The goal of this section was to ensure that all WDP system components were functioning properly at the rig site under all conditions.

1. Transmission of WDP data.
    a) There will be no interruptions in data transmission due to WDP connectivity.
    b) A strong signal is received at the surface to ensure that the data boosters are operational.

2. ASM pressure and temperature data is transmitted to the surface, and sensors are operational
3. Communication between interface sub (GRPI) and LWD tools
    a) make certain that all LWD data points are transmitted to the surface
4. The top drive's wiring. There is no data interruption due to top drive wiring
5. The entire system is operational and communicating as a fully integrated System.

A connectivity test is performed at the workshop facility prior to test the WDP system at the wellsite. The goal of this test is to ensure that all components are ready for field use and to identify any potential component failures at an early stage.
Figure 13 depicts the testing configuration. When this test is completed successfully, the WDP system is ready for deployment.

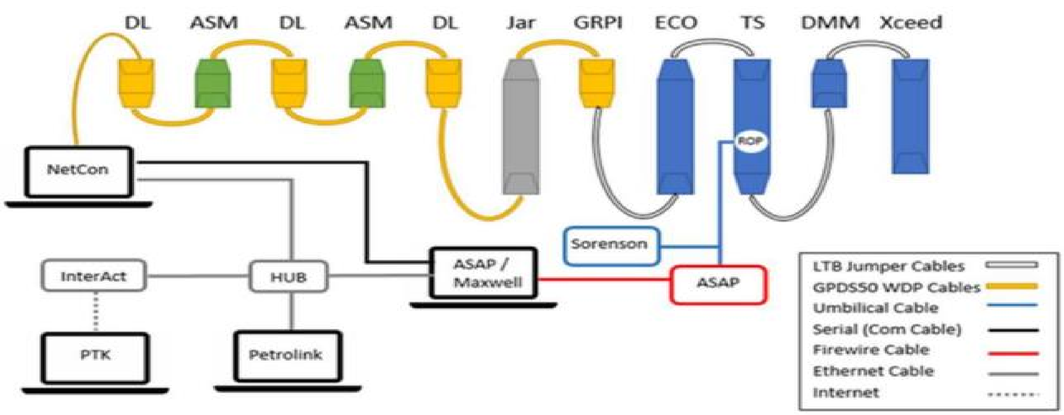


Figure 13 Connectivity test

One of the critical system components tested on the field was the surface system and top drive modification. Only at the wellsite can this be tested.
The fast WDP telemetry 57,000 bit/s transmission rate compared to mud pulse telemetry 3-6 bit/s transmission rate allowed for high density LWD logs to be obtained in real-time at high ROP rates. Aside from the fast telemetry, there are no limitations on the number of data points transmitted to the surface. In theory, all data collected by the LWD tools can be transmitted.

Figure 14 depicts the top drive modification and rig surface system configuration. The full WDP system was ready for the final downhole system test and functionality after testing the surface system and top drive modification.

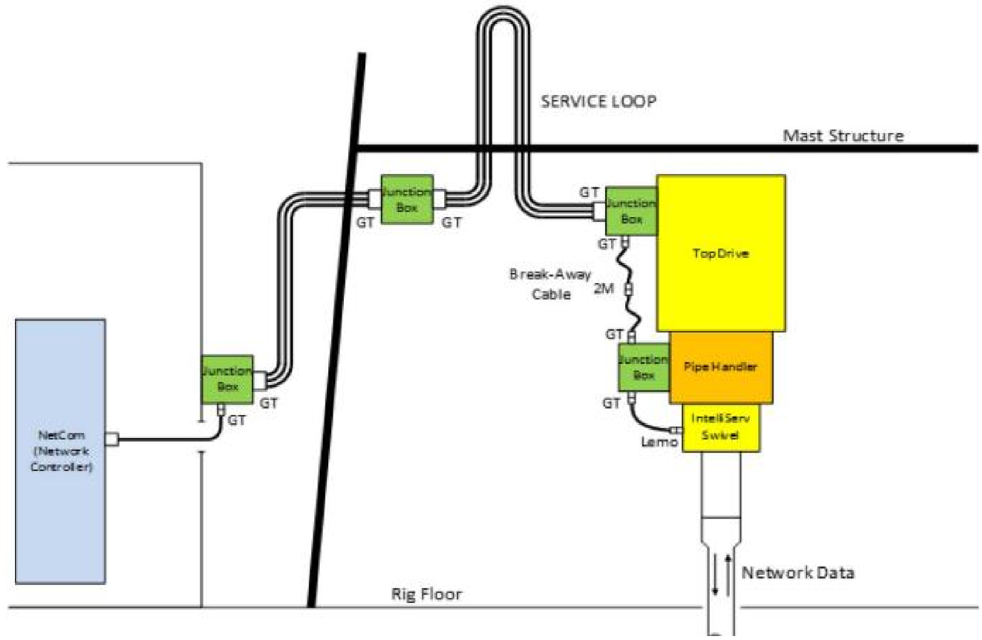


Figure 14 Required Top-Drive modifications and surface system wiring

2.4 Comparison of Conventional Mud Pulse Telemetry and WDP:

It is becoming more common to include a vibration/shock monitoring sensor as part of a MWD assembly. Typically, these sensors will only send a 'warning' if shock levels exceed a pre-set limit. Only transmitting a warning may impair the ability to detect underlying vibrational issues that do not exceed the predetermined limit. It is also common for downhole noise to interfere with pulse telemetry during times of high vibration, making detection of the mud pulse signal difficult. The resulting interruption of real-time data can mask the actual warnings from the downhole sensors, resulting in extended periods of high vibration, resulting in serious tool damage and, eventually, downhole tool failures. Full shock and vibration data, including magnitude and frequency, can be transmitted without restriction through a wired drill pipe system, resulting in a much clearer understanding of downhole drilling dynamics. Multiple shock sensors can be installed in the LWD string, and sensors mounted in the wired drill pipe repeaters have the potential to gain dynamic information on the entire drill string.

Another use for wired drill pipe has been the ability to request and receive directional check shot surveys at any stage of the well bore. Increased frequency of directional surveys reduces the well path's ellipse of uncertainty, allowing survey methods such as rotational check shots to become the norm. Using conventional mud pulse telemetry systems to take multiple rotational check shots is time-consuming and can be problematic. The Intellipipe system eliminates the need for a survey to be taken and transmitted to the surface via cycling mud pumps and prolonged pumping, reducing the possibility of downhole problems.

PWD tools are extremely useful in determining actual ECDs during the drilling process. When the mud pumps are turned off, no data is transmitted by a mud pulse telemetry system. With wired drill pipe, data is transmitted continuously, allowing accurate real-time information on swab and surge pressures to be received even during connections and tripping, and potential lost-circulation or influx situations to be avoided. Extra pressure sensors can be installed in wired pipe repeaters.

Another important feature is the ability to control downhole tools with wired drill pipe. Although existing downlinking systems can be very reliable and have little impact on drilling, using the wired drill pipe system allows control of tools such as rotary steerable systems, LWD formation testers, and geosteering sensors, allowing for 'instant' control and confirmation of commands, allowing for extremely precise system control.[8,9,10,11]

2.5 conclusion:

The use of wired drill pipe in the correct application opens up many new opportunities to increase the value of a project, such as:

- Higher drilling rates
- Reduced downhole tool failures as a result of improved real-time drill string management
- Better and smoother wellbore profiles
- Greater reservoir exposure as a result of more precise geosteering
- The implementation of new technology, such as seismic-while-drilling.

Wired drill pipe extracts full value from the increasing amounts of real-time downhole data generated by the latest rotary steerable systems, MWD and LWD technology, not only for pure formation evaluation, but also for precise geosteering, drilling dynamics analysis, and downhole tool control.[17]

CHAPTER 3

3.1 History of Automation in Drilling process:

Automated drilling operations originated in the form of a screw mechanism for drill feed in the past. The incorporation of a weight on bit (WOB) system was established in the 1860s when a steam-driven pump was utilized to provide additional weight if the drilling string weight was inadequate. However, advancements in automation were limited until the early 1900s, with the development of ineffective weight on bit indicators. In the 1920s, Halliburton and Hilde introduced a torque-based automation system that used torque as a threshold to recover the casing string if exceeded. In the 1930s, a hydraulic feed rotary table was developed, which, though automatic, was limited due to its slow speed and uneconomical nature. Later on, in 1971, computer-controlled automation systems were introduced, enabling monitoring of weight on the bit and rotary speed changes using a digital/analog system. The electro-mechanical device controlled the weight on the bit in the 1930s, and the pneumatic actuated feed control system was developed to implement band brakes for the rig five years later. An electronic pit feed system was designed in 1997, which is currently in use, and it controls various operations, such as tripping and reaming, measuring drag and torque, turning the pump on and off, among others. The automation of the rotary system evolved with time and advanced from a power swivel to a hydraulic power swivel and hoist, to an electric power swivel, which is widely used today as a top drive unit. In the past, plans were drawn up to automate an entire rig, but the design proved too complicated to build. However, a semi-automated drilling rig designed for atomic purposes to drill shallow holes requiring only two remote crew members was created. Another remotely controlled automated rig was designed in 1970 for use, but it was only 42 feet tall and required on-site personnel for maintenance tasks. Additionally, it was unable to detect and respond to kicks situations. There are various other automated drilling devices such as a mud mixing system that monitors mud weight and adjusts it based on drilling conditions. Automation also controls cementing operations through a recirculating system that ensures accurate cement density before pumping it down by comparing the mixed cement to a reference cement value. The bottom hole assembly can be semi-automated, depending on the availability of real-time data from by LWD, MWD, and PWD tools.[18,19,20,21]

3.2 Why There is Automation in Drilling process?

The utilization of automation in drilling operations has become increasingly popular due to a variety of factors, including the following:

1. Increased safety: Automated systems can minimize the risk of accidents and injuries to workers by reducing manual labor and improving the precision of drilling operations.
2. Enhanced efficiency: Automation can enhance drilling speed and accuracy, leading to shorter drilling times and reduced resource requirements.
3. Improved data collection and analysis: Automated drilling systems can offer real-time data and analysis, allowing for better-informed decision making and enhanced drilling performance.
4. Enhanced consistency: Automated systems can ensure that drilling operations are performed consistently and according to established standards, decreasing the risk of human error.
5. Cost-effectiveness: Automation can reduce labor costs and increase drilling operation efficiency, resulting in long-term cost savings.
6. Better monitoring and control: Automated systems offer real-time data and monitoring capabilities, providing better control and management of drilling operations.
7. Enhanced environmental protection: Automated systems can minimize the environmental impact of drilling operations by reducing waste, increasing energy efficiency, and decreasing emissions. Overall, the implementation of automation in

drilling can offer numerous advantages, such as enhanced safety, efficiency, and performance, as well as cost savings and reduced environmental impact.[22,23,24]

3.3 Different levels of Automation:

There are three broad categories of automation levels in drilling operations, namely fully manual, semi-automated, and fully automated. The degree of automation in each category can vary, depending on the level of control and decision-making power assigned to the operator or the computer system. In a fully manual system, the operator is solely responsible for all decisions and actions. In a fully automated system, the computer system takes charge of all decisions and actions without any human intervention. In a semi-automated system, both the operator and the computer system have some control and decision-making power, and the level of automation varies based on the specific design of the system. The semi-automated level allows for more flexibility and customization options compared to fully manual or fully automated systems. The choice of automation level depends on various factors such as the task being performed, desired level of efficiency and safety, and technical capabilities of the system.[25]

Figure 15 Automotive system

3.4 Fully automated drilling:

A fully automated drilling system is one in which all operations are performed by a computer system with no human intervention. The computer system is programmed to carry out the drilling process from beginning to end, including activities such as rigging, drilling the well, controlling the drill bit, monitoring the drilling parameters, and stopping the drilling process when necessary.

