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ABSTRACT

Due to energy demands and depletion of the existent reservoirs, the oil and gas industry is expanding new frontier exploration and production works such as in deep-water, HPHT zones and arctic regions. However, due to narrow operational window, drilling with conventional methods in these regions is difficult or even impracticable. The conventional drilling related problems, among others, include drill string sticking, kick and lost circulation. In addition, the problems increase the non-productive time (NPT) and costs the oil industry a considerable amount of money.

In order to overcome the narrow operational window limits and challenges, managed pressure drilling (MPD) technologies are developed, which are the extension of conventional drilling method.

Unlike conventional drilling method, MPD methods use equipment and techniques to control well annular pressure precisely and be able to drill through narrow window safely. There are several MPD variations and methods.

This thesis work presents the working principle of MPD variations, field case studies, MPD connection mode and managed pressure cementing (MPC) primary cementing job simulations studies.

Results from field case studies show that MPD reduces NPT, increase ROP, reduces loss circulation, increase tripping out speed and reduce the overall drilling days, thus minimizing operation costs. Moreover, MPC simulation study showed the safe fluid placement in narrow operational window that conventional method could not do it.

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LIST OF ABBREVIATIONS

AFP – Annular Friction Pressure

BDO – Bentonite Diesel Oil

BHA – Bottom Hole Assembly

BHP – Bottom Hole Pressure

BOP – Blow Out Preventer

BP - Backpressure

CBHP – Constant Bottom-Hole Pressure

CCS – Constant Circulation System

DAPC – Dynamic Annular Pressure Control

DGD – Dual Gradient Drilling

ECD – Equivalent Circulation Density

EBHP – Equivalent Bottom Hole Pressure

EMW – Equivalent Mud Weight

ERD – Extended Reach Drilling

ESD – Equivalent Static Density

FG – Fracture Gradient

GoM – Golf of Mexico

HAZOP – Hazard and Operability study

HC – Hydrocarbon

HPHT – High Pressure High Temperature

HSE – Returns Flow Control

IADC – International Association of Drilling Contractors

ID – Internal Diameter

IOR – Improve Oil Recovery

LCM – Lost Circulation Material

LRRS – Low Riser Return System

LWD – Logging While Drilling

MD – Measured Depth

MPC – Managed Pressure Cementing

MPD – Managed Pressure Drilling

MWD – Measurement While Drilling

NPT – Non-Productive Time

NRV – Non- Return Valves

OD – Outside Diameter

PDC – Polycrystalline Diamond Compact

PMCD – Pressure Mud Cap Drilling

POOH – Put out of Hole

PP – Pore pressure

RCD – Rotating Control Device

RMR – Riserless Mud Return

ROP – Rate of Penetration

RPM – Rotation per Minute

SAC – Sacrificial Fluid

SOM – Suction Module

TCI – Tungsten Carbide Insert

TOOH – Tripping Out of the Hole

TVD – True Vertical Depth

UBD – Underbalanced Drilling

UBO – Underbalanced Operation

WOB – Weight on Bit

LIST OF SYMBOLS

C_f = fann friction factor

d = diameter of the pipe

D = flow size.

k = surface roughness

k = consistency index

L = length of length of the flow line

n = flow index

P_{fs} = pressure loss through surface flow lines

P_{fdp} = pressure loss through drill pipe

P_{fdc} = pressure loss through drill collar

P_b = pressure loss through a bit

P_{fadc} = pressure loss through annulus around a drill collar

P_{fadp} = pressure loss through annulus around a drill pipe

P_{hyd} = hydrostatic pressure

$\Delta P_{annular\ fric}$ = annular pressure loss

u_m = the average velocity

ρ = density of fluid

ρ_{static} = static fluid density

ε = surface roughness coefficient (ε =k/d)

τ = Shear stress

τ_o = yield stress

1 Introduction

This MSc thesis presents the challenges associated with conventional drilling method in deep-water, HPHT and Horizontal well. Due to narrow operational window, drilling with the conventional method results in several drilling-related problems such as well collapse, well fracturing, kick influx along with their consequences. Moreover, the problems increase undesired non-productive time. The overall consequences are poor drilling efficiency and cost the oil industry a lot. Manage pressure drilling (MPD) is a proven drilling solution for the narrow operational window. The MPD principle, types, their applications, and performances, will be evaluated through field cases. Finally, MPD modeling and Manage pressure cementing (MPC) based simulations in deep-water drilling environments will be presented.

1.1. Background

Over the past several years, new drilling concepts have developed by extending the available technologies in order to solve challenges of onshore and offshore petroleum exploration and production related operations. The following section presents the challenges associated with the conventional drilling methods and the solution for the challenges.

1.1.1 Conventional Drilling and Challenges

Figure 1.1 shows the well program drilling operation. Well fracturing and well collapse pressures bound the safe operational window. The hydrostatic mud weight and the dynamic friction pressure determine the well pressure. The effective circulation pressure during conventional drilling process is determined accordingly to equations (1) and (2) (Azar & Robello, 2007);

$$BHP = P_{hydrostatic} + \Delta P_{annular\ friction} \qquad (1)$$

Where

- $\Delta P_{annular\ friction} = Annular\ pressure\ loss$,
- $P_{hydrostatic} = Hydrostatic\ pressure$

$$ECD(sg) = \rho_{static}(sg) + \frac{\Delta P_{annular\,friction}(bar)}{0.098 * TVD} \tag{2}$$

Where

- $\rho_{static} = Static\ mud\ density$ and
- $ECD = Effective\ circulation\ density$

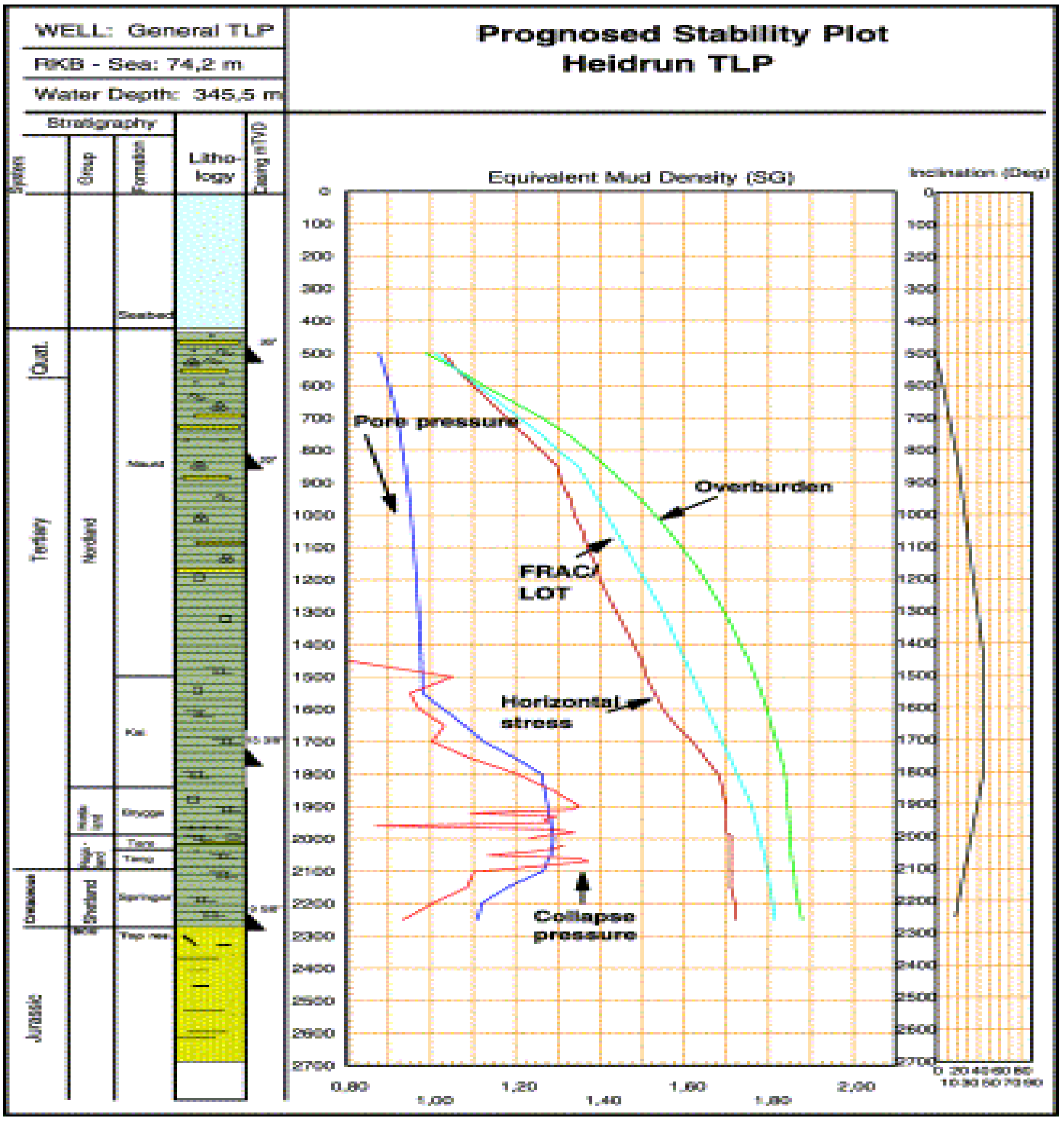


Figure 1.1: Well stability prognosis (Stjern, A., & Horsrud, 2003)

Loss circulation is the loss of drilling fluid into drilling formation. This occurs when the well pressure exceeds the fracture resistance of the formation or drilling in highly fractured formations. On the other hand, when the well pressure lower than the collapse gradient, the part of the wellbore fragments will fall into the well. This results in solid induced drill string sticking by creating bridging and pack off around drill string. In the worst case scenario, if operators don't manage to solve the drill string problem, stack part of the drill string needs to be cut and side truck. In addition, kick influx could occur. These incidents increase non-productive time. It is therefore important to design the well pressure as precise as possible in order to avoid well instability and well control problems. The well instability problem alone increases the overall drilling budget by over 10% (Aadnøy B. S., 2003).

Well instability problem is critical when drilling through narrow operational window. The following section presents the challenging drilling environments associated with the conventional drilling method and various manage pressure-drilling methods used as a solution, which is the main issue of this thesis work.

1.1.1.1 HPHT

By definition, a well is considered as HPHT when reservoirs pressures exceed 10.000 psi (690bar) and temperatures are greater than 300°F (150ºC) (Adamson, et al., 1998). Drilling in HPHT well is challenging since temperature and pressure influenced drilling fluid properties, and affect the equipment performance i.e. its physical strength, electronic function, sealing technology and chemical reaction of a technology or process.

Figure 1.2 displays an illustration of the simulated temperature profile in the pipe and annulus during circulation. Both temperature and pressure influence the rheological parameters and density drilling fluid. The impact of temperature on density is displayed in Figure 1.3. The simulation results presented in the figure are calculated using Kårstad et al model (Aadnøy B. S., 1997). As shown, if density is not properly predicted, the lower density in the reservoir section could risk kick occurrences.

