POLITECNICO DI TORINO
Department of Environment Land and Infrastructure
Master of Science in Petroleum Engineering

Master Thesis
Using Continuous Circulation Technology to Improve Drilling Efficiency and Mitigate Downhole Problems

By

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ABSTRACT

Since drilling of the first oil well over a century ago, fluid circulation must be stopped every time drill pipe connection. Circulation stopping represents one of the main reasons for typical drilling problems related to wellbore pressure. A continuous circulation technology is an innovative drilling method used to maintain the circulation of drilling fluid into the well during making and breaking drill pipe connections. The system contains a manifold connected to drill string that enables safe diversion, and subs installed at the top of each drill pipe stand, providing two independent flows. It can optimize drilling operations and overcome wellbore issues caused by the interruption of circulation fluid.

This thesis highlights the importance of continuous circulation technology by investigating wellbore issues caused by interruptions of circulation. It showed the advantages of utilizing this technology to improve overall drilling performances in terms of enhanced well control and safety, mitigating downhole drilling problems, minimizing annular pressure fluctuations, quality of drilling, saving rig time and reducing drilling operations cost, and improving well production. Potential applications of this technology are also presented, particularly in challenging drilling environments with narrow drilling windows, depleted formations, deep water wells, extended reach drilling, and high-pressure high-temperature wells. Furthermore, it presents the proposed solutions to mitigate downhole problems in the X- oil field, Iraq, by utilizing the continuous circulation method.

The simulations were created based on developing MATLAB codes to make hydraulic calculations and report the wellbore pressure changes that induced by the movement of the drill string for conventional drilling method and continuous circulation system (CCS). The simulation was further implemented for the drill pipe connections scenario to calculate the frictional pressure loss and required pressure to break the gel strength. Moreover, an annular pressure window was simulated for making a comparison between conventional drilling and CCS methods. Results show that downhole pressure variations are significantly reduced, and drilling operations are required a smaller pressure window when using CCS.

Acknowledgment

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Dedication

I dedicate my thesis work to our guide and leader; Imam Al-Mahdi (a), the Awaited Saviour.

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List of Abbreviations

Abbreviations	Meaning
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blow-out Preventer
CCS	Continuous Circulation System
CFS	Continuous Flow System
DGD	Dual Gradient Drilling
DSV	Drillstring Valve
E-CD^{TM}	Eni Circulation Device
ECD	Equivalent Circulation Density
EMW	Equivalent Mud Weight
ERD	Extended Reach Drilling
ESD	Equivalent Static Density
FG	Fracture Gradient
FPL	Friction Pressure Loss
HMI	Human-Machine Interface
HPHT	High-Pressure High-Temperature
IADC	International Association of Drilling Contractors
IBOP	Inside Blow-out Preventers
KCL	Potassium Chloride
LWD	Logging While Drilling
MAASP	Maximum Allowable Annular Surface Pressure
MPD	Managed Pressure Drilling
MW	Mud Weight
MWD	Measurement While Drilling
NPT	Non-Productive Time
NSD	Nonstop Driller
OBD	Overbalance Drilling
POOH	Pull Out of hole
PP	Pore Pressure
PV	Plastic Viscosity
ROP	Rate Of Penetration
SG	Specific Gravity
UBD	Under Balanced Drilling
YP	Yield Point

Chapter 1

Introduction

1.1 Introduction

In conventional drilling operations, a pump usually circulates drilling mud through the top drive and down the pipe string to the drill bit. Continued pumping thru the top drive moves the drilling fluid at the bottom of the wellbore and returns to the surface throughout the annular space between the wellbore wall and the drill string carrying cuttings out of the wellbore. The circulating drilling mud prevents influxes of formation fluids by balancing the pressures exerted of the rock formations, maintaining wellbore stability, cooling and lubricating the bit, gathering data on rocks and formation fluids, and transmitting hydraulic horsepower to the bit.

Continued drilling further draws the pipe string into the wellbore, ultimately requiring another drill pipe stand to the drill string. The circulation of drilling fluid into the well has to be stopped while a new joint or drill pipe stand was added to the drill string. This interruption of circulation conventionally means that the circulation of the mud ceases and has to be restarted when the drilling is resumed, which leads to a pressure spike. When the circulation of drilling mud stops, the pressure inside the wellbore can significantly decrease. This reduction in pressure will trigger formation fluids influx to the wellbore or allow the formation to be swelling cause sections of the wellbore to cave in. Moreover, the drill string can be stuck due to differential sticking (when the wellbore pressure is higher than formation pressure) or insufficient wellbore cleaning from drill cuttings when circulation is stopped, especially in deviated and horizontal sections of the wellbore. A stuck pipe string causes severe problems for the drilling operation that must be overcome at a great expense of time and money. Besides, when the pumps are switched off, the drilling fluid begins forming a gel as the mud circulating is stopped. Once the pumps are restarted, the pressure rises rapidly to break the gel, resulting in a pressure spike that can cause loss of circulation within weak formations, where fluids invade the formation or wellbore ballooning. The rig has downtime associated with circulating the cuttings out of the hole before a connection is made. This is needed to prevent the cuttings from settling at the bottom-hole assembly and have deleterious effects on the well-being of drilled walls and can cause issues in maintaining the well open. Furthermore, the mud weight is conventionally chosen to provide a static head pressure equivalent to the formation pressure at the top of the drill string while it is open when adding or removing tubular. The overweighting of the mud can cause loss of circulation in fractured formations.

Narrow-margin deep-water wells, extended reach drilling wells, depleted formations, high-pressure high-temperature wells (HPHT), narrow gradient windows, and salt formations environments are all exposed to drilling hazards due to fluctuation wellbore pressure with conventional drilling. Mitigating these hazards with conventional methods might result in huge non-productive time (NPT) and increase the cost of the drilling project to become uneconomical.

According to above mentioned reasons, it is reasonable to consider mud circulation as the "heart of drilling operations" at all times, and as a consequence, it should ideally never stop during drilling operations. One of the solutions offered is utilizing continuous circulation technology in drilling wells. The main objective of continuous circulation technology is to manage bottom hole pressure to achieve conditions where downhole problems are prevented or mitigated. Continuous circulation technology offers a direct solution in drilling the well to the targeted depth efficiently and safely by maintaining the continuous circulation of drilling fluid through the drill string during drill pipe connections and tripping operations.

1.2 Downhole Annular Pressure

In conventional drilling, the annular pressure is mainly controlled by three components; static pressure, dynamic pressure, and pressure due to restriction of hydraulic system.

1- The first component is a static head pressure due to the fluid density gradients in the borehole annulus. The mud column density includes drilled cuttings is called equivalent static density (ESD).

2- The Second is dynamic head pressure related to movement of the drill string, annular friction pressure loss (FPL) required for moving drilling fluid up the annulus, and break gel strength. When fluid flow encounters constrictions such as swelling formation or cutting beds, formation fluids flow into the borehole or losses drilling fluid and change in hole geometry all contribute to the dynamic pressure.

   When circulation is stopped for a drill pipe connection (stable conditions with no pipe movement), the downhole pressure represents only the static head component (Ayling et al. 2002). Figure 1.1 illustrates how bottom hole pressure changes depending on whether the system is static or dynamic.

3- The third component is due to the restriction in drilling hydraulic system when hole becomes pack-off due to excessive caving or cuttings.

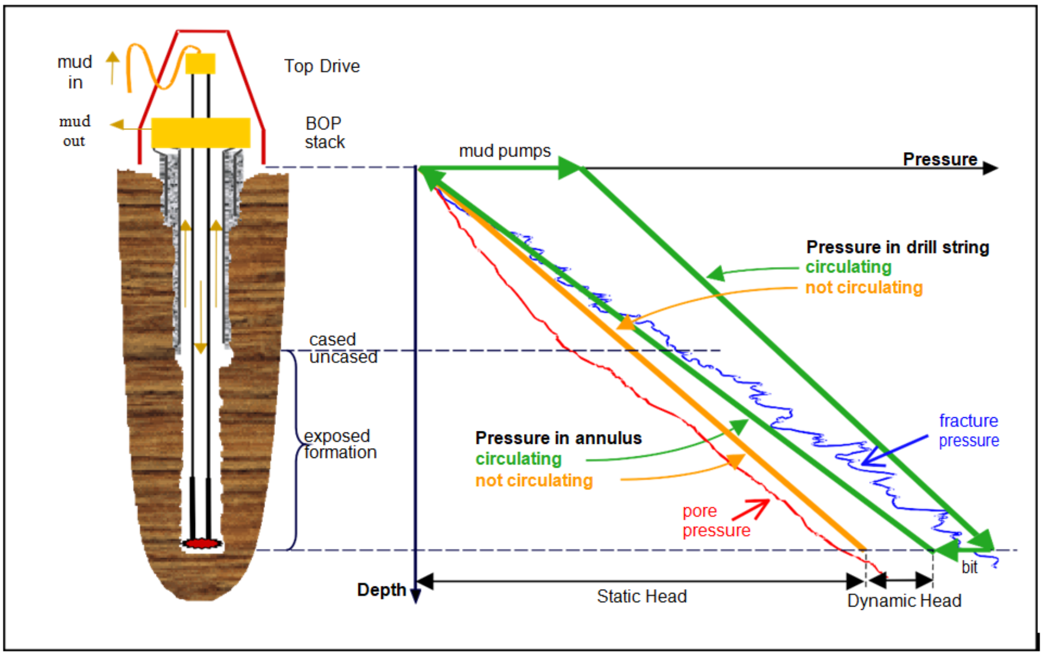

Figure 1.1 BHP in Conventional Drilling (Ayling et al. 2002)

1.3 Brief Introduction on Continuous Circulation Technology

Continuous circulation technology is one of the new drilling technologies used to drill wells, which might be challenging to drill using traditional drilling techniques due to depleted reservoir, high pressure-high temperature wells, and narrow pore pressure fracture gradient windows and other drilling issues. Continuous circulation technology has a very wide range of applications in the drilling industry.

1.4 Mud Window

The pressure limits for wellbore stability determine the mud weight window during the drilling operations, as shown in (figure 1.2). On the lower limit, the wellbore pressure is constrained either by the pore pressure PP or by the formation collapse pressure. In the normal burial trends, the formation under hydrostatic pressure, where the pore pressure is equivalent to that of a water column at the same depth. If the wellbore pressure is less than the pore pressure, then formation fluid could flow into the wellbore, with the subsequent risk of a blowout at the surface or underground. On the upper limit, the wellbore pressure is bounded by the formation fracture pressure (usually called the formation fracture gradient FG). If the wellbore pressure exceeds this pressure, there is a risk of creating or opening fractures, resulting in a lost circulation and formation damage.

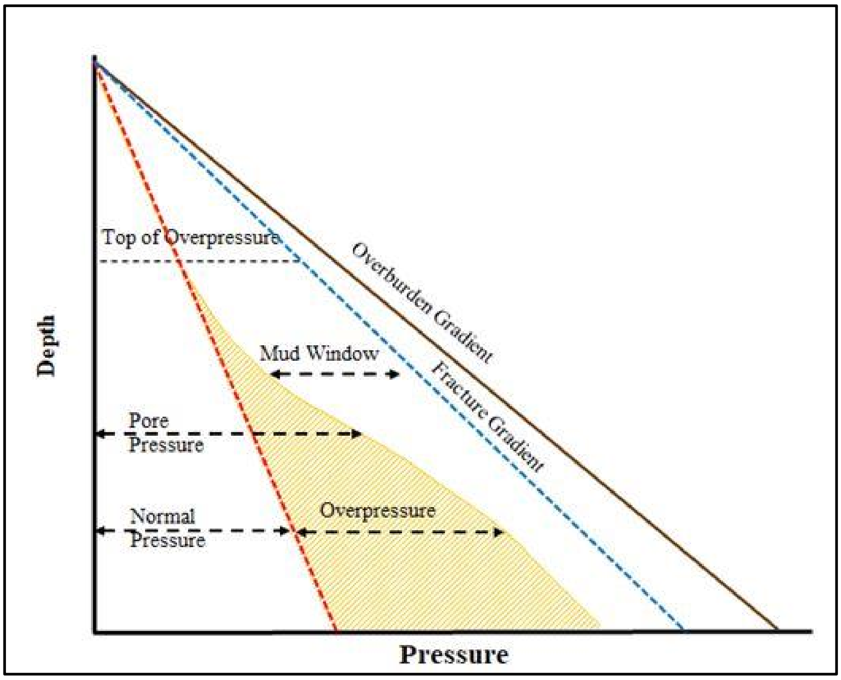

Figure 1.2 The mud weight window, figure was adapted

Normal pressure is the equivalent pressure of a column of water from the surface to depth.

Abnormal pressure is any pressure greater than normal pressure.

Pore Pressure (pp) is the pressure exerted by the fluid within the pores of a formation.

Overpressure is the difference between normal and abnormal pressure.

Overburden pressure is the pressure exerted by the overlying sediments and fluid.

The top of overpressure is the point at which the pore pressure first becomes greater than the normal formation pressure.

1.5 Parameters Affecting Wellbore Pressure

1.5.1 Equivalent Mud Weight (EMW)

In any drilling operation, the most commonly controlled parameter is the fluid density circulating through the wellbore. The definitions of equivalent mud weight (EMW), equivalent circulating density (ECD), and most recently equivalent static density (ESD) are important to understand. At any point, the ECD represents the effective mud weight created by the total hydrostatic pressure (mud column including the drill cuttings) and frictional pressure loss above that point.

1.5.2 Rheology Properties

Drilling fluid rheological properties play a significant role in wellbore pressure control. Most drilling fluids have a none zero yield point (YP). Yield Point is defined as the shear stress at zero shear rate. Gel strength is a thixotropic mud property which necessary to prevent drilled cuttings from dropping out of suspension when mud circulation is stopped. When fluid flow is started, there is a sudden increase in wellbore pressure above normal circulation pressure. This increase is occurred due to gelling property of drilling fluid. Moving the pipe up or down also causes fluctuations of pressure, regardless of pipe speed. These variations in pressure have to be taken into account during connection and tripping (Tian et al. 2007).

In terms of hydraulics, the main difference between YP and gel strength is that gel strength will not occur until the fluid moves and the gel has been broken, whereas the YP effect will not disappear unless the fluid ceases. Figure 1.3 indicates the pump pressure at the start of the pumping due to gel force and YP. As shown by the right plot in figure 1.3, at the beginning of the pumping, the pressure surge generated by the gel strength disappears rapidly. In contrast, surge pressure is not occurred by YP (figure 1.3 left plot).

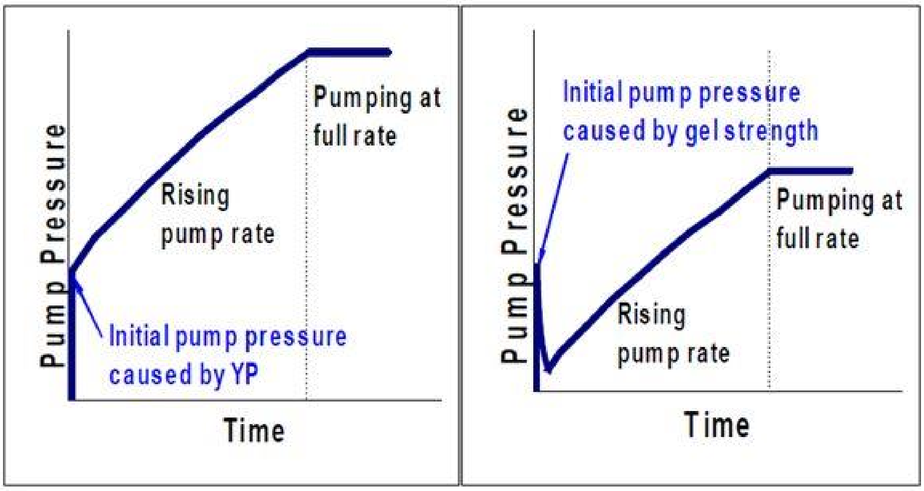

Figure 1.3 Effect of YP and Gel Strength on Circulation Pressure (Tian et al. 2007)

1.5.3 Wellbore Geometry

Wellbore trajectory, hole size, and drill string configuration, have an effect on hydrodynamic friction and hydrostatic head. The annular clearance may either increase the friction of fluid passing through the annulus or decrease it. Wellbore inclination may cause long sections to be exposed to the same hydrostatic pressure, especially horizontal drilling. In some cases, the influence of geometry could be detrimental to control the annular pressure. In other cases, the same geometry can be useful for effective control of the annular pressure. Unfortunately, the geometry is often fixed by drivers external to the drilling operation. Therefore, other parameters have to be changed to compensate for the geometry during the drilling operation.(Tian et al. 2007).

1.5.4 Circulation Rate

Drillers often lower the circulation rate to minimize ECD and consequent mud losses, but the mud weight may increase due to increasing of concentration of drilled cuttings. The drilling penetration rate must be reduced according to the rate of circulation. As the concentration of cuttings increases, the efficiency of hole cleaning decreases, and consequently, rate of penetration naturally decreases.

Inadequate circulation rate will cause issues in the cleaning of the borehole, whereas a higher circulation rate than required can result in higher frictional pressure losses, making it harder to maintain wellbore pressure along the open hole section inside the operating mud window. Figure 1.4 represents using the BHP curve for modelling the optimum circulating rate. In this case, the optimum circulating rate (about 140 GPM) is equivalent to the minimum BHP. Injecting lower than the optimum rate will cause cuttings accumulation along the wellbore annulus; this results in a higher BHP (at the left side of the BHP curve). While pumping more fluid than the optimal rate would result in a higher frictional pressure loss, it also results in a higher BHP (at the right side of the BHP curve) (Stone and Tian 2009).

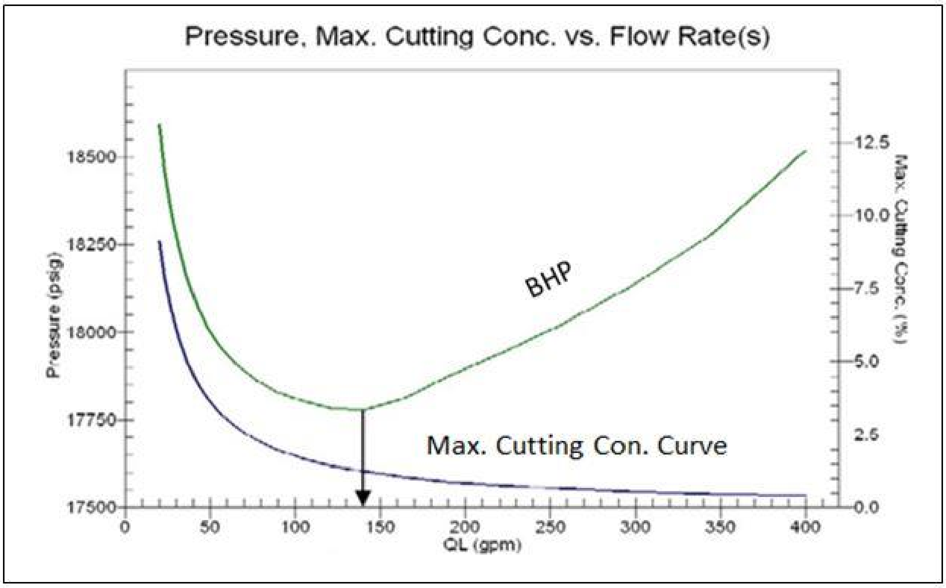

Figure 1.4 Impact of Circulating Rates on Hole Cleaning and BHP (Stone and Tian 2009)

1.5.5 Pipe Movement

Drillstring movement causes a transient pressure in the wellbore. The downward movement of the drill string increases the annular pressure below the drilling bits; as the drill string moves the drilling fluid in the annulus and induces upward flow over the drill collars at a faster velocity, which is called the "surge." On the other hand, upward movement of the pipe reduces the pressure below the bit since drilling fluid should displace past bottom hole assembly to fill the hole, called "swabbing." (Figure 1.5)

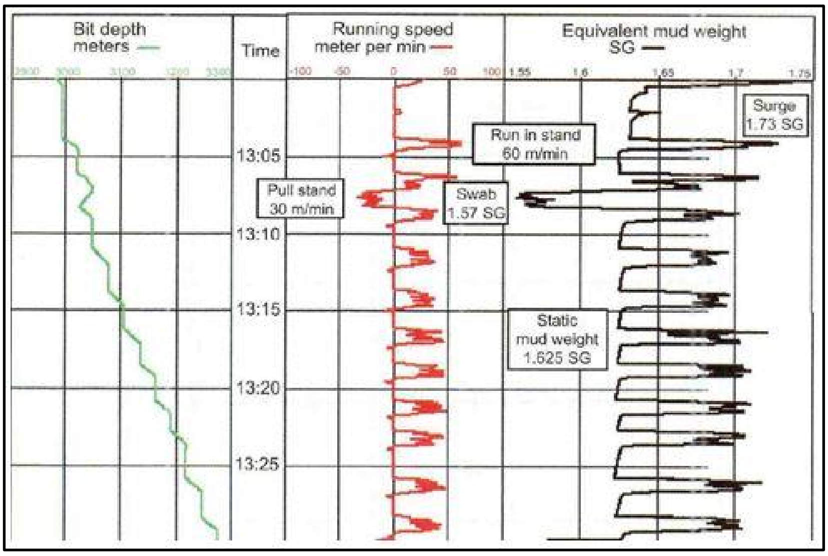

Figure 1.5 Swab and Surge pressure (Ward and Clark 1998)

1.6 Wellbore Events

In the fact that the drilling environment is not inherently simple to understand with a lot of data available if you have nothing to reference against. Many events in the downhole are sharing similar root causes. Kick and wellbore ballooning are both sharing common with regard to surface observation, such as relatively large pit gain volumes. However, resolution for each of them is achieved in a completely different way. The treatment of a wellbore ballooning impact in the same manner as a kick would possibly lead to a loss of the current borehole, if not, the ineffective treatment will cause delay in drilling operation.

When rig pumps are shut down, common drilling wellbore events such as thermal expansion, formation influxes, and U-tube effect in riser less drilling can occur and cause a change in downhole parameters, particularly equivalent circulating density (ECD). ECD is an important downhole parameter which represents the fluid behaviour in the annulus. Therefore it must be continually monitored and adjusted within a desired range. If the ECD trend deviates from the expected, this may indicate that a downhole event has occurred. Figure 1.6 shows some of downhole events occur during pumps off which cause deviate in the ECD trend.

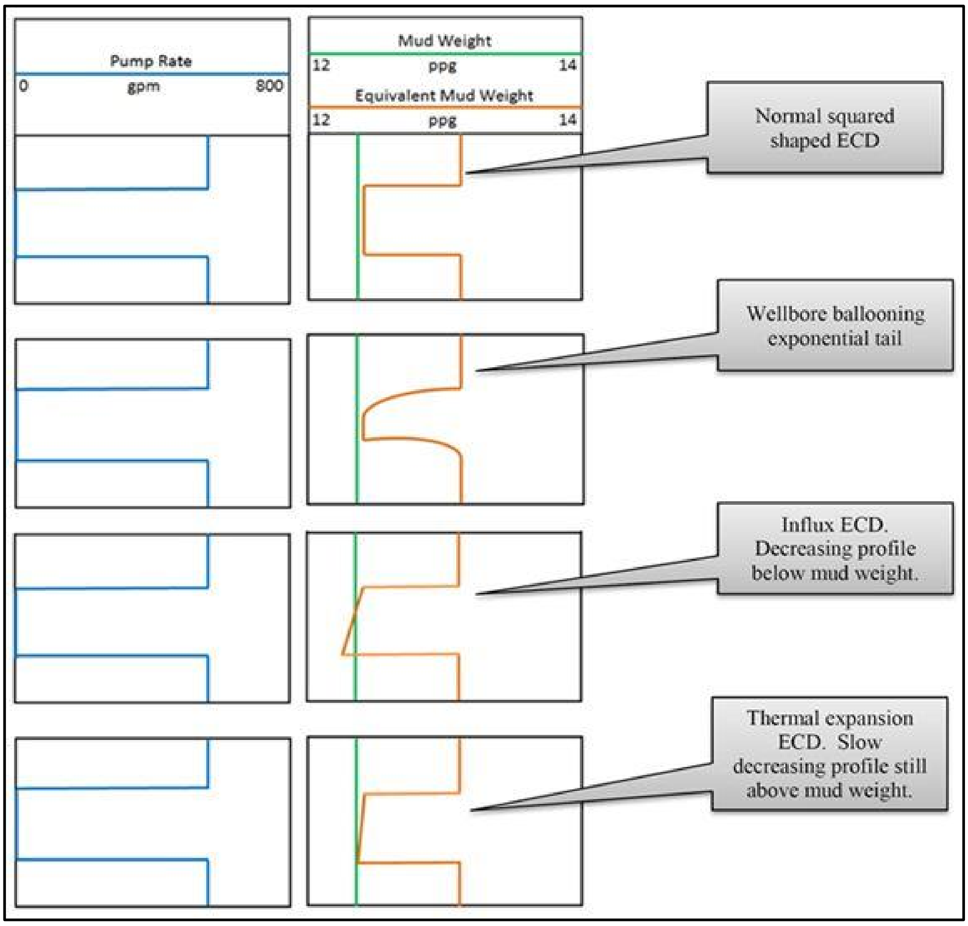

Figure 1.6 Typical ECD response during Pumps off. (Yuan et al. 2016)

The blue line shown in Figure 1.6 represents the pump rate, green line indicates the mud weight and the orange line indicates ECD at the depth of annular pressure while the drilling sensor**.** In the case of square-shaped ECD, it is indicated to the expected normal ECD. In a well ballooning situation, when the mud pumps are shut down, the ECD curve will usually adopt exponential decay. As pre-existing and drilling-induced fractures close when the annular pressure is lowered below the fracture's propagation pressure, the flow from such fractures compensates for the decrease in the ECD, resulting in a delayed stabilization in the annular downhole pressure. A lower ECD may indicate that a formation fluid influx has occurred because of the lightweight flow into the wellbore. In thermal expansion, the ECD curve can take a very similar form to the ECD kick pattern. Depending on heat attributes in the wellbore, the flow back will initially be seen at the drill pipe connections as the fluid heats up during the static condition (Yuan et al. 2016).