Fully automated drilling systems are intended to boost efficiency, cut costs, and reduce human error. These systems automate various aspects of the drilling process, such as monitoring well conditions, controlling the drill bit, and adjusting drilling parameters in real-time, by utilizing advanced sensors, control systems, and software algorithms.

Increased efficiency, reduced downtime, improved safety, and lower costs associated with human error and labor are all advantages of fully automated drilling systems. However, fully automated systems have limitations, such as the requirement for highly specialized personnel to maintain and repair the system, as well as a potential loss of control and flexibility in the drilling process.

Finally, as the oil and gas industry continues to embrace digital technologies and automation, fully automated drilling systems are becoming more popular. These systems provide numerous advantages, but before investing in this technology, it is critical to carefully consider the trade-offs and limitations.[25,26,27]

Figure 16 Automation Drilling research in SINTEF

CHAPTER 4

4.1 Benefits of Using High-speed Wired Drill String Telemetry Network:

High-Speed Telemetry Applications:

1. increased safety by utilizing continuous downhole pressure, drill string dynamics, and high speed drill string energy transfer regardless of rig conditions or flow.
2. improved efficiency by optimizing RSS and bit performance, reducing hidden NPTs, and monitoring well conditions while drilling.
3. enhance reliability by providing a redundant telemetry system and allowing the user to identify potentially harmful drill string dynamics
4. increased productivity due to more accurate wellbore placement

Safety:

The primary goal of any drilling operation has always been and will continue to be safety. In a variety of ways, the high-speed wired drill string has the potential to improve operational safety. This becomes increasingly important as drilling operations move into more difficult environments.

Monitoring of Annular and Formation Pressures in the Downhole:

The use of high-speed wired drill string telemetry allows for continuous data transmission at high speeds, enabling the monitoring of various aspects of the well's status. This includes the monitoring of downhole swab and surge pressure during tripping, which can be optimized to improve safety and efficiency. Additionally, certain fluid properties can be measured downhole to assist drilling fluid engineers in precisely arranging the composition of the drilling fluid to match the needs of the wellbore. By performing a real-time analysis of the full pressure profiles, adjustments can be made to parameters such as drilling fluid composition and pore pressure models, leading to significant time savings on the rig. The high-speed telemetry system is not affected by drilling fluid properties or circulation rate, providing reliable and continuous transmission of data.

Wellbore Positioning:

It is impossible to overestimate the importance of accurately defining the position of a drilled wellbore. In situations such as:

1. Lowering reservoir model errors
2. Error-free reserve reporting.
3. A well-control incident requiring the use of a relief well
4. Avoiding collisions with existing and future wells

The position of the wellbore is typically determined in "real-time" by acquiring data from the accelerometer and magnetometer sensors of the MWD system. To collect MWD investigative records, the drilling process must be stopped, trapped torque from the drill string calculated, drill string brought to static condition, survey acquired, and survey data transmitted to the surface via mud pulse telemetry.

Because the model does not account for gross error, survey data quality control should be considered critical in all cases.

The use of high-speed wired drill string can increase the efficiency and quality of this process. For near-instantaneous verification, data can be transmitted in real time to full sensor accuracy. This saves time and enables the immediate detection of low-quality data, such as that caused by drill string movement during survey acquisition.

It will also allow the MWD system's multiple directional sensors to be used in real-time while drilling.

Efficiency & Reliability:

The wired high-speed drill string improves drilling efficiency and reliability. WDP devices provide a significantly clearer view of the downhole drilling environment and enable near-instantaneous downlinking capability, allowing drilling decisions related to overall operational efficiency to be made earlier and with greater certainty.

Drilling Parameter Optimization for Efficient Drilling:

As the use of rotary steerable drilling systems and the level of formation evaluation LWD services has increased, BHAs have become increasingly longer and more complex. Simultaneously, well trajectories have become more difficult, drilling to greater depths and being more geometrically complex in order to improve recovery, access new reserves, and reduce environmental impact of drilling operations. As a result, the BHAs are subjected to harsher drilling conditions and are more susceptible to back vibration damage. Traditional mud pulse telemetry data rates may limit the effectiveness of drilling optimization services. For example, the CoPilotTM service is a real-time drilling optimization service that employs an advanced downhole acquisition and processing sub that is integrated into the BHA.

This downhole sub sampler simultaneously samples 14 sensors at 1 kHz:

1. Magnetometers are a type of sensor (for measuring downhole rotational velocity and for whirling detection)
2. Accelerometers are second in importance (for measuring acceleration in four different directions)
3. Temperature
4. Pressure in the annulus and borehole
5. Pressure gauges (for measuring downhole WOB, bending moment, torque, and bit bouncing)

This raw data is processed downhole before being transmitted to the surface, and it is written to the tool's downhole memory every 5 seconds for drilling process optimization. Even with moderate levels of LWD service provided by traditional MPT, these data sets are typically transmitted to the surface every 45 to 60 seconds.

High-speed wired drill strings provide a more complete real-time visualization of the downhole dynamic environment, allowing a much broader range of drilling dynamic variables to be monitored. This allows for faster identification and diagnosis of harmful vibration events, resulting in faster and more accurate parameterization to avoid downhole tool string/wellbore damage. In comparison to tracking trends in vibration levels, the effect of parameter adjustments can be seen more clearly and quickly. A traditional mud pulse update may take 10 minutes or more to appear. WOB data is continuously transmitted, allowing drill string hang-ups to be quickly identified and corrected with minimal impact on drilling performance. This is used in conjunction with continuous torque measurements downhole to determine bit dullness and eliminate uncertainty about when to trip to replace the drill bit.

Monitoring and Prediction of Borehole Stability:

LWD acoustic measurements, particularly formation shear velocity, can also be used to assess rock strengths for wellbore geomechanics applications.

Rock strength can also be used to calculate the fracture gradient of potential well breakout zones, which can cause pipe to become stuck. However, because accurate shear rate analysis necessitates the capture of the entire acoustic waveform at the ground surface, conventional mud pulse telemetry systems are limited in their capabilities for these applications. In addition to acoustic measurements, high-resolution borehole images can be used in real-time to identify fractures caused by borehole breakout and drilling. LWD images can be transmitted to the ground via conventional mud pulse telemetry using data compression techniques, but the resolution is either at the native resolution of LWD or limited due to limited data loss. FIGURE 17 shows a high-resolution electrical LWD image obtained using the StarTrak tool. This image depicts drill fractures as well as natural fractures caused by the drilling process.

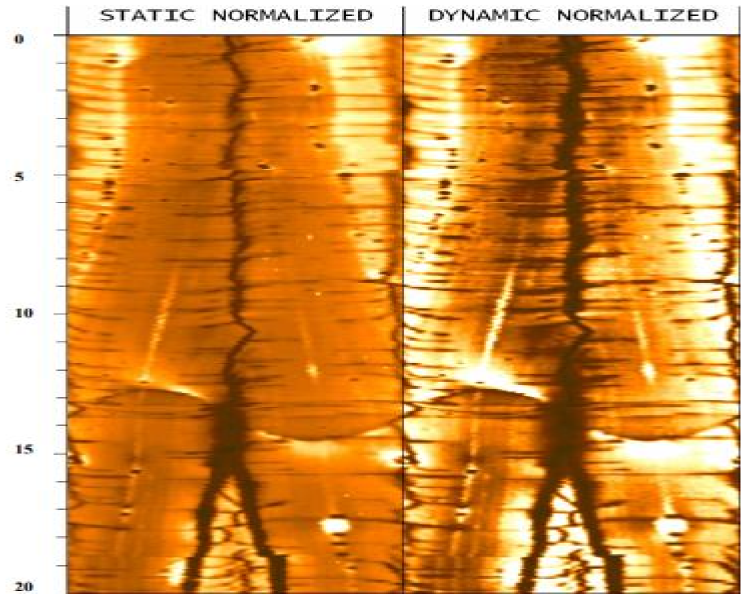


Figure 17 Drilling induced (vertical) fractures and natural (horizontal) fractures opened up during the drilling.

Summary and Prospects:

Early experience with high-speed wired drill pipe telemetry networks demonstrated their benefits in improving drilling operations' safety, efficiency, and dependability. It's also been used to drill wells that would be too dangerous or technically impossible to drill otherwise. Using real-time storage quality data from the most recent generation of BHA systems improves well placement within the reservoir. This is expected to increase well productivity, well life, and, eventually, field recovery while lowering development costs per barrel produced. The system improves and expands the capabilities of current drilling and evaluation technologies by enabling a "answers while drilling" strategy for field operations.

Automatic closed-loop directional drilling control is widely acknowledged today as a significant advantage. In the future, new telemetry networks are expected to stimulate technological development, facilitate automation of the entire drilling process, and address many of the industry's anticipated future challenges. This necessitates a focus on downhole and surface systems, as well as the ability to adapt to changes in working methods.[28,29,30,31,32]

4.2 Benefits of using CML systems in Deep Water Drilling:

Because of the following benefits, CML (Control and Monitoring System) systems are widely used in deep water drilling operations:

1. Increased Safety: CML systems offer real-time monitoring and control of drilling operations, reducing the risk of accidents and incidents. This is especially true in deep-water drilling, where conditions can be difficult and the consequences of an accident can be severe.
2. Enhanced Efficiency: CML systems allow drilling operations to be remotely monitored and controlled, reducing the need for human intervention and increasing operational efficiency. As a result, drilling times can be reduced, downtime is reduced, and operating costs are reduced.
3. Emergency Shut-Down Capabilities: In the event of an emergency, CML systems typically have emergency shut-down capabilities that allow drilling engineers to quickly and safely shut down operations. This can help to reduce the impact of an accident or incident and the risk of further injury to personnel or equipment.
4. Improved Data Management: CML systems collect and store data from drilling operations, acting as a centralized repository for all drilling-related data. This data can then be analyzed to identify trends, improve drilling performance, and make better decisions.
5. Better Environmental Monitoring: CML systems can be configured to monitor and control the discharge of drilling mud and other materials, reducing the environmental impact of drilling operations.
6. Real-time Monitoring: CML systems monitor drilling operations in real time, allowing drilling engineers to respond quickly to any issues or problems that arise. This can help to reduce downtime and the risk of expensive repairs or equipment failure.

Overall, the use of CML systems in deep water drilling operations helps to improve safety, efficiency, data management, and environmental monitoring, allowing drilling operators to achieve their goals in a more cost-effective and sustainable manner.[33,34]

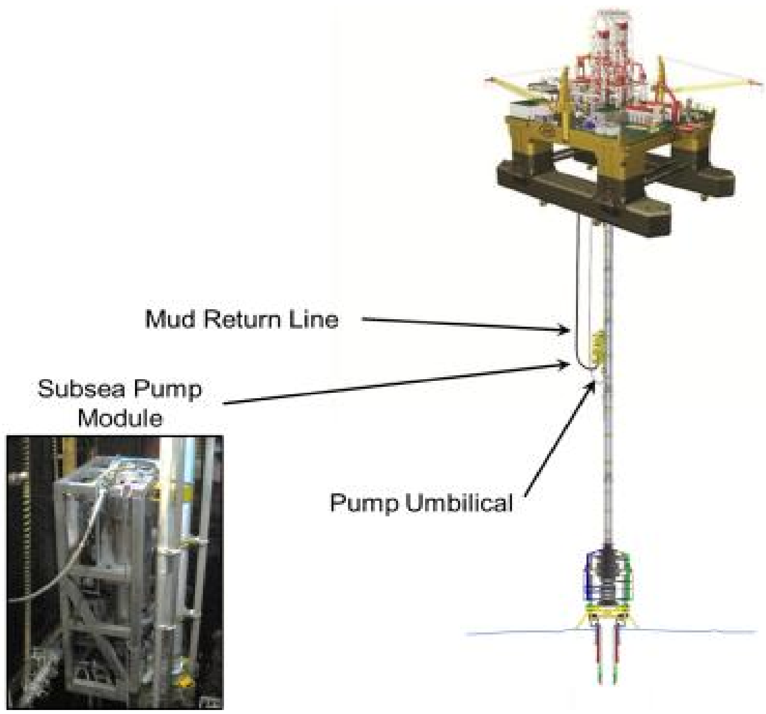


Figure 18 IADC Control mud level technology

4.3 Beneftis of using WDP in CML systems:

Bottom hole pressure (BHP) control is an essential aspect of well drilling and completion operations. Fully automated wired pipe control mud level (CML) systems can provide significant benefits in BHP management, ensuring well stability and preventing formation damage or blowouts.