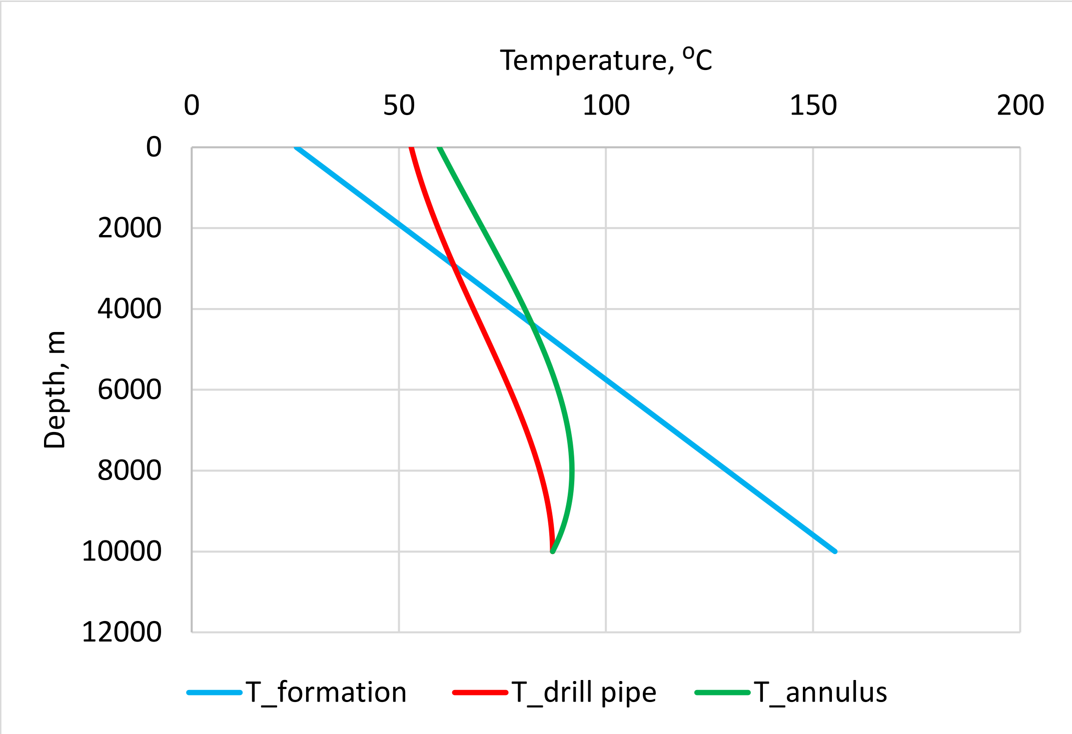


Figure 1.2: Temperature profiles during circulation

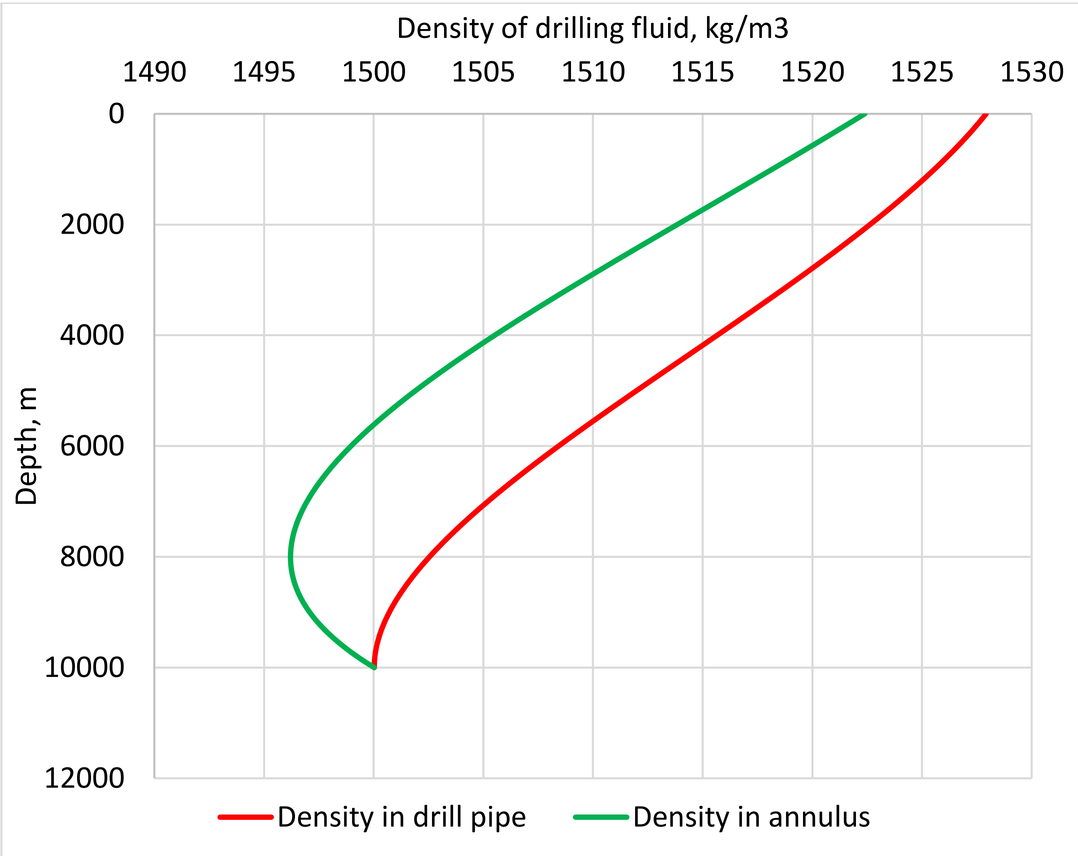


Figure 1.3: Temperature effect on the density of drilling fluid

1.1.1.2 Horizontal well

Extended Reach Drilling (ERD) is defined by wells with horizontal length over twice the vertical depth (K.Fisher, 2005). By the introduction of new drilling technologies and methods combined with the upgrading of rotary steerable, mud system and drill bits, it is preferable to drill an ERD well from a template closer to the reservoir. As shown in Figure 1.4, the horizontal well in red trajectory was able to cross the ERD envelop. However, the operation window for the horizontal well as shown in Figure 1.5 is narrow, which is a challenge for drilling longer offset unless one control the well pressure precisely.

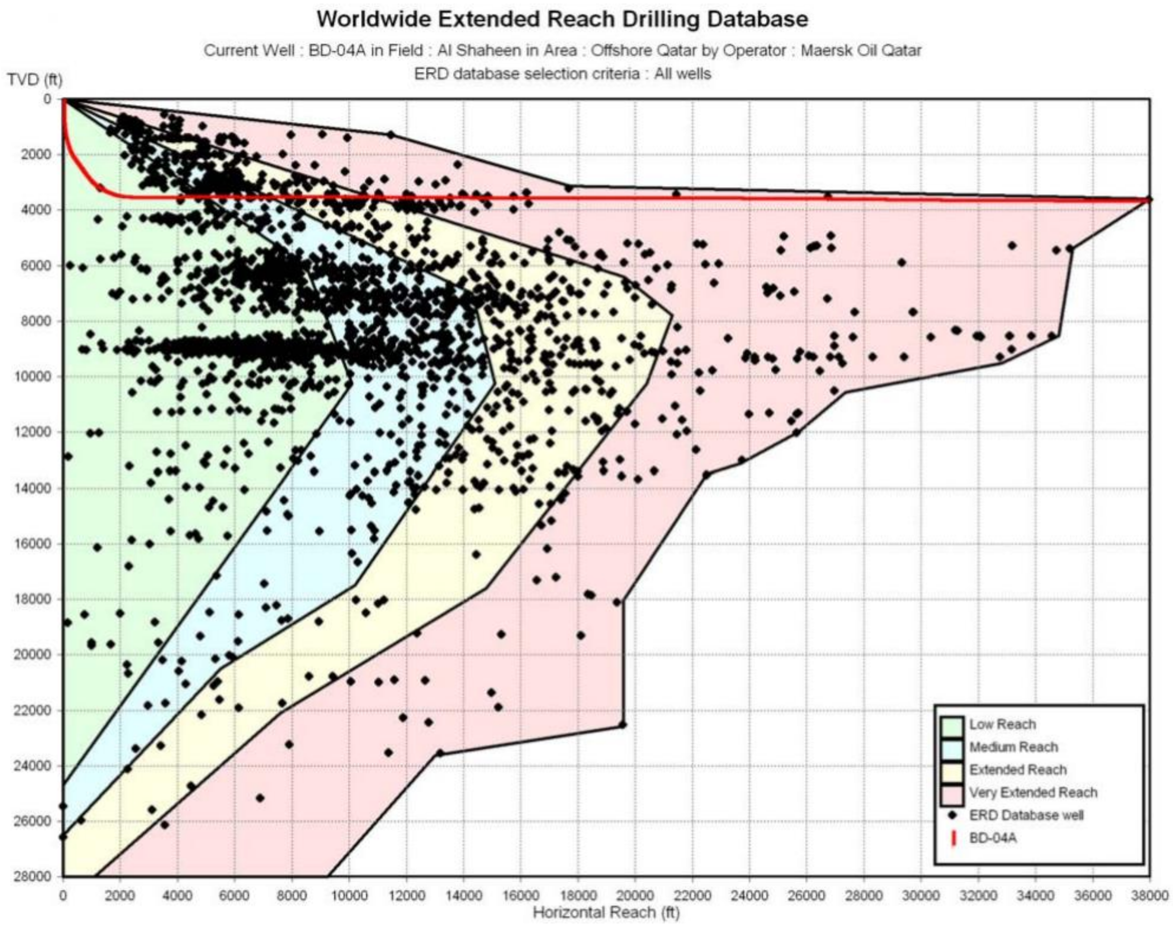


Figure 1.4: Extended Reach Drilling Envelope (Sonowal, Bennetzen, Wong, & Isevcan, 2009)

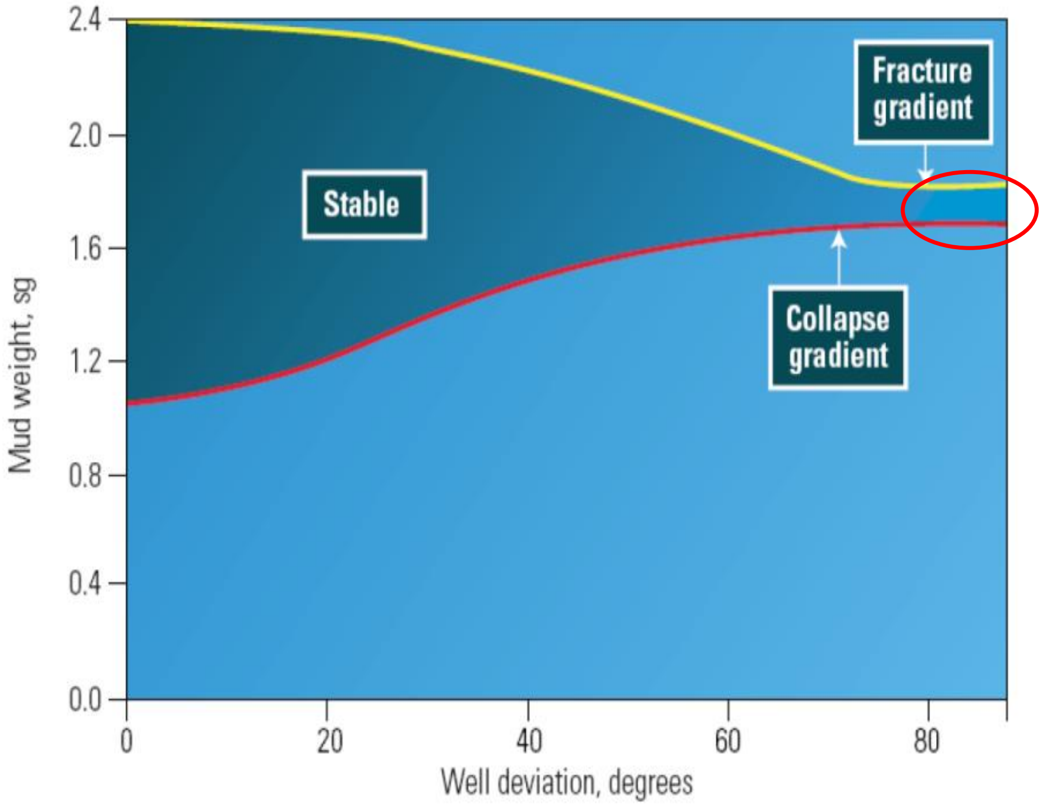


Figure 1.5: Fracture/Collapse window as a function of well inclination (W. Aldred, 1998)

1.1.1.3 Deep-Water

Deep-water is defined as a water depth greater than 1000ft. The depth of seabed varies from areas to areas, in some areas there are deep-water (1000-5000ft) and ultra-deep-water (>5000ft). Deep-water operations are found in regions such as Gulf of Mexico, West Africa, North Sea and other places in Asia can be mentioned. Exploration activities in deep-water are attracting the oil and gas industry, although operation in these environments is challenging.

One of the challenges, as shown in Figure 1.6, is that as deep-water depth increases, the operational window between fracture and collapse gets narrower. Maintaining well pressure in the operational window while drilling and during connection is challenging. As results, related well instability and kick influx problems could occur.

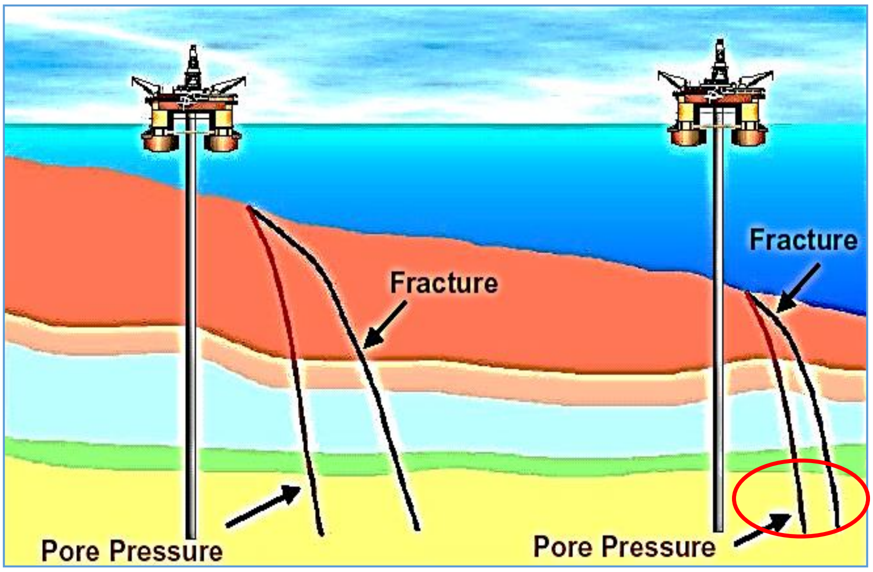


Figure 1.6: Shallow and deep-water drilling window (Kåre, 2018)

1.1.1.4 Depleted formation

After several years of production, the formation pressure will be depleted. The change in formation pressure causes a reduction of the original collapse and fracture gradients. Special attention should always be taken when drilling in depleted formation. The well pressure might cause well fracturing and results in a huge mud loss and formation damage. Figure 1.7 illustrates the operational window before and after depletion.