Chapter 2
Continuous Circulation Technology in Details

Continuous circulation drilling technology is a form of managed pressure drilling (MPD) enabling continuous circulation of the drilling fluid in the wellbore to maintain constant bottom hole pressure during making and breaking drill pipe connections (or tripping pipe) while drilling operations (R. Johnson et al. 2019), unlike conventional drilling operations, in which the circulation of the mud must be stopped while connection. Use the Continuous circulation method ensures no pressure peaks due to circulation interruptions, which increases the risk of fracturing the formation (or ballooning effects). Figure 2.1 describes changes in wellbore pressure among different phases of conventional drilling operations. During static phase, wellbore pressure is equal to mud hydrostatic pressure. When circulation is restarted, there is a sudden increase in wellbore pressure above normal circulation pressure as a result of gel braking. A positive pressure surge occurs when running the drill string inside the wellbore because the pipe behaves like a loose piston, while at tripping in operation phase, there is a temporary lowering of the hydrostatic head due to swab effect. In contrast, wellbore pressure is maintaining constant when utilizing continuous circulation technology. The main benefit is the ability to drill in conditions where a very narrow margin exists between the pore and fracture gradient. Advantages are also achieved operations to improve overall drilling performances in terms of safety increase and cost reduction, and a NPT. When using CCS, hole cleaning is improved, allowing the downhole problems section to be reduced. Maintaining circulation allows the established annular pressure regime, keeping constant drilling cycle displacement and equivalent circulation density. Preventing complex accidents caused by downhole pressure variations by means providing the uninterrupted circulation of drilling fluid into the well throughout the process of tripping and making/breaking drill pipe connections(Bardaj, Rafieefar, and Garmsiri, n.d.).

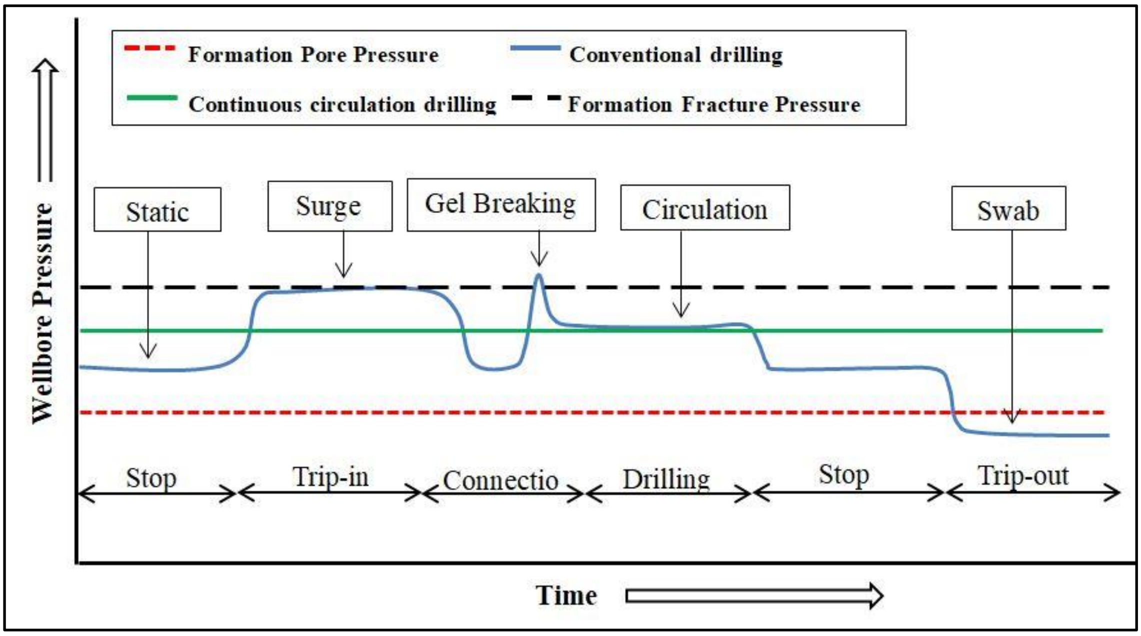

Figure 2.1 Wellbore pressure during various drilling operations, figure was adapted

2.1 IADC Definition of Continuous Circulation Method

The international association of drilling contractors (IADC) defined the continuous circulation method as “An MPD technique used to maintain flow down the drill pipe while making a connection, thereby maintaining equivalent circulating density (ECD) and thus keeping a constant pressure profile in well annulus to prevent an influx of formation fluids or potential hole collapse due to instability.”

2.2 History and Development of Continuous Circulation Method

Vail and Smith (1963) suggested the first practical idea for continuous circulation drilling a continuous air drilling- circulation sub. Their design consisted of a three-way valve in the shape of a hinged disk within a short sub with a side port. The side port was connected to the air supply line by a coupler. The hinged disk should have been in the vertical position in normal drilling mode, thereby creating an airtight seal on the side port. The hinged disc was designed to automatically switch to the horizontal position when the flow from the side port was required. It provided an airtight seal in the sub above side flow port against a seal to prevent the gas from leakage upward.

The industry seemed to lose the emphasis on continuous circulation after Vail and Smith's initial creation mentioned above and endured a long gap. in 2005, the first field trial on a continuous circulation system (CCS) presented a method to remove the pressure variations arising from starting and stopping circulation. The CCS operates by enclosing the linkage in a pressurized chamber consisting of a triple blowout preventer (BOP)—a body consisting of two pipe rams and a blind ram in the middle. Vogel et al. recorded some positive continuous circulation with the CCS (R. E. Vogel, Dunn, and Jenner 2007).

The industry was revisiting the idea proposed by Vail and Smith at the beginning of the century to establish sub-based continuous circulation. Torsvoll et al. typically dealt with a sub-based continuous circulation valve (CCV) on a kelly valve configuration . (Torsvoll, Horsrud, and Reimers 2006). The CCV contains a ball valve with a ball that can be turned 90 ° manually to cut off the drilling fluid flow from the top drive and move it to the side port. After the connection is complete, the CCV is turned manually to guide the drilling fluid to the top drive.

Calderoni et al identified the E-CD design in 2009, which is similar to Vail and Smith's idea . The E-CD is fitted with a hinged flapper in the side flow port, and a separate check valve in the sub bore. The difference in pressure at the side port between the flapper valve and the check valve in the sub indicates whether they are opened or closed. Indoor or outdoor actuator systems are not available.

In 2011, Mac Gregor et al. addressed another concept known as the Nonstop Driller (NSD) for continuous circulation. The NSD sub includes a ball valve close to a kelly valve on the side flow port and an externally mounted poppet-type valve. All of these valves are operated sequentially manually (Cunningham et al. 2014).

Another definition for continuous circulation was developed by Weir et al. (Weir, Goodwin, and Macmillan 2012). Their subset has two side ports rather than one, which can be seen in all the previously mentioned continuous circulation subsets. The ball resides in the side flow conduit built to prevent mud from flowing upward during contact. Because of differential pressure between the two ports, it is designed to pass in and out of the sub. Because it is made from a soft material, the ball has sealing properties. Cunningham discussed another design for continuous circulation referred to as a continuous flow system (CFS) (Cunningham et al. 2014). The sub of CFS has a full bore inside diameter without any constraints throughout normal drilling operation for allowing wireline operations, if necessary. The ball valve inside the CFS sub is fully covered up. The sleeve is in its bottom position in the regular drilling phase, while the ball valve is in the open position. The sleeve contains a circular side flow port at the end. There are double seals at the above and under the side port to avoid leakage of fluid to the outside and vice versa in the higher pressure event.

In 2018, Halliburton introduced an automated e-cd Plus continuous circulation system with a system that eliminates staff from the red zone around the drill pipe to improve safety and minimize operator efforts and risks while maintaining the same configuration for the e-cd circulating sub and diversion manifold. The automated continuous circulation device requires a connection tool that is mounted on a manipulator's arm; after being delivered to the drill string and clamped, a human-machine interface (HMI) will be used to automatically and remotely detach a threaded side port safety cap, attach the side port flow line and control the diversion mechanism of the manifold flow. At the HMI, the system is operated by an advanced software system that can operate autonomously, with operator verification steps. Efficiency is improved by reducing overall connection time, and the system allows for seamless integration with other equipment and real-time monitoring employing software and automation (R. Johnson et al. 2018).

2.3 Continues Circulation Drilling vs. Conventional Drilling

When drilling conventionally, the circulation of the mud is stopped before each connection is made, and the pressure of the mud in the wellbore drops rapidly. This negative pressure will generate swap or surge pressure during tripping; consequently, it may induce formation flow if mud hydrostatic pressure falls below formation pressure. When the circulation is restarted, the borehole pressure rises rapidly, usually by more than a few hundred psi, before falling to the circulating level. This surge pressure perhaps exceeds the pressure of fracture anywhere in the wellbore exposed. The exposed formation is depressed repeatedly before being "pumped up" or pressurize until normal circulation pressure is restored with each connection.

The solution is to maintain a continuous circulation of the drilling fluids during the drilling of each section to eliminate these pressure variations. This can be achieved by using continuous circulation to establish the dynamic fluid regime and maintain uninterrupted circulation while the top drive is disconnected (Jenner et al. 2004). Figure 2.2 describes a comparison of wellbore pressure profile between conventional drilling and continuous circulation method.

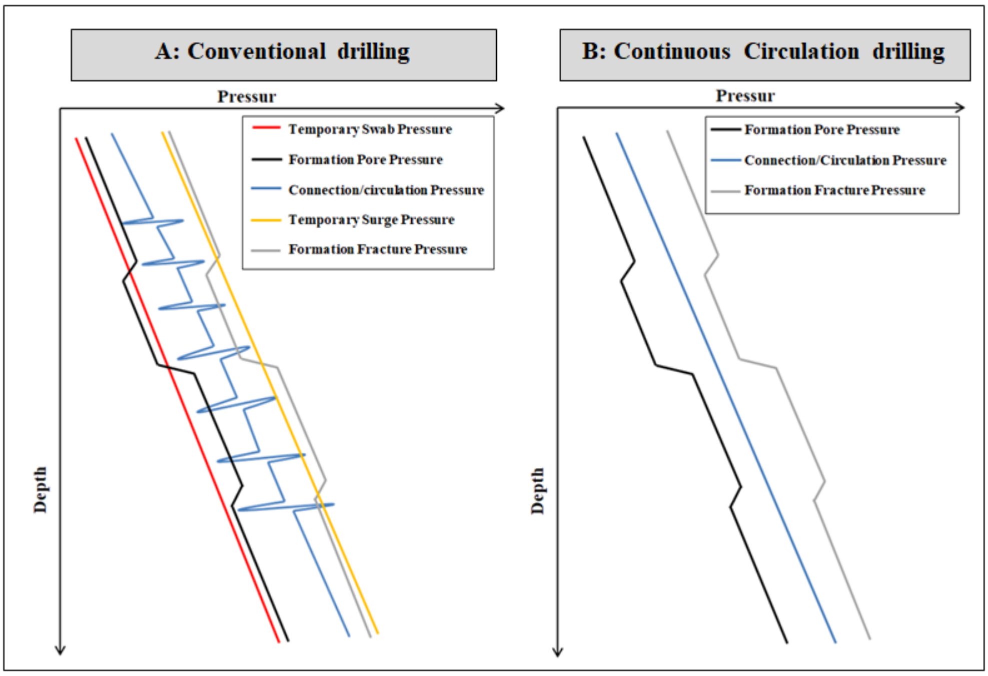

Figure 2.2 Pressure profile A: Conventional drilling, B: Continuous circulation drilling, figure was adapted.

2.4 MBD Technique VS. Continuous Circulation Drilling

MPD methods can be used to compensate for pressure loss and ECD while stopping circulation. However, MPD methods do not compensate for many of the disadvantages of interruption circulation. If a hole section has been drilled to its limit window (points **d** - **e** in figure 2.3 A), the annular pressure is already close to the fracture pressure at the last casing shoe (point **e**) and close to the formation pore pressure near the bottom (point **d**). When circulation is stopped, the static annulus pressure is lower than the dynamic pressure, so in this situation, the MPD provides pressure to compensate annular pressure losses to maintain BHP (point **d**). However, this results in more significant pressure than the circulation annulus pressure and may cause fracturing of the formation near the last casing shoe (at point **Y** in figure 2.3 B). On the other hand, if the pressure at the casing shoe is maintained constant, the pressure at the bottom (at point **Z** figure 2.3 C) will be lower than the pore pressure (Jenner et al. 2004).

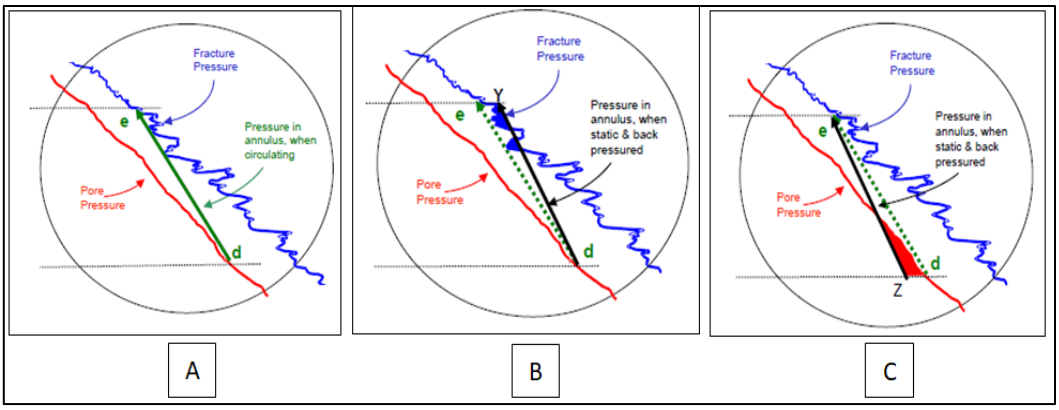

Figure 2.3 Downhole Pressure Maintenance (Jenner et al. 2004)

The benefits of continuous circulation compared to a traditional MPD technique are:

1. BHP compensation by surface annular back pressure is no longer needed during connection. Using CCS instead of MPD helps to avoid any potential errors during the transient process, where the back-pressure is increased or decreased by long and complicated procedures.
2. Connection time is decreased, as transitory phases are no longer required.

3. There are no fluctuations in the bottom hole temperature, and this allows avoiding changes in mud rheology that could be caused during the pipe connection.
4. It is possible to continue monitoring downhole parameters such as BHP and bottom hole temperature (BHT), gas data during pipe connections.
5. A kick can be detected promptly and circulated out safely while monitoring the BHP trend during drill pipe connection without the need to wait for bottom-up circulation before connection (Cunningham et al. 2014).

2.5 E-cd Continuous Circulation System

The circulating device e-cd™ is an Eni-patented system used in managed pressure drilling operations to allow continuous circulation and hole cleaning even during drilling and tripping. The E-cd™ system consists of three main items, the diversion manifold, the continuous circulation sub and e-cd hose (figure 2.4).

Figure 2.4 The e-cd™ system (R. Johnson et al. 2019)

<u>The E-CD™ diversion manifold:</u>

It enables safe diversion from the top drive to the side port connection and back when making connections. The main inlet and outlet connections on the diversion manifold (figure 2.5) are built into the standpipe . With additional auxiliary connections to bleed off, a small pump is used to fill up the drill pipe stand when installed, and a hose is connected during the drill pipe connection to the side inlet port of each continuous circulation unit. A three-valve manifold connected to the standpipe is installed to ensure safe isolation of either the manifold or the standpipe, as required by operations. The manifold enables the operator to perform all necessary steps, including bleed-off of the top drive, flow diversion to the side port of the continuous circulation sub, flow restoration, and bleed-off of the line connected to the side port when the connection is completed. The manifold is usually positioned on the rig floor to provide direct visibility between the driller and the continuous circulation operator or installed at ground level when rig floor space is short of room. However, this is not a requirement and may be installed on the rig in alternative positions as long as direct communication and operating plans are developed and understood. The manifold can be mounted on the rig during downtime and usually does not add any crucial track time to overall drilling operation schedule (R. Johnson et al. 2019).

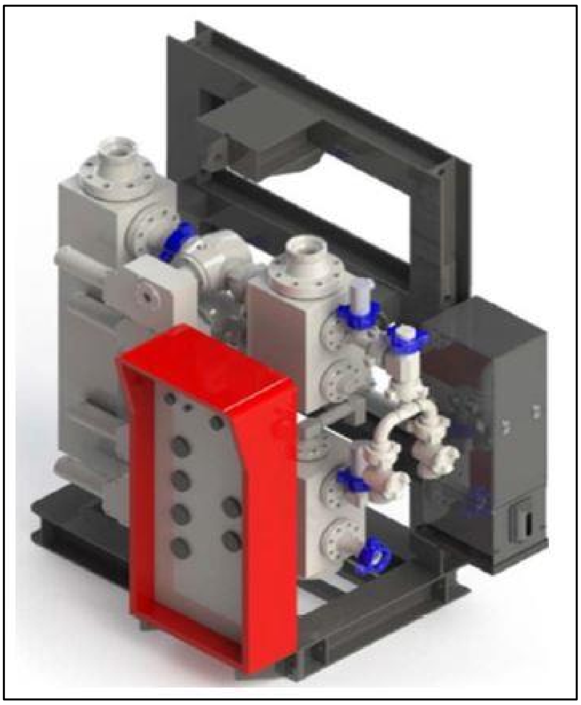

Figure 2.5 Diversion manifold
(R. Johnson et al. 2019)

E-CD™ Circulating Sub:

Circulating sub is a dual flapper valve with a side entry port running in a hole on top of the drill pipe stand. It enables access to the drill string flow through the side port entry (figure 2.6). It is made to fit existing drill pipe threads. The quantity of subs is determined according to the open hole section length through which the desired continuous circulation is created. The subs used in this system are equipped with two flap valves. During normal drilling operations, the first flapper remains open but is forced to close, employing a pressure differential generated by the manifold to allow the top drive to be isolated and bleed-off and attach a new stand. The second flapper is placed behind a safety cap, providing a tight metal-to-metal seal on the sub's side in a port. This flapper is closed spring-loaded and forced open once the flow is redirected through the sub-side port, providing the flow path for continuous circulation.

Figure2.6 E-CD™ Circulating Sub
(R. L. Johnson et al. 2019)

The e-cd™ system hose:

A hose connects the e-cd™ manifold to e-cd sub, allowing circulation through the side entry sub port. The top flapper closes at this point, and the top drive or upper drill pipe stand can be removed traditionally to perform the required connection. In the drill string below the e-cd™ sub, the circulation of mud continues uninterrupted.

2.6 The 2nd Generation Continuous Circulation System

A continuous circulation system has been developed for 2nd generation CCS, enabling automated switching circulation from the top drive to the side entry sub port of CCS during drill pipe connections. A remotely controlled clamp provides a fully automated opening and closing of the CCS sub.

2.6.1 The 2nd Generation CCS Description

The 2nd generation CCS is consist of four main components (figure 2.7).

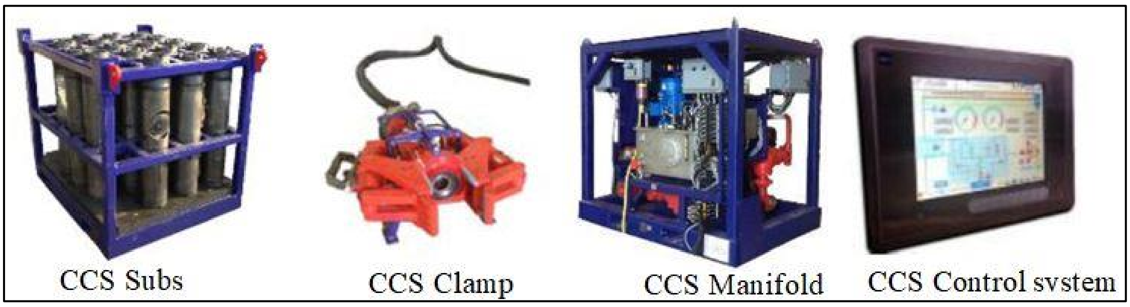

Figure 2.7 main components of 2nd continuous circulation system (Colaianni 2020)

1. **CCS Sub** is a tool installed at the top of each drill pipe stand, enables continuous mud circulation to the well through a fully automated side entry port sub when the top drive is disconnected from the drilling string.
2. **CCS Clamp** is a remotely controlled clamp that provides fully automated opening and closing of CCS sub, avoiding the presence of people in the red zone area during connections.
3. **CCS Manifold** enables automated safe diversion from the top drive to side port connection and back when making connections without interruption of mud circulation.
4. **CCS Control system** gives the operator complete control of the CCS and provides automated operational sequence during drill pipe connections.

2.6.2 How does The 2nd Generation of CCS Work

When continuous circulation is required, the subs are made up on top of every drill pipe stand, then drill pipe stands are racked in the derrick, and the operation can begin. Figure 2.8 shows the layout of 2nd generation of CCS, where the flow from the mud pump is pumped via the standpipe manifold, down through the top drive connected to the CCS sub and top of the drill pipe, then flow to the downhole.

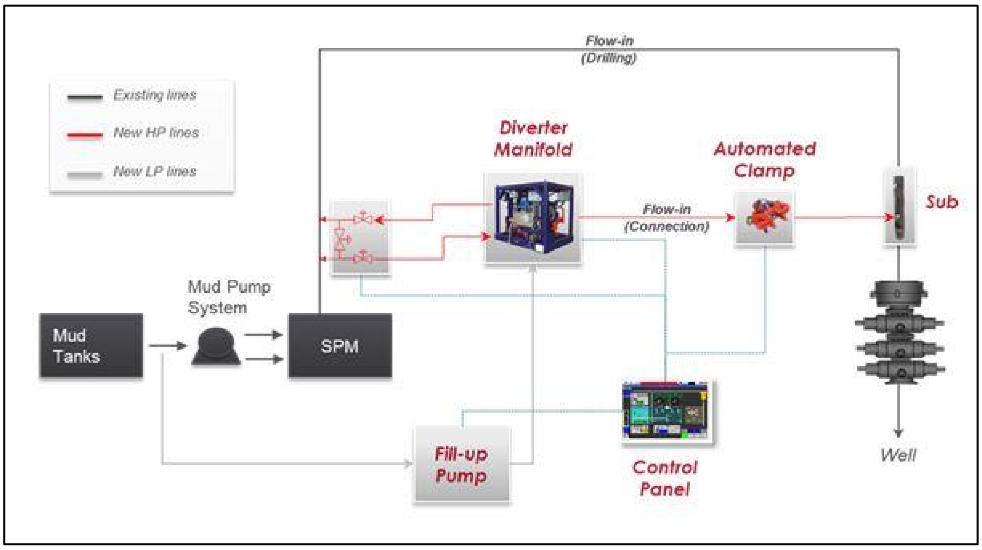

Figure 2.8 Layout the 2nd Generation of CCS

After the stand is placed in the slips (during drilling or tripping), the process of continuous circulation can start. First, connect the CCS clamp arms to the side entry sub (which is already installed on the top of the drill pipe stand). The operator activates the clamp on the control panel and opens a safety plug of CCS Sub that remains inside the clamp body during the operation sequence. When the control system confirms the open status of the plug, the manifold diverts mudflow from the top drive to the side entry sub before the top drive is disconnecting (Colaianni 2020). The operator can safely disconnect the top drive and add a new pipe stand as standard rig procedure for the connection without circulation interruption.

Once the new stand has been added, the reverse process is simple. A small auxiliary pump is used to fill the new stand to help avoid pressure changes on the surface and the bottom of the well until the flow is reversed. The previous process is then reversed once the external plug is closed and the clamp arms are removed, in which operations can proceed. The steps above repeat with every connection of drill pipe during drilling or tripping. This process involves approximately three to five minutes per sub on average. However, this gain is offset by the time it usually takes in conventional drilling to shut down the pumps, restart the pumps, restore circulation, and then complete hole cleaning or circulate gas connection (gas release during connection drill pipe in conventional operation). Therefore, the overall connection time can be roughly the same as a conventional connection; in some applications, the connection time can be reduced to improve the overall drilling schedule.

2.7 Connection Procedure of CCS vs. Conventional Drilling

The drill pipe connection procedures for different activities (drill stand down, drill off, pick up of bottom) required for conventional drilling method and continuous circulation technique are shown in Table 2.1.

Table 2.1 Connection CCS procedure vs. conventional drilling

Conventional Connection	Connection with CCS
Circulate, record weights	No activity
Stop rotation	Stop rotation
Shut down pumps, flow check	No activity
No activity	Turn the string to orient the CCS sub lateral port to connect the CCS clamp
Pick up off bottom and set slips	Pick up off bottom and set slips
No activity	Set the CCS clamp on sub, open sub external plug, divert flow from TDS to the clamp.
Close hydraulic IBOP and disconnect top drive	Close hydraulic IBOP and disconnect top drive
Connect next stand	Connect next stand
No activity	Fill-up new stand, divert flow from the clamp to TDS, close sub external plug, Remove the clamp from sub
Start pumps and bring to drilling flow rate	No activity
Start rotation and resume drilling	Start rotation and resume drilling

2.8 Well Planning Considerations with Continues Circulation

Well Consideration

The first criterion is to determine whether the well can be drilled without using the CCS. Having identified that its use seems necessary, all available information should be compiled and analyzed to establish the required drilling parameters. To use controlled pressure drilling, the offset well data and seismic data have to be analyzed to assess the gradients of the pore pressure and fracture pressure in the formations to be drilled. If previous attempts have been made, the types of mud, mud weight, and other reported data must be used to evaluate the ECD with the continuous circulation to be held.

MWD/LWD/PWD tools must be included in the designing of bottom hole assembly (BHA) to report and measure the ECD and other well data with continued drilling. Real-time ECD measurement allows the mud weight and circulation rate to be modified as drilling proceeds. Keeping the ECD within the pore pressure and fracture pressure window's gradient. After drilling a section with continuous circulation, the bit would usually be pulled to the last casing shoe with uninterrupted circulation before displacing the heavier mud to maintain an equivalent static bottom hole pressure before pulling out. By Knowing the ECD, the density of this heavier displaced mud could be measured to provide the necessary pressure of balance at the bottom of the wellbore.