One of the primary advantages of using CML systems is the real-time monitoring and control of mud level in the wellbore, which aids in the maintenance of consistent BHP and the prevention of over- or under-pressurization. The use of automated control algorithms in CML systems enables the mud level to be precisely adjusted in response to changes in well conditions, ensuring that the BHP remains within safe limits.

Furthermore, the drill pipe's wired connection allows for real-time data transmission, allowing the operator to monitor BHP and well conditions in real time and make adjustments to the CML system as needed. This helps to avoid unanticipated changes in BHP, which could result in well instability, formation damage, or even a blowout.

When it comes to well logging, combining wired drill pipe with control mud level (CML) systems can provide a number of advantages.

1. Real-time data transmission: The drill pipe's wired connection enables real-time data and telemetry transmission to the surface, providing the operator with detailed information on the well conditions and the logging process.
2. Improved control: The CML system aids in the maintenance of a consistent mud level in the wellbore, which reduces the risk of debris buildup, improves logging accuracy, and lowers the risk of stuck pipe.
3. Increased safety: The combination of the wired drill pipe and the CML system can reduce the need for personnel to be close to the wellbore, thereby improving safety during logging operations.
4. Improved well stability: The CML system's consistent mud level can help to stabilize the well, lowering the risk of downhole tool failure and improving the accuracy of logging measurements.

Combining wired drill pipe with control mud level systems can result in improved well stability, safety, control, and real-time data transmission, making it a valuable tool in well logging operations.

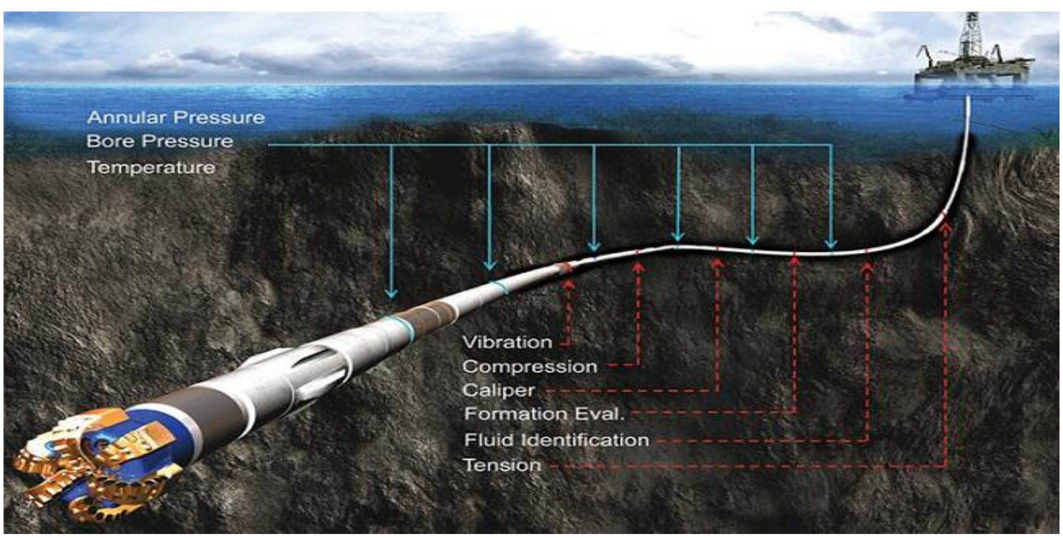


Figure 19 Wired drill pipe

CHAPTER 5

5.1 Rig hydraulic systems:

Drilling and production equipment such as oil and gas drilling rigs, well service rigs, and drilling support vessels all use rig hydraulic systems. The power and control various rig functions such as hoisting and rotating the drill string, running and retrieving the drill pipe, and operating the blowout preventer (BOP).

Hydraulic systems in drilling rigs typically consist of a series of pumps, valves, cylinders, and hoses linked to a power source, which is typically an engine or electric motor. The pump pressurizes the hydraulic fluid, which is typically a type of oil, and sends it through the system to actuate the various components.

One of the primary benefits of using hydraulic systems in rig operations is their ability to transmit large amounts of force over long distances, making them ideal for use in the harsh and frequently remote environments found in drilling operations. Furthermore, hydraulic systems can be precisely controlled, allowing for real-time fine-tuning of drilling operations.

It is critical to note that hydraulic systems in drilling operations must be designed and maintained in accordance with strict safety standards in order to operate reliably and without fail. Rig operators must inspect and maintain their hydraulic systems on a regular basis to ensure that they are in good working order, and they must be prepared to respond quickly in the event of a failure to reduce the risk of equipment and personnel damage.

5.1.1 Pressure losses in hydraulic circuit:

Figure 20 depicts the various components of the drill string, drill bit, and surface connections. When fluid is circulated from point 1 to 2 and back to point 3 in the mud tank, energy is lost due to friction, resulting in pressure drops. The goal of rig hydraulics is to calculate the pressure drops caused by friction in each component of the circulating system. There are four types of pressure losses: losses at the surface connection, losses in the pipes, losses in the annular space, and losses at the drill bit. The type of fluid used and the flow pattern in the circulation system both influence pressure losses.

The pump pressure, which is the pressure measured at the surface, is the result of all the pressure losses in various parts of the drilling system. This can be expressed mathematically as:

Pump Pressure = Total Pressure Loss in the System

Where the total pressure loss is the sum of the following factors:

- Pressure drop across mud pumps and related equipment used to circulate drilling mud
- Pressure loss as drilling mud moves through the flow line from the wellbore to the surface
- Pressure drop caused by the choke, a device that regulates mud flow rate while maintaining desired bottom-hole pressure.
- Pressure created by the weight of the drilling mud column
- Pressure drop as drilling mud flows through the drill bit nozzles and into the wellbore.

The pump pressure reading can provide valuable insight into the drilling system's efficiency by taking into account the various sources of pressure loss.

Equation 3

$$\text{Pump Pressure} = \Delta P\ \text{drill pipe} + \Delta P\ \text{drill collar} + \Delta P\ \text{bit} + \Delta P_{DC/Ann} + \Delta P_{DP/Ann} + \Delta P\ \text{surf}$$

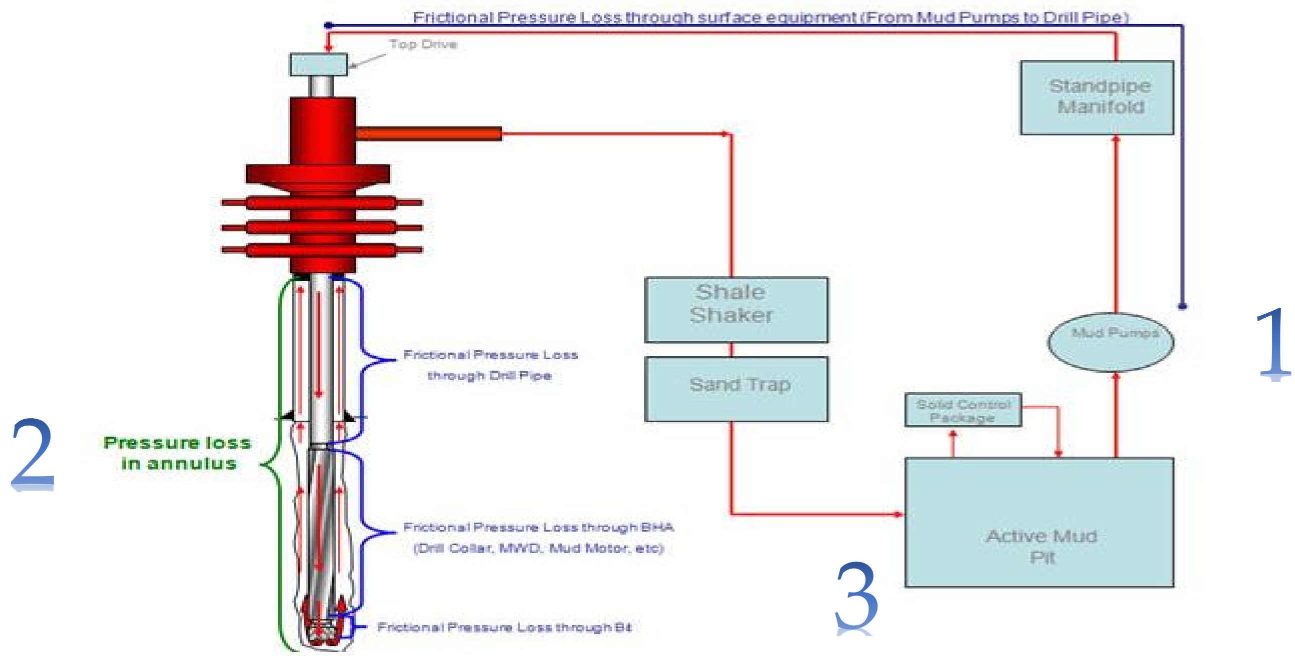


Figure 20 Hydraulic circulation

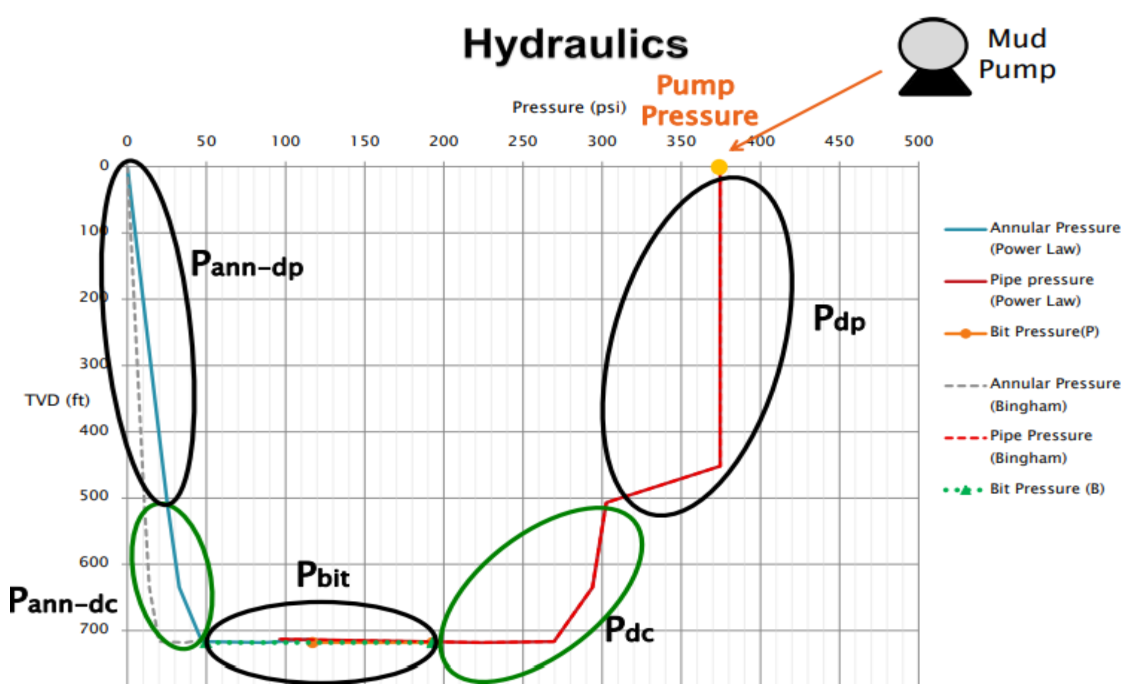


Figure 21 Pressure drops in hydraulic circuit

5.1.2 Pressure losses in pipe and annulus:

The decrease in fluid pressure that occurs as fluid flows through a pipe or annulus is referred to as pressure loss (a circular space between two concentric cylindrical surfaces). This pressure drop is caused by a combination of factors, including fluid viscosity, fluid velocity, pipe length, and pipe diameter.