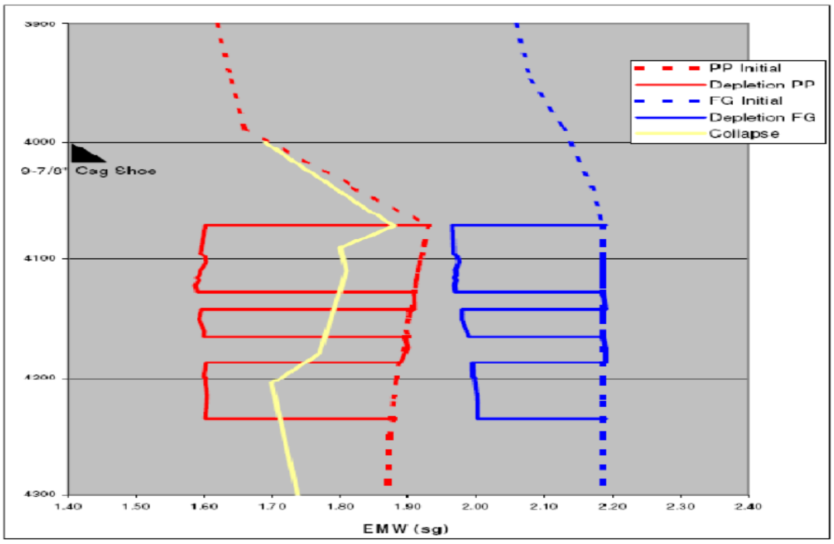


Figure 1.7: Illustration of pressure prognosis in formation before and after depletion (Belayneh, 2018)

1.1.2 Consequences and solution for conventional method challenges

The consequence is undesirable cost. An economic analysis done by James K. Dodson Company has shown that around 41% of the total Non Productive Time (NPT) is related to drilling operation and procedure and among them are kicks, lost circulation and stuck pipe problems. This cost the oil industry over 8 billion dollars annually. Figure 1.8 displays frequently problem incidents that affect NPT in water depth <600ft and total vertical depth >15000ft and <15000ft.

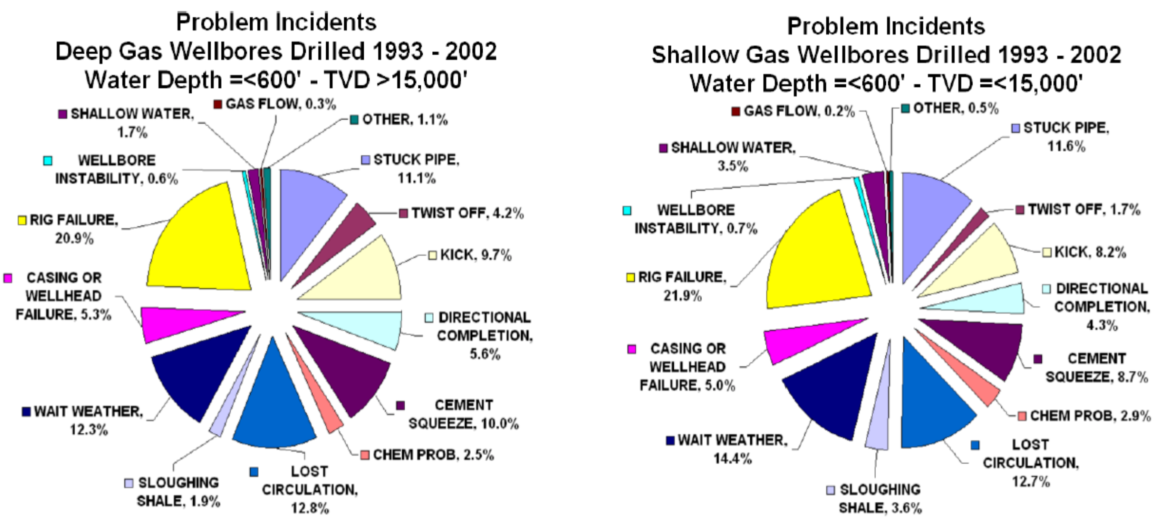


Figure 1.8: Wellbore Problems incidents in GoM (Dodson, 1993 - 2002)

Solutions

Nowadays, MPD is one of the evolving technologies in the drilling industry, promising solution for the conventional drilling methods challenges such as:

1. Deep-water environment
2. Depleted reservoirs,
3. High pressure high temperature and
4. Extended reach wells - Horizontal wells.

One of the keys with MPD technique is that one can precisely control the annular pressure with the help of techniques and tools. Figure 1.9 shows the operational windows for conventional drilling, MPD and Underbalanced Operations (UBO). As shows, MPD drill near overpressure, which does not significantly damage the formation as the conventional, and able to drill through narrow drilling window, which is not possible with conventional drilling method.

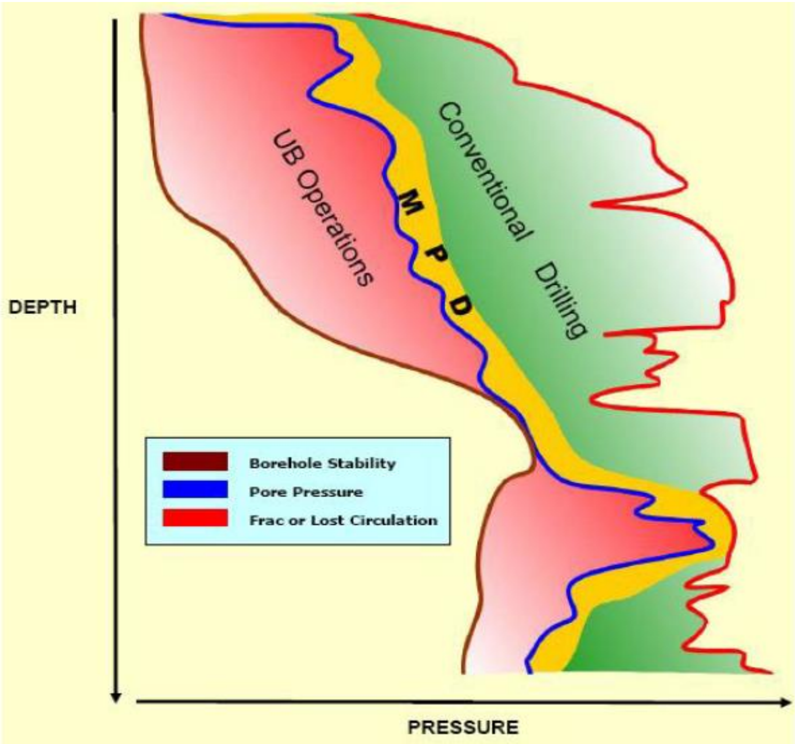


Figure 1.9: Drilling windows for Conventional, MPD and UBO (K. P. Malloy, 2009)

1.2 Problem statement

Technologies in drilling industries are developing and already show an increase in the drilling depth per day. However, non-productive times in conventional drilling method can even reach between 25-30% (Sigve Hovda, 2008). When the drilling window is narrow, the NPT increases up to 41% (Dodson, 1993 - 2002).

For the conventional drilling method problems, there are several types of MPD solution, which are under research and development as well as commercialized and implemented for field application.

This thesis, therefore, addresses issues such as:

- The field success rate of the MPD application
- The MPC and MPD performance in narrow operational window

1.3 Scope and Objective

The primary objective of this thesis is to analyze the aforementioned research issues. The activities are:

- to review the MPD technology working principle
- application different challenging environments
- to develop MPD drilling modeling and perform simulation
- to perform MPC for a deep-water environment field case from Gulf of Mexico using commercial software

1.4 Structure of the thesis

- *Chapter 1* presents Introduction and background for this thesis work. The main issue here is to present the problems associated with conventional drilling methods in different challenging environments.

- *Chapter 2* presents theory used for modeling of MPD operation to be implemented. (Simulation example will be presented in chapter 5).

- *Chapter 3* presents MPD variation along with their working principles and application.

- *Chapter 4* presents field case studies assessment of various MPD methods along with their performance and achievements.

- *Chapter 5* presents MPD and MPC simulation and sensitivity study.

- *Chapter 6* presents brief discussions based on field case studies and simulation studies.

- *Chapter 7* presents major key findings on the successful application of MPD and concluding remarks.

2 Theory

A proper hydraulic simulation is mandatory when operating with managed pressure drilling (MPD) and managed pressure cementing (MPC) in order to avoid drilling-related problems such as hydrocarbon influx and severe loss circulation (M. J Aljubran & C.O. Iturrios, 2018). This chapter presents the theory associated with the well pressure and pump pressure.

2.1 Rheology models

The hydraulics and well pressures in a drilling operation depend on the rheological and density of the drilling fluid. Rheology deals with the study of the deformation and flow of fluid. The shear and shear rate of drilling fluids described by rheological models, while the viscosity and density depend on several factors as for example, among others, the temperature and pressure. The effect of temperature on the density of drilling fluid is illustrated as in Figure 1.1 and 1.2.

Drilling fluid, in general, behaves as shear thinning. The best rheological model which describes the shear and deformation relation is defined by Herschel-Bulkley and it is a yielded power law model. Three parameters describe HB model and is mathematically defined as equation (3) (Bulkley, 1926):

$$\tau = \tau o + k\gamma^{n} \tag{3}$$

Where

- τ_o = yield stress
- n = flow index
- k= consistency index

Where, τ_o can be estimated from viscometer reading as (Zamora & Power, 2002):

$$\tau_o\ [Pa] = 0{,}511 \cdot [2 \cdot \theta_3 - \theta_6] \tag{4}$$

Figure 2.1 illustrates the comparison between measured drilling fluid viscometer data and the Herschel-Bulkley model prediction. As shown, the model captures the measurement. The rheological parameters can be determined graphically by fitting the measured data with the model.

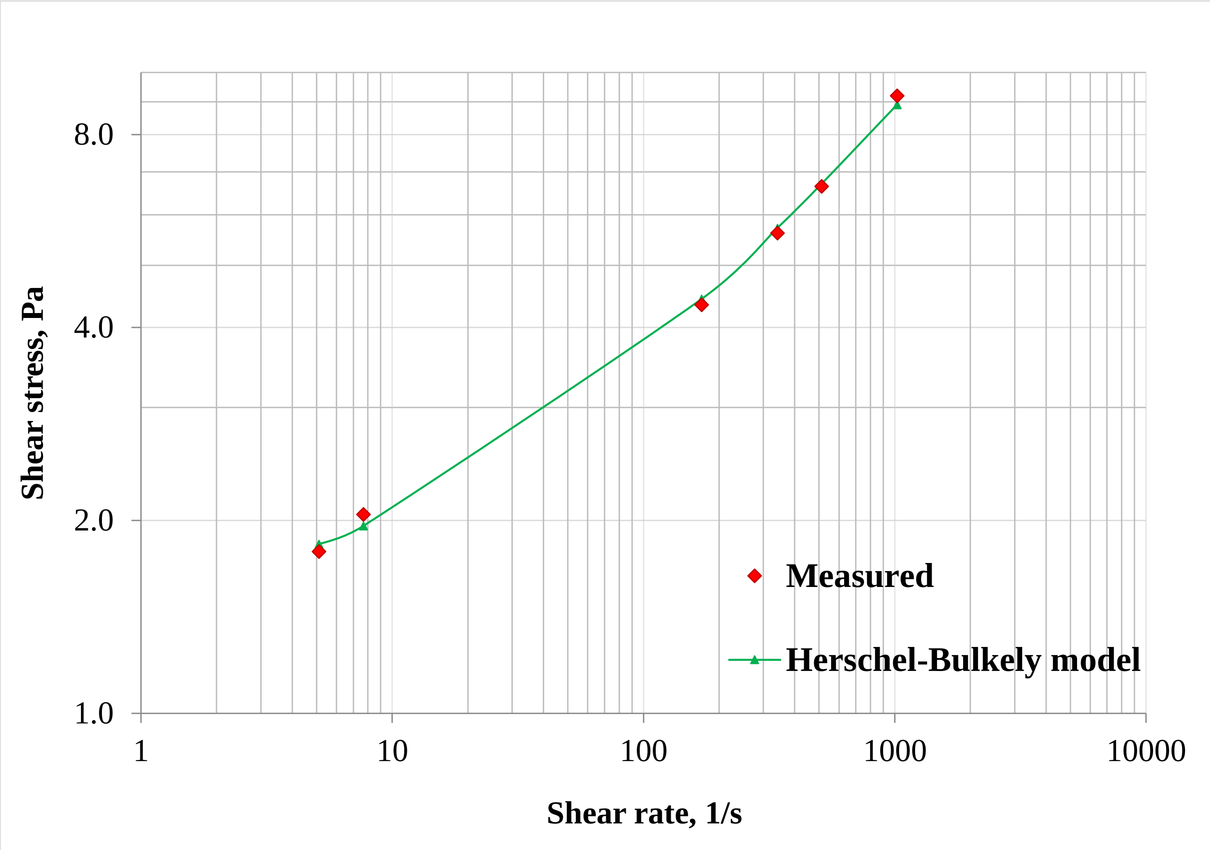


Figure 2.1: Illustration of comparison between Herschel Bulkley Model and viscometer data

2.2 Hydraulics model

During circulation, drilling fluids generate dynamic friction and it normally acts against the direction of the flow. As a result, an additional effective pressure will be created in the annulus. The effect circulation density (ECD) is given as (Lapeyrouse, 2002):

$$ECD = MW + \frac{\Delta P_{annulus}}{0.0981 \cdot TVD} \tag{5}$$

Where

- $\Delta P_{annulus}$ = pressure drop in the annulus
- MW = static mud weight
- TVD = true vertical depth to the point of interest.