Rig Consideration

The CCS can be used on any drilling unit equipped with a top drive drilling system. Before beginning continuous circulation operations, the service company's inspection team can examine the rig and decide what is needed to install the system. The team will arrange with the drilling contractor to provide electrical power, location the hydraulic power unit, and configuration of the hydraulics hoses and control cables. Other inspections will include top drive interface tools, the position and operation of the inside blow-out preventers (IBOP), and the alignment of top drive.

The number of the main mud pumps are other vital considerations. Typically there must be three mud pumps in location as usual; two pumps would run continuously with the continuous circulation operations. It is advisable to have a mud storage system with sufficient capacity to store and treatment the volume of mud in the borehole, as it is an effective treatment system for maintaining the needed mud weight in circulation (R. E. Vogel, Dunn, and Jenner 2007)

Well Control Consideration

In conventional drilling, the standard shut-in well control procedure is stop mud circulating, pick up the drill string off bottom in order to space out the tool joint of drill pipe away from pipe ram blowout preventer (BOP), close the BOP and take pressure readings for kill mud weight calculation and then circulate the kick out of the hole. When CCS is employed, the CCS sub should consider space out from the pipe ram BOP. Figure 2.9. shows space out configuration.

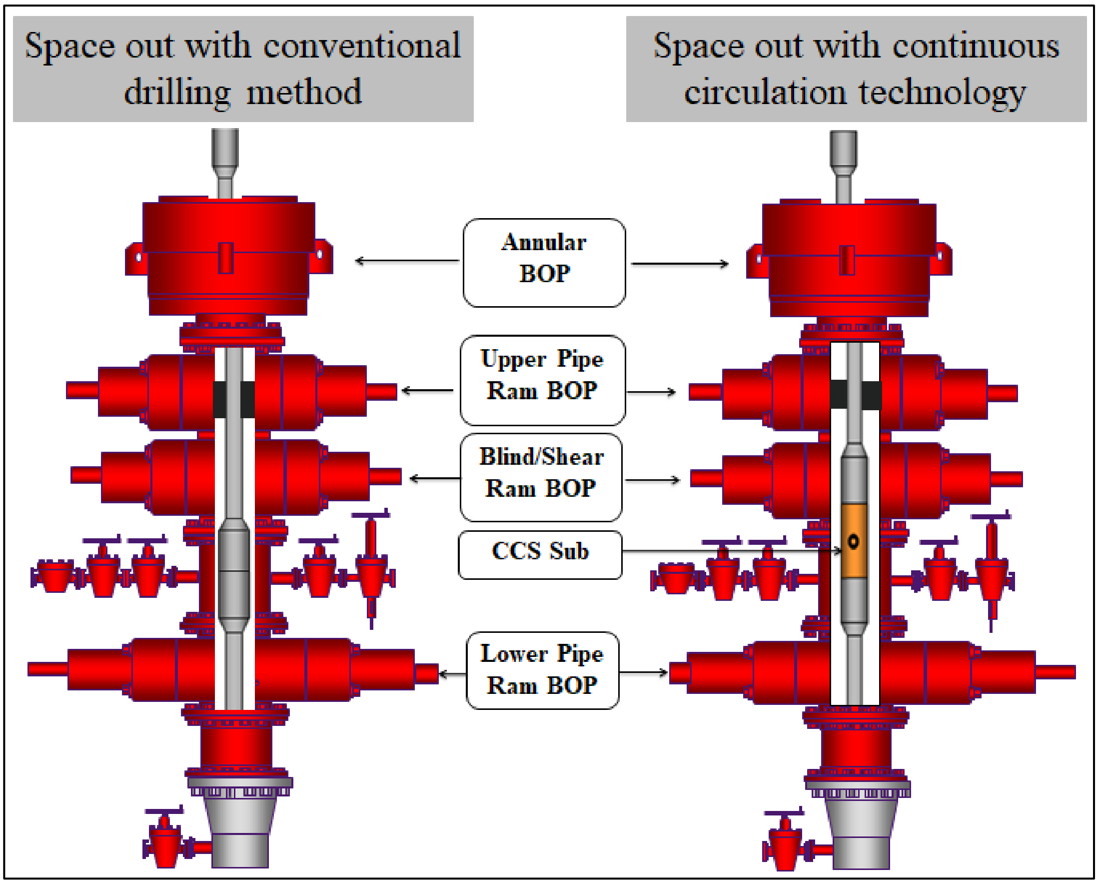

Figure 2.9 Space out tool joint and CCS sub through BOP during shut-in the well, figure was adapted

On the other hand, when using the continuous circulation method for balanced pressure drilling technique, the potential conditions of well-control must be discussed before drilling starts. In conventional drilling, the accepted practice is to use a drilling fluid of sufficient density to provide an overbalance and control the well when circulation is interrupted and prevent any influx into the wellbore under static conditions. If using balanced pressure drilling with continuous circulation method, the conventional shut-in well control cannot be done as it will cause the loss of balanced pressure condition when stop circulating. A significant factor is the circulation rate that should be set at a level where it will be slightly lowered to maintain a near-constant ECD. Correspondingly, when pulling out with continuous circulation, it might be required to raise the circulating rate to maintain a steady pressure at the bottom of the wellbore. As a result, circulation must be preserved during the well's shut-in, and, as a first step, the circulating rate must be increased to increase the ECD. Against this context, it is important to plan specific well control procedure and train the rig crew in their position.

Chapter 3

Advantages of Using Continuous Circulation Technology

Continuous circulation technology offers many advantages, including managed downhole pressure coupled with improved wellbore stability and hole cleaning. These characteristics become fundamental requirements for personnel safety, operational drilling efficiency, and cost reduction in the current oil and gas industry. The advantages of continuous circulation are various, depending on the form of well and the geological conditions, differ considerably from well to well, particularly in narrow margin drilling environments with increasingly extreme water depth and well situations characterized by high pressure and high temperature. Some general benefits of continuous circulation are discussed in the following sub-sections.

3.1 Well Control and Safety Implications.

Well control is one of the essential components for operational safety, personnel, and the environment, among various drilling elements. Primary well control is guaranteed by maintaining the mud hydrostatic pressure above the pore pressure through the open hole section. A failure of well control implies a flowing of the formation fluid into the borehole that can eventually result in a blowout.

A critical time for well-control with conventional drilling is when mud circulation is stopped to make a drill pipe connection. The cessation of the circulation removes the friction pressure between the drilling mud and the annulus, thereby decreasing the BHP. This reduction in pressure can cause a kick (the flow of formation fluid to the wellbore). If the well could not be controlled by a secondary well control, the related serious consequences could happen such as explosions and fire, rig collapse, personal injury, deaths, and environmental damage. However, in the continuous circulation method, BHP is determined by the hydrostatic pressure and the frictional pressure loss as always under dynamic conditions.

Utilizing continuous circulation technology can improve safety and reduce kick severity in the following ways:

1. Enhance early kick detection and allow the operator to react quickly, stopping the influx with a minimal gain as the drill pipe is always connected to the mud supply.
2. Elimination of connection kicks.
3. Circulate the kick from the well safely and efficiently.
4. Kicks are less likely with continuous circulation due to the absence of stop/start pressure transients.
5. Maintain kill pressure while re-installing the drill pipe to the bottom.
6. Circulating pressure can be immediately adjusted while drill pipe connections.
7. Lower risk of exceeding maximum allowable annular surface pressure (MAASP) with continuous circulation (because of the smaller influx) and lower risk of breaking down the casing shoe.
8. Avoid taking the second influx with continuous circulation (longer critical choke control needed while circulating out the larger volume of influx).

3.1.1 Eliminate Connection Kick and Trip Gas

Connection kick is a relatively small volume of the formation fluid that enters wellbore, which occurs during conventional connection operations. When the mud pump is turned off, the ECD decreases to the static mud density and causes a kick if the safety margin of the static mud column is low, where the gas connection proves that the weight of the mud column is lower than the formation pressure.

The connection kicks are not easily detected during drill pipe connection before the fluid formation is observed. Figure 3.1 demonstrates the connection gas appears as sharp peaks of produced gas as ECD decrease.

Trip gas is any gas that enters the wellbore while the hole appears to be static. Trip gas may be observed when mud circulating after a round trip. If the hydrostatic pressure of the mud column is adequate to balance the formation pressure, the trip gas would be caused by the swabbing and diffusion of the gas.

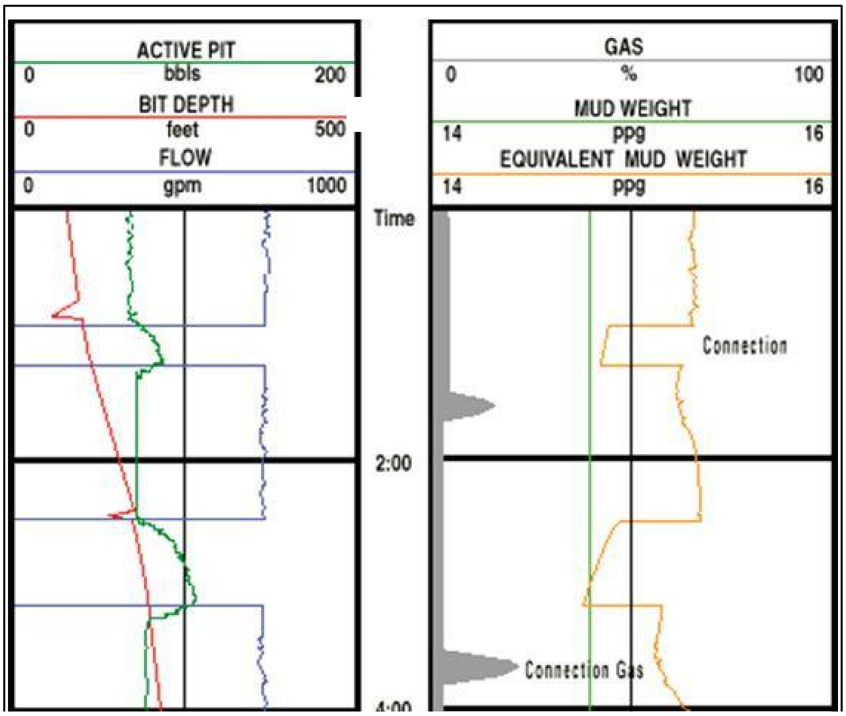

Figure 3.1 Releasing gas into wellbore during connections (Schneider, n.d.).

Connecting gas kicks are typically removed or minimized with CCS by providing continuous circulation (R. L. Johnson et al. 2019). Continuous circulation keeps the established stable dynamic condition in terms of pressure and flow regime through the exposed formation, ensuring no induced flow from the formation can occur.

3.1.2 Enhance Early Kick-Detection

Early detection of kicks is extremely important in well control operations and the prevention of possible uncontrolled blowouts. Early kick detection minimizes the amount of formation fluid that enters the well and reduces the surface pressure needed to control it. Avoiding large volumes of kicks also prevents problems that make well control is complicated.

An accurate flow meter is installed to measure the return flow rate from the return line. Additionally, the pump controller responds quickly to variations in inflow. Those calculations may result in excess, or a loss recorded more reliably and much sooner than traditional setup. The return flow line is always full of mud, resulting in continuous flow measurements (Fossli and Stave 2014). If a formation fluid enters the wellbore when drilling with the continuous circulation, the first indicator will be observed immediately in the mud returning to the surface by monitoring flow rate measurements and the pit level. Similarly, lost circulation monitoring by identifying the loss of drilling fluid from the well into fractured or permeable formations.

If any changes in pressure or flow happen during or after a connection, this can be described as an interaction between the annulus and the formation, giving a more receptive and immediate indication of what is occurring in downhole. The mud loggers should pick up these signs from the gas detectors and the pit level indicators.

Using continuous circulation technology during connections facilitates continuous and improved well control. The valves that regulate the flow of mud between CCS and top drive are proven equipment standard, available and safe. The drill string itself does not need additional valves or parts. Therefore when a kick occurs, the pressure can be controlled and sustained immediately as the drill pipe is always connected to the mud supply.

3.1.3 Considering Balance Pressure Drilling and Well Control

The reasons for drilling with continuous circulation should be remembered when considering balance pressure drilling and well-control. To keep the ECD and dynamic annulus friction pressure loss at the correct level, circulation must be maintained and well-controlled, unless impossible for safety reasons. The principal contributing factor is the circulation rate that should be set at a point where it could be marginally decreased as the hole section is deepened to maintain a nearly constant ECD. Likewise, it might be important to increase the circulating rate while pulling drill string out with continuous circulation to maintain a steady pressure in the bottom of the wellbore. For preserving the state of balance pressure, it may be necessary to increase or decrease the circulating rate slightly at any time.

3.1.4 Minimize Swabbing Pressure

Swabbing is a temporary lowering of the hydrostatic head due to pulling the pipe out of the hole (heriot 2005). The frictional drag combined with the piston effect will create a reduction in pressure. This reduction is known as the swabbing effect, which leads to the invasion of formation fluids.

The swab also induced when picking up the string at connections and as a result BHP temporarily will reduce below hydrostatic pressure (figure 3.2).

In conventional drilling, when the drilling fluid does not drop as quickly as the drill string is being pulled, it creates a suction force and lowers the pressure below the string. However, when using continuous circulation technology, this force will eliminate.

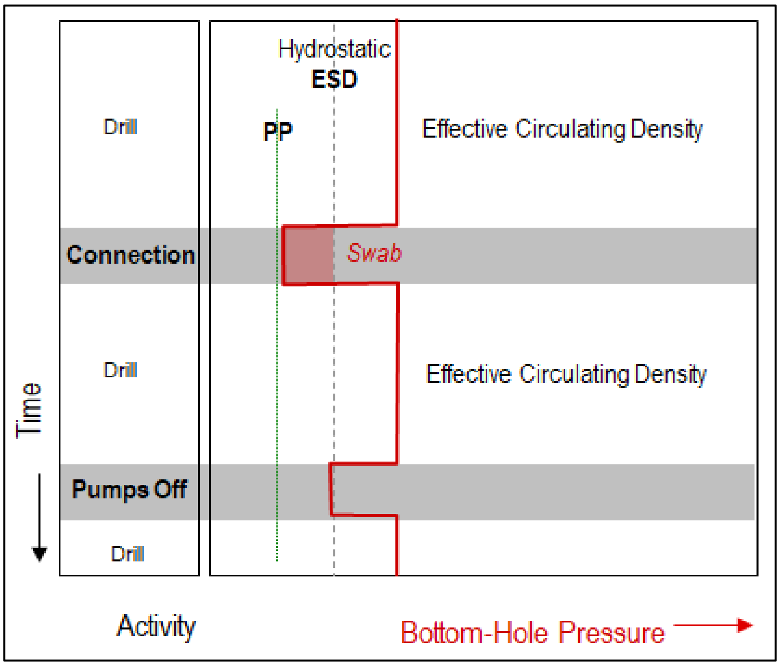

Figure 3.2 inducing swab during connections, figure was adapted.

3.1.5 Keep The Hole Full During A Trip

During a trip out operation in conventional drilling, the fluid level in the well is dropped the hole fails to take the correct mud volume. Consequently, the hydrostatic pressure exerted by the fluid will reduce.

A kick occurs while a trip out due to insufficient mud weight to control formation pressure as a result of the reduction of hydrostatic pressure. Maintaining continuous circulation during tripping will eliminate this issue as the wellbore will always be full of fluid.

3.1.6 Prevent Borehole Ballooning Phenomenon

Borehole ballooning is a drilling phenomenon where the well loses amount of a drilling fluid while pumps are on, and then returns much of the fluid when the pumps are shut down. The main problem with borehole ballooning is the correct identification of this problem and not mix it with any other loss of circulation and drilling problems. One of the most severe consequences of this phenomenon is the misinterpretation of the observed rapid sizeable mud flow into the wellbore as a kick when the pumps are shut down (Power, Ivan, and Brooks 2003). This is results in conducing unwarranted control procedures that can be costly (Ward and Clark 1998), like increasing the mud weight and require considerable time to circulate out to confirm.

If a well flow is just the returning mud, increasing the mud weight as a treatment of flowing may be extended the existing fractures makes it even more challenging to control the situation.

Continuous circulation technology aims to maintain a constant bottom hole pressure by maintaining ECD throughout the drilling process. It will effectively prevent borehole ballooning effects by removing the pumps-on/pumps-off condition during connections (R. L. Johnson et al. 2019). It provides steady-state conditions as there will no longer be downhole pressure fluctuations due to shutting pumps off, which might also enhance control and safety.

3.2 Quality of Drilling

Continuous circulation means transportation of the continuous cuttings and hole cleaning. This aspect is extremely relevant in deviated wells and extended reached wells through providing the benefits listed below:

- Increasing rate of penetration.
- More effective solids control due to the elimination of slugs of solids and solids break out.
- Reduction of reservoir and hole damage.
- Prevention of cuttings beds formation.
- Reduction of the likelihood of a stuck drill string.
- Elimination of re-drilling or settled cuttings and debris after making connections.

3.2.1 Increasing Rate of Penetration

One of the benefits of continuous circulation is increased drilling speed and decreased invasion of mud filtrate due to decreasing differential pressure. The decreasing of overbalanced pressure leads to a decrease in the confining pressure of the formation rock. The rock is more easily broken under the bit action, and the rate of penetration (ROP) increases. It is also evident that reducing the overbalanced results in reduced invasion and damage to mud filtrate.

Two holes sections wells were analysed and compared to quantify of the system time saving for drilling both with and without continuous circulation to properly demonstrate the drilling improvements provided by using the continuous circulation system. Figures 3.3 and 3.4 show well data. In this example, the top hole 26-inch hole section was drilled without continuous circulation, while the 17 1/2-inch hole was drilled with continuous circulation.

Many ROP fluctuations were recognized when drilling the 26-inch top hole section, as shown in figure 3.3. Compared to the 17 1/2-inch hole section drilled using continuous circulation (figure 3.4), ROP was also significantly reduced, averaging close to 50 m/h.

The ROP kept steadily at 60 m/h after implementing continuous circulation technology for the 17 ½ inch hole section, with few variations as connections were made or during the drilling process. The increase of ROP compared to the planned value because of outstanding benefits in terms of continuous cutting recovery that reduced both circulating and reaming times. This helped the operator reduce the overall drilling time and hazards by using the continuous circulation technology in the critical hole sections (R. Johnson et al. 2019).

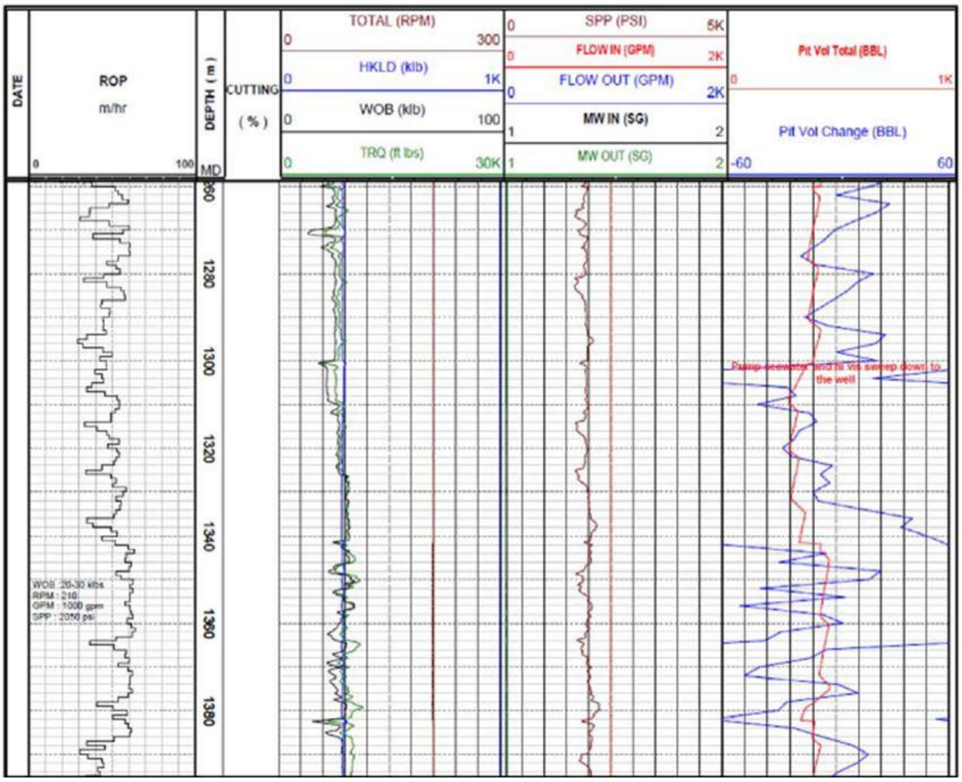

Figure 3.3 ROP without continuous circulation (R. Johnson et al. 2019)

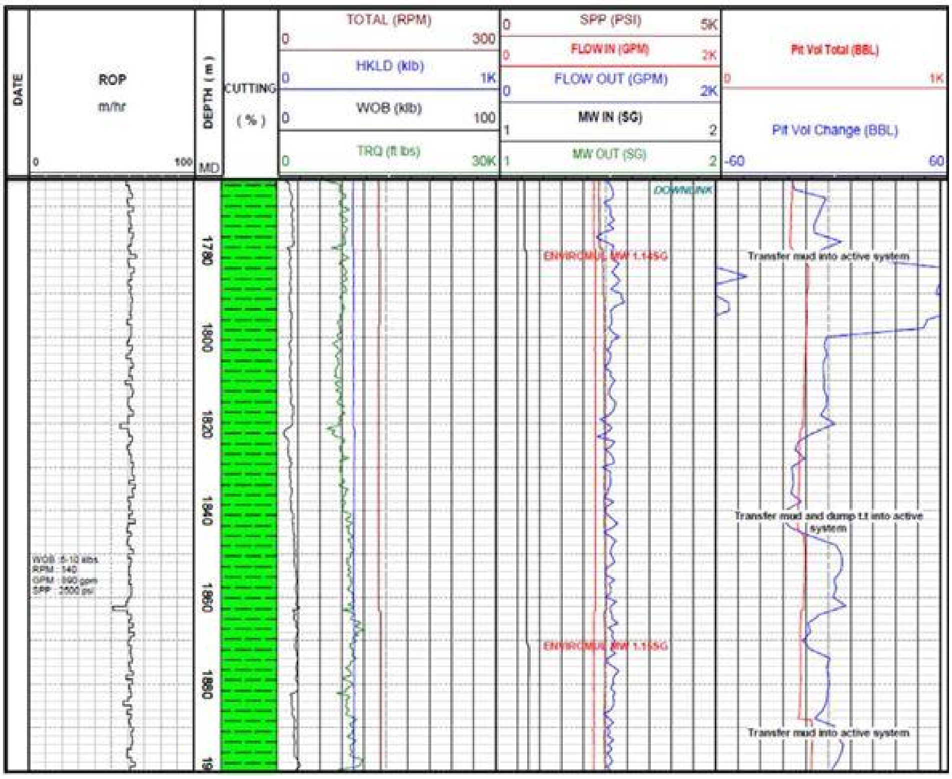

Figure 3.4 ROP with continuous circulation (R. Johnson et al. 2019)

3.2.2 Reduce Surge Effect

Every time the circulation of drilling fluid starts, bottom hole pressure is exceeded by an increase of dynamic pressure needed to shear static mud gel strength and commence to move the mud. This is a fairly sudden increase in pressure known as surge pressure. Besides, a positive pressure surge occurs when running the drill string quickly inside the wellbore because the pipe behaves like a loose piston. If this increase in pressure is extreme, then many drilling problems can occur, such as lost circulation of drilling fluid (Al-Abduljabbar et al. 2018). Continuous circulation during drilling could reduce the additional pressure caused by tripping-in and circulation interruptions and maintain stable bottom hole pressure (Feng et al. 2016).

3.2.3 Improving Hole Cleaning

In conventional drilling, when the pump is turned off to make a connection, a large amount of suspended cuttings are settling to the bottom hole assembly, or the downward sliding of a stationary, formed cuttings bed on the low side of a directional well and increase the friction in the hole, which causes stuck pipe (hole pack-off). This is particularly noticeable when drilling mud properties are not adequately designed to sustain cutting suspension (Alhamed et al. 2020).

Stuck pipe event is one of the most common problems that lead to high costs in the drilling industry. After failed attempts to free the stuck pipe, different fishing techniques are used to retrieve the drill string. Sometimes have to cut the drill pipe and leave BHA inside the wellbore and then having to side-track, involving significant NPT to the well construction operation.

For all wells, the proper resistance of the mud gel is preserved to minimize the accumulation of cuttings and waste while stopping the circulation. However, the pressure required gel breakdown can be severe and adds pressure to the surge when the circulation starts again (Ayling et al. 2002). Besides, the static mud often heats up, which causes the properties of the mud to change considerably.

Maintaining sufficient continuous circulation can prevent stagnancy of mud, which helps to reduce the need for mud gel strength and keeps a more steady mud temperature and mud properties. It optimizes well-being cleaning by efficiently removing drill cuttings, preventing accumulated cutting in extended reached and deviated wells, and eliminating weight materials from dropping out of the drilling fluids (Torsvoll, Horsrud, and Reimers 2006) and provides a cleaner hole. The removal of cuttings reduces friction between the drill pipe and the borehole and reduces the likelihood of a stuck pipe and pack-off incidents.

3.2.4 Significant Reduction in Differential Sticking Incidents

A differential sticking is one category of stuck pipe incidents might occur while drill pipe connection, where the drill string becomes stuck against the wall of the hole. This problem might occur when the wellbore pressure is greater than the permeable formation pressure. The overbalance could be a result of the increasing mud density to cope with a sloughing problem. When drilling mud is not circulated, a differential pressure develops and forces a stationary drill string into a thick filter cake of a permeable zone. The hydraulic force then acts around the separated portion of the drill string and holds it against the formation. This force is proportional to the differential pressure (overbalance pressure) and the contact area of the drill string against the wall. Over connection time, the problem gets worse as filter cake builds up around the sticking part of the pipe in this section. (Figure 3.5).