Pressure loss in pipes is commonly caused by frictional losses, which are proportional to the fluid velocity and the roughness of the pipe wall. Frictional losses increase as pipe length increases and decrease as pipe diameter increases.

Pressure loss in annuli can occur due to friction between the inner and outer surfaces as well as changes in fluid velocity. The pressure drop in an annulus is proportional to the velocity of the fluid, the length of the annulus, and the difference in diameter between the inner and outer surfaces.

This section discusses the pressure losses that occur during the drilling process, which are classified into two types: pipe losses and annular losses. Pipe losses occur within the drill pipe and drill collars and are denoted as P2 and P3 in the illustration. P4 and P5 annular losses occur around drill collars and drill pipe.

Three major factors influence the magnitudes of these pressure losses, P2, P3, P4, and P5.

1. The properties of the drilling mud, such as its weight, plastic viscosity, and yield point;
2. The dimensions of the drill pipe or drill collars, such as inside and outside diameters and length; and
3. The flow type, which can be laminar, plug, or turbulent.

It is important to remember that the actual behavior of drilling fluids underground is not well understood, and fluid properties measured at the surface may differ at bottom hole conditions. There are several pressure loss models available, but each model produces different results for the same set of conditions.[26]

5.1.3 Power Low fluid model:

A non-Newtonian fluid is one that does not obey Newton's law of viscosity, which states that the viscosity of a fluid is constant and independent of its shear rate. Non-Newtonian fluids, on the other hand, have viscosity that varies with shear rate. Non-Newtonian fluids come in a variety of forms, including:

• Pseudo-plastic fluids: The viscosity of these fluids decreases with increasing shear rate, making them easier to pump and handle at higher flow rates.

• Dilatant fluids have a viscosity that increases with shear rate, making them more difficult to pump and handle at higher flow rates.

• Bingham plastics: These fluids have a yield point below which they have little or no flow and flow characteristics similar to a pseudo-plastic fluid above which they have little or no flow.

Thixotropic fluids have viscosities that decrease over time when subjected to a constant shear rate and then increase when the shear rate is stopped.

Drilling fluids, paint, ketchup, shampoo, and toothpaste are examples of non-Newtonian fluids. The behavior of non-Newtonian fluids is important to understand in a variety of industrial applications such as drilling, pumping, and fluid transport.

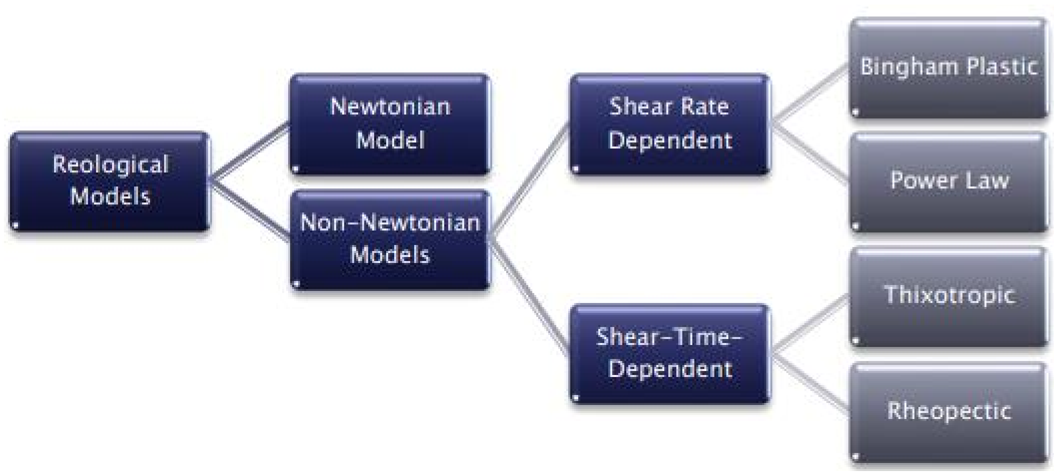


Figure 22 Rheological models

Power low model:

The Power-Law Model is a mathematical model used to describe the behavior of non-Newtonian fluids in a pipe or annulus, such as drilling fluids. The Power-Law Model assumes that the viscosity of a fluid is a function of its shear rate, rather than being constant as in a Newtonian fluid. The Power-Law Model is represented by the following equation:

Equation 4

$$\tau = k(\gamma)^n \qquad \tau = k(-\frac{dv}{dr})^n$$

$\tau =$ Fluid viscosity

K = consistency index

$\frac{dv}{dr}$= shear rate

n = flow behavior index

The Power-Law Model is frequently used to calculate the pressure loss in drilling fluids as they pass through the drill string and annulus. It can be used to design drilling systems and predict the behavior of drilling fluids in the wellbore.

While the Power-Law Model is widely used in the drilling industry, it is only a rough approximation of the actual behavior of drilling fluids, and there may be significant differences between model predictions and actual fluid performance in the wellbore.

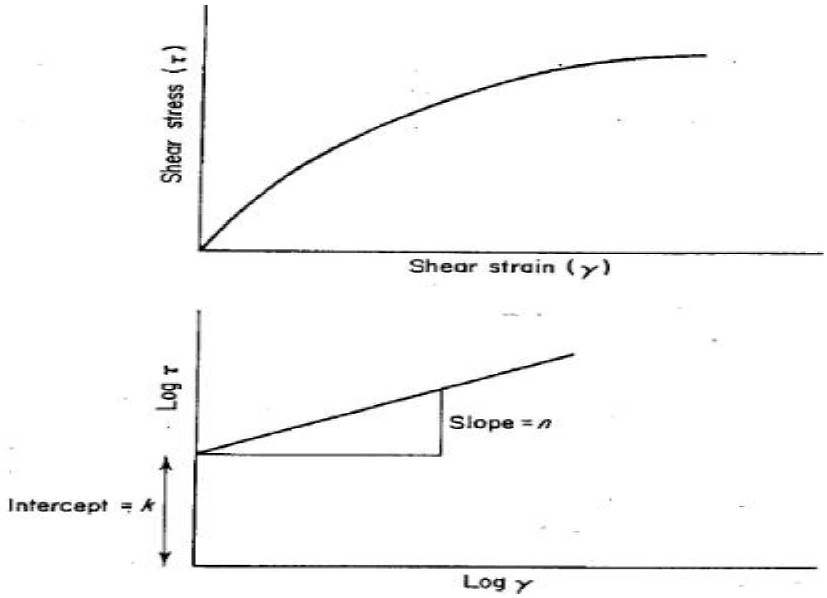


Figure 23 Power-low model

When n equals 1, the equation simplifies to τ=k(γ). In this case, k equals and the relationship is analogous to that of a Newtonian fluid. The value of n represents non-Newtonian behavior, with larger values indicating a greater degree of non-Newtonian behavior. The term k refers to the consistency of the fluid, with higher values indicating that the fluid is very thick.

Plastic viscosity (PV):

The resistance of a non-Newtonian fluid to flow under stress is described by the term plastic viscosity. It measures a fluid's ability to deform and retain its shape when subjected to a shearing force. Unlike Newtonian fluids, which have constant viscosity, the viscosity of a non-Newtonian fluid varies with shear rate.

The presence of solid particles significantly influences the plastic viscosity (PV) of mud. Particle size and concentration both have an impact on this. The greater the amount of solids in the mud and the smaller the particle size, the greater the surface area for the liquid to coat. This causes an increase in internal flow resistance and higher plastic viscosity. In other words, a higher concentration of smaller solid particles in mud results in greater flow resistance and a thicker, more viscous fluid.

Equation 5

$$\text{Plastic Viscosity} = (\Theta 600 - \Theta 300)$$

Yield point (YP):

The yield point is a term used in the study of non-Newtonian fluids to describe the point at which a fluid transitions from a liquid-like to a solid-like state under stress. It is the point at which the fluid begins to deform and flow, rather than maintaining its shape and resisting flow as it does at lower stress levels. The yield point is an important property of non-Newtonian fluids because it can have a significant impact on their behavior in industrial and practical applications. Some non-Newtonian fluids, such as viscose-plastic fluids and shear-thickening fluids, have high yield points, whereas others, such as dilatant fluids, have low or no yield points. YV is influenced by two factors:

1. Particle charges and
2. Particle concentration.

The more charged particles there are in the mud, the more structured the fluid becomes, resulting in an increase in internal shear resistance. As a result, the yield point increases, which is calculated as the difference between the fluid's apparent viscosity at 300 seconds of shear (300) and its plastic viscosity (PV). In other words, a higher charged particle concentration in mud results in greater shear resistance and a higher yield point.

Equation 6

$$\text{Yield Point} = (\Theta 300 - PV)$$

5.1.4 Flow regimes:

The flow regime in a wellbore is the pattern of fluid flow within the borehole that is influenced by factors such as fluid properties, well geometry, and flow rate. In a wellbore, several common flow regimes can occur, including:

1. Laminar flow: When a fluid flows in parallel layers with no turbulence, this is called laminar flow. It is commonly found in small diameter wells or pipes and is typically associated with low flow rates.
2. Turbulent flow: When the fluid flow is disrupted by turbulence and eddies, this is referred to as turbulent flow. It is commonly found in larger diameter wells or pipes and is associated with high flow rates.
3. Transitional flow occurs when the fluid flow transitions from laminar to turbulent. It is a complex mixture of laminar and turbulent flow and is difficult to predict.

Laminar flow is commonly observed in wellbores in small diameter wells or wells with low flow rates. The fluid velocity is low in these wells, and the fluid can flow in parallel layers with little or no turbulence.

Turbulent flow, on the other hand, is more commonly seen in larger diameter wells or wells with high flow rates. Fluid velocity is high in these wells, and the fluid is unable to flow in parallel layers, resulting in turbulence and eddies within the wellbore. Turbulence can cause significant fluid mixing, as well as significant pressure losses and flow resistance.