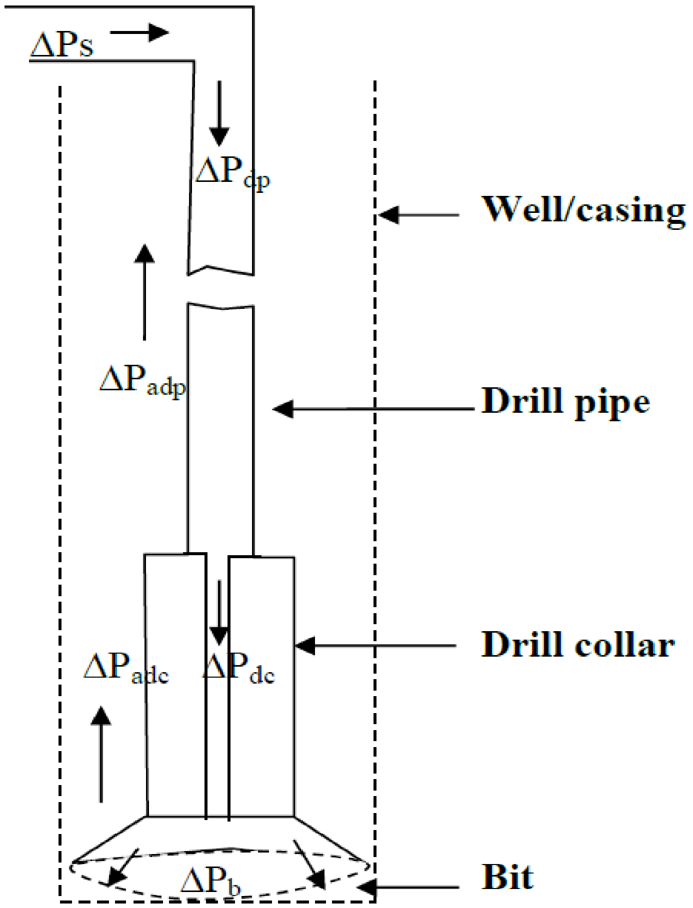


Figure 2.2: Circulation system and friction pressure losses (Samuel, 2007)

As shown in the figure 2.2., in order to circulate the drilling fluid starting from drilling fluid tank through the circulation system and back to mud tank, the pump should overcome the frictional pressure loses.

The pump pressure (P_p) is therefore the sum of friction pressure loss, which is given as (Robert F. Mitchell, 2011):

$$P_p = \Delta P_{fs} + \Delta P_{fdp} + \Delta P_{fdc} + \Delta P_b + \Delta P_{fadc} + \Delta P_{fadp} \quad (6)$$

Where:

- P_{fs} = pressure loss through surface flow lines
- P_{fdp} =pressure loss through drill pipe
- P_{fdc} =pressure loss through drill collar
- P_b =pressure loss through a bit
- P_{fadc} = pressure loss through annulus around a drill collar
- P_{fadp} = pressure loss through annulus around a drill pipe

The pressure loss can be given as (Robert F. Mitchell, 2011)

$$\Delta p = \frac{2C_f L \rho u_m^2}{D} \tag{7}$$

Where

- C_f is the fann friction factor
- L is the length of length of the flow line
- ρ is the density of fluid
- u_m is the average velocity
- D is the flow size.

Haaland formula estimates the friction factor, which is a function of surface roughness. The model reads (Massey, 1989):

$$\frac{1}{\sqrt{C_f}} = -3.6 \log_{10}\left\{\frac{6.9}{R_e} + \left(\frac{\varepsilon}{3.71}\right)^{1.11}\right\} \tag{8}$$

Where,

- ε is the surface roughness coefficient (ε =k/d)
- k is surface roughness
- d is the diameter of the pipe

For the MPD drilling modeling to be presented in Chapter 5 section §5.1, the Unified model hydraulics model has been used. Table 1 shows the summary of the hydraulics models through pipe, annulus and bit nozzles. The reason for the selection of the Unified hydraulics model was based on the hydraulics models evaluation results conducted by (Sadigov, 2013). His analysis on laboratory and field measured hydraulics data has shown that Unified model predicted better than the other considered model. The parameters shown in the summary table are listed under the list of symbols.

Unified model	
Pipe Flow	Annular flow
$\mu_p = R_{600} - R_{300}, [cP]$ $\quad \tau_y = R_{300} - \mu_p, [lbf/100ft^2]$ $\quad \tau_0 = 1.066 \cdot (2 \cdot R_3 - R_6)$	
$n_p = 3.32 \cdot log\left(\frac{2 \cdot \mu_p + \tau_y}{\mu_p + \tau_y}\right)$ $k_p = 1.066\left(\frac{\mu_p + \tau_y}{511^{n_p}}\right)$	$n_a = 3.32 \cdot log\left(\frac{2 \cdot \mu_p + \tau_{y-\tau_y}}{\mu_p + \tau_{y-\tau_y}}\right)$ $k_a = 1.066\left(\frac{\mu_p + \tau_y - \tau_0}{511^{n_a}}\right)$ $k = [lbf \cdot sec^n/100ft^2]$
$G = \left(\frac{(3-\alpha)n+1}{(4-\alpha)n}\right) \cdot \left(1 + \frac{\alpha}{2}\right)$ $\alpha = 1\ for\ pipe$ $\qquad \alpha = 1\ for\ annuli$	
$v_p = \frac{24.51 \cdot q}{D_P^2}$	$v_a = \frac{24.51 \cdot q}{D_2^2 - D_1^2}$ $v = [ft/min]$
$\gamma_w = \frac{1.6 \cdot G \cdot v}{D_R} = [sec^{-1}]$	
$\tau_w = \left[\left(\frac{4-\alpha}{3-\alpha}\right)^n \tau_0 + (k \cdot \gamma_w^n)\right] = [lbf/100ft^2]$	
$N_{Re} = \frac{\rho \cdot v_p^2}{19.36 \cdot \tau_w}$	$N_{Re} = \frac{\rho \cdot v_a^2}{19.36 \cdot \tau_w}$
$f_{laminar} = \frac{16}{N_{Re}}$ $f_{transient} = \frac{16 \cdot N_{Re}}{(3470 - 1370 \cdot n_p)^2}$ $f_{turbulent} = \frac{a}{N_{Re}^b}$ $a = \frac{\log(n) + 3.93}{50}$ $\quad b = \frac{1.75 - \log(n)}{7}$	$f_{laminar} = \frac{24}{N_{Re}}$ $f_{transient} = \frac{16 \cdot N_{Re}}{(3470 - 1370 \cdot n_a)^2}$ $f_{turbulent} = \frac{a}{N_{Re}^b}$ $a = \frac{\log(n) + 3.93}{50}$ $\quad b = \frac{1.75 - \log(n)}{7}$
$f_{partial} = ({f_{transient}}^{-8} + {f_{turbulent}}^{-8})^{-1/8}$	
$f_p = ({f_{partial}}^{12} + {f_{laminar}}^{12})^{1/12}$	$f_a = ({f_{partial}}^{12} + {f_{laminar}}^{12})^{1/12}$
$\left(\frac{dp}{dL}\right) = 1.076 \cdot \frac{f_p \cdot v_p^2 \cdot \rho}{10^5 \cdot D_p} = [psi/ft]$ $\Delta p = \left(\frac{dp}{dL}\right) \cdot \Delta L = [\mathrm{psi}]$	$\left(\frac{dp}{dL}\right) = 1.076 \cdot \frac{f_a \cdot v_a^2 \cdot \rho}{10^5 \cdot (D_2 - D_1)} = [psi/ft]$ $\Delta p = \left(\frac{dp}{dL}\right) \cdot \Delta L = [\mathrm{psi}]$
$\Delta p_{Nozzles} = \frac{156 \cdot \rho \cdot q^2}{({D_{N1}}^2 - {D_{N2}}^2 - {D_{N3}}^2)^2} = [psi]$	

Table 2.1: Summary of Unified hydraulics models in pipe, annular and bit nozzles (Sadigov, 2013)

3 Managed Pressure Drilling Technology and Application

MPD is a relatively recent technology. The main principle of MPD is to manipulate the annular pressure profile accordingly to its needs and this control is made through the hydrostatic fluid column in addition to the application of a surface pressure known as backpressure. The backpressure is normally done by a choke which can vary from manual to semi or automatic, thus maintaining the desired pressure profile during the operation. MPD focuses not simply on the bottomhole pressure but also on the entire pressure profile.

According to the International Association of Drilling Contractors (IADC) MPD is defined as:

> *"An adaptive drilling process used to <u>precisely control the annular pressure profile</u> throughout the wellbore. The objectives are to ascertain the downhole-pressure-environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface."*

Figure 3.1: Definition of MPD

Other goals of MPD which can be considered as important drives for the using of this technique are the elimination of one or more casing strings, the ability to drill longer extended reach drilling wells (ERD) with constant bottom hole pressure (BHP), to control shallow gas and water flows (deep-water) and also to provide a safer drilling environment.

To accomplish MPD a combination of techniques is necessary to be applied as follows:

- Backpressure
- A variable fluid density
- The fluid(s) rheology
- Circulation friction factor
- And the hole geometry

3.1 Principle of MPD

MPD system consists of surface and subsurface tools. MPD process controls the annular pressure profile safely. As mentioned earlier, the main target is to avoid any NPT incident caused by narrow pressure profile.

MPD is a closed and pressurized circulating fluid system. Using the appropriate tools while drilling, the well pressure is controlled by dynamic, static and backpressures. The equivalent weight of the mud in the hole at the time is thus determined as:

Circulating (dynamic):

Conventional drilling during circulation:

$$ECD = MW_{HP} + AFP \qquad (9)$$

MPD during Circulation:

$$ECD = MW_{HP} + BP_{SURFACE\ BACKPRESSURE} + AFP \qquad (10)$$

Where,

- MW_{HP} is the mud weight hydrostatic pressure
- AFP is the annular friction pressure
- BP is the surface backpressure

Not circulating (static):

During connection, when no circulation condition, the annular friction part will disappear and the well pressure is due to static mud weight, which is the case for conventional drilling. In a narrow window, the well pressure could be lower than the formation and collapse pressure, and hence cause undesired problems such as well collapse and kick. However, to solve this problem, MPD system maintain the well pressure to be within the narrow window by applying backpressure.

Conventional drilling during static:

$$ESD = MW_{HP} \qquad (11)$$

MPD during static:

$$ESD = MW_{HP} + BP_{SURFACE\ BACKPRESSURE} \qquad (12)$$

Comparing Eq. 11 and 12, the amounts of surface backpressure during static condition will be roughly equal to the circulating annular friction pressure (AFP) when the last stand was drilled in.