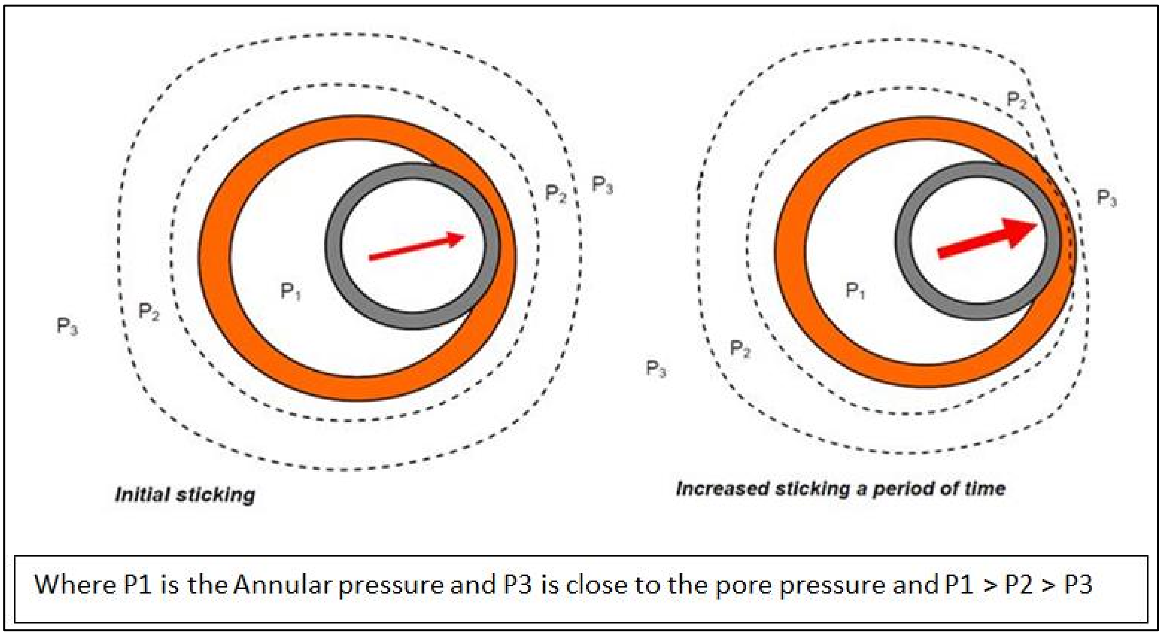

Figure 3.5 The drillstring is embedded in the filter cake (Jenner et al. 2004)

Employing CCS allows the differential between the mud pressure and the pore pressure to be kept continuously.
The following actions could decrease the probability of differential sticking when using continuous circulation technology (Jenner et al. 2004):

1- keep a low differential pressure while drilling.
2- Eliminate 'pumping up' the formation with stop/start circulation.
3- Maximize lubricate of the drill pipe and reduce the gelling of the drilling fluid.
4- It helps to keep the drill string loose while stationary.
5- Creating a thinner and tighter filter cake.
6- Prevents developing the differential pressure.

In drilling with liner technique where hole conditions require liners to circulate via part or all of the open cavity, this situation is improved with continuous circulation drilling. Continuous circulation increases the cleaning of the annulus and eliminates the risk of the liner being stuck when the circulation is interrupted during making a connection (Jenner et al. 2004).

The application of this technology has helped avoid the occurrence of stuck pipe incidents, resulting in costly fishing jobs and potentially loss of BHA in the hole with consequent side-tracks and additional cost impact (R. Vogel and Brugman 2013).

3.2.5 Minimise Lost Circulation

A loss of drilling fluid into the formation is a common problem encountered during drilling operations. Lost circulation can occur due to naturally fractured formation, induced fractures, cavernous formations, or high permeable formations (figure 3.6). Besides the natural causes of the lost circulation, it occurs if the mud weight is increased to the point where the formation fracture pressure is exceeded.

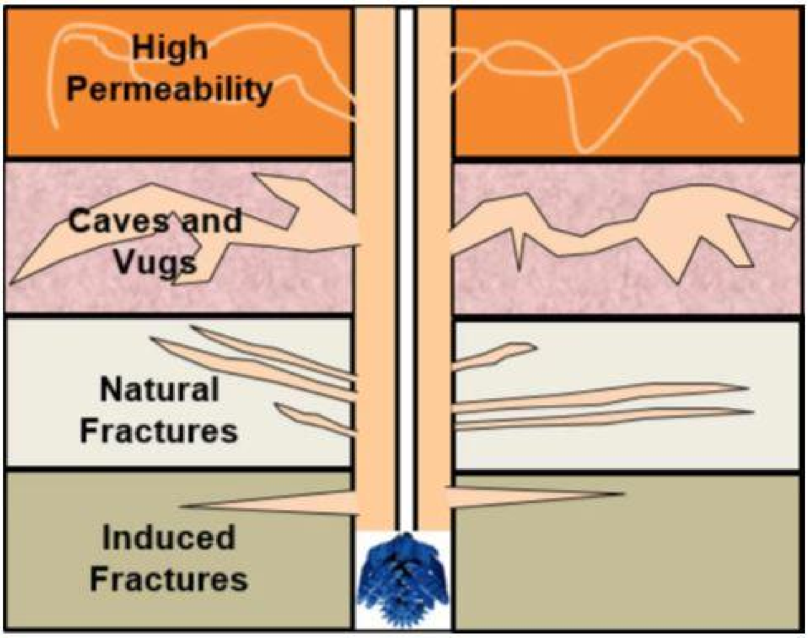

Figure 3.6 Candidate Formations for Lost Circulation (Alkinani et al. 2020)

Lost Circulation is expensive in drilling fluid usage, especially when the type of mud is an oil base mud or high-performance mud for drilling. Lost circulation may lead to associated drilling problems such as a well kick, which resulting from the reduction in the vertical height in the mud columns, borehole instability, stuck pipe, and producing formation damage (skin effect) due to mud particle plugging pores and porous throats (Ramasamy and Amanullah 2017).

When the circulation is resumed after drill pipe connection, a positive pressure surge accelerates the mud and temporarily increases the bottom hole pressure over the ECD, Pumping fluid to the adjacent borehole formation at higher pressures that may exceed the fracture pressure (Ayling et al. 2002).

When the dynamic state is established by applying CCS, it allows maintaining BHP value to be always above pore pressure and below the fracture pressure during drilling (there is a possibility to minimize mud weight). This effectively prevents the positive and negative pressure surges associated with making a connection under normal drilling conditions (figure 3.7). Also, it helps to maintain a minimum filter cake and reducing exposed surface erosion.

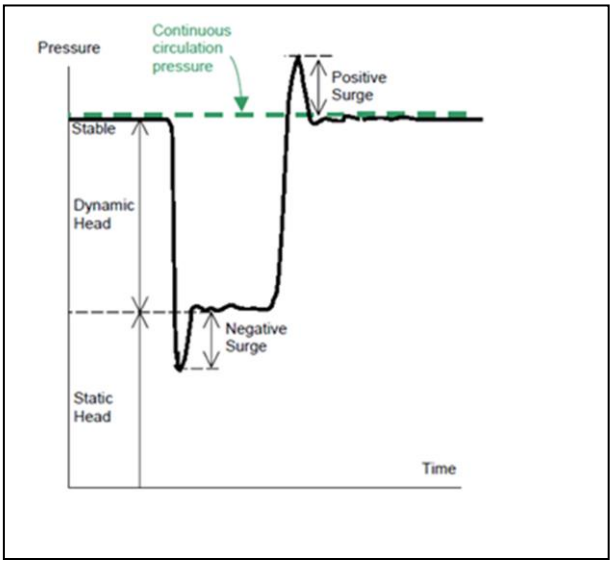

Figure 3.7 Downhole pressure transients on stop/starting circulation (Ayling et al. 2002)

3.2.6 Survey Accuracy and Continuous

The directional driller or MWD engineer is able to perform a survey whenever a need occurs, with little rig time to be used, significantly improving the accuracy of the survey and the well positioning. It results in a much better representation of the actual well path in real-time than using periodic gyro surveys.

3.2.7 Availability of Downhole Data

Measurement while drilling, logging while drilling, pressure while drilling tools can be used with continuous circulation. Therefore a distinct benefit of the constant circulation system will be continuous availability of downhole formation data (MWD/ LWD) and real-time ECD measurements (PWD) through mud pulse telemetry, as the pumps are not shut off during connections (R. Vogel and Brugman 2013).

It is possible to continuously monitor downhole pressure through a PWD tool during drilling, making precise adjustments to the mud density and circulation rate. This activity was not feasible until continuous circulation technology was employed. The two red horizontal lines in figure 3.8 mark roughly when the connection began and ended using the continuous circulation system, where the PWD chart gathered downhole information as a continuous circulation was performed.

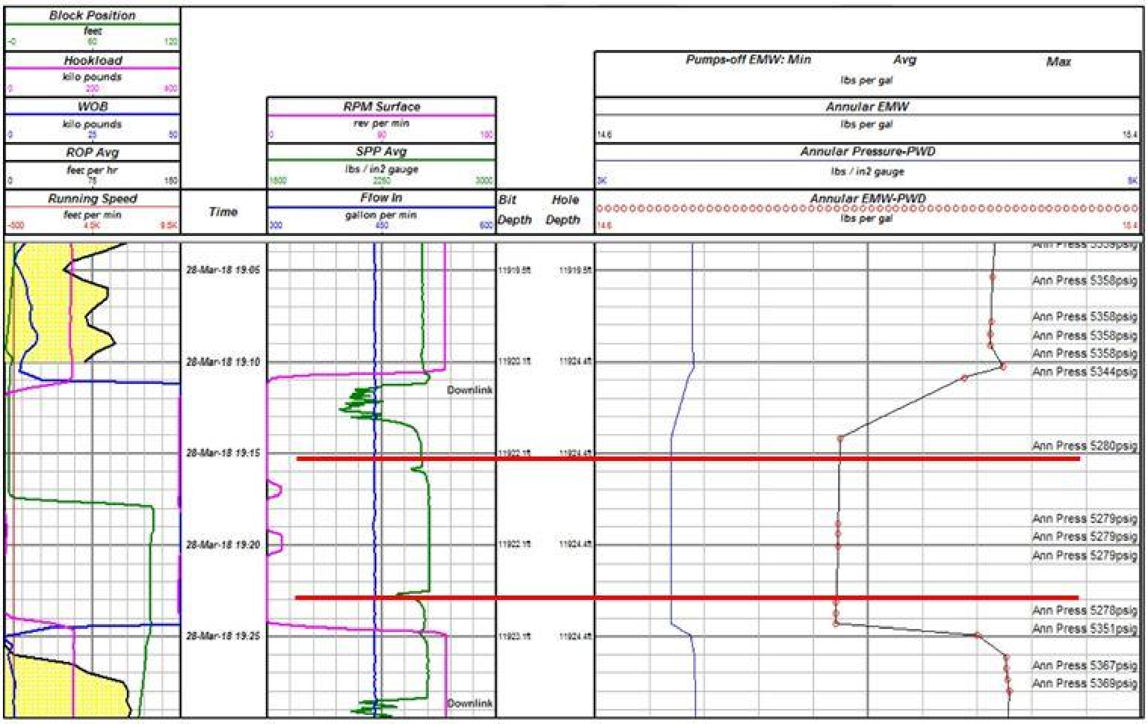

Figure 3.8 PWD chart gathered downhole information as a continuous circulation was performed (R. Johnson et al. 2018)

3.2.8 Improve Wellbore Stability

Maintain wellbore stability is one of essential importance during drilling operations until running casing and finish cement job. Complex instability borehole issues like collapse, caving, washout (wellbore does not maintain its gauge size), and sticking must be prevented.

Wellbore stability requires an adequate balance between uncontrollable formation strength and pore pressure and controllable mud column pressure factors (J.B.Cheatham 1984)**.** Most wellbore instability problems occur in sensitive formations, e.g., shale formation related to the stresses around the wellbore exceeding the rock strength due to lack of pressure support from the drilling fluid. The effect is mainly associated with water base mud and is rare in oil-based mud. Upon exposure of the shale wall to the water of drilling fluid, clay hydration happens through water absorption, swelling, and dissipation, so the distribution of stress across the borehole wall also changes, which causes increased pore pressure in the borehole (She et al. 2019).

Maintain continuous mud circulation at all times is keeping BHP above the mechanical wellbore stability point and does not change the downhole 'pressure dynamics,' which can damage the wall of the borehole and make it more unstable. This results in preventing caving settlement, eliminating the need to increase mud weight, which causes failure of pre-existing micro fractures and inducing breakout and hydraulic fracturing of the rock (figure 3.9).

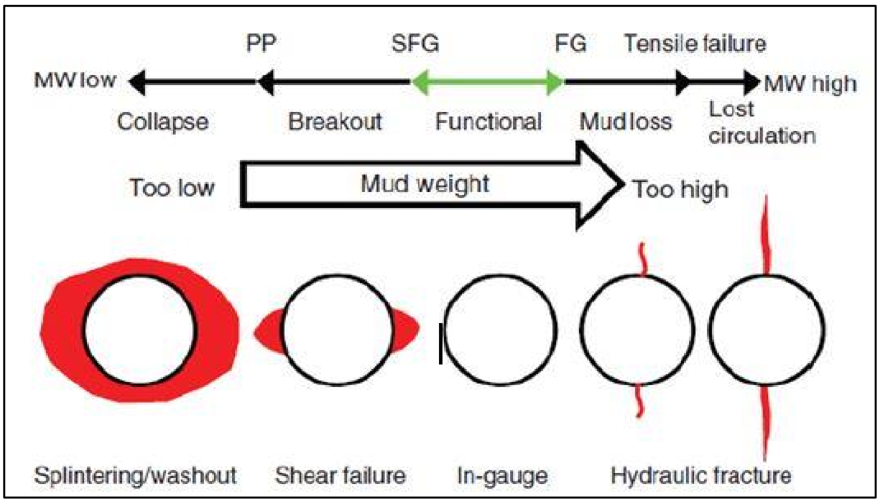

Figure 3.9 Schematic relationship of mud weight and wellbore (Lang, Li, and Zhang 2011)

3.2.9 Maintain Drilling Mud Thixotropic

Mud rheology properties are very significant features for drilling fluids, which should be stable under different conditions while drilling to avoid drilling problems. Most drilling fluids exhibit thixotropic in their rheology. If they are left in static condition for some time during tripping and connections, their rheology properties tend to increase. Once the circulation resumes after a static period while drilling a well, sections of the wellbore will undergo pressure peaks for a short time before the gel strength is broken.

Moreover, the viscosity of the mud will remain increased for some time after breaking the gel (Bjørkevoll et al. 2007). This can significantly impact, particularly when drilling with deep water, HPHT, and extended reach wells, where gelling consume much energy to move the mud.

By using continuous circulation technology, the downhole steady-state fluid dynamic is established while drilling. Therefore the mud rheology can be kept continuously at the optimum condition with uniform parameters throughout the system, making the hydraulics consistent and easier to calculate.

3.2.10 Keeping A Lower Bottom Hole Temperature

Bottom hole temperature well condition often affected on drill string tools and the rheological properties of the drilling fluid during drilling operations. Mud temperatures in the borehole became very high during long stationary periods while round trips to change BHAs were made.

Continuous circulation method maintains a dynamic bottom hole temperature even during the drill pipe connection process because fluid never becomes static. The mud circulation temperature is relatively lower than in static conditions, even when the formation temperature is very high (Tian et al. 2007). This results in adequately cooling and conditioning of wellbore. The drill bit could be lowered without being gained heat by high bottom hole temperature, bottom hole assembly components continuously cooling while running into the hole. With this cooling method, the drilling tools could survive high downhole temperature; therefore, their lives will be extended by keeping the dynamic well temperature.

On the other hand, the high temperature of deep wells causes low yield point, degradation of apparent fluid viscosity, and low plastic viscosity (Nguyen, Bae, and Hoang 2016), and mud density. It affects the ability of mud to perform its useful purpose in drilling operations. When circulation is stopped to make a connection in HPHT wells, the static mud column heats up and can significantly change its rheology properties and density. Using continuous circulation establishes the steady-state flow of mud (Jenner et al. 2004); therefore, it keeps a lower temperature with uniform parameters throughout the system.

3.3 Improve Production

The production performance of a well is highly influenced by the extent of damage in near wellbore formations. Formation damage reduces permeability in a reservoir rock caused by an invasion of drilling fluid to the section adjacent to the wellbore (in some condition sets, can extend outward some distance from the wellbore).

The formation damage can occur in over-balanced and under-balanced drilling techniques. In the overbalanced drilling process, the bottom hole pressure is set to ensure that the hydrostatic pressure created by the drilling fluid column exceeds the reservoir pressure to keep the reservoir fluids from flowing into the borehole. The increment in over-balanced pressure may result in two main potential sources of formation damage; the first is lost circulation within the pay zone. The mud loss into the pay zone reduces the flow path or plugs the pore throat of production fluids with particles in the drilling fluid (Aljabbar and Rizkiaputra 2016). Consequently, lost circulation may decrease the subsequent flow rate of production fluids.

The second mechanism of formation damage is the invasion of mud filtrate and solids into the near-wellbore (Civanphd et al., n.d.), especially if the filtrate is incompatible with the rock-fluid reservoir. The depth of mud-filtrate invasion is strongly dependent on overbalanced pressure, directly proportional to the increase in overbalanced (figure 3.10). When formation pressure and dynamic mud-column pressure are balanced, the amount of mud-filtrate invasion will be small (Won and Virginia 2008) (figure 3.11).

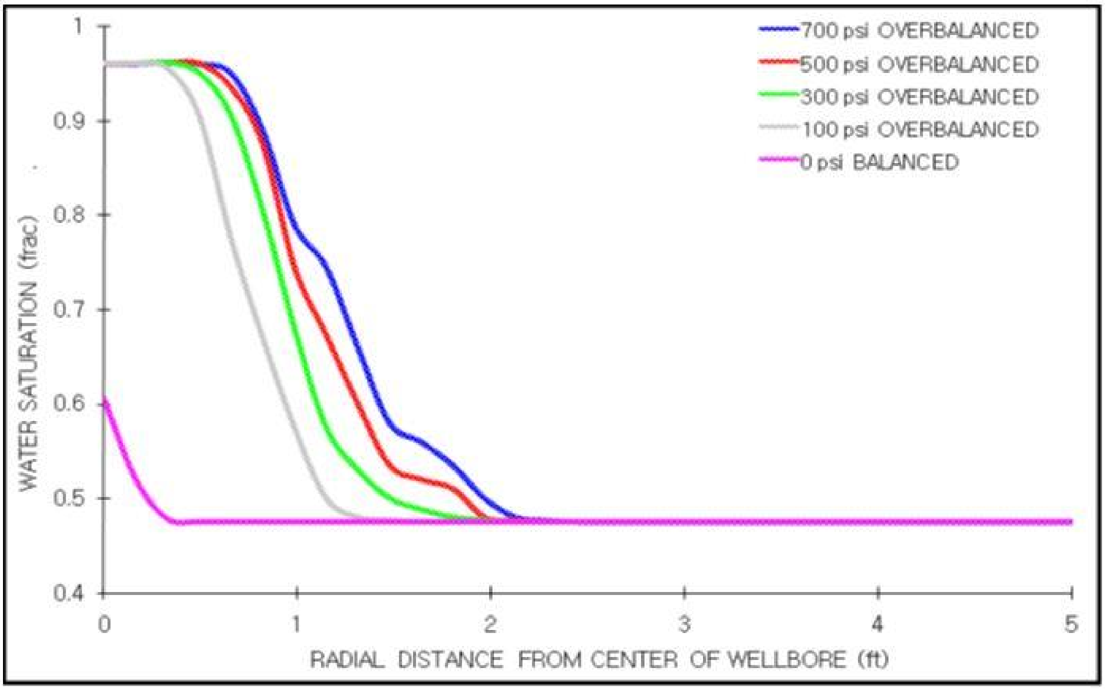

Figure 3.10 Variation of saturation profile and depth of invasion with overbalanced (Won and Virginia 2008).

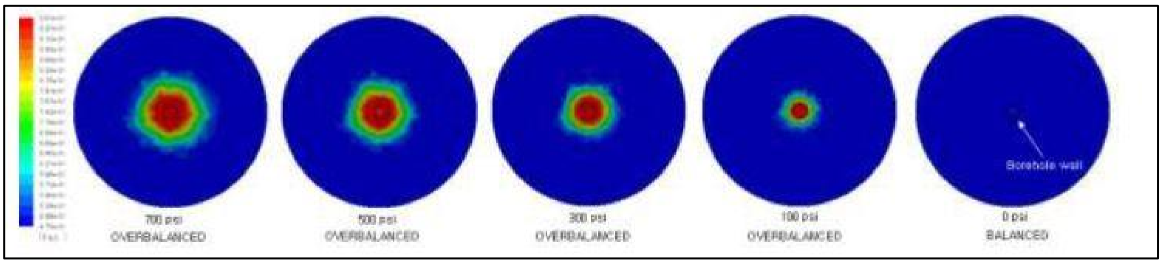

Figure 3.11 The effect of overbalanced pressure on water saturation contour (Top view) corresponding to the plots in Figure 3.10 (Above) (Won and Virginia 2008)

On the other hand, although used the under-balanced drilling techniques to reduce formation damage and increased well productivity compared with OBD techniques dealing with massive loss of circulation, in some cases, imbibition occurs and reduces well productivity. The imbibition is a phenomenon in which reservoir fluid flows through the matrix in the opposite current direction of the hydrocarbon flow due to high capillary forces when aqueous drilling fluid is used in low permeability reservoirs and results in a kind of damage to a formation called phase trapping reduce well productivity (Khansari and Integration 2009).

By using continuous circulation technology, the circulating pressure and ECD can be adjusted to the optimum to control the well. The static mud density can be reduced hence avoided the mud loss into the producing formation.
Generally, continuous circulation greatly minimizes formation damage of the production intervals by maintaining steady-state pressure, temperature, and mudflow throughout the drilling of a reservoir. Therefore well productivity is improving (Jenner et al. 2004).

3.4 Time and Costs Saving

The non-productive time (NPT) is any event that interrupts the progress of a planned operation and causes a delay in time; it represents the overall time required to solve the problem until the planning activities are resumed from the point or depth at which the NPT occurred (Ashena et al. 2020).

The drilling challenges encountered were examined by York et al. (York et al. 2009) and analysed standard procedures used to address the drilling hazards. They conclude that the drilling trouble zones associated with NPT could consume from 10% up to 40% of the budgets for well-construction if not prepared accordingly. It has been demonstrated that the problem zones can be effectively drilled if correct drilling techniques with validated drilling methods, equipment, and processes are considered and implemented.

Continuous circulation technology helps reduce NPT by overcoming several drilling challenges and increasing operational efficiencies, and as a result, reducing overall project costs (R. L. Johnson et al. 2019).

The main benefits in terms of time and money-saving are the following:

- Aid in the avoidance of stuck pipe incidents occurrence, resulting in costly fishing jobs and possibly loss of BHA in the borehole with consequent side-tracks and related cost effects.
- Elimination of mud weights changes while tripping.
- Allows continuous monitoring of gas drilling data while pipe connections, no need to wait until the gas trend is stabilized before connection operations are carried out.

- Extended bit life and increased ROP, leading to reduced NPT and reduced number of tripping.
- Elimination of required circulation time ensures the hole is in good condition before making a connection while drilling.
- Reduced typical drilling NPT.
- Mitigate extended wellbore conditioning and nuisance gas circulation.
- Time reduction for testing and handling of connection influx.
- Elimination of the need to circulate accumulated gas after connections in UBD wells.
- Reducing the risk of differential sticking potential colossal cost saving.
- Mitigate excessive bottom hole temperatures and bottom-hole assembly heat soak damage.
- Removing time required to re-establish two-phase circulation with air-foam drilling fluid in under balance drilling.
- Mitigating casing running problems related to hole condition.
- Elimination of required circulation time while tripping.
- Prevent waste time related to misinterpretation between a ballooning formation and a kick. Eliminated the extra circulation time due to wellbore breathing.
- Minimize cost due to drilling fluid losses and troubles related to loss of circulation while drilling.
- Providing a balance pressure condition between bottom hole pressure and formation pressure will minimize invasion of mud into the formation. This results in minimizing the formation damage of the pay zone that could later impact the production and reduces the stimulation costs.

Chapter 4
Potential Applications of Continuous Circulation Technology

Continuous circulation technology is applicable in challenging drilling environments particularly in deep water wells, extended reach drilling, HPHT conditions due to its geological characteristics. The drilling operations in such environments are exposed to drilling hazards due to fluctuation wellbore pressure with conventional drilling. Mitigating these hazards with conventional methods might result in huge NPT and increase the cost of the drilling project to become uneconomical. The use of continuous circulation may allow for greater operational efficiency where near-balance drilling is key.

4.1 Deep water Wells

Deep water wells are usually distinguished by a narrow margin between pore and fracture gradients compared to the onshore wells (Squintani et al. 2019), making drilling operations very difficult. A significant concern that exacerbates drilling issues in these wells is maintaining annulus pressure above pore pressure so that the well does not kick and lower than fracture pressure. The well does not hydraulically fracture and lose circulation. Figure 4.1 demonstrates mud hydrostatic pressure gradients for offshore drilling. Due to the column of seawater and the unconsolidated nature of sediments below the seafloor, the curves of pore pressure (A) and fracture pressure (B) are typically close together, making it impossible to maintain annulus pressure between these curves (Cohen and Deskins, n.d.).

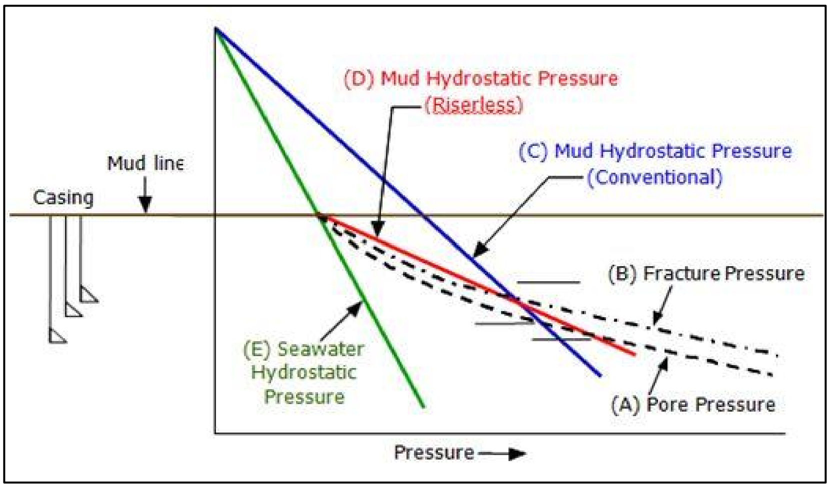

Figure 4.1 Hydrostatic Gradients (Cohen and Deskins, n.d.)