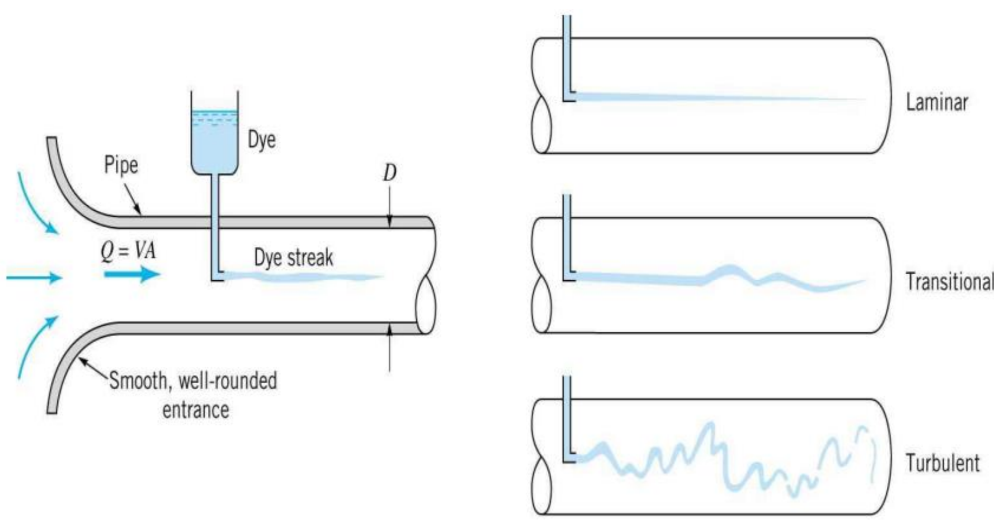


Figure 24 Different flow regime

It is important to note that changes in fluid properties, well geometry, and flow rate can cause the flow regime within a wellbore to change. In a well with a narrow section followed by a wider section, for example, as the fluid velocity increases in the wider section, the flow regime may shift from laminar to turbulent. Changes in fluid properties, such as viscosity or density, can also have an effect on the flow regime.

5.2 Experimental work:

The main idea behind this project is to design a fully automatic CML systems with WDP in order to manipulate pressure automatically at bottom hole especially at deep water drillings without human interruption.
The project is fully done by python coding language.
The project is consisting of several steps:

1. Mathematical hydraulic model
2. Comparing created model with PWD data
3. Playing with mud level in the riser in dynamic condition
4. Playing with mud level in the riser in static condition
5. Introduction to deviated wells

5.2.1 Mathematical mode:

The first and main step in project is to design a precise hydraulic model in order to analysis behavior and performance of the system accurately.
The assumption while creating a model in order to avoid from complexity is having a vertical well.

Data collection:

One of the crucial part of the mathematical model is to having a proper data or input for the system. All required input data are collected in Excel.
Essential input data’s for designing mathematical model are:

1. Mud rheological data
2. Drilling parameters
3. Survey data
4. Len, OD, ID of Bottom hole assembly components

Mud rheological data including:

1. PV
2. YV
3. Gel strength: a measure of a material's mechanical strength when it is in a gel-like state.
4. Apparent viscosity: a measurement of flow resistance under moderate shear stress.
5. Dynamic viscosity: a measurement of flow resistance under high shear stress.
6. Shear thinning: a decrease in viscosity as shear stress increases.
7. Shear thickening: an increase in viscosity as shear stress increases.

All parameters are obtained from laboratories and are typically measured with rheological testing instruments such as a rotational viscometer or a piston viscometer.
Drilling parameters including:

1. Start depth
2. End depth
3. Cum depth drilled
4. Interval ROP
5. Total ROP
6. Drilling Torque
7. SPP
8. Drilling time
9. Rotating time
10. Circulation time

Drilling engineers can optimize mud formulations and ensure that drilling operations run smoothly and efficiently by taking these drilling parameters into account and monitoring changes in the rheological properties of mud.

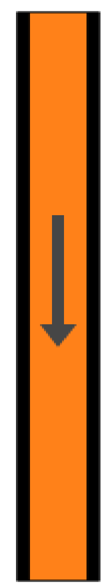
Survey data is consist following parameters:

1. MD
2. TVD
3. Incl
4. Azm

Wired HWDP, Jars, float sub, circulating sub, stabilizer, MWD mod stab, star-track, rotary steerable tool and etc. are part of bottom hole assembly component.

Pressure losses in DP:

After collecting and importing data to python is the time to calculate pressure losses in different parts of hydraulic circuit which is mentioned in above chapter 5.1.



Formulas for calculation of pressure losses are related to Power low model. In order to determine pressure losses in pipe, θ_{300} and θ_{600} should be calculated in advance. According to the obtained results, n and k could be determined.

After determination of n and k, V and V_c is calculated respectively.

V and V_c are important factors in determination of flow regime at wellbore.

If $V < V_C$ in this case flow is laminar otherwise flow is turbulent.

θ_{300} and θ_{600}**:** describe the resolution of dial indicators

V**:** flow velocity

V_c **:** critical velocity

```
import math
theta600 = (2*(PV)) + YV
theta300= PV + YV

n=3.32*math.log(theta600/theta300,10)
k=theta300/(511)**n

#determination of Vc&V:
import math
Vc=(((5.82*(10**4)*k)/MW) **(1/(2-n)))*(((1.6*((3*n)+1))/(ID*4*n)))**(n/(2-n))
V=24.5*Q/(ID**2)

#Pressure loss inside Drill pipe
import numpy as np
import math

if V<Vc:
    P2_laminar=(((1.6*V*((3*n)+1))/((ID*4*n)))**n)*((k*L1)/(300*ID))
    P2_turbulent=0
elif V>Vc:
    P2_turbulent=(8.91 *(10 **(-5))*(MW **(0.8)) * (Q **(1.8)) * (PV ** (0.2) )*L1) / (ID **(4.8))
    P2_laminar=0

print('P2_laminar=',P2_laminar)
print('P2_turbulent=',P2_turbulent)
```

Note: All the units that has been used in this project are field units.

Result: As flow velocity is higher than critical velocity so the type of flow is turbulent in DP.

Pressure losses in DC:

After calculation of pressure losses in DP is the time to check flow regime in DC. The same procedure will be taken just parameters will be adjusted according to size of DC

```
Vc2=(((5.82*(10**4)*k)/MW) **(1/(2-n)))*(((1.6*((3*n)+1))/(ID2_DC*4*n)))**(n/(2-n))
V2=(24.5*Q)/(ID2_DC**2)
print('V2=',V2)
if V2<Vc2:
    P3_laminar=(((1.6*V2*((3*n)+1))/((ID2_DC*4*n)))**n)*(k*L2/300*ID2_DC)
    P3_turbulent=0
elif V2>Vc2:
    P3_turbulent=(8.91 *(10 **(-5))*MW **(0.8) * (Q**(1.8)) * (PV ** (0.2) )*L2) / ID2_DC **(4.8)
    P3_laminar=0

print('P3_laminar=',P3_laminar)
print('P3_turbulent=',P3_turbulent)
```

Results: Similarly, $V>V_C$ thus there will be turbulent flow regime in DC. The only difference is about the larger value of pressure loss in DC in compare to DP.

Annular losses around DP:

The casing has been installed, so it will be necessary to determine the annular losses in both the open hole and the cased hole sections.

Here calculation will be doubled, mean above calculations will be done both for cased and open hole sections.

Equation 7

$$\text{Annular distance} = \text{ID} - \text{OD}$$

Coding regarding to cased hole section in python is mentioned below:

```
Vc3=(((3.878*(10**4)*k)/MW) **(1/(2-n)))*(((2.4*((2*n)+1))/((ID3_C-OD_p)*3*n)))**(n/(2-n))

V3=(24.5*Q)/((ID3_C**2)-(OD_p**2))
print('V3=',V3)

if V3<Vc3:
    P4_laminar=(((2.4*V3*((2*n)+1))/(((ID3_C-OD_p)*3*n)))**n)*(k*L3/(300*(ID3_C-OD_p)))
    P4_turbulent=0
elif V3>Vc3:
    P4_turbulent=(8.91 *(10 **(-5))*(MW **(0.8)) * (Q**(1.8)) * (PV ** (0.2) )*L3) / (((ID3_C-OD_p) **(3))*((ID3
    P4_laminar =0

P4=P4_laminar+P4_turbulent
print('P4_laminar=',P4_laminar)
print('P4_turbulent=',P4_turbulent)
```

As a result, $V<V_C$ so we obtained only laminar flow in cased hole annular section of DP and the obtained pressure loss is too low.

The same procedure will be repeated for pressure loss around DP in open hole section but the only difference will be regarding Annular distance and open hole section length.

Annular distance and open hole section formulas respectively:

Equation 8

$$\text{Annular distance} = \text{Hole D} - OD_{DP}$$

$$\text{Open hole section} = L_{DP} - L_{\text{CASED SECTION}}$$

```
Vc4=(((3.878*(10**4)*k)/MW) **(1/(2-n)))*(((2.4*((2*n)+1))/((Hole_diameter-OD_p)*3*n)))**(n/(2-n))
V4=(24.5*Q)/((Hole_diameter**2)-(OD_p**2))
print('V4=',V4)

print('Vc4=',Vc4)

if V4<Vc4:
    P5_laminar=(((2.4*V4*((2*n)+1))/(((Hole_diameter-OD_p)*3*n)))**n)*(k*L4/(300*(Hole_diameter-OD_p)))
    P5_turbulent =0
elif V4>Vc4:
    P5_turbulent=(8.91 *(10 **(-5))*MW **(0.8) * (Q **(1.8)) * (PV ** (0.2) )*L4) / (((Hole_diameter-OD_p) **(3))
    P5_laminar =0

P5=P5_laminar+P5_turbulent
```

Result: Here also we only have laminar flow due to value of V which is higher than V_C. Here obtained $P_{LAMINAR}$ is higher than $P_{LAMINAR}$ in cased hole section.

After finding pressure losses around DP both in cased hole and open hole condition, by summing them we can find total pressure loss around DP.

Equation 9

$$P_{TOTAL}=P4+P5$$

Annular Pressure loss around DC:

The same steps will be taken like above ones, so the code regarding this section will be:

```
Vc5=(((3.878*(10**4)*k)/MW) **(1/(2-n)))*(((2.4*((2*n)+1))/((Hole_diameter-OD_C)*3*n)))**(n/(2-
V5=(24.5*Q)/((Hole_diameter**2)-(OD_C**2))
#print('V5=',V5)

if V5<Vc5:
    P6_laminar=(((2.4*V5*((2*n)+1))/(((Hole_diameter-OD_C)*3*n)))**n)*(k*L2/(300*(Hole_diameter-OD_C)))
    P6_turbulent =0
elif V5>Vc5:
    P6_turbulent=(8.91 *(10 **(-5))*MW **(0.8) * (Q **(1.8)) * (PV ** (0.2) )*L2) / (((Hole_diameter-OD_C) **(3))
    P6_laminar =0

P6=P6_laminar+P6_turbulent
print('P6_laminar=',P6_laminar)
print('P6_turbulent=',P6_turbulent)
```

Result: As a result, we will see $P_{LAMINAR}$ pressure loss around DC which is close to $P_{LAMINAR}$ cased section around DP.

Total Annular Pressure loss:

Total annular pressure loss will be summation of pressure losses in annular and the coding regarding this section will be demonstrated below:

```
#Total annular pressure loss:
delta_p_anular=Pfinal_laminar+P6
print('delta_p_anular',delta_p_anular)
```

ECD Calculation:

ECD is a term used to describe the fluid flow rate in a wellbore, per unit area of the borehole cross-section. The ECD is an important parameter in drilling because it affects the hydraulic efficiency of the drilling fluid, which in turn influences the rate of penetration and the overall performance of the well.

Higher ECD values indicate a higher fluid velocity and a correspondingly greater potential for hydraulic issues, such as turbulent flow, erosion, or increased frictional losses. Conversely, lower ECD values indicate a slower fluid flow and a correspondingly lower potential for these issues.