There are several configurations which are available for MPD equipment. They vary in accordance with the objective of the work and the reservoir characteristics. For an accurate choice of which equipment is necessary for MPD operations, there is a series of relevant inputs and considerations to take into account for each case. Figure 3.2 shows the surface and subsurface equipment as listed below:

- Rotating Control Devices
- Drilling Chokes
- Choke Manifold
- Flowmeter
- Oil/Gas Separators
- Non-return valves, downhole isolation valves, downhole measurement

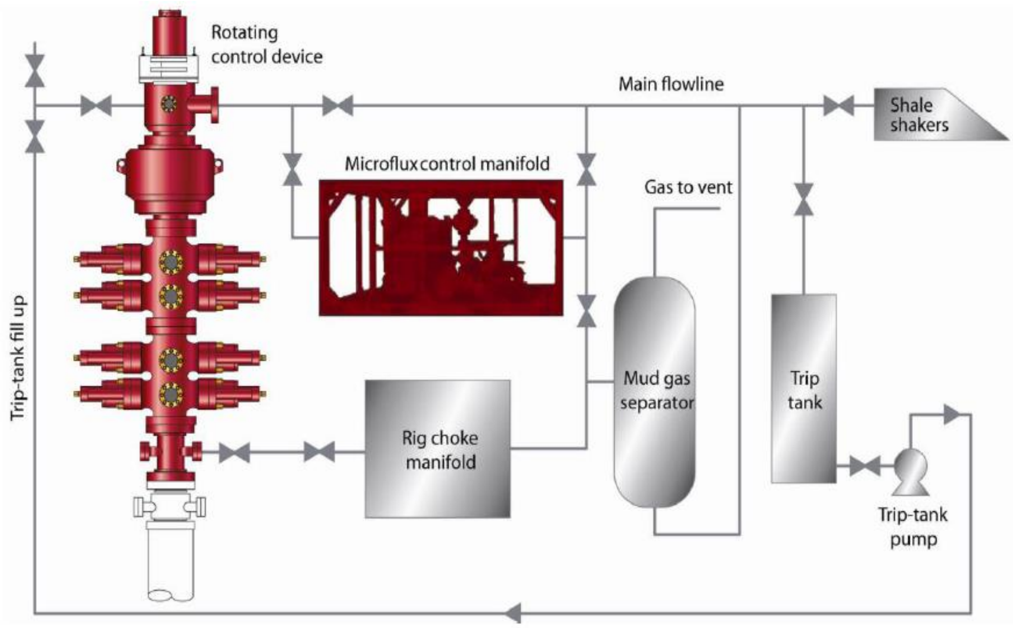


Figure 3.2: MPD system arrangements (Nas S. , 2011)

3.2 Advantages

As already mentioned, MPD successfully allows the drilling of narrow operational windows between pore pressure (PP) and fracture gradient (FG). The advantages of MPD among others:

- Reduced number of casing
- Reduces the number of tripping and cost for cementing operation
- Reduced non-productive time
- Reduced the overall drilling cost
- Drill un-drillable formation, which is challenging for conventional methods
- Allows to drill a highly fractured formation
- Control annular pressure precisely during drilling and connection
- Increase Rate of Penetration (ROP)

Figure 3.3 illustrates how the number of casing reduces when using dual gradient MPD as compared with the conventional method. As shown, the number of casing reduced by six. This significantly reduces the drilling cost.

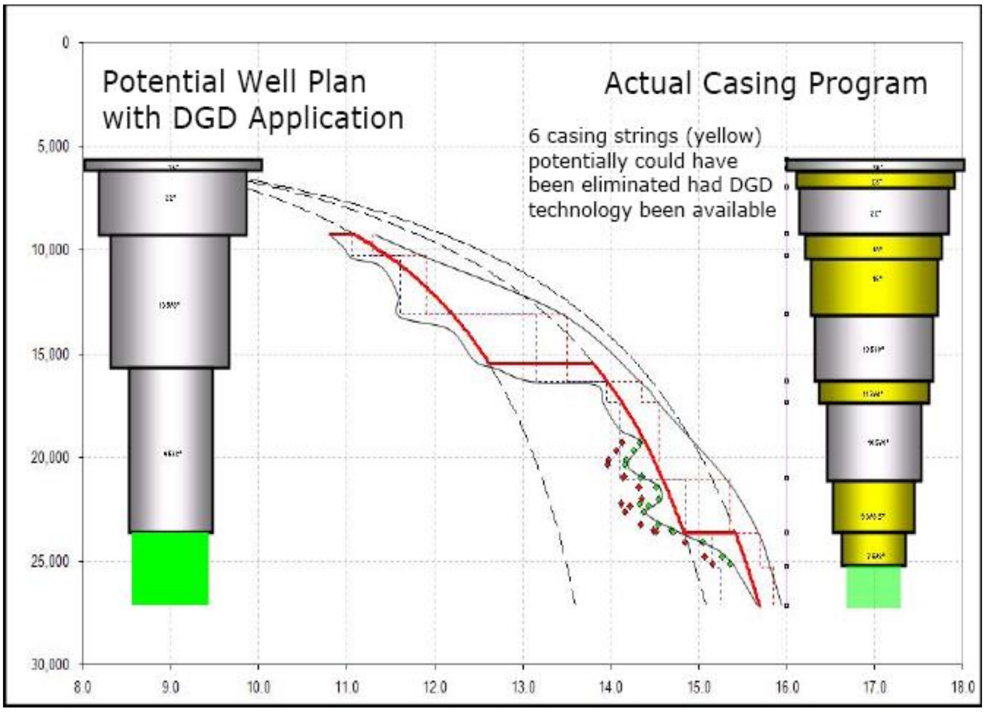


Figure 3.3: Casing program with and without riser (Khan, 2012)

3.3 Equipment

As shown in Figure 3.2, in addition to the conventional system, MPD uses both surface and downhole equipment. The surface equipment are rotating control device, micro influx control, mud gas separator, flow meter and rig choke manifold. The subsurface equipment is non-return valve. The following presents the description of this equipment.

3.3.1 Rotating Control Device (RCD)

Among the MPD operations basic equipment, RCD is one of the main important part (Figure 3.4). It is located at the top of the annular preventer and has a dual conic seal elements. The main function of RCD is to divert a pressurized return annular drilling fluid to the micro-influx unit and sealant tool allowing drill string circulation.

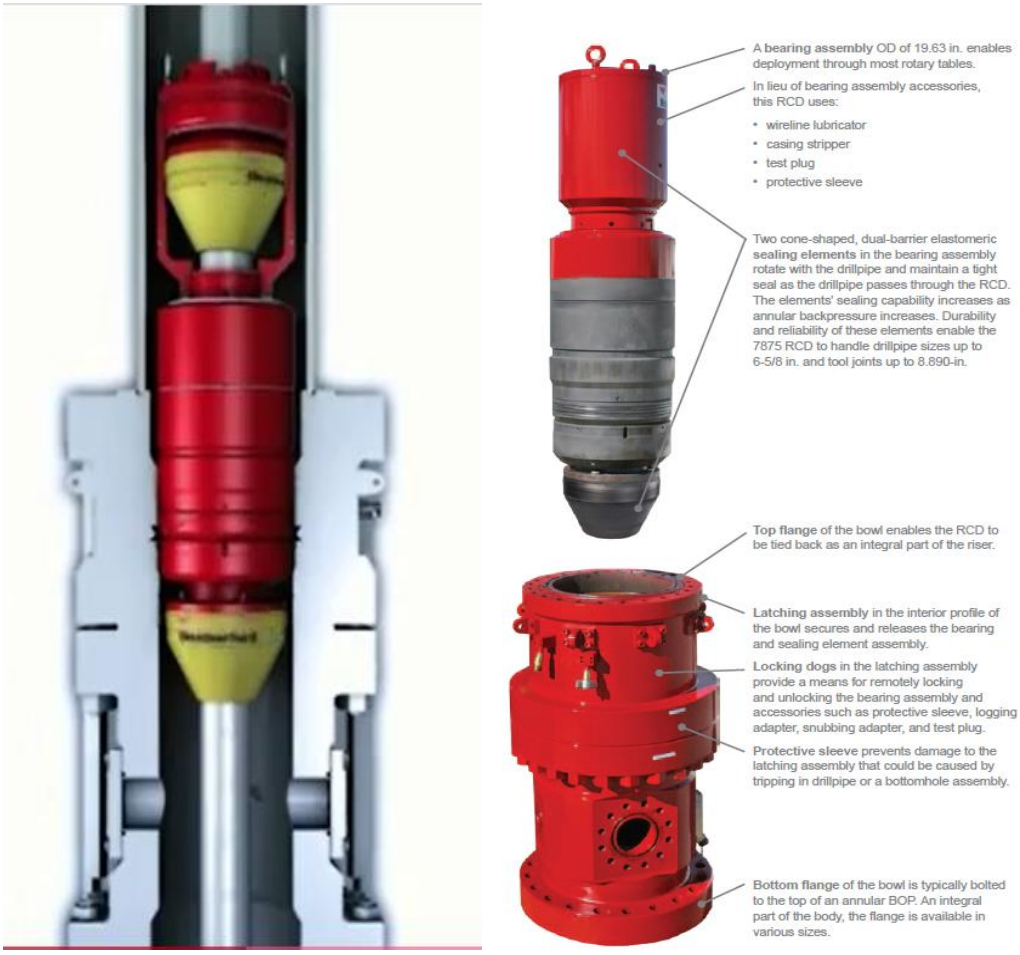


Figure 3.4: RCD part (Weatherford International Oil Field Services, u.d.)

3.3.2 Advanced Micro flux control system

Figure 3.5 is the product of Weatherford. According to the produces, the micro-flux control technology is designed to conduct measurement in real time, perform flow, and pressure data analysis. Moreover, according to Weatherford, the system is able to detect kick and fluid loss during MPD operation. The system is fully automated and able to manage wellbore pressure profile.

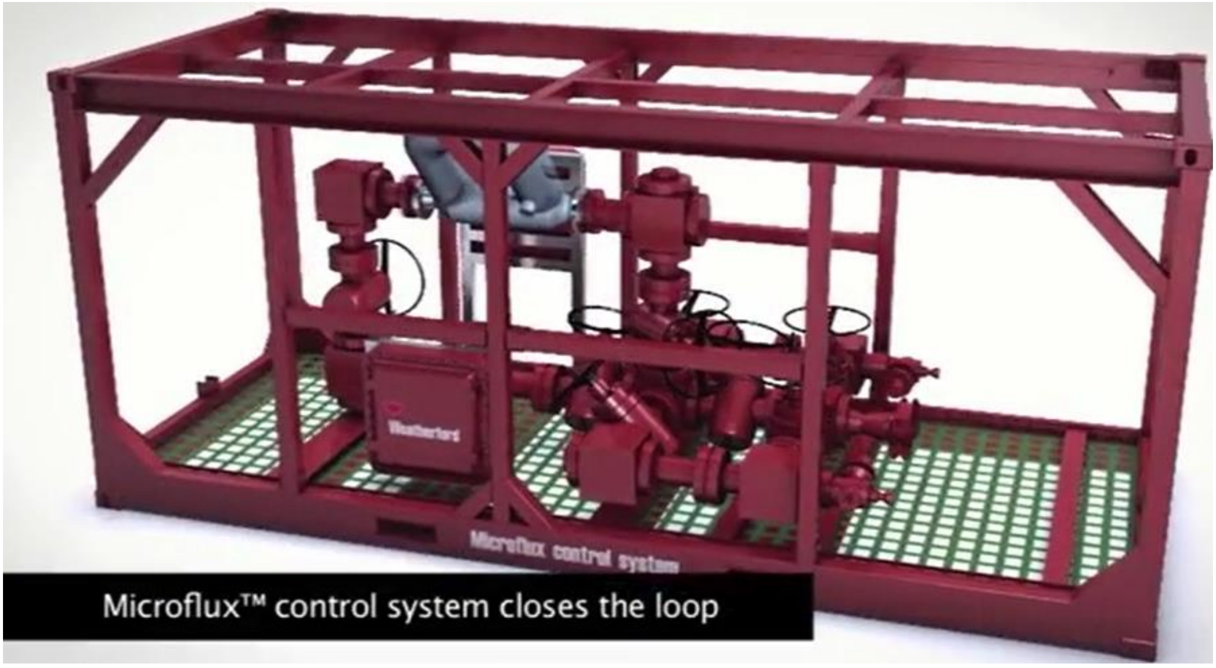


Figure 3.5: Micro-flux control (Weatherford International Oil Field Services, u.d.)

3.3.3 Surface separation equipment

In general, during drilling with MPD techniques, the well pressure is managed to be near over formation pressure. However, due to wrong pore pressure profile, it could happen that formation fluid influx into the wellbore which is not desirable. However, in case of any hydrocarbon influx, MPD system employs the use of surface-separation equipment as shown in Figure 3.6.

Figure 3.6: Surface separation equipment for land and offshore (Weatherford International Oil Field Services, u.d.)

3.3.4 MPD choke manifold

In MPD operations, chokes are used primarily to control the flow. The opening and closing of the choke valve control the backpressure. Depending on the closure system, chokes are classified as: choke gates, sliding plates and shuttles. Figure 3.7 shows an illustration of manually controlled choke, which controls the size of the flow.

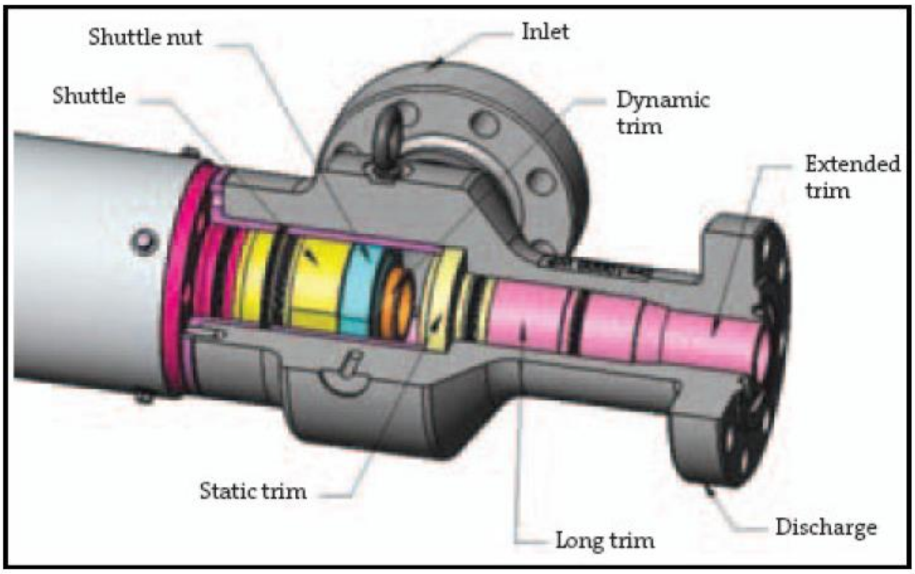


Figure 3.7 Crossection of auto-choke and its parts (Nauduri, 2009)

Depending upon its operation it is classified as:

- ✓ Manual choke,
- ✓ Semi-automatic and
- ✓ Automatic.