The mud hydrostatic gradient (blue line) in conventional riser drilling represents a straight line starting from the floating drillship. This hydrostatic gradient crosses the pore and fracture gradients over a fairly short vertical distance, resulting in a higher number of casings to achieve the total depth.

In case the annular wellbore pressure at the seabed in the riser is reduced to that of seawater, the hydrostatic curve (D) would be a straight line extending from the seabed. This line slope is significantly reduced, enabling drilling a much greater vertical distance while maintaining bottom hole pressures between the pore and fracture gradient curves. It allows fewer casing lines, smaller vessels for drilling and reduces drilling costs.

Using continuous circulation technology with real-time monitoring could adjust and monitor the pressure at the bottom of the hole. Consequently, able to maintain the bottom hole pressure within the drilling window margin, or in the other word, possibly increasing the operation margin by means making the dynamic bottom hole pressure higher than the pore pressure but lower than the fracture value as long as the static mud weight less than the pore gradient.

The use of continuous circulation technology will be helpful in two ways: reducing the mud trip margin while drilling. On the other hand, the pressure fluctuation induced by tripping (surge and swab effects) will be eliminated. The main effect is the possibility of lowering or eliminating the safety margin used by conventional drilling to compensate for gradient uncertainties. Nevertheless, this approach for pressure management deviates from standard procedures; therefore, this requires a new team to monitor the operation in real time and make a prompt decision according to the real time indications continuously by updating the gradients and the kick tolerance margin (Squintani et al. 2019).

4.2 Extended Reach Drilling

Extended reach drilling wells and lateral are characterized by high-angle wellbores with long horizontal displacements compared to the vertical depth. This involves some critical issues that can pose significant challenges for operator (Cameron 2007). The horizontal section length is limited by the difference between the pore and fracture pressure, but the circulating pressure at the bit increases with the length. The common technical difficulties that exist in the drilling of extended reach wells are:

1- Poor hole cleaning.
   ERD is a high-angle directional well and a long horizontal section. Therefore, when circulation is stopped, cuttings have only a short distance to fall and accumulate in low side of the hole, forming a cuttings bed. When circulation is resumed, the effective hole diameter is gradually decreased, and the potential to restrict the drill string movement is increased. Consequently increases the torque when a drill string starts to rotate and may become stuck in severe cases. Besides, the cuttings bed will cause pack off during tripping and increase the probability of downhole complications.

2- Fluctuations of equivalent circulation density.
   An increment length of the annulus horizontal section and the associated increase in annular pressure loss with depth does not correspond with an equivalent increase in the formation strength, as fracture pressure gradient remains relatively constant in the horizontal direction while the ECD increases with measured depth. This results in a reduction of the mud gradient window (figure 4.2) and can restrict the pump rate to such an extent that it can be challenging to achieve adequate transport of solids and wellbore stability and more severe lost circulation. (ALDRED et al. 1998).

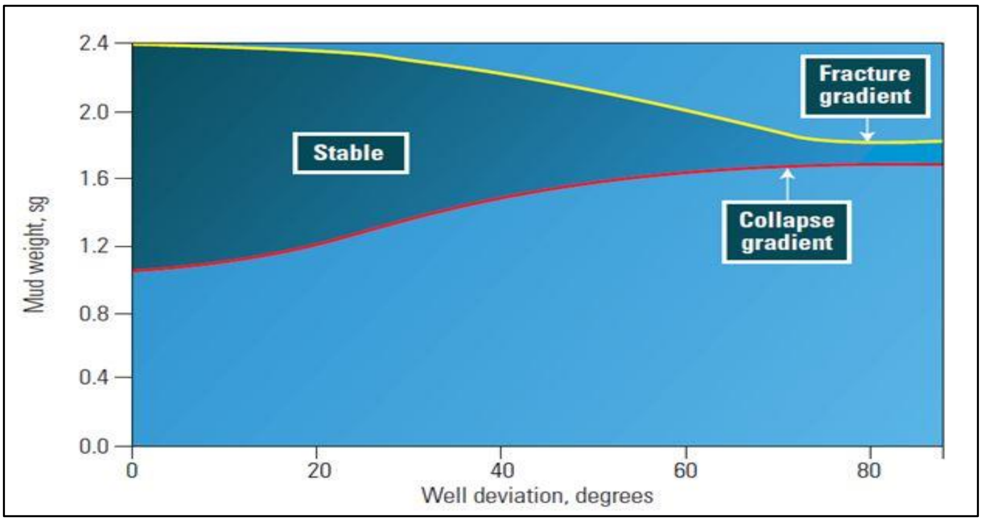

Figure 4.2 Influence of well deviation angle on the pressure window (ALDRED et al. 1998)

These problems could be solved by introducing continuous circulation technology. Continuous circulation will keep drilled cuttings moving and prevents them from settling in the low side of the well and accumulating during pumps off. It eliminates any time for stagnation and minimizes cuttings settlement, reduces the risk of stuck pipe. It considerably reduces or eliminates the time consumed in circulating while drilling long sections of a highly deviated hole. The cleaner annulus also decreases the rotary torque and helps improve the directional control of the drill string. It is possible to reduce or even remove the need for wiper trips to clear the open hole (R. Johnson et al. 2019).

During drill pipe connections, maintaining continuous circulation will allow the ECD to be carefully adjusted and controlled to stay steady throughout the exposed formation from the bit to the previous casing shoe, permitting the static mud gradient to reduce (figure 4.3).

In lateral wellbores, the steady state in circulation pressure, temperature, and density provides an effective way to construct and sustain long and more well stability before setting casing.

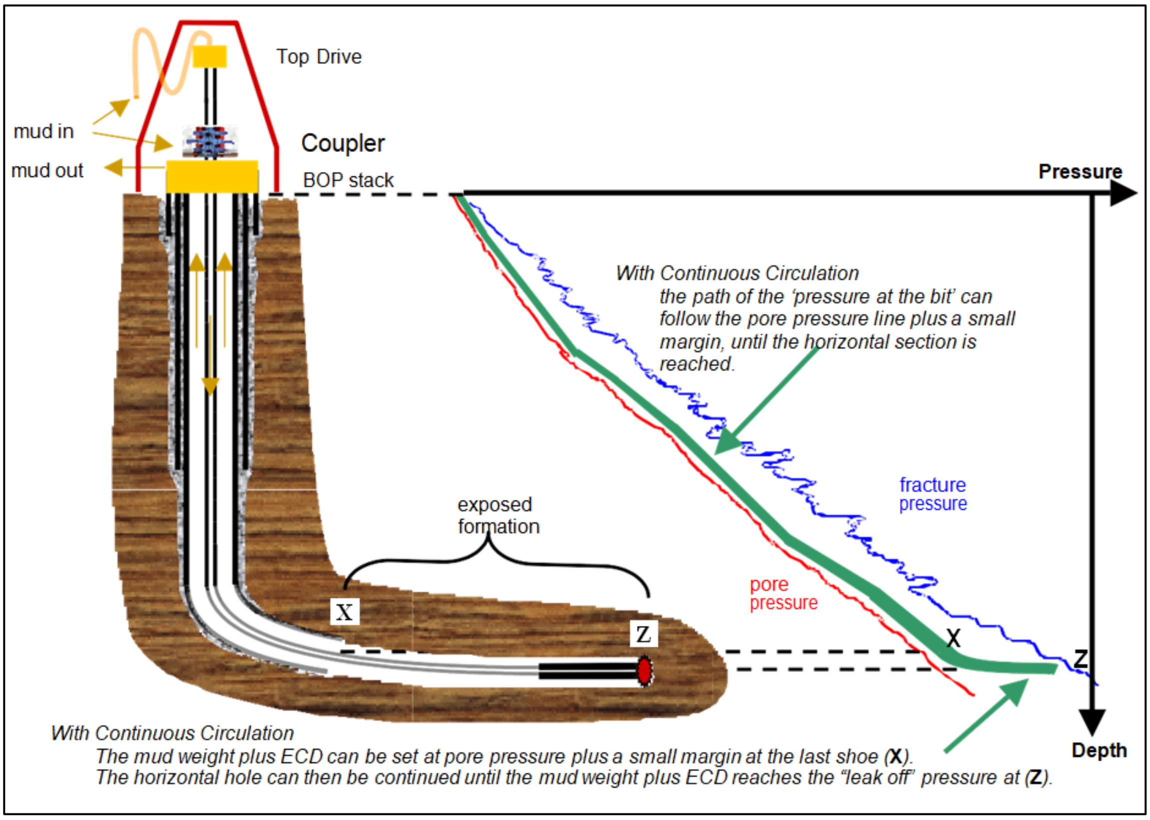

Figure 4.3 Pressure at the bit Path (Ayling et al. 2002)

4.3 Depleted Reservoir Drilling

Pressure depletion refers to a drop in the pore pressures over the lifetime of the reservoir due to the production of reservoir fluids in the long term. The mud gradient window may be further reduced from initial conditions if the reservoir is depleted.

Figure 4.4 shows the variation in operational pressure window in the non-depleted sand and depleted. In the non-depleted sand, the upper limit is considered the fracture gradient and the lower limit to the pore pressure (or collapse pressure). The mud weight window bounded between 1.96 sg and 2.04 sg (maximum ECD). Where the domain of safety margin from 0.08 sg up to the fracture gradient (Torsvoll, Horsrud, and Reimers 2006).

The depletion affects both the lower boundary of the drilling fluid density and the upper boundary. The pore pressure reduction will reduce the stresses acting within the reservoir; in turn, the fracture gradient will be decreased (Torsvoll, Horsrud, and Reimers 2006). Therefore, when using the same ECD as in the early stage of oilfield development, significant lost circulation and sticking problems will occur during the drilling process due to the current lower pore pressure and fracture pressure.

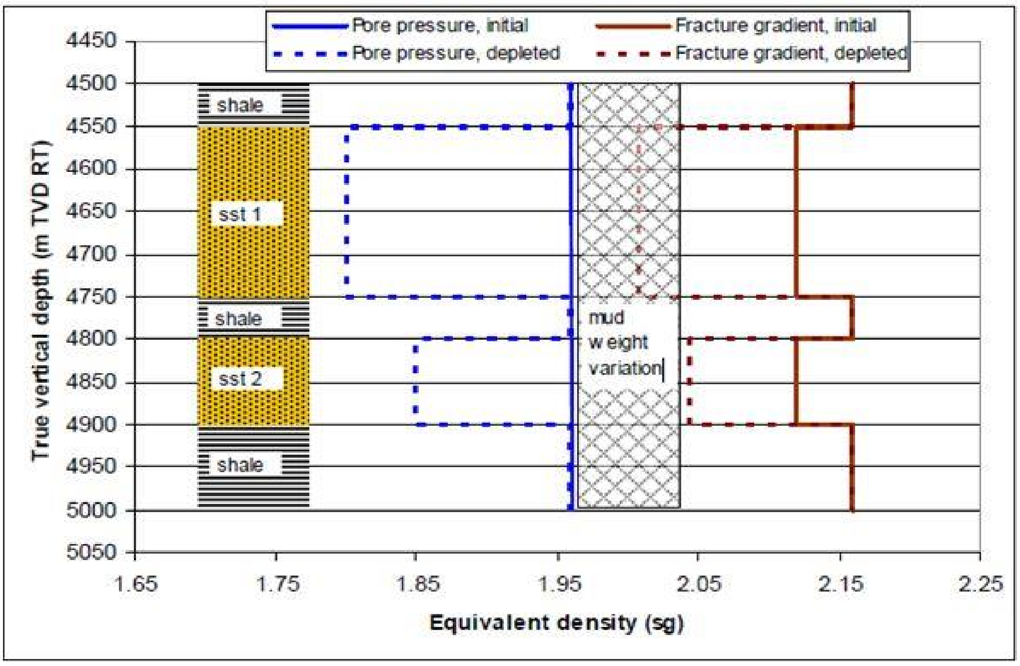

Figure4.4 Schematic illustration of change in operational pressure window before and after depletion (Torsvoll, Horsrud, and Reimers 2006).

The continuous circulation technology could enable drilling wells in depleted formations without losses, eliminate the variation in mud weight between equivalent static density and ECD (when the pump is off), maintaining a constant effective mud weight at the selected lower ECD level. Consequently, it can reduce damage to the reservoir, prevent differential sticking and loss of circulation, and much more beneficial in potentially unstable shale sections. Figure 4.5 illustrates using continuous circulation in depleted reservoir pressure (Ross et al. 2012).

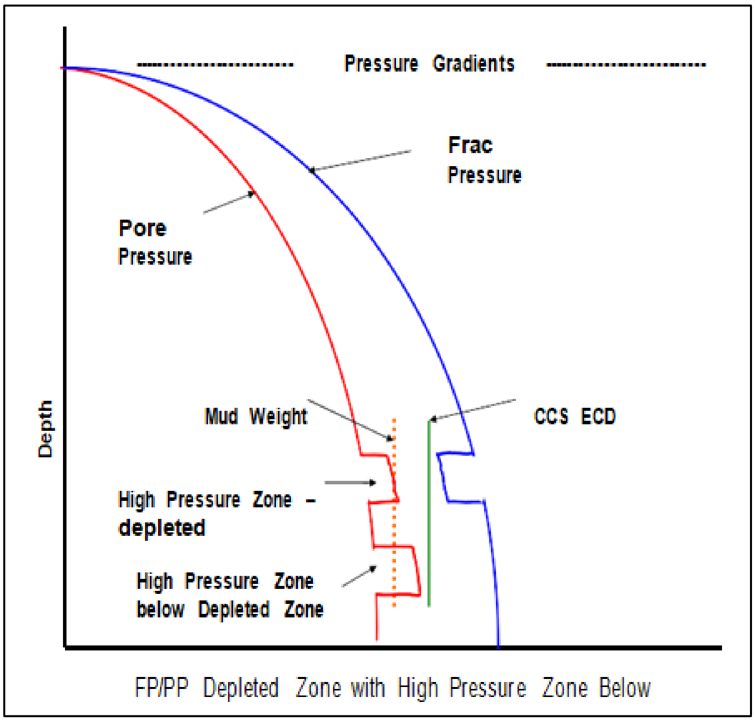

Figure 4.5 Using CCS in depleted reservoir pressure (Ross et al. 2012)

4.4 High Pressure-High Temperature Drilling

Drilling processes in HPHT environments can be challenging. In conventional drilling, this type of wells may require extra casing strings that could make the drilling to target depth is impossible or uneconomic. HPHT wells have limited drilling windows between the pore- and fracture pressures (Ayling et al. 2002). BHP in HPHT reservoirs is highly varied and sensitive to high ECD and temperature changes. When the circulation stops to make a connection, the mud properties can change due to heat up the mud in HPHT sections. This change in mud properties (such as mud weight and viscosity) can significantly impact the accuracy of hydraulic calculations and hydrostatic pressure. The gel breaking could also significantly impact BHP while stopping-starting circulation, causing downhole problems in HPHT fields. Therefore, the accuracy of the ECD is necessary to avoid the loss of fluid due to fractures or to the flow from the reservoir.

When the pumps are turned off, the ECD is lost, a mud backflow can result. Interpretation of the reason is often very complicated, particularly in HPHT wells. It may be critical to separate ballooning effects, fluid influx, formation collapse, and compressibility effect of the drilling fluid due to pressure and temperature change when the circulation is stopped (Karstad 1998). Take into consideration the time lost while observing the well for determining whether a connection is safe.

Continuous circulation technology permits circulation during connection and tripping to mitigate ECD change during pumps on/off while allowing the BHP to stay within the limited drilling window. It allows the connection to be made safely without spending the time required for flow check (Ayling et al. 2002). The only way to control the effect of changing downhole temperature in HPHT wells is to keep full circulation at all times. It can achieve almost near hydraulic stability in the wellbore by maintaining a downhole temperature profile with small variations (Syltøy et al. 2008). Consequently, the mud properties could be maintained in a steady state, which gives an accuracy of the hydrostatic pressure and making the hydraulics consistent.

4.5 Under Balanced Drilling

Underbalanced drilling refers to all those deliberately undertaken drilling operations and techniques with designed wellbore pressure being lower than formation pressure at least in one point of the open hole.

4.5.1 Advantage of Under Balanced Drilling

Drilling underbalanced results in many benefits such as faster rate of penetration, increased drill bit life, testing of reservoirs instantaneously, improvement in production performance because of reduction formation damage due to whole mud filtrate and solids invasion into high permeability reservoir, minor drilling problems associated with differential sticking, loss circulation, and surge/swab impact.

4.5.2 Under Balanced Drilling and Conventional Drilling

The key difference between UBD and conventional drilling is the effective downhole pressure value will be held compared to the pore pressure at the bottom of the hole or at a part of the well path.

In conventional drilling, the wellbore pressure is maintained above the pore pressure by controlling the density of the drilling fluid to prevent the well from kicking in static conditions. This involves overcoming the component of annular friction in dynamic states of circulation, resulting in an overbalance or BHP increment. The high over-balance leads to fluid infusion into the formation, reduction in ROP, and causes other associated drilling problems.

Conversely, in UBD, the wellbore pressure is at least in a section of the wellbore less than the pore pressure of the exposed formation, decreasing the overbalance and avoiding some of the problems associated with this extra overbalance in conventional drilling techniques.

4.5.3 Dynamic of Underbalanced Operations

Figure 4.6 illustrates the UBD operations perfectly by explaining how the BHP is varied during different intervals of the drilling process.

Part 1- Overbalanced drilling reflects drilling of the segment of the non-reservoir. The gas injection starts at the end of this segment since Part 2 is supposed to be a reservoir.

Part 2- Drilling underbalanced.

Part 3- Pipe connection the stop of circulation contributes to a decrease in BHP, may result in bringing formation fluids to the borehole. If increased amounts of influx, BHP will a further decrease approaching a collapse.

Part 4- The connection is made, well continuous flowing, which develops a kick (Potokin et al. 2015).

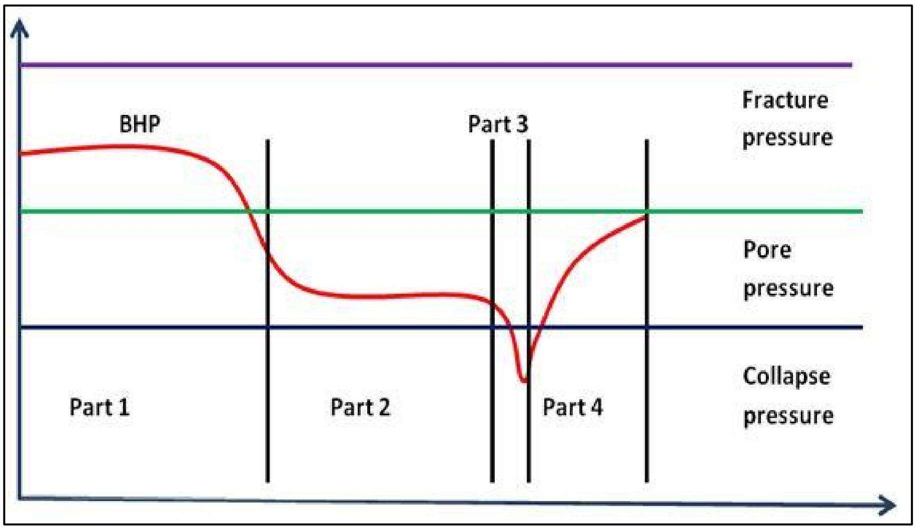

Figure 4.6 Dynamics of Underbalanced Operations (Potokin et al. 2015)

The wellbore pressure has to be kept as close to constant as possible, which is hard when connecting; not only because of loss of the annular friction pressure when the pump is off but since formation fluids, gas in special, collect in the annulus, disturb the pressure balance and must be circulated out before drilling is resumed. It can take several hours of NPT per connection to circulate the formation fluids and re-establish a steady state downhole.

4.5.4 Enabling of UBD with CCS

A big issue with underbalanced drilling is that when drilling ceases, the gas will be accumulated. This gas must be circulated out of the hole before a resumption of the drilling operation. The accumulation of gas can be prevented by continuous circulation. Also, there is no need a time to circulate gas out, and the drilling operation will resume as soon as the new drill pipe is connected. A stable, controlled downhole pressure environment in UBD operations could be achieved by utilizing continuous circulation technology (Jenner et al. 2004). Enables the establishment of steady circulating pressure, prevents the annulus pressure fluctuations generated by pump off/ pump on (Ayling et al. 2002), minimizes the risk of damage to the exposed reservoir, and much easier to manage the BHP (figure 4.7).

By maintaining continuous circulation during connections, no fluid and cuttings drop out in the annulus, eliminating a lengthy period of fluid circulation. The steady state down the hole pressure system is retained throughout, enabling the drilling to resume soon, which could save considerable rig time for each connection (Ayling et al. 2002).

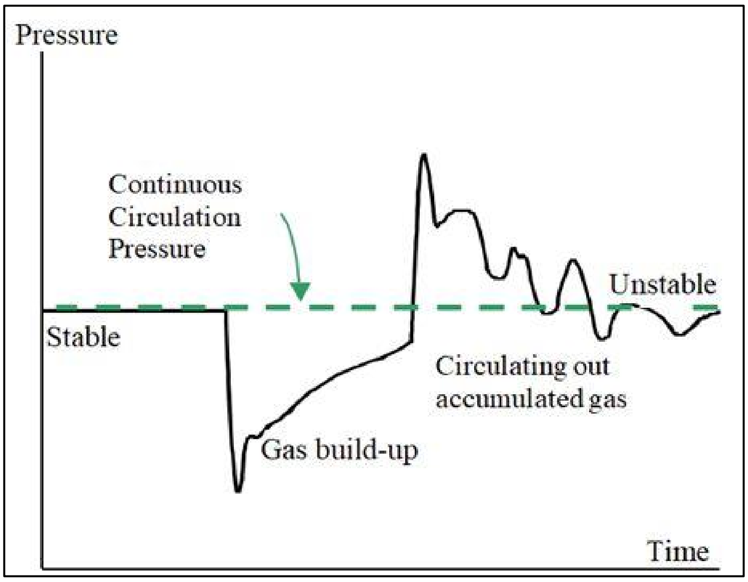

Figure 4.7 Underbalance drilling pressure conditions during connection (R. Johnson et al. 2019)

4.6 Narrow Pore pressure/Fracture Gradient Windows

For certain narrow pore pressure/fracture pressure drilling conditions, the discrepancy between the ECD and the ESD is greater than (or near to) the difference between pore pressure and fracture pressure (gradient window).

4.6.1 Conventional Drilling in Narrow Gradient Windows

Conventional drilling of narrow margin pore-pressure/fracture-gradient environment could not safely and controlled. Conventional drilling requires shut off the pump to make a connection, which causes elimination of annular friction pressure resulting in a reduction in ECD. This reduction in ECD may be sufficient to cause downhole change such as borehole instability, influx, wall collapse, and differential sticking.

On the other hand, the well target depth may not be reached because the ECD gradient exceeded the formation fracture gradient in the normal circulation (Calderoni et al. 2006).

4.6.2 Utilization Continuous Circulation Method

Using continuous circulation technology allows ECD to stay within the safe drilling margins of a narrow window throughout a hole section by adjusting drilling fluid density and circulation rate. This will make the drilling operations more safe, effective, and efficient where the pore pressure and formation fracture gradients are close.

Figure 4.8 illustrates graphically how continuous circulation provides a constant ECD throughout the drilling process, allowing the navigation of narrow drilling windows. Enabling to manage BHP makes it easy to reduce the risk of lost circulation and the chance of kicks. Reducing the pressure spikes associated with break circulation will lead to the stability of the wellbore and improving the hole cleaning. As a result, it will reduce the risk of having the drill pipe stuck. Considerable downtime on the rig will be involved in controlling the outcomes of this situation (Jenner et al. 2004). Without continuous circulation, the ECD varies each time the drill pipe is connected.

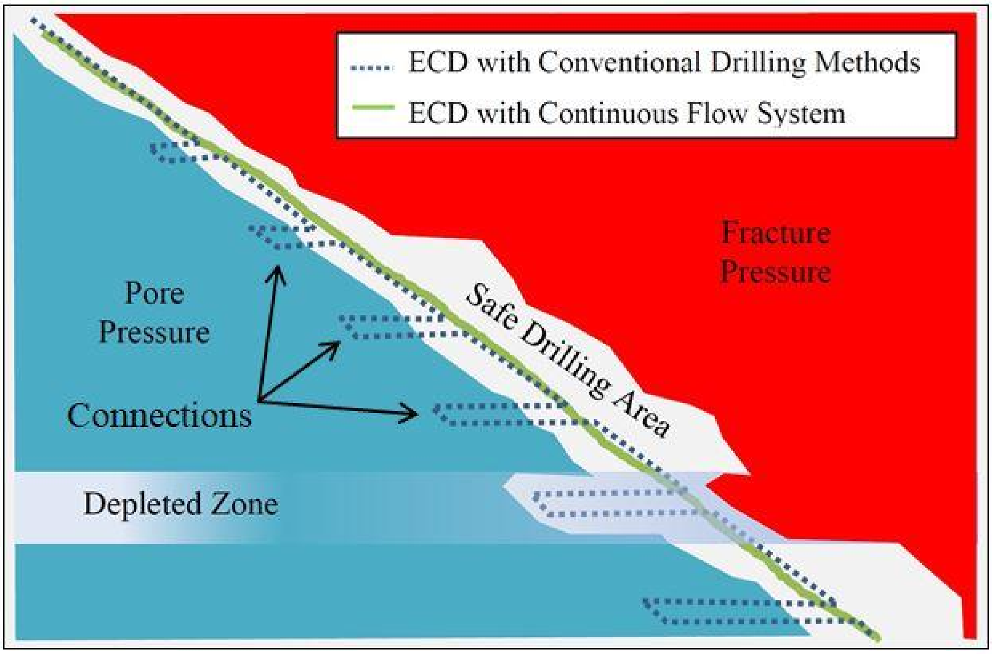

Figure 4.8 Application continuous circulation technology in narrow gradient window (Dharma, Hidayat, and Irawan 2016)

4.7 Dual Gradient Drilling

Dual gradient drilling (DGD) is a drilling technology that proved to be a breakthrough as it presented a solution to managing the narrow pore and fracture pressure gradients in deep-water wells.