The ECD is carefully controlled in managed pressure drilling (MPD) and underbalanced drilling (UBD) to achieve specific goals such as reducing formation damage or improving core sample quality. Drillers can reduce the risk of well control problems, such as lost circulation or formation damage, by controlling the ECD, and ensure that the well is drilled efficiently and safely.

ECD is a parameter that only exists in Dynamic mode.

There could be three different value of ECD:

1. ECD=MW when circulation is stopped
2. ECD>MW when there is circulation
3. ECD<MW

The target of project is to lowering ECD below MW which could be achieved by lowering mud level in the riser in order to drill in narrow mud window.

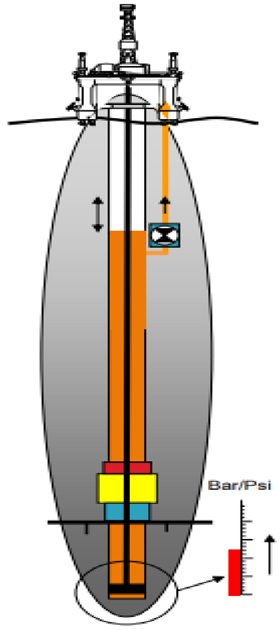


Figure 25 Adjustment of mud level in the riser

BHP Dynamic calculation:

(BHP) is a drilling term that refers to the pressure at the bottom of the wellbore. It is an important parameter that is used to ensure the well's safety and stability during drilling operations.

BHP is produced by the weight of the fluid column in the wellbore and the pressure at the bottom of the well caused by formation and geothermal gradients. Controlling the BHP during drilling operations is critical to preventing the well from blowing out, which can result in fluid loss, damage to the wellbore and formation, and even death.

In drilling, BHP is used to control the (ROP) and design the drilling fluid program in order to maintain well control and prevent blowouts. The drilling fluid is used to balance pressure in the wellbore and prevent the influx of formation fluids, which can affect BHP and well stability.

Bottom Hole Pressure is a critical factor in drilling operations that must be carefully monitored and managed to ensure the well is completed safely and efficiently

Understanding the (BHP) is critical in drilling operations for several reasons:

1. Safety: BHP contributes to the well's and personnel's safety by preventing blowouts, which can result in fluid loss, damage to the wellbore and formation, and even death.
2. Well control: BHP is used to maintain well control and prevent blowouts by controlling the rate of penetration (ROP) and designing the drilling fluid program. The drilling fluid is used to balance pressure in the wellbore and prevent the influx of formation fluids, which can affect BHP and well stability.
3. Drilling performance: BHP is used to assess the wellbore and surrounding formation conditions. This information is used to improve drilling performance and efficiency by optimizing drilling parameters such as bit weight, rotary speed, and fluid properties.
4. Formation evaluation: BHP is used to estimate the potential for fluid or gas production by evaluating formation pressure. This information is critical in the selection of finishing techniques and the design of manufacturing systems.
5. Reservoir management: BHP is used to track changes in reservoir pressure over time, which can provide useful data for reservoir management and production optimization.
Because ECD and BHP are important factors in the hydraulic design process, the coding for them in Python will be as follows:

```
#ECD from Power low model
ECD_Dynamic=[]
count=0
while count<=(len(tvd)-1):
    ECD_Dynamic.append((delta_p_anular/ (0.052 * tvd[count]))+MW)
    count+=1
#print('ECD_Dynamic=',ECD_Dynamic)

#calculation of bottom hole pressure
BHP_Dynamic=[]
count=0
while count<=(len(tvd)-1):
    BHP_Dynamic.append((ECD_Dynamic[count]) * 0.052 * (tvd[count]))
    count+=1
print('BHP_Dynamic=',BHP_Dynamic)
```

5.2.2 Importing PWD Data:

PWD involves measuring the pressure at the drill bit and transmitting this information to the surface in real-time. The data is then analyzed to detect any changes in pressure that may indicate a problem. This allows drilling engineers to make informed decisions and take appropriate action to address any issues that may arise.

If our model is true, then there should be 2%-7% difference between PWD data and BHP obtained from mathematical model otherwise either PWD sensor behind bit is not working properly or the created model is wrong.

Mud window:

In order to have efficient drilling process, the pressure created by mud column should be always under control of driller.

Mud window is a window which shows limitation of BHP which should be between Fracture and Pore pressures or close to Pore pressure.

Controlling BHP and keeping it in border specially in ultra-deep drilling is quite difficult which we want to achieve in this project.

In this stage of modeling we created mud window by pore and fracture pressure and draw BHP from mathematical model and PWD from sensor in order to determine their situation with respect to limits.

The coding regarding explained part above will be:

```python
#mud window
Pore_P=pf['pore_pressure'].values.tolist()
Frac_P=pf['frac_pressure'].values.tolist()



count=0
BHP_Dynamic_modified=[]
while count<=(len(tvd)-1):
    if (BHP_Dynamic[count]>(PWD[count])) :
        BHP_Dynamic_modified.append( ECD_Dynamic[count] * 0.052 *(tvd[count]))
    elif (BHP_Dynamic[count]<(PWD[count])):
        BHP_Dynamic_modified.append(ECD_Dynamic[count] * 0.052 * (tvd[count]))
    else:
       BHP_Dynamic_modified.append((ECD_Dynamic[count]) * 0.052 * (tvd[count]))
    count+=1
#print('BHP_Dynamic_modified=',BHP_Dynamic_modified)
#print('Delta_Pressure3=',Delta_Pressure3)

BHP_Dynamic_modified_ppg=[]
count=0
while count<=(len(tvd)-1):
    BHP_Dynamic_modified_ppg.append((BHP_Dynamic_modified[count]/ (0.052 * (tvd[count]))))
    count+=1
#print('BHP_Dynamic_modified_ppg=',BHP_Dynamic_modified_ppg)
```

According to calculated data we can draw our mud window:

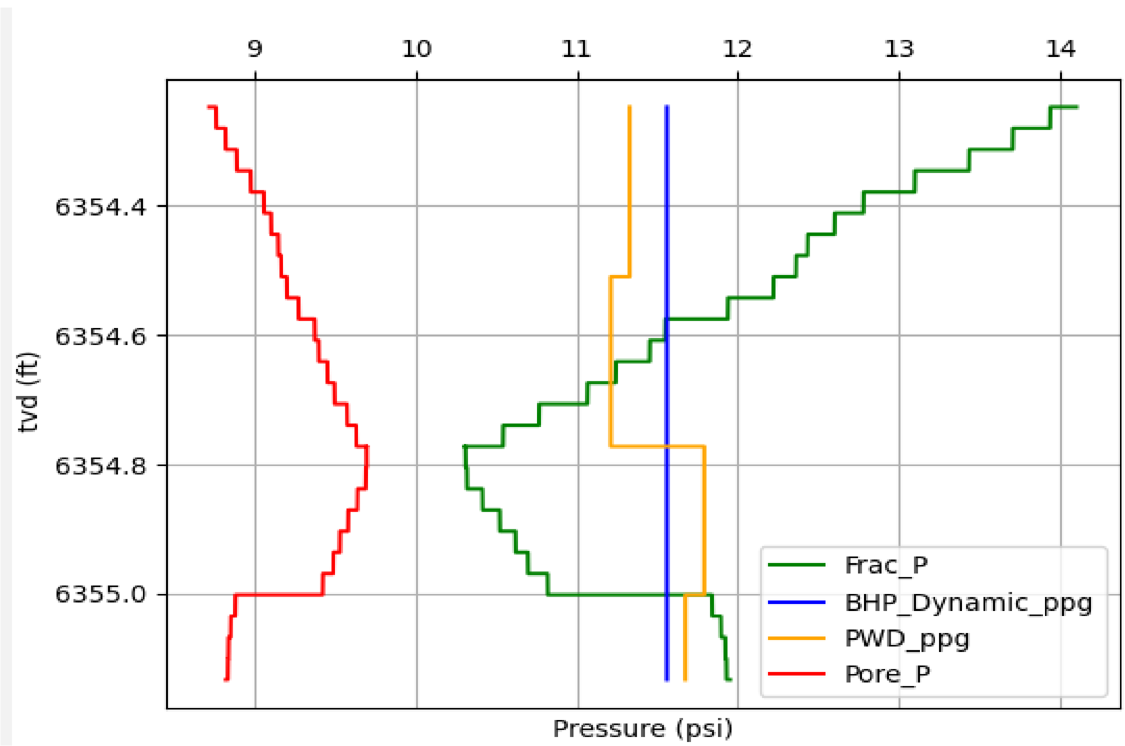


Figure 26 Dynamic BHP and PWD outside of Mud window

As we see from above graph PWD data and BHP calculated according to mathematical model are close to each other but they are out of limit. So in this case we have to play with mud level in the riser and adjust BHP with in limit.

Mud level in the riser for dynamic condition:

In order to fit Dynamic BHP in mud window I started to play with mud level in the riser as a result BHP replaced and putted in between pore and fracture pressures

Mud level in the riser represented as CML in coding and it could be reduced till 450 meter. The coding regarding this part represented below:

```
BHP_middle=[]
count=0
while count<=(len(tvd)-1):
    if BHP_Dynamic_ppg[count] >= (Frac_P[count]):
        BHP_middle.append(BHP_middle_ppg[count] * 0.052 *tvd[count])
    elif BHP_Dynamic_ppg[count]<Frac_P[count]:
        BHP_middle.append((BHP_middle_ppg[count]*0.052*tvd[count]))
    count+=1
#print('BHP_middle',BHP_middle)

CML1=[]
count=0
while count<=(len(tvd)-1):
    if BHP_Dynamic_ppg[count] >= (Frac_P[count]) or BHP_Dynamic_ppg[count] <= (Pore_P[count]):
       CML1.append (tvd[count]-((BHP_middle[count])/((delta_p_anular/tvd[count])+(0.052*MW))))
    elif BHP_Dynamic_ppg[count] < (Frac_P[count]) or BHP_Dynamic_ppg[count] > (Pore_P[count]):
        CML1.append(0)
    count+=1
print('CML1=',CML1)
```

Firstly, BHP in middle is introduced. BHP middle is a desired pressure that we want to obtain in this project. The next step was introduction of CML which represents mud level in the riser.

According to this obtained parameters now is the time to calculated BHP in dynamic condition in desire location.

Note: As it is mentioned above, all units are field units here but in mud window unit is [ppg] so after obtaining pressure we do also unit change.