Operator communicating with driller manually operates manual chokes. Automatic chokes are operated based on measurements and hydraulic model prediction to maintain constant set point pressure.

3.3.5 Coriolis Flowmeter

During MPD operation, it is important to measure the flow rate in and out of the wellbore. For this, Coriolis Flow meter is used as one of MPD equipment, especially to detect in case of kick influx and loss circulation. The flow meter is a high accuracy mass flow meter, which measures:

- ✓ mass flow,
- ✓ volumetric flow,
- ✓ density and
- ✓ Temperature.

Figure 3.8 shows the external physical structure of the Coriolis flow meter.

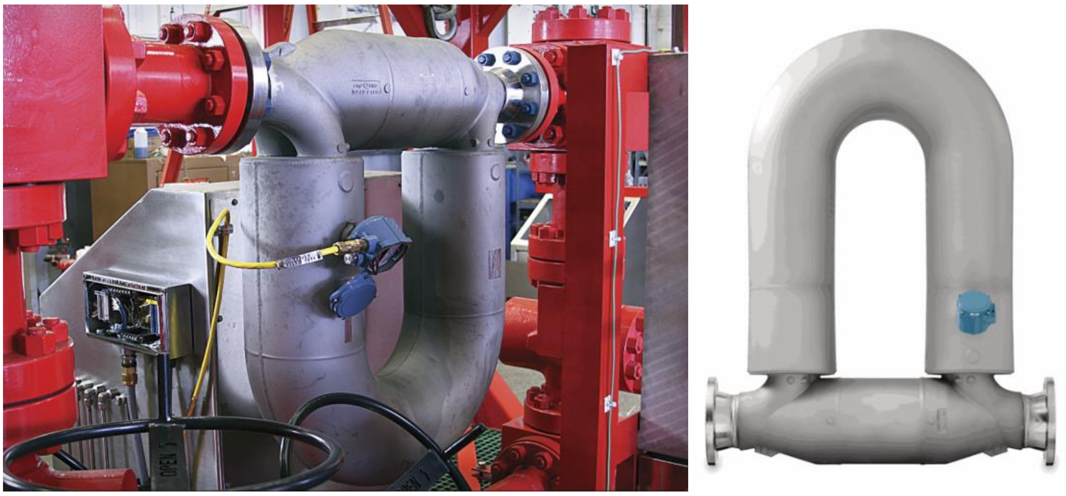


Figure 3.8: Coriolis Flow meter (Bhavin Patel, 2013)

3.3.6 Downhole control-Drill-Pipe Non Return Valves (NRV)

The check-valves, or non-return valves, are in the drilling column and allow the flux of drilling fluid to flow in one direction only, preventing to return inside the column. During MPD operation, the application backpressure through annulus, due to U tube effect, fluid may flow back through pipe. In order to prevent the back of flow up in the drill string, the non-return valve is also called a float or one-way value is implemented in the drill string. Figure 3.9 shows the product of Weatherford's NRV.

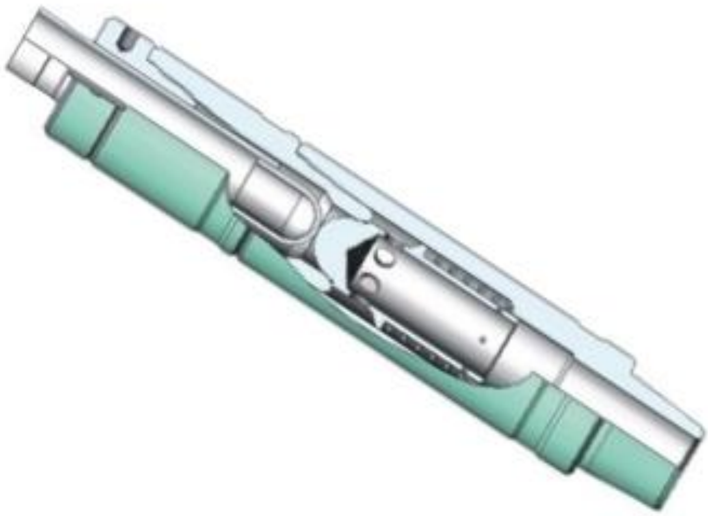


Figure 3.9: NRV (Weatherford, u.d.)

3.4 Equipment Flowchart for MPD Operations and risk analysis

Equipment determination, selection and recommendation, can be part of the MPD *feasibility study*[1] which could be advantageous in the later stages of operations. Some parameters are determinant on MPD application and equipment selection as shown in Figure 3.10.

Primarily, the reasons for applying MPD should be acknowledged and determined by the operator. Following, hydraulic simulations gathering input from mud properties, backpressures

[1] Feasibility Study takes into consideration different options of drilling techniques depending on the project objectives for the reservoir, well or field.

and depths will determine parameters such as BHP, annular pressure, ECD and surface pressure, which should be compared with the limits allowed in the operation (Sagar Nauduri).

If simulation results are acceptable within the operational window and pressure tolerances, then specific equipment for MPD can be chosen accordingly, together with available conventional equipment on the rig. The MPD equipment can be divided in two (Sagar, George H, & Jerome J, 12-12.February.2009):

- Essential Equipment: as the name says, are indispensable equipment for any variation of MPD operation
- Optional Equipment: depends on the operation objective and which variation will be used

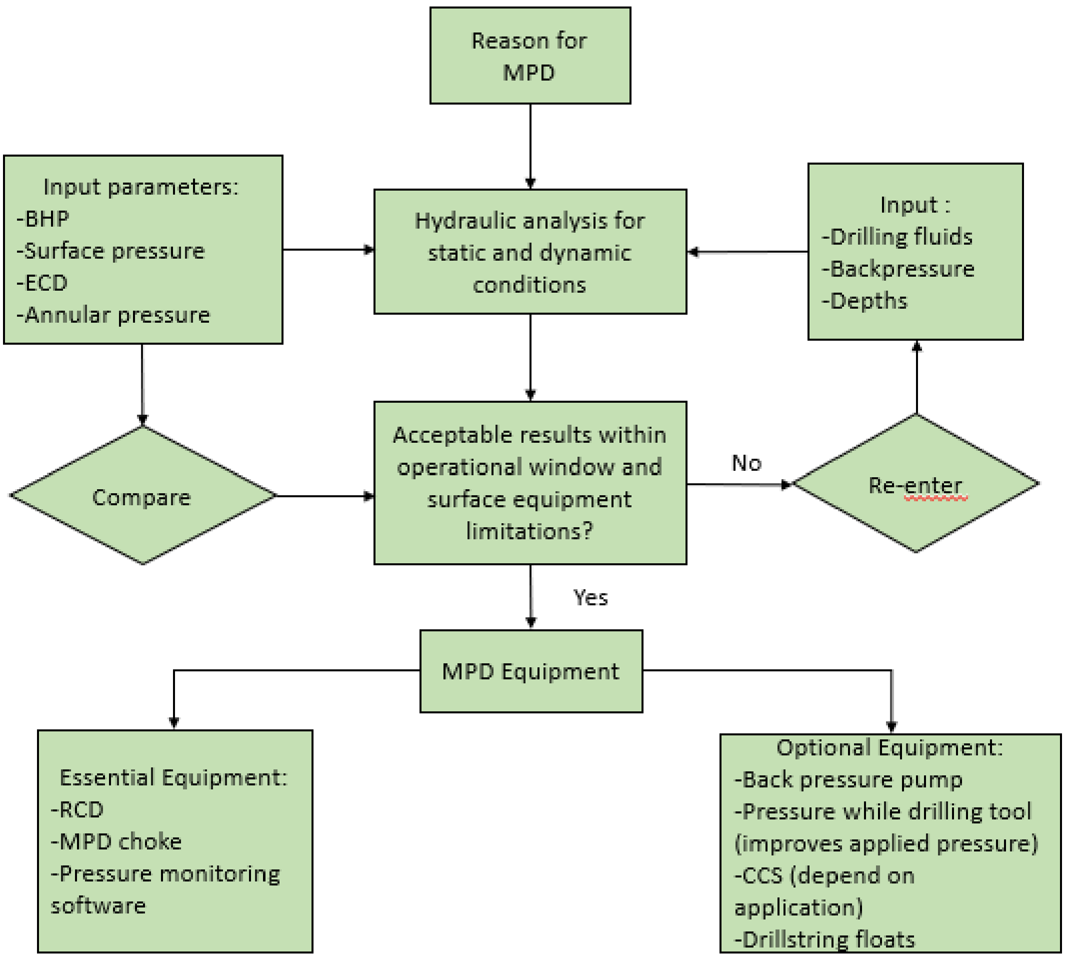


Figure 3.10: Equipment Flowchart for MPD Operations

Each drilling operation has different risks, therefore risk assessment should be done prior to each operation for each possible scenario. For instance, the risk depends on:

- Formation characteristics (risk of packoff, fluid loss, stuck pipe)
- Uncertainty of geological data can also be considered in the risk analysis
- There are certain risks inherent of adopting MPD instead of conventional drilling

One can use simulations to assess the risk. For example, time-cost relation for each simulated scenario can be helpful in deciding the technique most appropriated (less risky, less costly). In the end, it's up to the operator to decide the acceptable risk they're willing to take for saving cost. Some techniques that can be used to assess risk are:

- Decision tree (Decision tree analysis, u.d.)
- HAZOP (P.J Comer and J.S. Fitt, 1996)
- IME is also a tool of risk analysis and it was specially developed for MPD in terms of kick and pressures tolerance (O. R. Gabaldon, 2017) and (M. S. Culen, 2016)
- Probabilistic Approach (Kenneth P. Malloy, 2008)

3.5 Categories of MPD

Managed Pressure Drilling operations can be classified as:

3.5.1 Reactive

Commonly in onshore operations, the well is projected to use conventional drilling but MPD equipment are available on the rig as a contingency plan if needed. Tooled up to more efficiently rate to downhole surprises (using surface backpressure to adjust equivalent mud weight (EMW), enhance well control, etc.)

3.5.2 Proactive

The well is projected to be drilled using MPD technique, allowing to extend or eliminate liner sections. The project has a specific program for liners, fluids and well diameter to aid on the bottom hole pressure. This MPD category offers better benefits when drilling offshore wells since it can deal with drilling contingencies immediately and kick detection is more effective.

It's important to point out that, in principle, the MPD system is not meant to control the well in case of an eventual kick. For this purpose exists an influx matrix of volume and pressure that indicate if it's possible to keep drilling or not using MPD system. In case it's not possible, the well has to be closed with the BOP and the rig has to take control of it.

3.6 Variations of MPD

MPD can be presented in seven different main variations:

3.6.1 Constant Bottom Hole Pressure

Also known as CBHP, it is used to report actions to reduce or correct the effect of circulation friction loss, or equivalent circulating density (ECD) to avoid exceeding the limits of fracture gradient when drilling ahead. This variation is uniquely suited to deal with narrow pressure environments.

Normally the fluids program is designed to be at the predetermined depth or nearer balanced than conventional. In practice, the hydrostatic pressure transmitted by the mud, when not circulating, may result in a reasonable disequilibrium, and for that, jointed pipe connections are made with a surface backpressure roughly equivalent to the circulating annulus friction pressure, noted on the last stand of the drill string. The backpressure is applied through a choke manifold system connected to the RCD, hence maintaining the desired overbalance level to avoid an influx from the formation into the well.

An adjustable choke is used to control the annular pressure independently if the mud pump is working or not. Even without the pump flow rate, the pressure can be applied in two diverse ways: by circulation through BOP booster line or by circulation through a dedicated pump during connection. In that way, the bottom hole pressure resulted from fluid circulation (ECD) is replaced by the application of surface pressure, in other words, the fluid density is reduced and the hydrostatic pressure loss or friction loss is compensated by the backpressure. This fact allows the bottom pressure to be slightly over than the pore pressure, decreasing the risk of circulation loss and overlap the formation fracture gradient.

Nowadays, CBHP is the MPD variation most used in the industry. It allows to extend the shoe casings depth once it's possible to continue drilling even when narrow operation window and possibly reducing the phases (sections) of the well.