4.7.1 Principle of Dual Gradient Drilling

The principle is to have two fluid gradients to get the same bottom hole pressure, usually accomplished with a single fluid gradient. The BHP is the sum of seawater gradient from surface to water-mud interface and mud gradient within the well. The mud gradient is referred to as mud line rather than RKB, and the difference between gradients of the pore and fracture gradient (PP/FG) is increased significantly (Smith et al. 2001).

Pressure at depth single gradient = TVD(ft) x .052 x MW ……………………..(4.1)

Pressure at depth DGD = (WD x .052 x $G_{sea\ water}$) + [(TVD - WD) x .052 x MW] …....(4.2)

Where:

MW: Mud weight

WD: Well depth

TVD: True vertical depth

4.7.2 Drillstring Valve (DSV) to Prevent The U-Tube Effect

Once the pumping is stopped, a heavy mud in the drill string free-falls and the mud level in the annulus is increased due to pressure. Thus a U-tube phenomenon occurs to hydrostatically balance the drilling mud column in the drilling string and hole annulus (variable volume) and the seawater column in the riser above the subsea rotating control system (fixed volume) (figure 4.9).

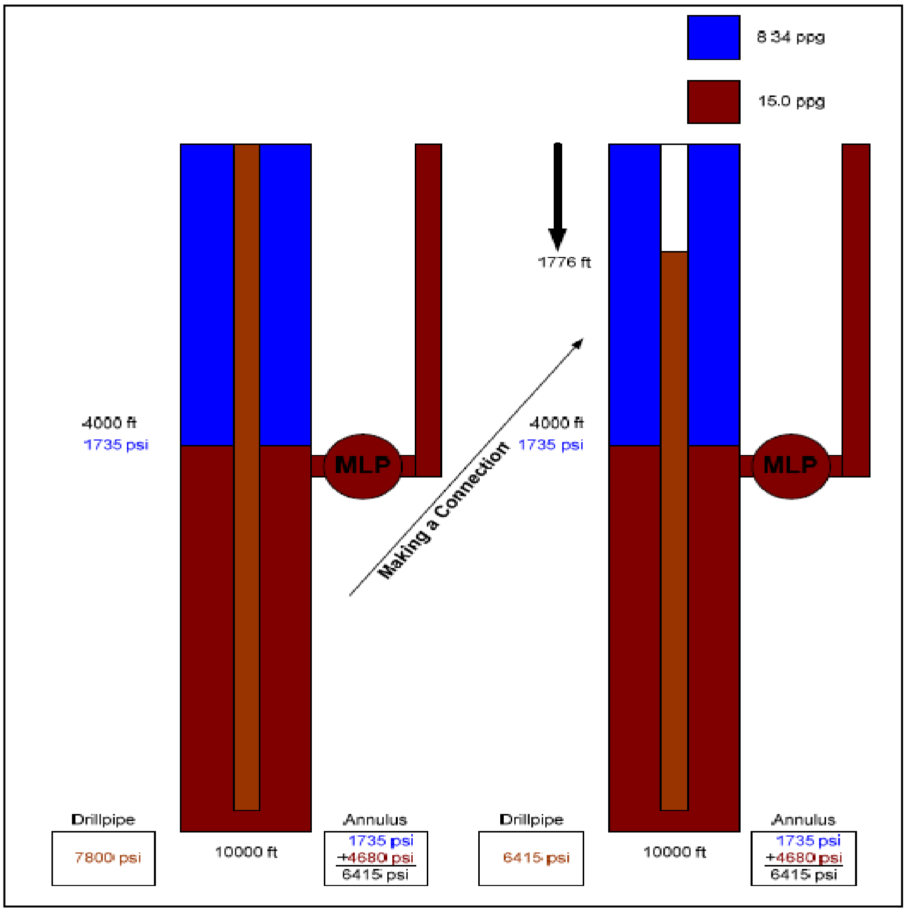

Figure 4.9 U-tube phenomenon during connection in DGD (Malloy 2011)

The occurrence of the U-tubes complicates the detection of taking a kick. The decay of flow from the U-tube can also continue for several minutes. Drilling operations cannot afford this decay because time is money, and if the U-tube covers a kick, with every second, the kick could get bigger (Malloy 2011).

The DSV holds U-tube due to the light density fluid in the riser, which would occur in DGD operations. It is a tool that is installed in the drill string to maintain the hydrostatic pressure of drilling fluid (figure 4.10). The valve is kept open under dynamic conditions, and when the circulation is stopped, it automatically closes with change to static condition, thereby the process of drilling is getting safer.

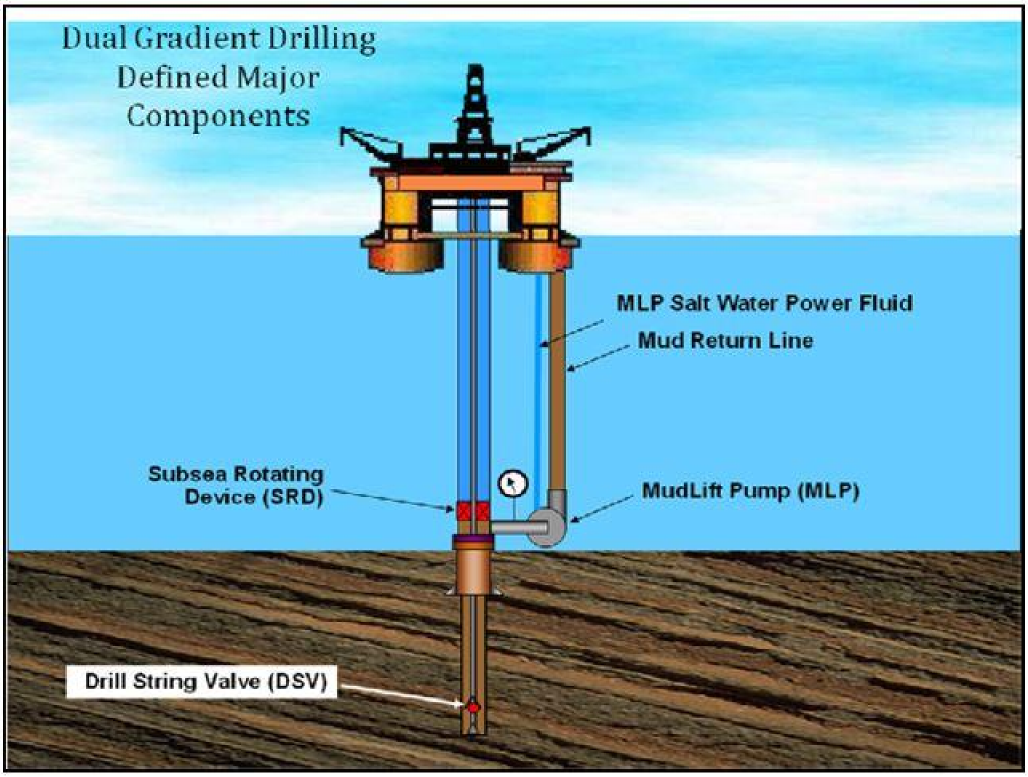

Figure 4.10 Subsea Components in DGD (Malloy 2011)

4.7.3 Utilization of Continuous Circulation in DGD

The operation of DSV has proven to be problematic and can cause extreme surge pressure when the circulation is resumed. Figure 4.11 illustrate the pressure circuit of dual gradient drilling, as the path from A to G and then return to A again, demonstrates how the BHP at D and the pressure gradient over the exposed formation can be controlled by regulating the mud density, mudflow, and inlet and outlet pressure at A. Nevertheless, the perfect gradient, D – E, cannot be reached in certain situations, since the weight of the mud will yield a gradient of Y –Z when the diffusion stopped, where either crosses the fracture limit or the pore pressure limit.

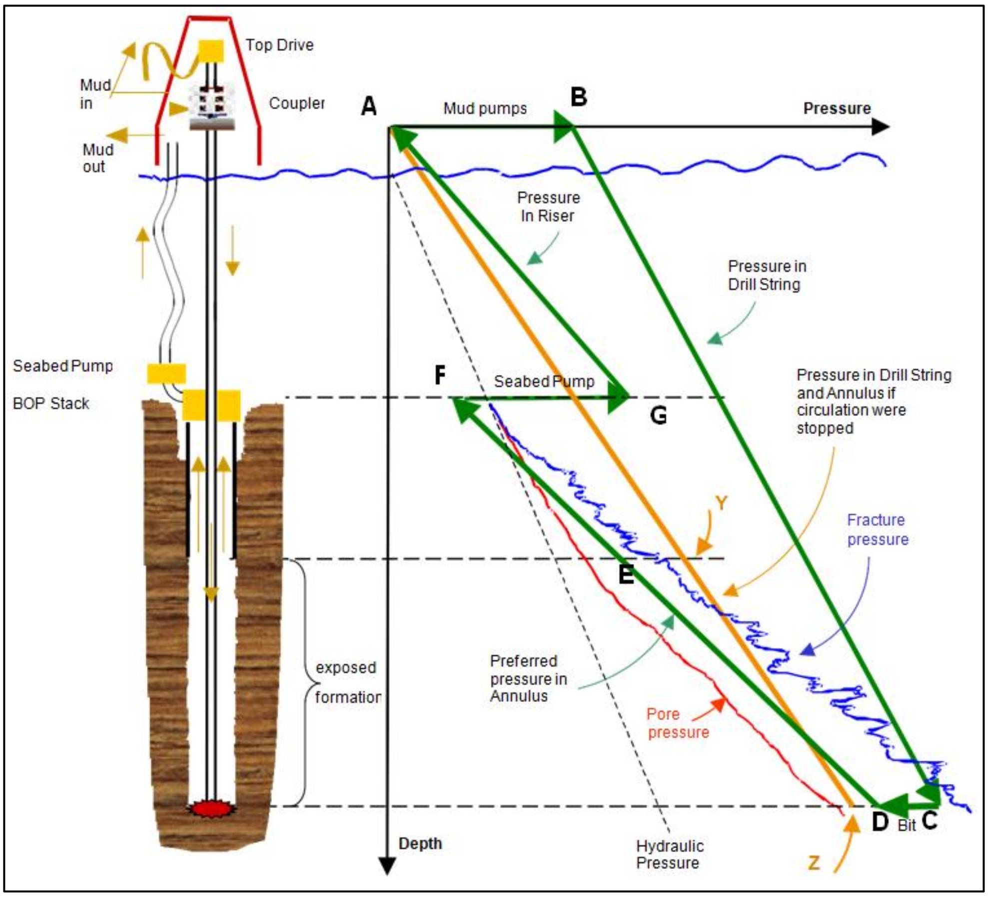

Figure 4.11 Using Continuous Circulation in DGD (Ayling et al. 2002)

The use of a continuous circulation technology with dual gradient drilling allows adjusting and maintaining continuous circulation. Consequently, it is easy to achieve the optimum downhole pressures and pressure gradients within mud gradient window (Ayling et al. 2002).

Chapter 5

Proposal of Using Continuous Circulation Technology In X- Oil Field, Iraq

The following potential drilling hazards have been identified in X- Oil Field, Iraq, and THE suggested proposal solutions with continuous circulation technology are outlined to avoid occurrence.

5.1 Potential Risks During Drilling 12 1/4" Intermediate Suction

The following potential drilling hazards have been identified during drilling of intermediate suction:

- Lost circulation the in Dammam and Hartha formations
- Sulphurous water flow from Tayrat formation

5.1.1 Lost Circulation

Drilling through the Dammam and Hartha formations is commonly associated with significant amounts of NPT caused by severe and frequently total drilling fluid losses.

Dammam and Hartha formations are characterized by porous and vuggy dolomites in nature; thus they are prone to mud loss. Therefore, the increase in the over-balanced wellbore pressure has exposed the formation for total mud losses.

Mud weight (MW) is a critical factor as it is the driving force for losses in terms of loss prevention. At a given depth, the pressure acting on the formation is directly related to the mud weight:

Hydrostatic pressure = height x density x constant of gravity …….. (5.1)

Dammam mud loss event was found to be significantly affected by MW and ECD. Excessive mud weight would either trigger or intensify the issue of lost circulation. Figure 5.1 presents volume loss vs. mud weight for more than 75 wells drilled via Dammam formation. When the mud weight exceeds 1.06 gm/cc, the data shows a noticeable rise in losses.

As a result, the appropriate mud weight for drilling the Dammam formation from this plot is 1.05 gm/cc to 1.06 gm/cc. Using this range of mud weight can prevent or minimize lost circulation (Al-hameedi et al. 2017).

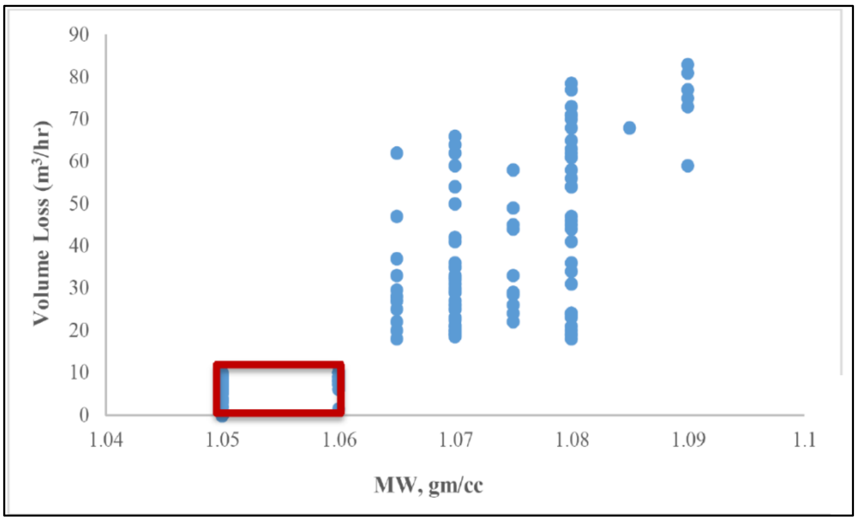

Figure 5.1 Mud Weight versus Volume Loss (Dammam Zone, more than 75 wells) (Al-hameedi et al. 2017)

Besides mud weight, ECD has a significant effect on dynamic loss circulation events. ECD effect on lost circulation rate has been investigated for more than 75 wells drilled via the Dammam formation. The study indicates a significant rise in loss rate when the ECD exceeds 1,075 gm/cc. Figure 5.2 shows that the proper ECD for drilling the Dammam formation is 1.06 gm/cc to 1.075 gm/cc. Using this range, it is possible to prevent or minimize lost circulation (Al-hameedi et al. 2017).

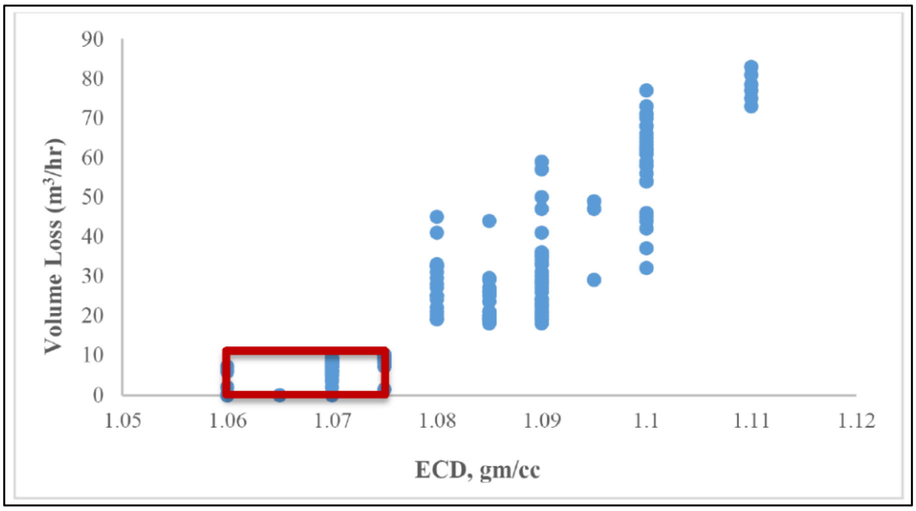

Figure 5.2 Equivalent Circulation Density (ECD) versus Losses rate (Dammam Zone, more than 75 wells) (Al-hameedi et al. 2017)

Proposal Solution with continuous circulation technology

Continuous circulation technology is suggested as a solution to minimize loss circulation in several ways:

- The possibility of reducing overbalance pressure against formations by lower mud weight within allowable limits, reduces the hydrostatic column of fluids in the annulus. Consequently, decrease extra ECD during mud circulation.
- Eliminated the gel strength pressure beak after each connection, as it is not expected that the well will become static to make/Break connections.
- Reducing the surge pressure due to having circulation while tripping in the well.
- Maintaining continuous circulation enhances hole cleaning and prevents solids build-up to avoid overloading the annulus with cuttings.

5.1.2 Sulphurous Water Flow from Tayrat Formation

The phenomenon of sulphurous water flow from Tayrat formation is encountered when the hydrostatic head of the drilling fluid is not enough to overcome the pressure of this formation. In all cases, the flow of this water starts after losing circulation in Dammam or Hartha formations.

Enhance well control with continuous circulation technology by:

- Suppose there is occurring a loss of circulation or a well kick while drilling with continuous circulation. In that case, the first indicator will be observed immediately in the mud returning to the surface by monitoring flow rate measurements and the pit level. Easily and quickly response to kicks and influx size reduced as drill pipe is always connected to the mud supply.
- During tripping out operation, the drill string can be tripped faster without a significant swabbing on the wellbore. Therefore, the well remains under continuous control with connected circulation at all times.
- Maintain BHP above formation pressure by adjusting the flow rate opposite this formation.
- Kill pressure can be maintained while re-installing the drill pipe to bottom, if necessary.

5.2 Potential Risks During Drilling 8.5"Production Suction

It is a challenge to drill the 8.5" section (production suction) with high differential pressures. Shale instability, tight hole, differential sticking, lost circulation, and stuck pipe incidents are frequently encountered problems while drilling this suction. Drilling will become highly challenging with considerable NPT and the loss of a drilling BHA. Most Challenges in this suction that could be dealing with continuous circulation technology are the following:

- Wellbore instability
- Lost circulation
- Differential sticking
- Poor hole cleaning

5.2.1 Wellbore Instability in Tanuma/ Ahmadi/NahrUmr/Upper Shale

Drill string obstructions are frequently observed while pulling out through the shale formations, Tanuma/Ahmadi/NahrUmr/Upper Shale formations after reaching well target depth due to lack of pressure support from the drilling fluid.

Proposal solution with continuous circulation technology

- Maintain continuous mud circulation at all times is keeping BHP above mechanical wellbore stability point and does not change the downhole 'pressure dynamics,' which can damage the borehole wall and make it more unstable.
- Minimize swab during connections and pull out of hole (POOH).
- Insure keep the hole full during POOH.
- Minimize reaming while drilling section, do not need to ream during connections in Shale.
- Help to maintain mud properties to ensure the shale inhibitor concentrations (KCL, Glycol, Barotrol).

5.2.2 Lost Circulation and Well Control Issues in Mishrif Formation

The Mishrif formation occasionally yields lost circulation while drilling due to the current lower pore pressure and fracture pressure because of depletion. Loss circulation in this formation became more challenging to deal with because of:

- This formation is a production zone; therefore, a loss circulation will damage the reservoir, and it will be worst in the case of treatment with a cement plug.
- Loss circulation reduces the annulus flow rate; thus, the accumulation of cuttings in the annulus could not be avoided, and pack-off events are expected.
- When the level of the mud drops, there is an increasing chance of kick in this formation as it is a producing zone.
- The lack of hydrostatic pressure results in sloughing and caving in Tanuma formation. Consequently, a stuck pipe is expected.

<u>Proposal Solution with continuous circulation technology</u>

Continuous circulation technology is suggested as a solution to minimize loss circulation in several ways:

- Static mud weight can be reduced to be slightly overbalanced pressure against formations as can the fluid loss into the producing formation. Therefore, undamaged production formation is greatly enhanced.
- Eliminated the gel strength pressure beak after each connection.
- Control ECD at all times during drilling, connection, tripping, and fluid displacement.
- Reducing the surge pressure by maintaining a slow circulation rate while tripping in.
- Maintaining continuous circulation enhances hole cleaning and avoids overloading the annulus with cuttings.

5.2.3 Differential Sticking

As the hole drilled through porous zones formations (Sadi, Mishrif, Nahr Umr, Zubair), pipe sticking can be encountered. A differential pressure develops and forces a stationary drill string into a thick filter cake of a permeable zone particularly in depleted zones (Zubair and Mishrif).

<u>Proposal solution with continuous circulation technology</u>

Continuous circulation technology is suggested as a solution to decrease the probability of pipe sticking problem through:

- Limit mud weight to the minimum required for hole stability and well control.
- Creating a thinner and tighter filter cake.
- Optimize mud hydraulic flow to minimize ECD.
- Eliminate 'pumping up' the formation during connection.
- Keeping lubricate the drill string and reduce the gelling of the drilling fluid.
- It helps to keep the drill string loose while stationary.
- Avoid developing the differential pressure while drilling pipe connections, as no loss of dynamic pressure.

5.2.4 Lost Circulation in Shuaiba Formation

Shuaiba formation is characterized by compact limestone, often with vuggy, porous dolomite. Potential mud lost circulation is expected at the base of Shuaiba at the interface with Zubair formation, which is troublesome while drilling in this suction. Lost circulation in this formation causes severe wellbore stability issues in other formations such as swelling and caving in shale formations.

Shuaiba mud loss has been significantly affected by mud weight and ECD. Excessive mud weight would either trigger or intensify the issue of lost circulation. Figure 5.3 shows volume loss versus mud weight for more than 75 wells drilled via Shuaiba formation. When the mud weight exceeds 1.16 gm/ cc., the data shows a noticeable rise in losses.

As a result, the appropriate mud weight for drilling the Shuaiba formation from this plot is 1.15 gm/cc to 1.16 gm/cc. Using these values, it is possible to prevent or minimize lost circulation (Al-Hameedi et al. 2017).

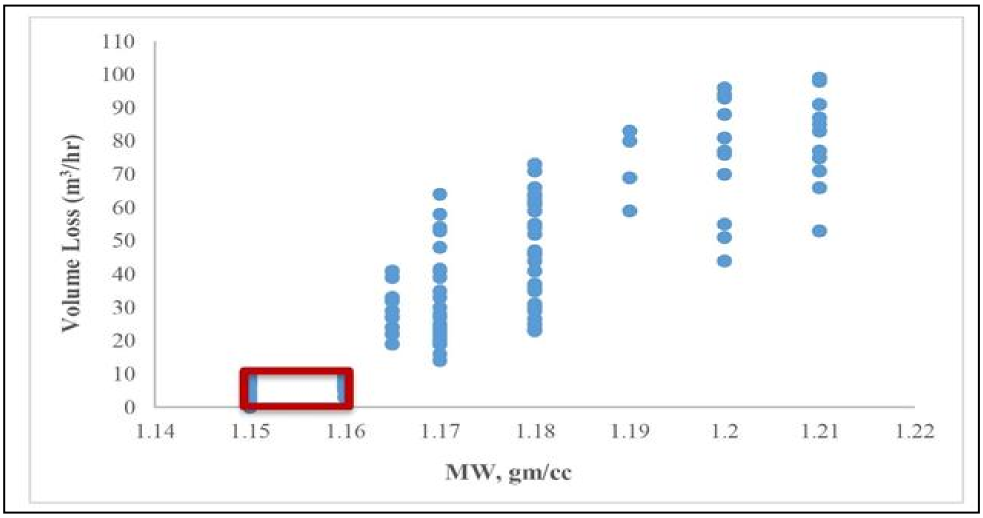

Figure 5.3 Mud weight versus volume loss (Shuaiba zone, more than 75 wells) (Al-Hameedi et al. 2017)

ECD also has a significant effect on dynamic loss circulation events. The effect of ECD on lost circulation rate has been investigated for more than 75 wells drilled via the Shuaiba formation. The study indicates a significant rise in loss rate when the ECD exceeds 1.18 gm/cc. Figure 5.4 shows that the proper ECD for drilling the Shuaiba formation is 1.16 gm/cc to 1.18 gm/cc. Using these values, it is possible to prevent or minimize lost circulation (Al-Hameedi et al. 2017).

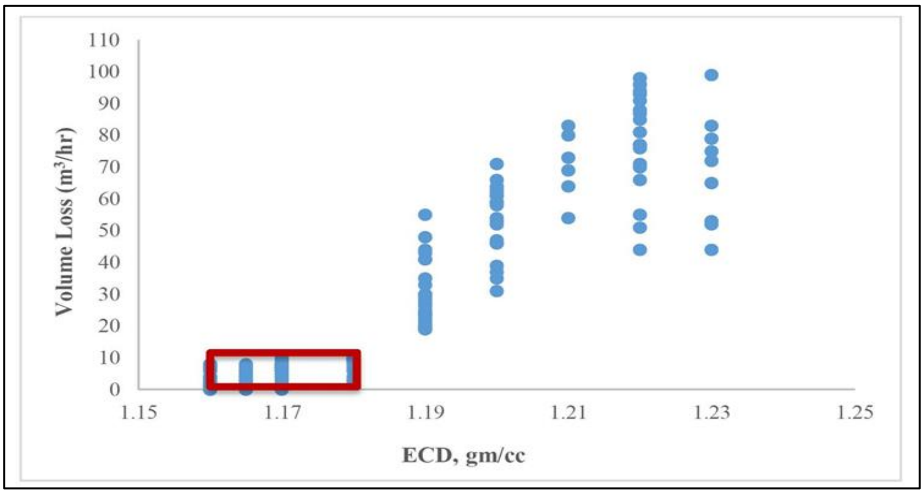

Figure 5.4 Equivalent Circulation Density (ECD) versus Losses rate (Shuaiba Zone, more than 75 wells) (Al-Hameedi et al. 2017)

Proposal Solution with continuous circulation technology

Using continuous circulation technology and following the similar methods that mentioned to treat lost circulation in Dammam and Hartha formations.