The coding will be accordingly:

```
count=0
BHP_Dynamic_2=[]
while count<=(len(tvd)-1):
    if BHP_Dynamic_ppg[count] >= (Frac_P[count]) or BHP_Dynamic_ppg[count] <= (Pore_P[count]):
        BHP_Dynamic_2.append( BHP_middle_ppg[count] * 0.052 *(tvd[count]-CML1[count]))
    elif BHP_Dynamic_ppg[count] < (Frac_P[count]) or BHP_Dynamic_ppg[count] > (Pore_P[count]):
        BHP_Dynamic_2.append((BHP_middle_ppg[count]) * 0.052 * (tvd[count]-CML1[count]))
    count+=1
print('BHP_dynamic_2=',BHP_Dynamic_2)

BHP_Dynamic_ppg2=[]
count=0
while count<=(len(tvd)-1):
    BHP_Dynamic_ppg2.append((BHP_Dynamic_2[count] / (0.052 * (tvd[count]-CML1[count]))))
    count+=1
print('BHP_Dynamic_ppg2=',BHP_Dynamic_ppg2)
```

As a result, we were successful to locate BHP Dynamic in between to pressure limits. The graph obtained from python coding is:

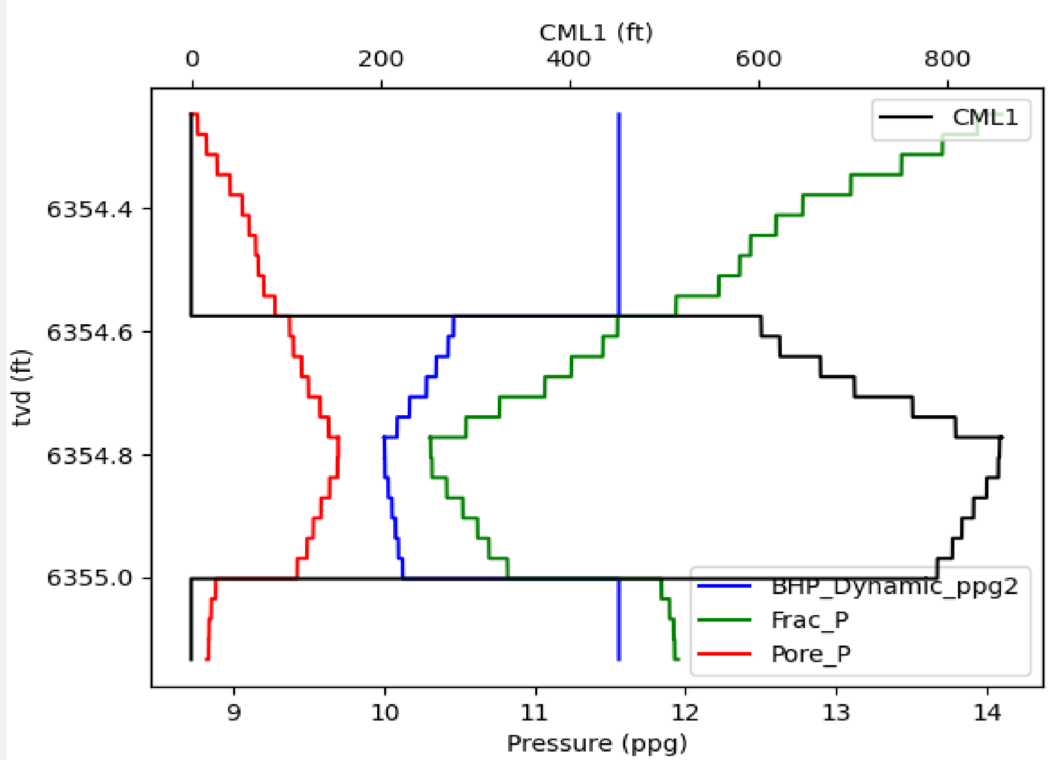


Figure 27 fitting dynamic BHP inside mud window by adjusting mud level

The black and blue lines respectively represent CML mud level and Dynamic BHP.

As we see till somewhere as pressure is inside limit so CML level is Zero but the where that pressure cross limit, CML start to increase from zero depth and push pressure back to inside limit. This process will continue until pressure is out of limit. Finally, after putting all pressure within limit, CML will come back to zero depth.

Mud level in the riser for dynamic condition:

Now is the time to fit static BHP inside mud window, between pore and fracture pressures. In static condition there is no circulation, due to not having circulation ECD is negligible so BHP is function of MW not ECD.As a result static BHP< dynamic BHP and mud level in the riser in static condition is lower than dynamic condition

The graph regarding fitting static BHP in mud window will be same as above and coding regarding static BHP calculations and mud level in the riser is depicted below:

```
CML2=[]
count=0
while count<=(len(tvd)-1):
    if CML1[count]>0:
        CML2.append((tvd[count] - (BHP_middle[count] / (0.052 * MW))))
    elif CML1[count]==0:
        CML2.append(0)
    count+=1
print('CML2=',CML2)


ECD_new_3=[MW]*4200
BHP_connection=[]
count=0
while count<=(len(tvd)-1):
        BHP_connection.append(ECD_new_3[count]*0.052*(tvd[count]-CML2[count]))
        count+=1
print('BHP_connection=',BHP_connection)

BHP_connection_ppg=[]
count=0
while count<=(len(tvd)-1):
    BHP_connection_ppg.append((BHP_connection[count] / (0.052 * (tvd[count] ))))
    count+=1
print('BHP_connection_ppg',BHP_connection_ppg)
```

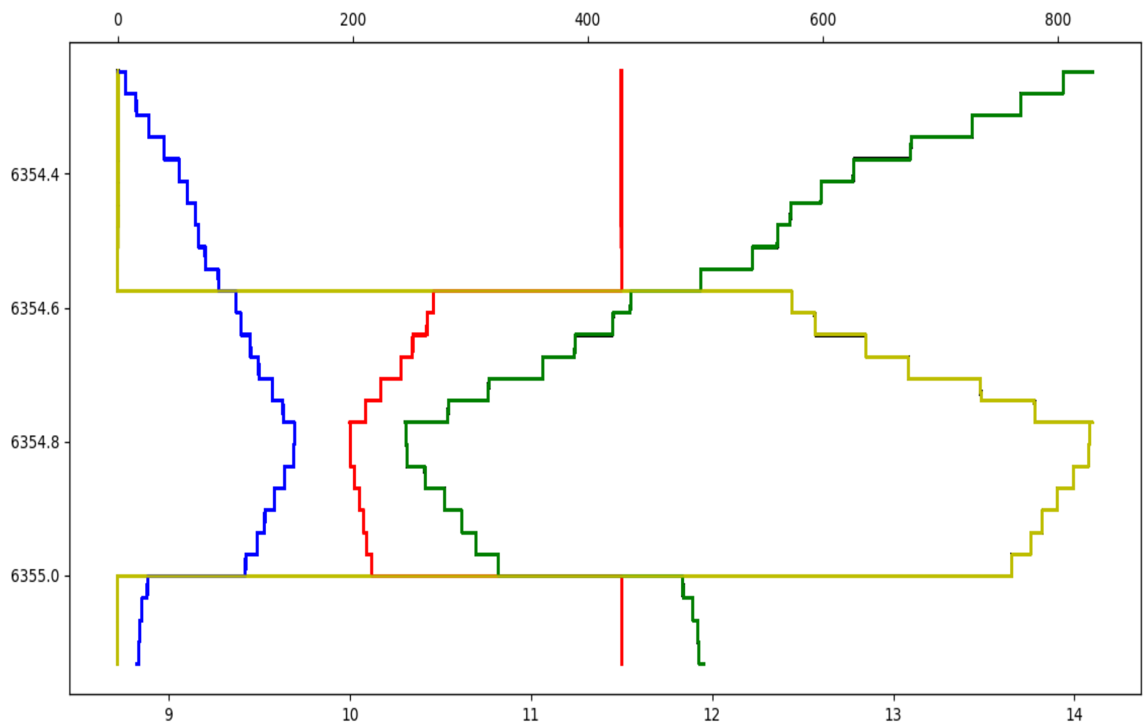


Figure 28 Fitting static BHP inside mud window by adjusting mud level

In figure-28 Orange and red lines depicted respectively mud level in the riser and static BHP.

As it is obvious from above graph till BHP is inside limit, mud level in the riser is zero but then when pressure goes out of limit, CML is activated and mud level is increases in riser and adjust BHP. As I mentioned above the mud level here will be a bit lower than mud level in dynamic condition because BHP static< BHP dynamic so less effort is required to adjust pressure in static condition.

5.2.3 Deviated well:

A deviated well is an oil or gas well that is drilled at an angle as opposed to straight down. This technique is frequently used to reach reservoirs that are inaccessible via vertical drilling. To follow the desired path, the wellbore is steered in a controlled manner using specialized drilling equipment. Deviated wells can boost a well's productivity and allow it to access multiple reservoirs from a single drilling location.

Drilling a deviated well also necessitates careful planning in order to keep the wellbore within the target zone and avoid geological hazards. This could include analyzing drilling cuttings and other tools to assess the properties of the rock formations being drilled, as well as using 3D seismic data to determine the location and structure of the reservoir.

Furthermore, deviated wells frequently necessitate more casing strings and more complex cementing jobs in order to maintain wellbore integrity and prevent fluid and gas migration. Overall, drilling a deviated well is more difficult and expensive than drilling a vertical well, but the potential benefits of increased production and access to difficult-to-reach reservoirs can make it a worthwhile investment for oil and gas companies.

Directional Calculations:

Deviated wells are distinguished by a number of parameters, including the following:

1. Inclination angle: The angle that the wellbore deviates from the vertical axis. Deviated wells can range in inclination angle from a few degrees to nearly horizontal.
2. Azimuth angle: The compass direction from which the wellbore deviates. It is measured in degrees from North and is used to control the wellbore's direction.
3. Total vertical depth (TVD): The depth from the surface at which the wellbore intersects the vertical axis.
4. Measured depth (MD): The total length of the wellbore from the surface. MD denotes the actual distance drilled, including any deviations from vertical.
5. True vertical depth (TVD): This is the vertical depth of the wellbore measured from a reference point, usually sea level or the drilling platform. TVD considers the

wellbore's inclination and azimuth angles and is used to calculate critical parameters such as pressure and temperature.

In this section MD, Inclination and Azimuth are the inputs of system which are imported from Excel to Python and will let the system to calculate following parameters:

1. TVD
2. North, South directions
3. East, West directions
4. Vertical section drift
5. Closure drift
6. Dogleg

The coding regarding Directional calculations will be the following:

```
MD=pf['MD'].values.tolist()
section_Azimuth=200
Azimuth=pf['Azimuth'].values.tolist()
inclination=pf['inclination'].values.tolist()


import math

RTE=180/(math.pi)

D=[]
count=1
while count<=(len(MD)):
    D.append(inclination[count-1] / (RTE))
    count+=1
print('D=',D)

E=[]
count=1
while count<=(len(MD)):
    E.append(Azimuth[count-1]/(RTE))
    count+=1
print('E=',E)
```

It is obvious that TVD in vertical section will be different from TVD in directional wells. In general, TVD (Total Vertical Depth) is usually greater in directional wells than in vertical wells. This is because directional wells are drilled at an angle and can extend much farther horizontally than vertically, whereas vertical wells go straight down. As a result, the TVD in a directional well may include both the vertical and horizontal components of the wellbore, making it greater than the TVD in a vertical well.

```
F=[]
count=0
while count<=(len(MD)-1):
    if count==0:
        F.append(0)
    elif count>0:
        F.append(math.acos(math.cos(D[count])*math.cos(D[count-1])+math.sin(D[count-1])*math.sin(D[count])*math.c
    count+=1
print('F=',F)

G=[]
count=1
while count<=(len(MD)):
    if (F[count-1]/(2))==0:
        G.append(1)
    else:
        G.append(math.tan(F[count-1]/2)/(F[count-1]/2))
    count+=1

print('G=',G)
```

```
T_V_D=[]
count=0
while count<=(len(MD)-1):
    if count==0:
        T_V_D.append(0)
    elif count>0:
        T_V_D.append((((MD[count]-MD[count-1])/2)*(math.cos(D[count-1])+math.cos(D[count]))*G[count]+T_V_D[coun
    count+=1
print('T_V_D=',T_V_D)
```

After TVD parameter is the time to calculate North-South and East- West directions in directional wells.

North-South (NS) parameter: The angle of deviation of the wellbore from the North-South axis is represented by this parameter. It is expressed in degrees and can be positive or negative depending on whether the wellbore is deviating east or west of the North-South axis.

The East-West (EW) parameter represents the wellbore's angle of deviation from the East-West axis. It is also expressed in degrees and can be positive or negative depending on whether the wellbore is deviating north or south of the East-West axis.