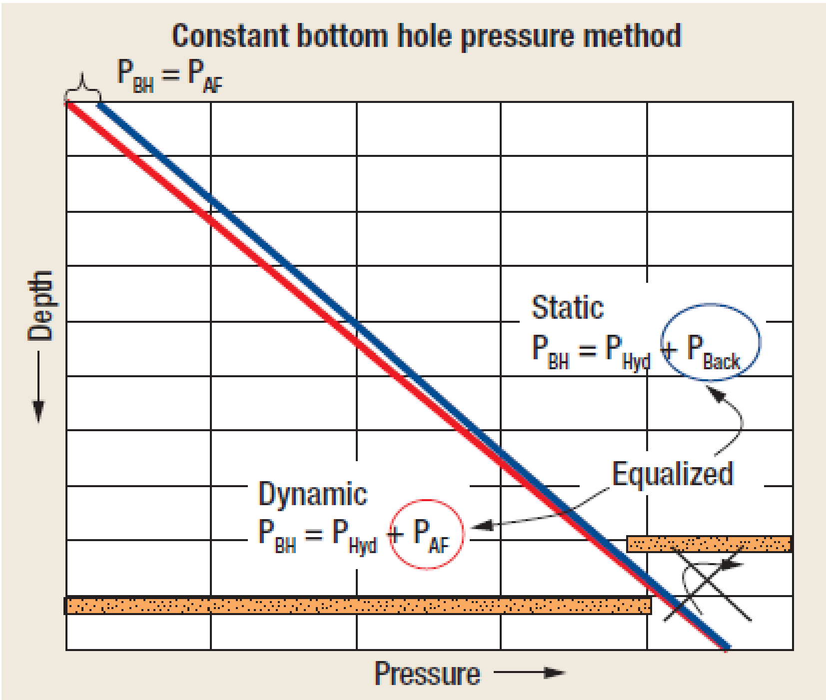


Figure 3.11: Constant Bottom Hole Pressure (Malloy, 2007)

3.6.2 Pressurized Mud Cap Drilling

The pressurized mud cap drilling technique (PMCD) is used to solve problems related to severe or total circulation losses and in depleted formation. Figure 3.12 is an illustration of PMCD method. PMCD uses two types of fluid, the first one is a heavy viscous mud pumped down to the annulus. It acts as a mud cap above the weak zone, which is used to keep flow from escaping. The second fluid is a lightweight fluid called 'sacrificial' drilling fluid, such as seawater, which is used to drill. The driller can apply optional backpressure if needed to control the desired annular pressure.

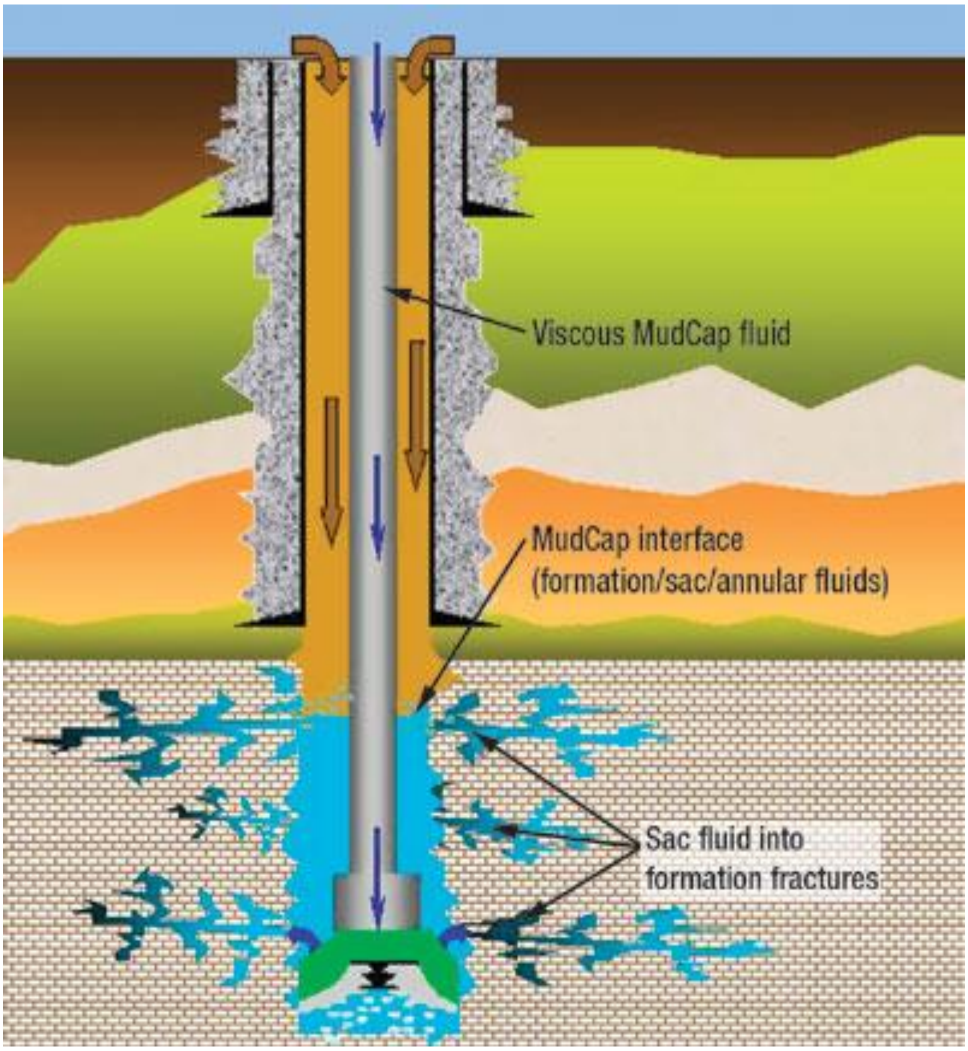


Figure 3.12: Illustration of how PMCD works (Paschoa, 2014)

MANAGED PRESSURE DRILLING TECHNIQUES, EQUIPMENT & APPLICATIONS

PMCD technique trap fluid and cuttings beneath the surface—eliminating the need to dispose of them, preventing dangerous gases from reaching the wellsite, and, in many cases, helping to stabilize the formation.

A sacrificial fluid is pumped through the drillstring and lost to the formation while the annulus is full of the so called “dual gradient” fluid system, i.e. the sacrificial fluid itself on the lower portion of the hole, and the (heavy) Mud Cap Drilling in the upper portion.

Figure 3.13 shows the pressure profile of the pressurized mud cap method. A lighter mud is used to drill the depleted section and the heavier mud forces the fluid into the loss zone. Drilling continues, and all the lighter mud and any influx are forced into the depleted zone. This method keeps the well under control even though all returns go to the depleted zone.

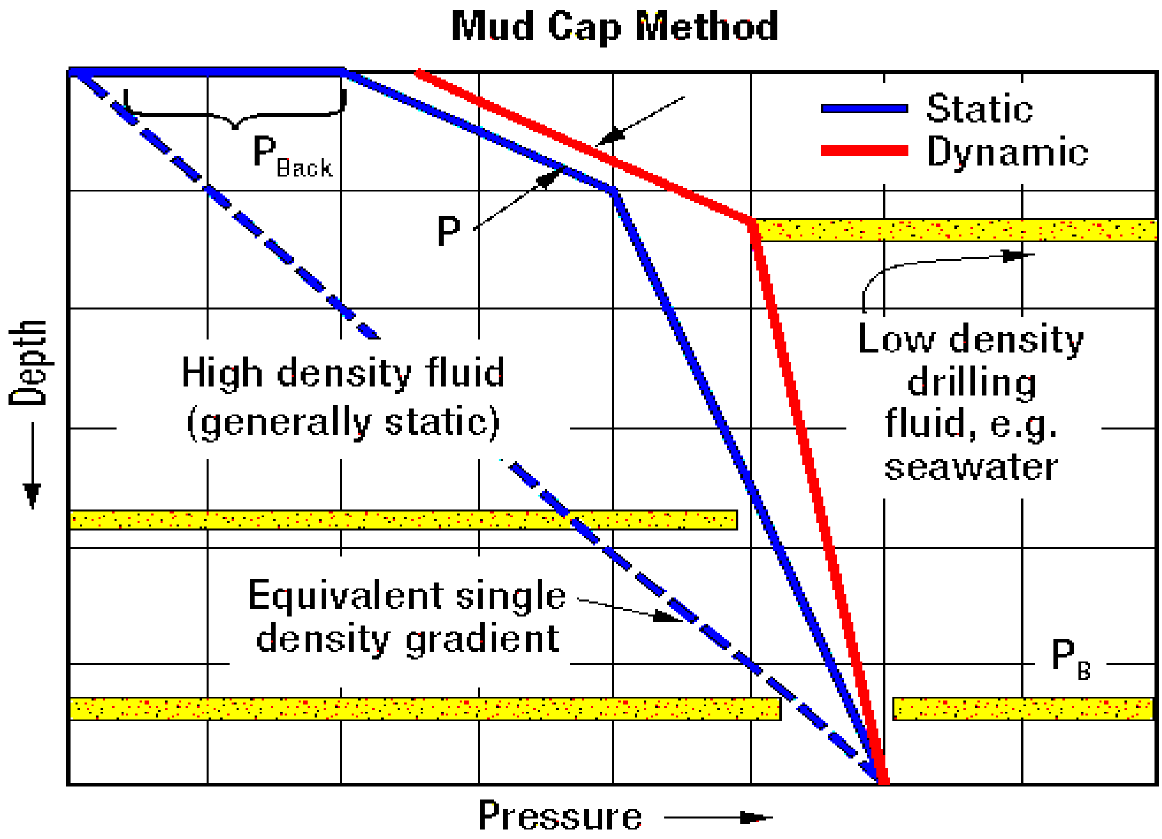


Figure 3.13: Mud cap pressure profiles (Malloy, 2007)

The advantage of the PMCD method is that it can keep the well under control even while suffering severe losses to the formation. The use of lighter drilling flows allows to increase the rate of penetration. In terms of cost, the lighter mud is cheaper than the one used for the conventional drilling. Another advantage is that drilling with lighter fluid is underbalanced and resulting in less formation damage.

3.6.3 Dual Gradient (With and without a riser)

Drilling with dual gradient has been in the industry since the 60's. But due to economic viability at the time, and easier prospects yet to be drilled, it wasn't given the importance that it has been nowadays - once facing more challenges to achieve the desired target in deepwater scenarios. Even though intensive researches keep going in order to find a project with large commercial application but only a few of them have been commercially accepted, which will be discussed in this topic.

Among all the others MPD methods, DGD has the goal to provide more safety and operation possibilities in areas before considered undrillable using conventional drilling. This can be achieved by using two fluids with different densities making it possible to better manage the bottom pressure. For example, increasing or decreasing the volume of the lower density fluid, i.e. nitrogen, enabling the bottom pressure to be always within the operational window, which was difficult or even impossible conventionally.

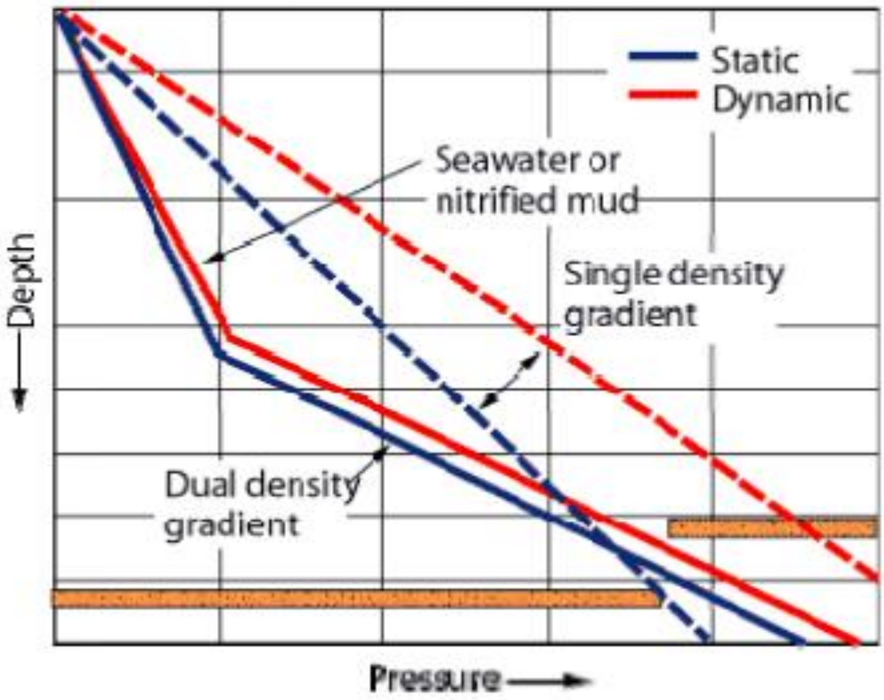


Figure 3.14: Dual Gradient Method (Malloy, 2007).

Dual gradient can be done in different ways, and categorized as follows:

- **With Riser**
    - Nitrogen injection
    - Subsea MudLift Drilling
- **Without Riser**
    - Riserless Mud Recovery (RMR)

The main advantages of DGD are: safer operation, less number of liners (deeper shoe settling) due to the possibility of spending longer time drilling within the operational window, and less costs especially because of the decrease on NPT.