5.2.5 Hole Cleaning in The Whole Section

In most situations where torque, drag and fill are noted during drilling and tripping in this suction, particularly along deviated hole suction. The problem often is attributed to cuttings and cavings accumulation in the wellbore when circulation is stopped.

Proposal solution with continuous circulation technology

Continuous circulation technology is suggested as a solution to optimize well-being cleaning through:

- It prevents cutting in deviated wells from falling on the low side.
- It keeps more steady mud rheology and mud properties.
- Ability to hold the drilling parameters with ECD to provide optimum hole cleaning.
- Move cuttings away from the BHA to ensure trouble free during connection.

Chapter 6

Mythology and Simulation Results

In this chapter, the methodology of hydraulic calculations and comparison of annular pressure window between conventional drilling and CCS methods is described. The procedure for hydraulic calculations are made based on API RP 13D (Rheology and Hydraulics) and utilizing Fenton technique (Fontenot and Clark 1997. A simulation created based on developing MATLAB codes that calculate the pressure changes in the wellbore induced by the movement of drill string for conventional drilling method and continuous circulation technology. The simulation was further implemented for the drill pipe connections scenario to calculate the frictional pressure loss and required pressure to break mud gel strength. Finally, annular pressure windows were simulated for a comparison between conventional drilling and CCS methods.

6.1 Assumptions for The Hydraulic Simulator:

- The wellbore is vertical.
- Considering power law model for hydraulic calculations.
- The drilling fluid is water base mud, therefore no fluid compressibility effect in pressure calculations.
- Drill string has float valve (closed-end) to allow one-way flow. Fluid is allowed to flow out of the float; otherwise, the float is treated as a closed pipe.
- Steady-state mud flow conditions.
- The flow regime in the annulus while tripping (with CCS) is laminar flow.
- The temperature is assumed to be constant, and mud properties do not change.
- There are no constrictions in the hydraulic system (such as swelling formation or cutting beds, influxes of formation fluid to the borehole, or drilling fluid losses).
- The mud density in the annulus is equal to the original density (no cuttings effect).

6.2 Workflow Summary

Figure 6.1 provides a workflow for the overall procedure, reports with simulation of hydraulic pressure calculation and comparison between conventional drilling method and CCS technology.

The simulation has been done in MATLAB version R2020b and made use of the built-hydraulic model. The difference between conventional and CCS methods for surge/swab calculation is due to the difference value of average effective annular velocity. In the conventional method, the average effective annular velocity (V_{ae}) is the mud velocity which produces due to drill pipe displacement and the viscous drag component (clinging viscosity). In contrast, in CCS, there is additional velocity resulting from pump flow.

$V_{ae} = V_p + V_{cling} + V_{disp}$, For calculation surge pressure ....(6.1)

$V_{ae} = V_p - V_{cling} - V_{disp}$, For calculation swab pressure ....(6.2)

Where :

V_{ae}: average effective annular velocity.

V_p: pump velocity.

V_{cling}: Clinging velocity due to due to the viscous drag of the drill string.

V_{disp}: Displacement velocity due to the drill string displacement.

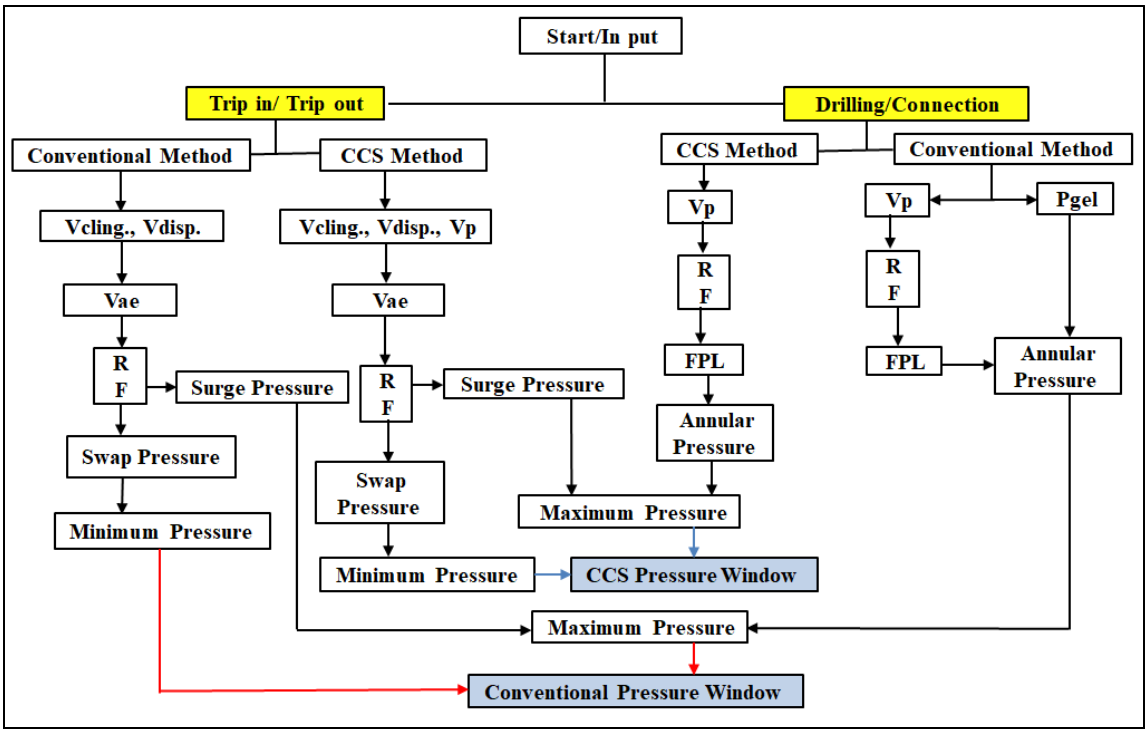

Figure 6.1 Schematic workflow for construction MATLAB code to do hydraulic calculation, figure was adapted.

6.3 Simulation Set up

A 10800 ft vertical well having drill string with considered for the virtual well simulation. The outside (Dp) and inside (DI) of drill pipe diameters are 5", 4.276" consequently. Table 6.1 shows the well geometry and drilling fluid properties.

Table 6.1 well geometry and drilling fluid properties

Well Geometry		Drilling Fluid Properties	
Measured depth of well	11600ft	Mud Type	WBM
Length of the cased hole(Lc)	6000 ft	Mud density (rho) (ppg)	10.5
Length of open hole (Lh)	5600 ft	Gel strength for 10 min (GS) (lbf/100ft^2)	10
Inside casing diameter (ICD)	8.681"	Dial reading at 100 rpm (R100)	25
Open hole size (DH)	8.5"	Dial reading at 3 rpm (R3)	9
Drill pipe Diameter (DP)	5"		

6.4 Simulation Results and Discussion

6.4.1 Trip in Drill String Mode

Based on the result shown in figure 6.2, surge pressure generated during trip in with conventional drilling method is more significant compared with generated surge pressure with CCS at the same tripping speed. With a circulation in the well at 20 GPM, the surge pressure was decreased from 44.8 psi to 39.8 psi at total depth.

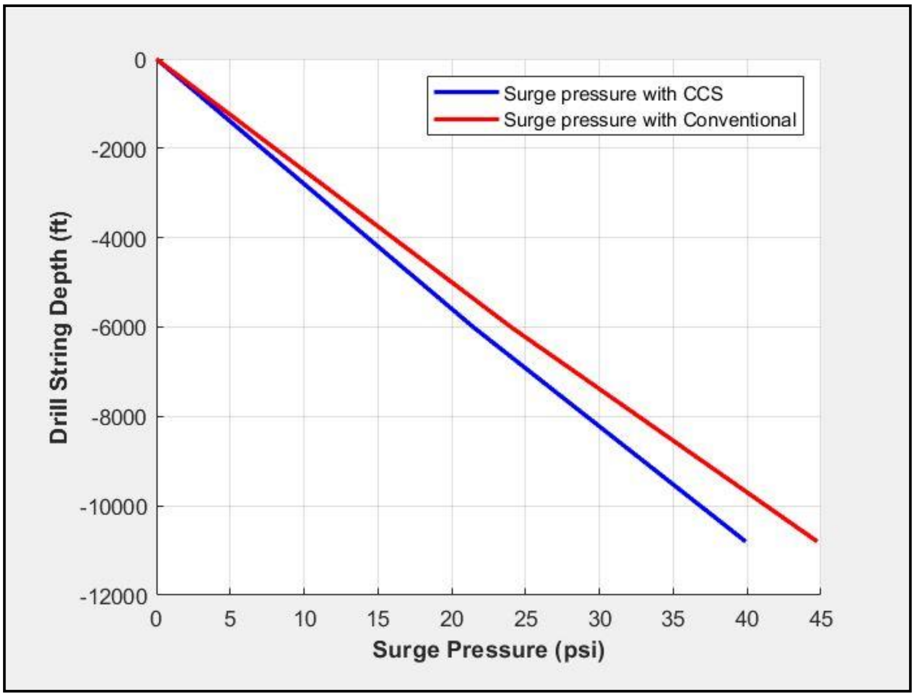

Figure 6.2 Simulated Surge pressure for conventional and CCS, published with MATLAB® R2020b.

6.4.2 Trip out Drill String Mode

Figure 6.3 illustrates the results of simulation swab pressure generated during a trip out with conventional drilling and the CCS method. The value of generated swab pressure with circulation at a flow rate of 50 GPM is 11.6 psi at the total depth, whereas the value is 20.9 psi with the conventional method at the same tripping speed. Having circulation reduced the swab pressure to 55% from its value with no circulation.

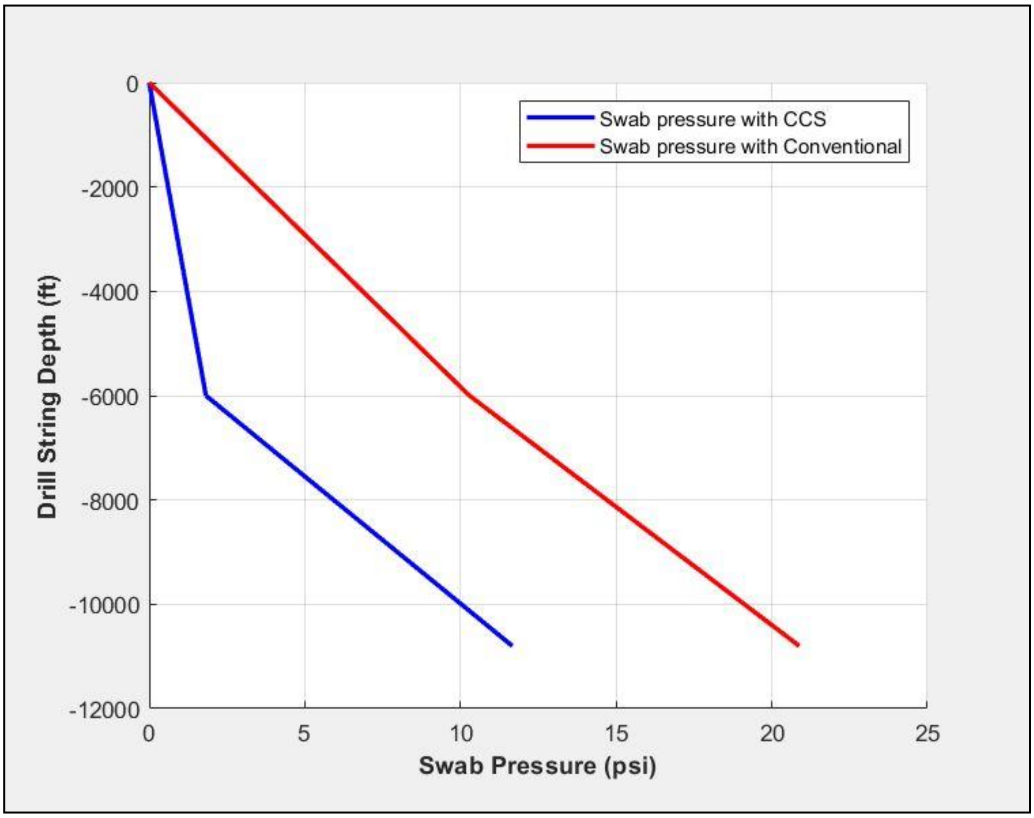

Figure 6.3 Simulated Swab pressure for conventional and CCS, published with MATLAB® R2020b.

6.4.3 Drilling and Connection Mode

Figure 6.4 displays the simulation results of connection mode of the CCS and conventional drilling methods. During recirculate the drilling fluid after making a connection, annular pressure increases due to breaking gel strength with conventional drilling. The total annular pressure at total depth was equal to 153.5 psi. In order to eliminate the effect of gel strength, maintain continuous circulation while making a connection. Therefore the annular pressure was lower in the case of using CCS. As shown, the blue line, which represents annular pressure with CCS, reduced below the red line by 59%, and the total annular pressure at total depth was equal to 63.4 psi.

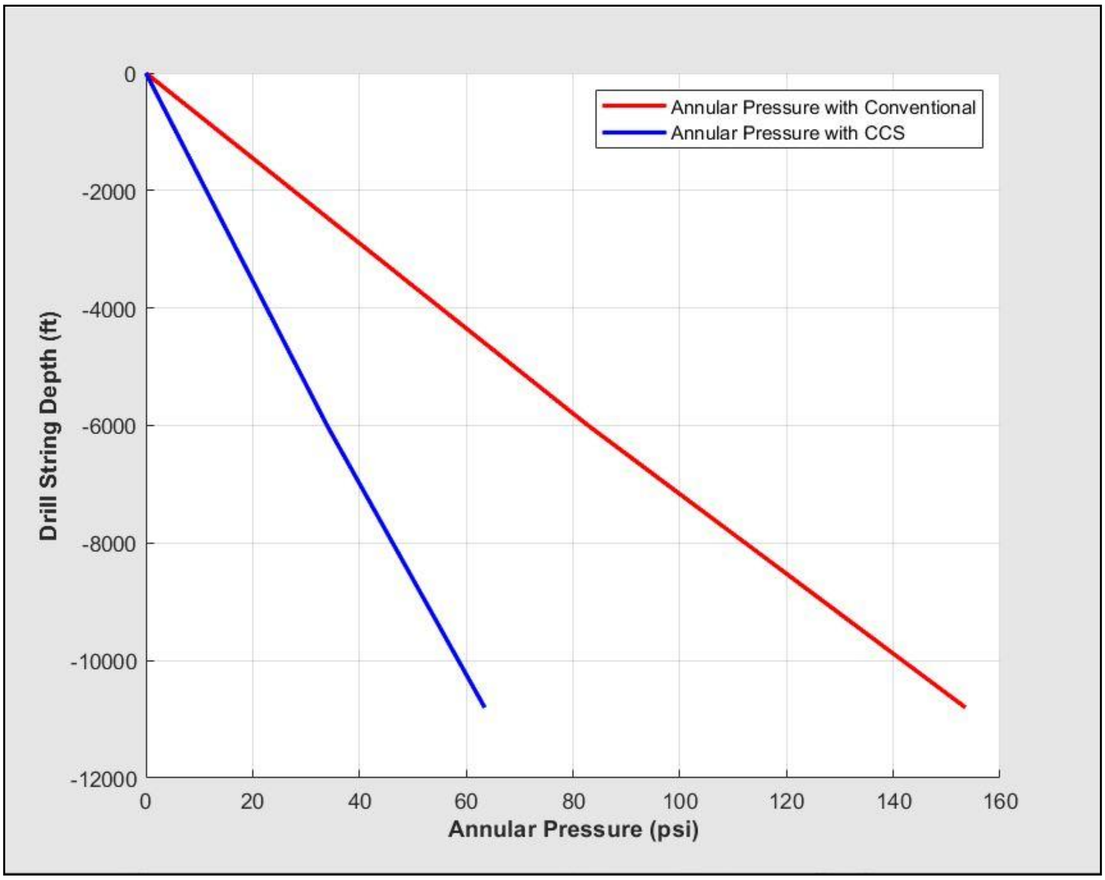

Figure 6.4 Comparison of simulated annular pressure variations during drilling and connection for conventional and CCS. Published with MATLAB® R2020b.

6.4.4 Annular Pressure Window

Comparing simulation results between two methods, conventional and CCS methods in terms of the annular pressure window are presented in figure 6.5. The annular pressure window in conventional drilling is defined by the maximum pressure (red line) and minimum pressure (black line). In the CCS method, the annular pressure window is defined by the maximum pressure (blue line) and minimum pressure (green line). As shown, the required annular pressure window with the CCS method to accommodate all well-drilling operations is narrower than the required annular pressure window with the conventional drilling method.

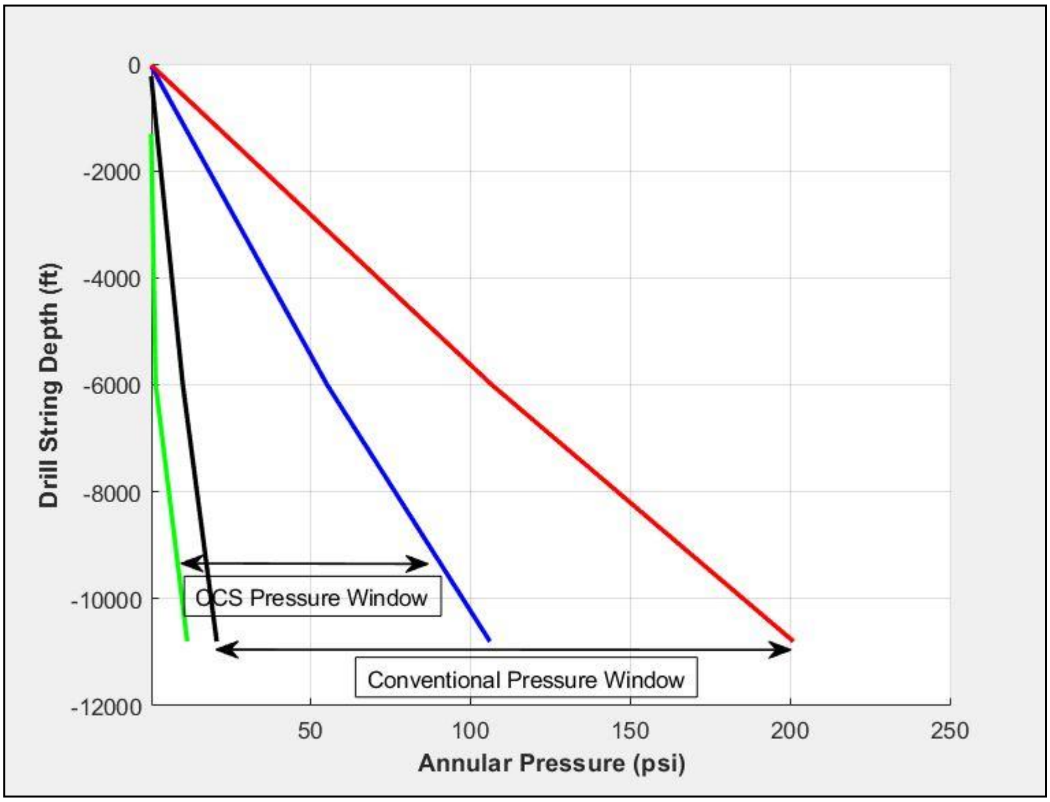

Figure 6.5 Comparison Annular pressure window between conventional method and CCS , Published with MATLAB® R2020b

Chapter 7
Conclusion, Future work, and Recommendations

7.1 Conclusion

This thesis aims to analyse how to drill wells following the highest safety standards while improving performance, moving the drilling operations from discontinuity to continuity applying the continuous circulation drilling technology.

A continuous circulation system (CCS) is an innovative drilling method used to maintain the circulation of drilling fluid into the well during making and breaking drill pipe connections, unlike conventional drilling, in which the circulation must be stopped while connection. It contains a manifold connected to drill string that enables safe diversion, and subs installed at the top of each drill pipe stand, providing two independent flows.The annular pressure with the CCS method can be significantly controlled by removing fluctuations in pressure caused by pipe movement and circulation interruptions. It can improve drilling efficiency and overcome wellbore problems caused by interruption of fluid circulation while drilling and tripping operations.

The use of CCS to maintain a continuous flow of mud while drilling a specific section should have the main well control and safety benefits:

1 Enhance early kick detection

2 Elimination of connection kicks and trip gas.

3 Prevent well ballooning phenomenon

4 Minimize swabbing pressure

In terms of drilling enhancing performance, the CCS can improve the overall drilling process by promoting faster drilling, enhance wellbore stability, prevention cuttings beds formation, decrease the probability of differential sticking, help to avoid the occurrence of stuck pipe incidents, minimize loss circulation of drilling fluid, a possibility to monitor downhole pressure continuously, reducing non-production time. Moreover, continuous circulation drilling is greatly enhancing well productivity throughout the drilling of a reservoir. As a result, saving rig time and reducing overall well operations costs.

Potential applications of CCS have been investigated in difficult drilling environments to evaluate benefits when combined with advanced drilling techniques; these include:

- Under-balanced drilling (UBD)
- Help to drill high-pressure high-temperature (HPHT) wells throughout maintain drilling fluid properties throughout the drilling operations.
- Extended reach drilling (ERD) wells
- Deep-water wells
- Depleted reservoirs drilling
- Narrow pore-pressure/fracture-gradient windows
- Dual gradient drilling

The potential drilling hazards in X-oil field, Iraq have been identified, and the suggested proposal solutions with continuous circulation technology are outlined to avoid occurrence. Most drilling challenges in this field, such as lost circulation, well-control issue, wellbore instability, and differential sticking, could be dealing with CCS in several ways, particularly reducing the surge and swab pressure and eliminating the gel strength pressure after each connection.

The simulations were created to make hydraulic calculations and compare the annular pressure window between conventional drilling and CCS methods. The simulations were performed by developing MATLAB codes that calculated the wellbore pressure changes induced by the movement of drill string for the conventional drilling method and continuous circulation system (CCS). The simulation is further implemented for the drill pipe connections scenario to calculate the frictional pressure loss and required pressure to break gel strength. Moreover, annular pressure windows were simulated for making a comparison between conventional drilling and CCS methods. The simulation results indicated that reduction of the swab/surge pressure proved when utilizing CCS compared to its value with conventional drilling. Results showed also that a required pressure window with CCS to accommodate all drilling operations is narrower than the required pressure window for the conventional drilling method.

7.2 Future Work

- Continuous circulation technology enhances the economics of drilling wells by reducing drilling problems and eliminate NPT. Further economic analyses are required to determine how much of that CCS will offer for time and cost saving in a specific situation.

- Additional study about the concept should investigate how continuous circulation is used to enhance the well casing design and the drilling fluid program.

- Moreover, developing a wellbore pressure simulator to utilize in well planning for simulating hydraulic calculation through various wellbore conditions. Furthermore, the simulator could be developed to use in real-time for decision support during drilling operations. It should consider all parameters affecting wellbore pressure like equivalent mud weight, wellbore geometry, and percentage of drilled cuttings in the wellbore.

7.3 Recommendations

- Using a continuous circulation technology in southern Iraqi oil fields will optimize drilling operations and mitigate potential drilling problems.

- Contingency planning shall be in place to mitigate the risks associated with the continuous circulation method complexities. Contingency planning also gives the confidence to proceed in case of failure of the circulation system and to be ready for probable or less expected incidents.

- All CCS operations should be linked to conventional well-control practices and must be clearly communicated to guarantee the safety of all crew involved and equipment.

- Due to varies potential application of continuous circulation technology in different drilling environments, the industry needs to standardize and automate continuous circulation drilling operations. For this, further developments and research are needed.