The North-South and East-West parameters describe the wellbore's orientation and direction relative to the horizontal plane. Drillers can steer the wellbore in different directions and angles by adjusting these parameters. For example, if a driller wishes to steer the wellbore to the north, they can change the North-South parameter to do so.

In directional drilling, accurate control of the North-South and East-West parameters is critical because even minor deviations from the desired path can cause the wellbore to miss the target. This can lead to the wellbore being installed in the incorrect location, which can be both costly and dangerous. As a result, meticulous monitoring and adjustment of these parameters is critical to the success of directional drilling operations.

```
North_South=[]
count =0
while count <= (len(MD)-1):
    if count==0:
        North_South.append(0)
    elif count>0:
        North_South.append(North_South[count-1]+((MD[count]-MD[count-1])/2)*((math.sin(D[count-1])*math.cos(E[cou
    count+=1
print('North_South=',North_South)

East_West=[]
count = 0
while count<=(len(MD)-1):
    if count ==0:
        East_West.append(0)
    elif count>0:
         East_West.append(East_West[count-1]+(((MD[count]-MD[count-1])/2)*(math.sin(D[count-1])*math.sin(E[count-
    count+=1
print('East_West',East_West)
```

Now is the time to calculate other important parameters of Directional wells like Closure drift, Vertical section drift and dogleg.
Here is some important information about mentioned parameters:

Closure Drift:

The tendency of the wellbore to deviate from its intended path due to pressure imbalances in the formation being drilled is referred to as closure drift. Closure drift happens when the pressure on one side of the wellbore rises above the pressure on the other, causing the wellbore to curve or "drift" towards the lower pressure side.
Closure drift is important to understand in deviated wells because it can have a significant impact on drilling efficiency and safety. If the wellbore deviates too far from its intended path, reaching the target may become difficult, if not impossible. Furthermore, closure drift can increase the risk of wellbore instability and collapse, which can be dangerous and costly.
Drilling engineers can mitigate the effects of closure drift by adjusting the drilling mud weight or using specialized tools to steer the wellbore in the desired direction. Accurately monitoring closure drift and making necessary adjustments can help keep the wellbore on track and drilling operations safe and efficient.

Vertical-section Drift:

The deviation of the wellbore from its planned trajectory in the vertical direction is referred to as vertical section drift in deviated wells. It is a measure of the deviation from the wellbore's vertical section, which is typically designed to achieve a specific goal, such as reaching a specific formation or avoiding a specific hazard.
Vertical section drift is an important parameter to monitor in drilling because it can affect the accuracy and efficiency of many drilling operations, including wellbore placement, cementing, and logging. If the wellbore deviates too far from its intended path, the risk of wellbore instability, stuck pipe, and other drilling hazards increases.
The type of formation being drilled, the drilling equipment used, the drilling fluids, and the drilling parameters are all factors that can contribute to vertical section drift in

deviated wells. Drilling engineers can reduce the amount of vertical section drift and improve the overall efficiency and safety of the drilling operation by monitoring and controlling these factors.

Dogleg:

A dogleg is a change in wellbore trajectory, usually a sudden change in direction, that results in a curved wellbore in drilling. This is important in deviated wells, which are drilled at an angle from vertical to reach a specific target zone.

The amount of curvature in the wellbore is measured as dogleg severity (DLS), which is an important parameter to monitor during drilling. The severity of the dogleg can have an impact on drilling efficiency and cause increased wear and tear on drilling equipment, resulting in higher costs and potential safety hazards. A wellbore with a high degree of curvature increases the risk of drilling problems such as stuck pipe, lost circulation, and wellbore instability.

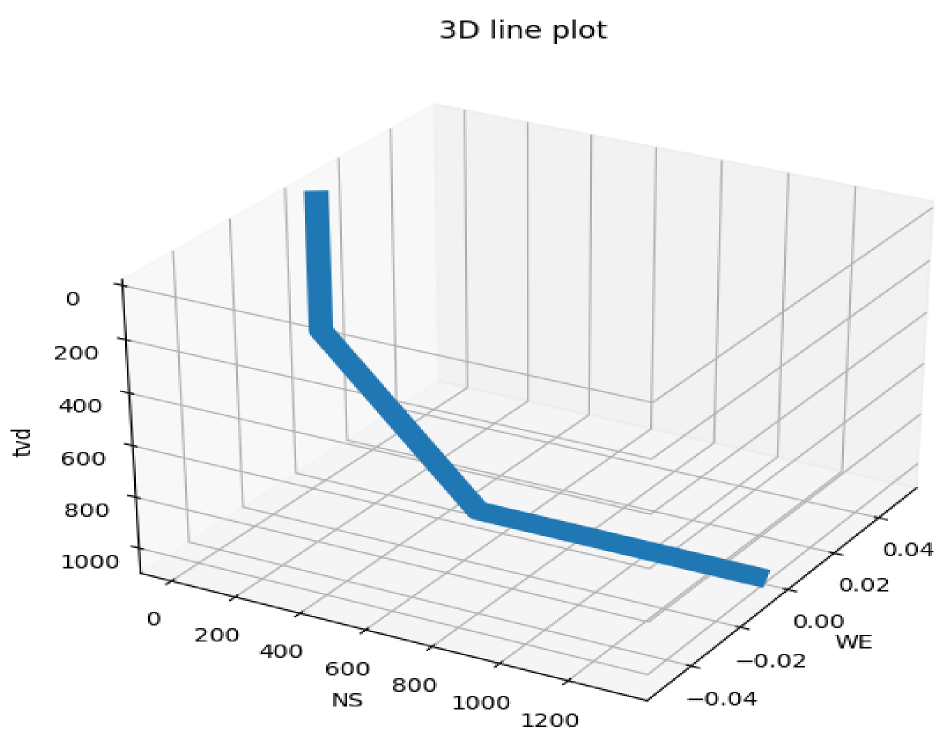
```
closure_drift=[]
count=0
while count<=(len(MD)-1):
    closure_drift.append(math.sqrt((East_West[count]**2)+(North_South[count]**2)))
    count+=1
print('closure_drift',closure_drift)

Dir=[]
count=0
while count<=(len(MD)-1):
    if North_South[count]==0 and East_West[count]==0:
        Dir.append(0)
    elif North_South[count]>0:
        if East_West[count]>0:
            Dir.append(math.atan(East_West[count]/North_South[count])*RTE)
        else:
            Dir.append(360+math.atan(East_West[count]/North_South[count])*RTE)
    else:
        Dir.append(180+math.atan(East_West[count]/North_South[count])*RTE)
    count+=1
print('Dir=',Dir)
```

```
Vertical_section_drift=[]
count=0
while count<=(len(MD)-1):
    Vertical_section_drift.append((closure_drift[count])*math.cos((section_Azimuth-Dir[count])/(RTE)))
    count+=1
print('Vertical_section_drift',Vertical_section_drift)


dogleg=[]
count=0
while  count<=(len(MD)-1):
    if count==0:
        dogleg.append(0)
    elif count>0:
        dogleg.append((math.acos((math.sin(inclination[count-1]/(57.3))*math.sin(inclination[count]/(57.3))*math.
    count+=1
print('dogleg',dogleg)
```

By calculating all important parameters, we can have a 3D view of deviated well as below:



CONCLUSION

The aim of project was to make a fully automated system with coding which it works without human intervention. The plan was to enter inputs to the system, let it work efficiently and return required outputs.

Advantage of system:

Coding was built according to various assumptions, in a simplified version but it works successfully, without any interruptions and error. Consequently, with considered assumptions, fully automated system can be applied for deep water and ultra-deep water drilling.

The coding and system that has been made in this thesis is quite important project which prestigious petroleum companies specially in Norway currently are working on it.

Some of important advantages are mentioned below:

1. **Improved drilling efficiency:** In traditional drilling operations, maintaining a consistent mud level in the wellbore can be challenging and often requires manual intervention. This can result in non-productive time (NPT) when the drilling process is interrupted to adjust the mud level. With a CML system, the mud level can be automatically maintained within a narrow window, minimizing the need for manual intervention and reducing NPT. This can lead to improved drilling efficiency and lower drilling costs.
2. **Increased safety:** Automated drilling systems can help minimize human error and improve safety by reducing the need for manual intervention during drilling operations. In addition, the use of a wired drilling pipe can provide real-time monitoring of drilling parameters and early detection of potential problems, allowing operators to take corrective action before accidents occur.
3. **Enhanced wellbore stability:** The CML system can help stabilize the wellbore by maintaining a consistent mud level. This can reduce the risk of formation damage or instability, which can result in costly delays or even the abandonment of the well.

4. **Improved accuracy and precision:** Automated systems can provide highly accurate and precise control of drilling parameters, leading to more consistent and predictable drilling performance. This can result in improved wellbore quality, faster drilling times, and lower costs.
5. **Increased data collection and analysis:** Automated drilling systems can collect and analyze a wealth of data in real-time, allowing operators to make informed decisions and optimize drilling performance based on actual conditions. This can help identify potential problems before they occur, reduce NPT, and improve overall drilling efficiency.
6. **Reduced environmental impact:** Automated drilling systems can help reduce the environmental impact of drilling operations by minimizing the amount of drilling fluid needed and reducing the risk of spills or leaks. In addition, the use of wired drilling pipes can reduce the need for heavy equipment and reduce the overall footprint of drilling operations.

Regarding the assumptions listed in the question (fixed diameter, constant viscosity, not considering temperature and cutting concentrations), it's important to note that these factors can impact the performance and accuracy of the automated drilling system. For example, changes in mud viscosity or temperature can affect the system's ability to maintain a consistent mud level. However, even with these limitations, a fully automated drilling system with a CML system can still provide significant benefits over traditional drilling methods.

Disadvantage of system:

As it is mentioned above, model was made according to various assumptions that are following:

- Temperature is constant within well
- the well is vertical
- Viscosity is constant
- fix diameter

In order to avoid complexity, various assumptions were made while creating a mathematical model. As if mathematical model doesn't match PWD data, in this case assumptions are wrong and should be removed which will make a complex system.
As an example while making a model, cutting concentration and friction factor in different rocks was not considered, but also pressure loss calculations only done for case and open hole sections, excluding riser and joints
Thus disadvantage of the system could be regarding mismatching between real and mathematical models due to assumption.

1. **Limited Applicability**: This system may not be suitable for drilling in all types of formations or wells. Different formations have varying properties that affect the drilling process, including changes in mud weight, viscosity, and temperature. Ignoring these variables may lead to inefficient drilling or even operational failures.

2. **Inaccurate Data:** Ignoring temperature effects can lead to inaccurate measurements and data, which can impact the system's ability to control the drilling process effectively. Temperature changes affect the mud properties, which in turn affect the pressure, flow, and other drilling parameters. Without accurate temperature data, the system may not be able to make precise adjustments to maintain constant BHP.

3. **Limited Flexibility**: The constant viscosity assumption can limit the system's flexibility and adaptability. In reality, the mud viscosity changes over time as it interacts with the formation and drill cuttings, which can affect the pressure drop and the drilling process. Ignoring these changes can limit the system's ability to adapt and respond to changing drilling conditions.

4. **Increased Risk of Accidents**: The lack of flexibility in the system's design can increase the risk of accidents. For example, a sudden increase in formation pressure or the occurrence of a stuck pipe may cause the system to lose control of the bottom hole pressure, leading to a blowout or other operational failure.

Overall, while a fully automated drilling system with a CML system along wired drill pipe can provide benefits in terms of increased efficiency and reduced human error, the assumptions made in its design may limit its applicability and control over drilling parameters, which could ultimately result in operational failures or increased costs.

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