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Appendix

Appendix A

Mud Hydraulic Formulas

<u>Surge and swab pressure calculations</u>

1- Calculation of the mud velocity due to volumetric mud flow produced by the displacing pipe opposite cased hole and opposite open hole (Vdis.):

Vdis=Vp*(((DP^2)-(DI^2))/((ICD^2)-(DP^2)+(DI^2)));

Vdis=Vp*(((DP^2)-(DI^2))/((DH^2)-(DP^2)+(DI^2)));

Where:

DP: Drill pipe Diameter

DI: Inside Drill pipe Diameter

DH: Open hole size

ICD: Inside casing diameter

2- Calculation of mud velocity due to mud clinging to the inner moving annular opposite cased hole and opposite open hole (Vcling.):

Vcling = -Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2)))); cased hole

Vcling = -Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2)))); open hole

3- Calculation of the mud velocity in the annulus resulting from pump flow opposite cased hole and opposite open hole (Vpump):

Vpump = (0.408*Q)/((ICD^2)-(DP^2));

Vpump = (0.408*Q)/((DH^2)-(DP^2));

4- Calculation average effective annular velocity opposite cased hole and opposite open hole (Vae):
Vae=(Vpump1-Vcling1-Vdis1); for swab calculation
Vae=(Vpump1+Vcling1+Vdis1); for surge calculation

5- Calculation of the flow index in annulus (na):
na=0.657*log10(R100/R3); %

6- Calculation of the consistency index in annulus (Ka):

Ka=(R100/(170.3)^na

7- Calculation of effective Viscosity in annulus opposite cased hole and opposite open hole (mu):

mu =100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae)/(ICD-DP))^(na-1); cased hole

mu =100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(DH-DP))^(na-1); cased hole

8- Calculation of Reynold number opposite cased hole and opposite open hole (Re):
Re=(928*(ICD-DP)*Vae*rho)/mu; opposite cased hole
Re=(928*(DH-DP)*Vae2*rho)/mu; opposite open hole

Where:
rho: Mud density

9- Calculation of annular fraction factor opposite cased hole (F1) and opposite open hole (F1):
F=24/Re

10- Calculation of swap and surge pressure opposite cased hole and opposite open hole :

P = (F1*(Vae^2)*rho*Lc)/(25.81*(ICD-DP)); opposite cased hole

P = (F1*(Vae^2)*rho*Lh)/(25.81*(DH-DP)); opposite open hole

Where:

LC: Length of open hole

Lh: Length of open hole

Annular pressure calculations

1- Friction pressure loss opposite cased hole and opposite open hole (FPL) :

FPL= (F*(Vpump^2)*rho*Lc)/(25.81*(ICD-DP)); opposite cased hole

FPL= (F*(Vpump^2)*rho*Lh)/(25.81*(DH-DP)); opposite open hole

2- Pressure gel strength opposite cased hole and opposite open hole (Pg):
Pg = (Lc*9)/(300*(ICD-DP)); opposite cased hole
Pg = (Lh*9)/(300*(DH-DP)); opposite open hole

3- Annular Pressure (Pa) :
Pa = (FPL+Pg)

Appendix B

Mud Hydraulic Calculations Published with MATLAB® R2020b

```
%----------------MATLAB script to calculate Swab Pressure----------------%

%%%%% Use API RP 13D for Hydraulic calculations
%%Deceleration of various parameters%%
%%%%Swab pressure opposite Cased Hole%%%%
rho=10.5; %ppg – Mud density
Vp=0.8; %ft/sec – velocity of drill string while tripping
Q=50; % Pump Flow rate (gals/min)
ICD=8.681; %in -Inside casing diameter
DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus
Lc1=0 ;        %% Lc:- measured length of cased hole(feet)
step=-400 ;
Lc=Lc1:step:step*15;
%%%%Surge pressure opposite Cased Hole with CCS
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite cased hole(Vdis1)
Vdis1=Vp*(((DP^2)-(DI^2))/((ICD^2)-(DP^2)+(DI^2))); % Open End drill string

% mud velocity due to mud clinging to the inner moving annular opposite
%cased hole(Vcling1)
Vcling1=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));

% the mud velocity in the annulus resulting from pump flow opposite cased
%hole(Vpump1)in(ft/sec)
Vpump1=(0.408*Q)/((ICD^2)-(DP^2));
%average effective annular velocity opposite cased hole(Vae1)
Vae1=(Vpump1-Vcling1-Vdis1);

% Effective Viscosity in annulus opposite cased hole(mu1)
mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(ICD-DP))^(na-1);

Re1=(928*(ICD-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite cased hole

F1=24/Re1 ;  % Annular fraction factor opposite cased hole
% Psgc1: Surge pressure opposite cased hole with CCS

Pswc1=-(F1*(Vae1^2)*rho*Lc)/(25.81*(ICD-DP));

hold on
plot(Pswc1,Lc,'b');


%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
```

```
%%%Swab pressure opposite Cased Hole with Conventional Drilling%%%
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite cased hole(Vdis2)
Vdis2=Vp*(((DP^2)-(DI^2))/((ICD^2)-(DP^2)+(DI^2))); % Open End drill string

% mud velocity due to mud clinging to the inner moving annular opposite
%cased hole(Vcling2)
Vcling2=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));


%average effective annular velocity opposite cased hole(Vae2)
Vae2=-(Vcling2+Vdis2);

% Effective Viscosity in annulus opposite cased hole(mu2)
mu2=-100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(ICD-DP))^(na-1);

Re2=-(928*(ICD-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite cased hole

F2=24/Re2 ;  % Annular fraction factor opposite cased hole

% Pswc2: Surge pressure opposite cased hole with CCS
 Pswc2=-(F2*(Vae2^2)*rho*Lc)/(25.81*(ICD-DP));
hold on
plot(Pswc2,Lc,'r');

 %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
                %%%%% Swab pressure opposite Open Hole %%%%%%
rho=10.5; %ppg – the density of the mud
Vp=1.5; %ft/sec – velocity of drill string while tripping
Q=20; % Pump Flow rate (gals/min)
DH=8.5; %in -open hole diameter

DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus

%%%%Swab pressure opposite Open Hole with CCS%%%%
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;
  % Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite open hole(Vdis1)
 Vdis1=Vp*(((DP^2)-(DI^2))/((DH^2)-(DP^2)+(DI^2))); % Open End drill string
% mud velocity due to mud clinging to the inner moving annular opposite
%open hole(Vcling1)
 Vcling1=-Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2))));
% the mud velocity in the annulus resulting from pump flow opposite open
%hole(Vpump1)in(ft/sec)
```

```
 Vpump1=(0.408*Q)/((DH^2)-(DP^2));
 %average effective annular velocity opposite open hole(Vae1)
 Vae1=(Vpump1-Vcling1-Vdis1);

% Effective Viscosity in annulus opposite open hole(mu1)
 mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(DH-DP))^(na-1);

 Re1=(928*(DH-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite open hole

 F1=24/Re1 ;  % Annular fraction factor opposite open hole
% Psgh1: Surge pressure opposite Open hole with CCS
 Pswh1=-(F1*(Vae1^2)*rho*Lh)/(25.81*(DH-DP));

 Pswc1=1.822;
% Psg1: Total Surge pressure with CCS
 Psw1= Pswc1+ Pswh1;
 hold on
 plot(Psw1,D,'b');

%%%%Swab pressure opposite Open Hole with Conventional
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;

% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite open hole(Vdis2)
Vdis2=Vp*(((DP^2)-(DI^2))/((DH^2)-(DP^2)+(DI^2))); % Open End drill string

% mud velocity due to mud clinging to the inner moving annular opposite
%open hole(Vcling2)
 Vcling2=-Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2))));
%average effective annular velocity opposite open hole(Vae1)
Vae2=-(Vcling2+Vdis2);

% Effective Viscosity in annulus opposite open hole(mu2)
mu2=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(DH-DP))^(na-1);

Re2=(928*(DH-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite open hole

F2=24/Re2 ;  % Annular fraction factor opposite open hole
 Pswh2=-(F2*(Vae2^2)*rho*Lh)/(25.81*(DH-DP));
 Pswc2=10.288;

% Psg2: Total Surge pressure with Conventional
Psw2= Pswc2+ Pswh2;
 hold on
plot(Psw2,D,'r');
 xlabel('Swab Pressure (psi)')
 ylabel('Depth (ft)')
 grid
 legend ('Swab pressure with CCS','Swab pressure with Conventional');
```

```
%---------------MATLAB script to calculate Annular Pressure--------------%
%%%%% %declaration of various parameters
rho=10.5; %ppg – the density of the mud
Q=550; % Pump Flow rate (gals/min)
ICD=8.681; %in -Inside casing diameter
DP=5; %in -Drill pipe diameter
GS=10; %%% GS: Gel strength for 10 min (lbf/100ft²)
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus)

%%%%%%Annular Pressure opposite cased hole
Lc1=0 ;        %% Lc:- measured length of cased hole(feet)
step=-400 ;
Lc=Lc1:step:step*15;

%mud velocity in the annulus opposite cased hole(Vpump)(ft/sec)
Vpump=(0.408*Q)/((ICD^2)-(DP^2));

% Effective Viscosity in annulus opposite cased hole(Mu)
Mu=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vpump)/(ICD-DP))^(na-1);
Re=(928*(ICD-DP)*Vpump*rho)/Mu ; % Reynolds Number opposite cased hole
F=24/Re ;  % Annular fraction factor opposite cased hole

 %Friction  pressure loss opposite cased hole (FPLc)
FPLc=-(F*(Vpump^2)*rho*Lc)/(25.81*(ICD-DP));

%%%% Pressure required to break the mud's gel strength in the annulus
Pgc=-(Lc*9)/(300*(ICD-DP));% Pressure gel strength opposite cased hole (Pgc)

%%%%% Annular Pressure with conventional drilling (Pac1)
Pac1=((FPLc+Pgc));

%%%%% Annular Pressure with CCS (Pac2)
Pac2=((FPLc));

hold on
plot(Pac1,Lc,'r');
hold on
plot(Pac2,Lc,'b');

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
                  %%Annular Pressure opposite Open hole %%%
rho=10.5; %ppg – the density of the mud
Q=550; % Pump Flow rate (gals/min)
DH=8.5; %in -open hole diameter
ICD=8.681; %in -Inside casing diameter
DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
```

```
% Depth of bit (D)
D=Lc+Lh;
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus)

%mud velocity in the annulus opposite open hole(Vpump)(ft/sec)

Vpump=(0.408*Q)/((DH^2)-(DP^2));

% Effective Viscosity in annulus opposite open hole(Mu)
Mu=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vpump)/(DH-DP))^(na-1);
Re=(928*(DH-DP)*Vpump*rho)/Mu ; % Reynolds Number opposite open hole

F=24/Re ;  % Annular fraction factor opposite open hole

%Friction  pressure loss opposite Open hole (FPLo)
 FPLo=-(F*(Vpump^2)*rho*Lh)/(25.81*(DH-DP));

 %%%% Pressure required to break the mud's gel strength in the annulus
 Pgo=-(Lh*9)/(300*(DH-DP));% Pressure gel strength opposite open hole (Pgo)

 %%%%% Annular Pressure with conventional drilling (Pao1)
 Pac1=82.839;
 Pao1=((FPLo+Pgo+Pac1));
 hold on
 plot(Pao1,D,'r');

%%%%% Annular Pressure with CCS  (Pao2)
Pac2=33.94;
Pao2=((FPLo+Pac2));

hold on
plot(Pao2,D,'b');
grid
xlabel ('Annular Pressure (psi)')
ylabel ('Depth (ft)')
legend ('Annular Pressure with conventional ','Annular Pressure with CCS');
```

```
%----------------MATLAB script to calculate Surge Pressure----------------%

%%%%% Use API RP 13D for Hydraulic calculations
%%%%% %Deceleration of various parameters
%%%%Surge pressure opposite Cased Hole%%%%
rho=10.5; %ppg – the density of the mud
Vp=1.5; %ft/sec – velocity of drill string while tripping
Q=20; % Pump Flow rate (gals/min)
ICD=8.681; %in -Inside casing diameter
DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus

Lc1=0 ;        %% Lc:- measured length of cased hole(feet)
step=-400 ;
Lc=Lc1:step:step*15;
%%%%Surge pressure opposite Cased Hole with CCS
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite cased hole(Vdis1)
Vdis1=Vp*(((DP^2)-(DI^2))/((ICD^2)-(DP^2)+(DI^2))); % Open End drill string

% mud velocity due to mud clinging to the inner moving annular opposite
%cased hole(Vcling1)
Vcling1=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));

% the mud velocity in the annulus resulting from pump flow opposite cased
%hole(Vpump1)in(ft/sec)
Vpump1=(0.408*Q)/((ICD^2)-(DP^2));
%average effective annular velocity opposite cased hole(Vae1)
Vae1=(Vpump1+Vcling1+Vdis1);

% Effective Viscosity in annulus opposite cased hole(mu1)
mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(ICD-DP))^(na-1);

Re1=(928*(ICD-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite cased hole

F1=24/Re1 ;  % Annular fraction factor opposite cased hole
 % Psgc1: Surge pressure opposite cased hole with CCS

Psgc1=-(F1*(Vae1^2)*rho*Lc)/(25.81*(ICD-DP));

hold on
plot(Psgc1,Lc,'b');
grid
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%Surge pressure opposite Cased Hole with Conventional Drilling
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite cased hole(Vdis2)
Vdis2=Vp*((DP^2)/((ICD^2)-(DP^2))); % closed End drill string

% mud velocity due to mud clinging to the inner moving annular opposite
```

```
%cased hole(Vcling2)
Vcling2=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));

%average effective annular velocity opposite cased hole(Vae2)
Vae2=(Vcling2+Vdis2);

% Effective Viscosity in annulus opposite cased hole(mu2)
mu2=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(ICD-DP))^(na-1);

Re2=(928*(ICD-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite cased hole

F2=24/Re2 ;  % Annular fraction factor opposite cased hole

% Psgc2: Surge pressure opposite cased hole with CCS
 Psgc2=-(F2*(Vae2^2)*rho*Lc)/(25.81*(ICD-DP));

hold on
plot(Psgc2,Lc,'r');

rho=10.5; %ppg – the density of the mud
Vp=1.5; %ft/sec – velocity of drill string while tripping
Q=20; % Pump Flow rate (gals/min)
DH=8.5; %in -open hole diameter

DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus

%%%%% Surge pressure opposite Open Hole %%%%%%
%%%%Surge pressure opposite Open Hole with CCS
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;

% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite open hole(Vdis1)
Vdis1=Vp*(((DP^2)-(DI^2))/((DH^2)-(DP^2)+(DI^2))); % Open End drill string

% mud velocity due to mud clinging to the inner moving annular opposite
%open hole(Vcling1)
Vcling1=-Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2))));

% the mud velocity in the annulus resulting from pump flow opposite open
%hole(Vpump1)in(ft/sec)
Vpump1=(0.408*Q)/((DH^2)-(DP^2));

%average effective annular velocity opposite open hole(Vae1)
Vae1=(Vpump1+Vcling1+Vdis1);
```

```
% Effective Viscosity in annulus opposite open hole(mu1)
mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(DH-DP))^(na-1);

Re1=(928*(DH-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite open hole

F1=24/Re1 ;  % Annular fraction factor opposite open hole
% Psgh1: Surge pressure opposite Open hole with CCS
Psgh1=-(F1*(Vae1^2)*rho*Lh)/(25.81*(DH-DP));

Psgc1=21.452;
% Psg1: Total Surge pressure with CCS
Psg1= Psgc1+ Psgh1;

 xlabel('Surge Pressure (psi)')
 ylabel('Depth (ft)')
 hold on
plot(Psg1,D,'b');

%%%%Surge pressure opposite Open Hole with Conventional
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;

% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite open hole(Vdis2)
Vdis2=Vp*((DP^2)/((DH^2)-(DP^2))); % closed End drill string

% mud velocity due to mud clinging to the inner moving annular opposite
%open hole(Vcling2)
Vcling2=-Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2))));

%average effective annular velocity opposite open hole(Vae1)
Vae2=(Vcling2+Vdis2);

% Effective Viscosity in annulus opposite open hole(mu2)
mu2=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(DH-DP))^(na-1);

Re2=(928*(DH-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite open hole

F2=24/Re2 ;  % Annular fraction factor opposite open hole

 Psgh2=-(F2*(Vae2^2)*rho*Lh)/(25.81*(DH-DP));
 Psgc2=24.011;

% Psg2: Total Surge pressure with Conventional
Psg2= Psgc2+ Psgh2;
hold on
plot(Psg2,D,'r');

legend ('Surge pressure with CCS','Surge pressure with Conventional');
```

```matlab
%----------------MATLAB script to calculate Pressure Window----------------%


%%%%Maximum pressure opposite Cased Hole%%%%
rho=10.5; %ppg – the density of the mud
Vp=1.5; %ft/sec – velocity of drill string while tripping
Q=20; % Pump Flow rate (gals/min)
ICD=8.681; %in -Inside casing diameter
DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus
Lc1=0; %% Lc:- measured length of cased hole(feet)
step=-400 ;
Lc=Lc1:step:step*15;
%%%%Surge pressure opposite Cased Hole with CCS
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite cased hole(Vdis1)
Vdis1=Vp*(((DP^2)-(DI^2))/((ICD^2)-(DP^2)+(DI^2))); % Open End drill string
% mud velocity due to mud clinging to the inner moving annular opposite
%cased hole(Vcling1)
Vcling1=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));
% the mud velocity in the annulus resulting from pump flow opposite cased
%hole(Vpump1)in(ft/sec)
Vpump1=(0.408*Q)/((ICD^2)-(DP^2));
%average effective annular velocity opposite cased hole(Vae1)
Vae1=(Vpump1+Vcling1+Vdis1);
% Effective Viscosity in annulus opposite cased hole(mu1)
mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(ICD-DP))^(na-1);
Re1=(928*(ICD-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite cased hole
F1=24/Re1 ;  % Annular fraction factor opposite cased hole
 % Psgc1: Surge pressure opposite cased hole with CCS
Psgc1=-(F1*(Vae1^2)*rho*Lc)/(25.81*(ICD-DP));
 %%%%%%Annular Pressure opposite cased hole
Qd=550; % Pump Flow rate (gals/min)
GS=10; %%% GS: Gel strength for 10 min (lbf/100ft²)
Vpumpd=(0.408*Qd)/((ICD^2)-(DP^2));
% Effective Viscosity in annulus opposite cased hole(Mu)
Mu=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vpumpd)/(ICD-DP))^(na-1);
Re=(928*(ICD-DP)*Vpumpd*rho)/Mu ; % Reynolds Number opposite cased hole
F=24/Re ;  % Annular fraction factor opposite cased hole
 %Friction  pressure loss opposite cased hole (FPLc)
FPLc=-(F*(Vpumpd^2)*rho*Lc)/(25.81*(ICD-DP));
%%%%% Annular Pressure with CCS (Pac)
Pac1=((FPLc));
Pmax1=Psgc1+Pac1;
hold on
plot(Pmax1,Lc,'b');


%%%%Surge pressure opposite Cased Hole with Conventional Drilling
Vdis2=Vp*((DP^2)/((ICD^2)-(DP^2))); % closed End drill string
```

```
Vcling2=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));
Vae2=(Vcling2+Vdis2);
mu2=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(ICD-DP))^(na-1);
Re2=(928*(ICD-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite cased hole
F2=24/Re2 ;  % Annular fraction factor opposite cased hole
% Psgc2: Surge pressure opposite cased hole with Conventional
Psgc2=-(F2*(Vae2^2)*rho*Lc)/(25.81*(ICD-DP));
%%%% Pressure required to break the mud's gel strength in the annulus
Pgc=-(Lc*9)/(300*(ICD-DP));% Pressure gel strength opposite cased hole (Pgc)
%%%%% Annular Pressure with conventional drilling (Pac2)
Pac2=((FPLc+Pgc));
Pmax2=Psgc2+Pac2;
hold on
plot(Pmax2,Lc,'r');


%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
                %%%%Maximum pressure opposite Open Hole%%%%
rho=10.5; %ppg – the density of the mud
Vp=1.5; %ft/sec – velocity of drill string while tripping
Q=20; % Pump Flow rate (gals/min)
DH=8.5; %in -open hole diameter
DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus)
%%%%Surge pressure opposite Open Hole with CCS
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;
Vdis1=Vp*(((DP^2)-(DI^2))/((DH^2)-(DP^2)+(DI^2))); % Open End drill string
Vcling1=-Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2))));
Vpump1=(0.408*Q)/((DH^2)-(DP^2));
Vae1=(Vpump1+Vcling1+Vdis1);
mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(DH-DP))^(na-1);
Re1=(928*(DH-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite open hole
F1=24/Re1 ;  % Annular fraction factor opposite open hole
% Psgh1: Surge pressure opposite Open hole with CCS
Psgh1=-(F1*(Vae1^2)*rho*Lh)/(25.81*(DH-DP));
% Annular Pressure opposite open hole
Qd=550; % Pump Flow rate while drilling(gals/min)
%mud velocity in the annulus opposite open hole(Vpump)(ft/sec)
Vpumpd=(0.408*Qd)/((DH^2)-(DP^2));
 % Effective Viscosity in annulus opposite open hole(Mu)
Mu=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vpumpd)/(DH-DP))^(na-1);
Red=(928*(DH-DP)*Vpumpd*rho)/Mu ; % Reynolds Number opposite open hole
Fd=24/Re ;  % Annular fraction factor opposite open hole
% Friction  pressure loss opposite Open hole (FPLo)
 FPLo=-(Fd*(Vpumpd^2)*rho*Lh)/(25.81*(DH-DP));
```

```
%%%%% Annular Pressure with CCS  (FPLo)
PmaxCCS=Psgh1+FPLo+55.392;
hold on
plot(PmaxCCS,D,'b');
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
 %%%% Pressure required to break the mud's gel strength in the annulus%%%%
 Pgo=-(Lh*9)/(300*(DH-DP));% Pressure gel strength opposite open hole (Pgo)
 Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;
Vdis2=Vp*((DP^2)/((DH^2)-(DP^2))); % closed End drill string
Vcling2=-Vp*((1/(2*log(DP/DH))+(((DP/DH)^2)/(1-((DP/DH)^2)))));
Vae2=(Vcling2+Vdis2);
mu2=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(DH-DP))^(na-1);
Re2=(928*(DH-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite open hole
F2=24/Re2 ;  % Annular fraction factor opposite open hole
Psgh2=-(F2*(Vae2^2)*rho*Lh)/(25.81*(DH-DP));
PmaxCON=Psgh2+FPLo+Pgo+106.851;
hold on
plot(PmaxCON,D,'r')
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
           %%%%Min pressure(Swab pressure opposite Cased Hole)%%%%
rho=10.5; %ppg - the density of the mud
Vp=0.8; %ft/sec - velocity of drill string while tripping
Q=50; % Pump Flow rate (gals/min)
ICD=8.681; %in -Inside casing diameter
DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus
Lc1=0 ;        %% Lc:- measured length of cased hole(ft)
step=-400 ;
Lc=Lc1:step:step*15;
%%%%Surge pressure opposite Cased Hole with CCS
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite cased hole(Vdis1)
Vdis1=Vp*(((DP^2)-(DI^2))/((ICD^2)-(DP^2)+(DI^2))); % Open End drill string
 % mud velocity due to mud clinging to the inner moving annular opposite
 %cased hole(Vcling1)
Vcling1=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));
% the mud velocity in the annulus resulting from pump flow opposite cased
%hole(Vpump1)in(ft/sec)
Vpump1=(0.408*Q)/((ICD^2)-(DP^2));
%average effective annular velocity opposite cased hole(Vae1)
Vae1=(Vpump1-Vcling1-Vdis1);
 % Effective Viscosity in annulus opposite cased hole(mu1)
mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(ICD-DP))^(na-1);
Re1=(928*(ICD-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite cased hole
F1=24/Re1 ;  % Annular fraction factor opposite cased hole
 % Psgc1: Surge pressure opposite cased hole with CCS
```

```
Pswc1=-(F1*(Vae1^2)*rho*Lc)/(25.81*(ICD-DP));
hold on
plot(Pswc1,Lc,'g');
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%Swab pressure opposite Cased Hole with Conventional Drilling
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite cased hole(Vdis2)
Vdis2=Vp*(((DP^2)-(DI^2))/((ICD^2)-(DP^2)+(DI^2))); % Open End drill string
% mud velocity due to mud clinging to the inner moving annular opposite
%cased hole(Vcling2)
Vcling2=-Vp*((1/(2*log(DP/ICD)))+(((DP/ICD)^2)/(1-((DP/ICD)^2))));
%average effective annular velocity opposite cased hole(Vae2)
Vae2=-(Vcling2+Vdis2);
% Effective Viscosity in annulus opposite cased hole(mu2)
mu2=-100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(ICD-DP))^(na-1);
Re2=-(928*(ICD-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite cased hole
F2=24/Re2 ;  % Annular fraction factor opposite cased hole
% Pswc2: Surge pressure opposite cased hole with CCS
Pswc2=-(F2*(Vae2^2)*rho*Lc)/(25.81*(ICD-DP));
hold on
plot(Pswc2,Lc,'k');
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
                %%%%% Swab pressure opposite Open Hole %%%%%%
rho=10.5; %ppg – the density of the mud
Vp=1.5; %ft/sec – velocity of drill string while tripping
Q=20; % Pump Flow rate (gals/min)
DH=8.5; %in -open hole diameter
DP=5; %in -Drill pipe diameter
DI=4.276; %in -Inside Drill pipe diameter
R100=25 ; % Dial reading at 100 rpm
R3=9; % Dial reading at 3 rpm
na=0.657*log10(R100/R3); %the flow index (in Annulus)
Ka=(R100/(170.3)^na); % the consistency index (in Annulus)
%%%%Swab pressure opposite Open Hole with CCS
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite open hole(Vdis1)
Vdis1=Vp*(((DP^2)-(DI^2))/((DH^2)-(DP^2)+(DI^2))); % Open End drill string
% mud velocity due to mud clinging to the inner moving annular opposite
%open hole(Vcling1)
Vcling1=-Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2))));
% the mud velocity in the annulus resulting from pump flow opposite open
%hole(Vpump1)in(ft/sec)
Vpump1=(0.408*Q)/((DH^2)-(DP^2));
%average effective annular velocity opposite open hole(Vae1)
Vae1=(Vpump1-Vcling1-Vdis1);
% Effective Viscosity in annulus opposite open hole(mu1)
mu1=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae1)/(DH-DP))^(na-1);
Re1=(928*(DH-DP)*Vae1*rho)/mu1 ; % Reynolds Number opposite open hole
```

```
F1=24/Re1 ;  % Annular fraction factor opposite open hole
% Psgh1: Surge pressure opposite Open hole with CCS
Pswh1=-(F1*(Vae1^2)*rho*Lh)/(25.81*(DH-DP));
Pswc1=1.822;
% Psg1: Total Surge pressure with CCS
Psw1= Pswc1+ Pswh1;
hold on
plot(Psw1,D,'g');
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%Swab pressure opposite Open Hole with Conventional
Lc=-6000 ;%%  measured length of cased hole(feet)
Lh1=0 ;%
step=-400 ;
Lh=Lh1:step:step*12;
% Depth of bit (D)
D=Lc+Lh;
% Mud velocity due to volumetric mud flow produced by the displacing pipe
% opposite open hole(Vdis2)
Vdis2=Vp*(((DP^2)-(DI^2))/((DH^2)-(DP^2)+(DI^2))); % Open End drill string
% mud velocity due to mud clinging to the inner moving annular opposite
%open hole(Vcling2)
Vcling2=-Vp*((1/(2*log(DP/DH)))+(((DP/DH)^2)/(1-((DP/DH)^2))));
%average effective annular velocity opposite open hole(Vae1)
Vae2=-(Vcling2+Vdis2);
% Effective Viscosity in annulus opposite open hole(mu2)
mu2=100*Ka*(((2*na)+1)/(3*na))^na *((144*Vae2)/(DH-DP))^(na-1);
Re2=(928*(DH-DP)*Vae2*rho)/mu2 ; % Reynolds Number opposite open hole
F2=24/Re2 ;  % Annular fraction factor opposite open hole
Pswh2=-(F2*(Vae2^2)*rho*Lh)/(25.81*(DH-DP));
Pswc2=10.288;
% Psg2: Total Surge pressure with Conventional
Psw2= Pswc2+ Pswh2;
hold on
plot(Psw2,D,'k');
ylabel('Depth (ft)')
xlabel('Annular Pressure (psi)')
grid
legend ('Max pressure with CCS','Max pressure with Conventional');
```