3.6.3.1 Nitrogen Injection

This DGD variation is accomplished by adding a fluid with lower density, the nitrogen, on the dynamics of conventional drilling. To increase well safety, it's necessary to add a RCD (Rotating Control Device) to the system just below the rig and above sea level, in order to act as redundancy to BOP now that it will be normally treated with gas flow. In addition, to diverge the flow coming from the well before to the rig and keep a closed system even with mud circulation (Rehm, Schubert, Hagshenas, Paknejad, & Hughes, 2008).

To increase the project viability, a concentric pipe can be used along with the drilling pipe so the nitrogen can be driven to this "new" annular. In this way, a lower volume of gas is needed, thus reducing costs. Besides that, the concentric tube can be used as the next liner once it's time to settle it.

The injection of gas together with drilling fluid, now heavier by density, will dislocate to superior regions already coated, letting the fluid heavier in the zone of open hole. It can be said that, in regions where the well is already completed will be under pressure, but it won't take any risk to the operation. The open area, after sum and balance of the hydrostatic pressure generated by the two fluid gradients, will have to be overpressure to guarantee the drilling safety, avoiding influx from the formation for example. The nitrogen injection can be done through the kill line, as shown in Figure 3.15, or through the booster line which is more common due to its bigger diameter, allowing higher flow rate.

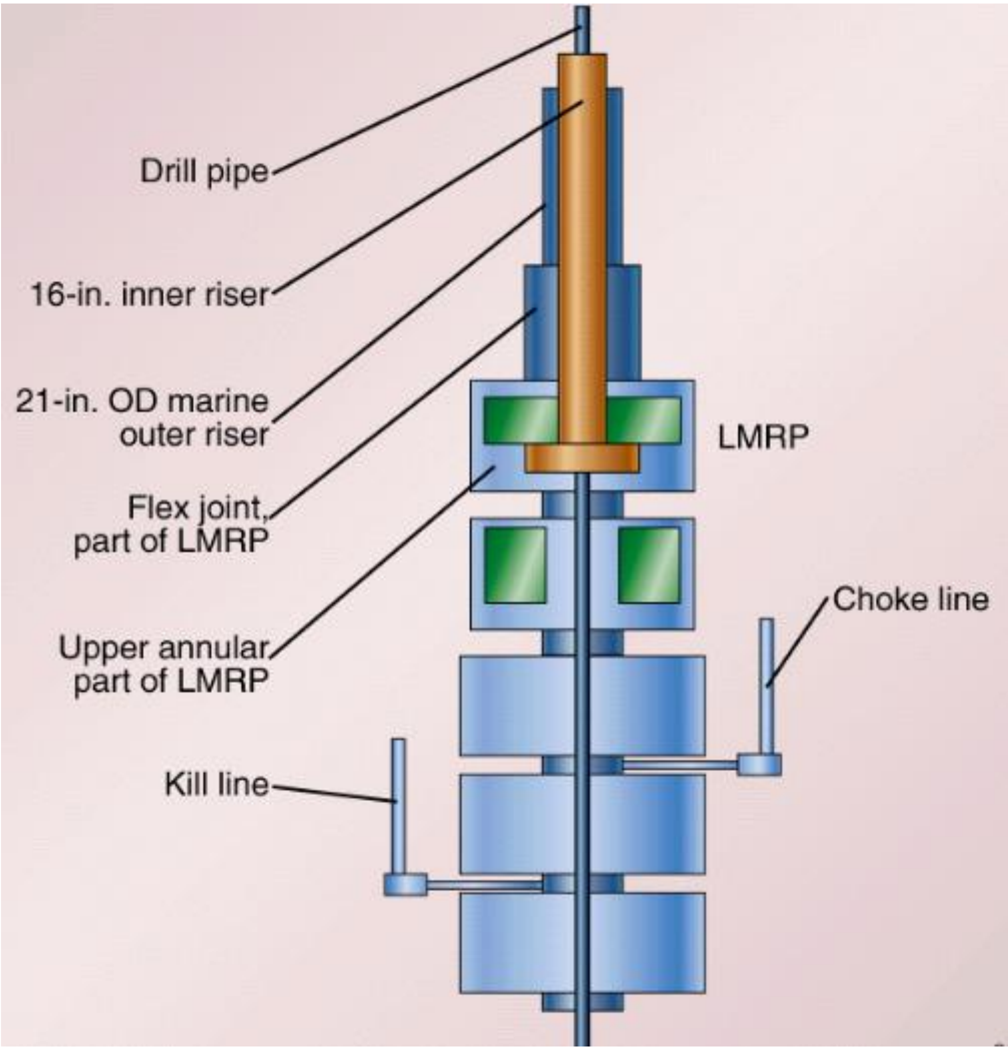


Figure 3.15: Seafloor arrangement for nitrogen injection through kill line -Subsea BOP (Shaughnessy & Hermann, 1998)

Lastly, the bottom pressure will be regulated by changing the fluid density, as done conventionally, and also by controlling the flow rate of nitrogen injection, in order to maintain the open hole within the operational window. As long as it last to overcome the economic barriers related to the use of numerous liners.

It’s important to mention that, due to a higher dynamic and pre-determined existence of gas in the annulus, the procedures for well control and verifications of influx from the formation will be more complex. Making necessary to modify some procedures traditionally used, as for example the engineer or volumetric method.

3.6.4 Riserless Mud Recovery (RMR)

This variation is specially used to drill the first sections of the well and it has been given promising results in fields with water depth up to 330m in Jack Up rigs. Differently from the nitrogen injection, the injection of a second fluid in the system it's not necessary. Once salt water will play the role of the second fluid, above mud level and there isn't available equipment to restraint fluids return, example the rotary table or BOP. On the first sections, neither of them is installed yet.

The main motivations behind the development of this variation were the amount of waste mud when drilling the first hole-sections by conventional method. Considering that the *pump and dump*[2] is the most used method, apart from being expensive, the benefits are:

- a lot of space on the rig designated to stock of all this amount of fluid;
- more drilling fluid will be saved,

To avoid using a riser is interesting because:

- none of them used nowadays are intended to support high differential pressures (collapse pressure, mud-external pressure, salt water), eventually causing a collapse because of the increasing depth of the wells;
- better pressure control and pumped volume making possible to verify the risk of shallow influx of water and gas,
- what before wasn't possible once all the fluids were dumped on the seafloor, so there was no information arriving from the well to the rig, making it dangerous once the BOP isn't installed on the first sections yet;

Not using a riser,

- less space required at the rig, together with more available space due to less amount of mud that will be needed;
- smaller rigs can be rented on this phase reducing operation cost;
- the external forces like waves and current will have less impact on the drilling pipe once the smaller the pipe diameter, the lower the impact,

[2] *Pump and dump:* conventional way used to drill the first well sections. As the BOP isn't installed yet, a mud return closed system still doesn't exist, making a high volume of drilling fluid that pass through the drill bit to be released in sea floor, uncapable of recovering it.

- limiting problems as fatigue for example;
- ultimately but not less important, the maintenance of zones environmentally sensitive, being a system of "zero" discharge.

As shown on Figure 3.16, the system counts with a suction module, installed above the conductor, which integrates a drilling pipe, pressure sensors and cameras to verify the mud level. The annular mud return, which is a line parallel to the drilling pipe, is controlled by a subsea pump as showed on Figure 3.17. It is only activated when there's excess of mud in the module due to unexpected events in the operation, since that the increase in depth will require a higher volume of mud to fill the drilled hole.

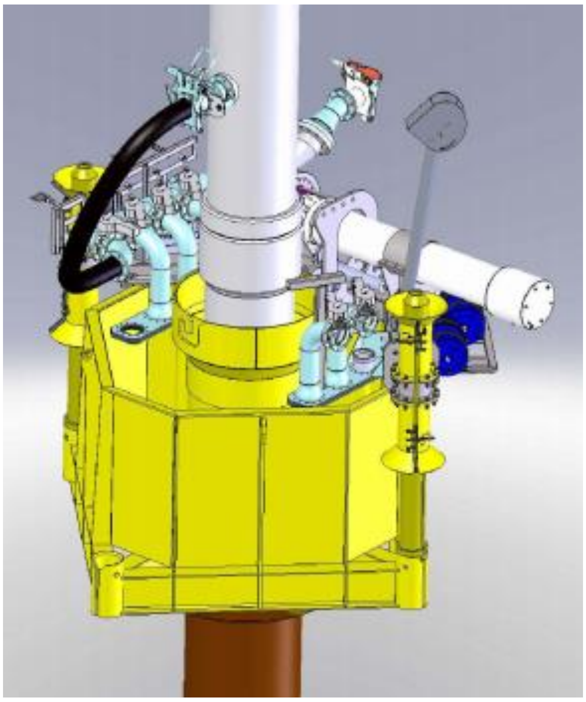


Figure 3.16: Suction module used in Jack Up rig to drill the first sections (Scanlon, 2011)

Cameras and pressure sensors act concomitantly to ensure that an overflow of drilling fluid does not occur on the seabed. This is possible through pressure measurement at certain points on the suction module by automotive equipment's. Those regulate the fluid level by pumping less or more fluid back to the rig, avoiding seafloor contamination.

After finishing drilling with RMR, the dual-gradient drilling can continue after the conductor and BOP are installed. One of the main advantages of drilling the first sections with more accuracy and safety is to deepen the first casing shoe, enabling the last casing shoe to be settled as deep as possible, increasing the liner diameter and the production potential of the well.

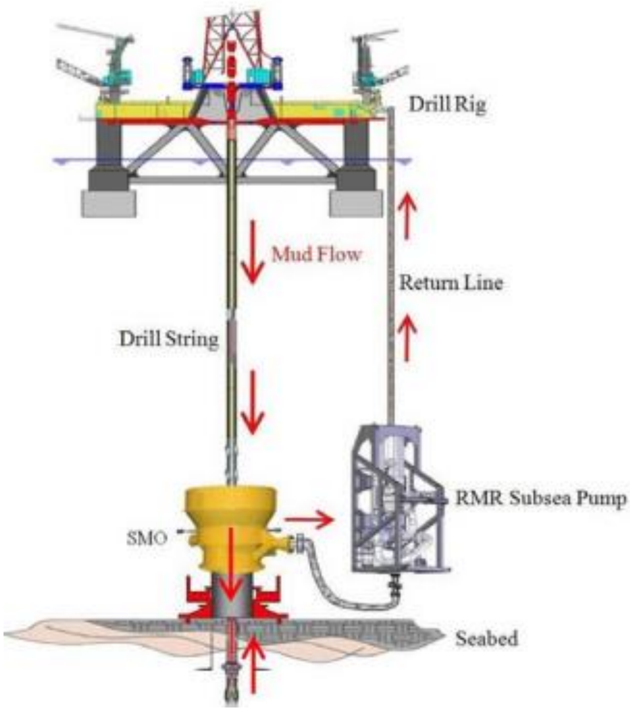


Figure 3.17: Example of RMR configuration for shallow water depth with subsea pump. (Scanlon, 2011)

For deep water, the RMR system uses dual upper and lower subsea pump modules as illustrated in Figure 3.18. Pump is controlled automatically, which responds to any downhole condition at once without any operator intervention.

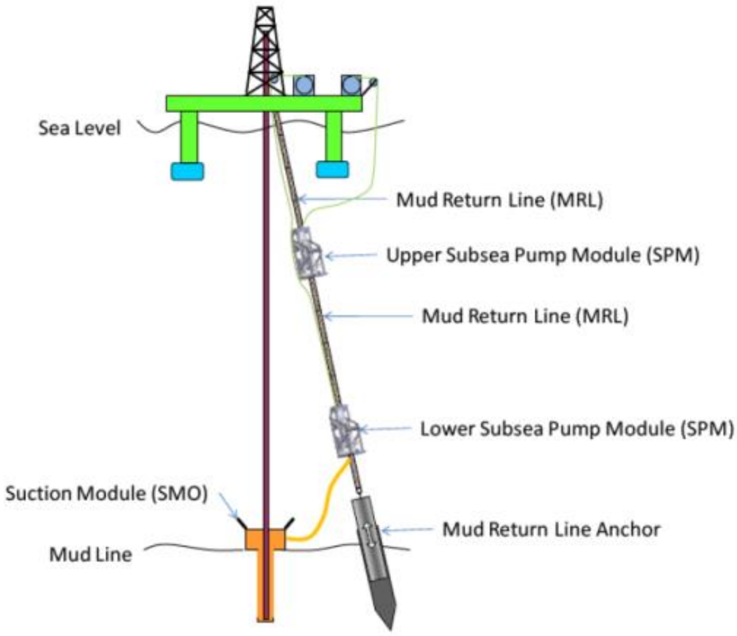


Figure 3.18: Deepwater riserless mud recovery system (Dave Smith, 2010)

3.6.5 Subsea MudLift Drilling (SMD)

SMD is a DGD MPD and the working principle is quite similar to the RMR when it comes to both using subsea pump. However, the SMD can be used not only in the first sections but also to drill deep sections.

In mud lift system, the pumps are installed at seabed where flow is directed to, and they pump it back to the rig floor through a separate line. The marine riser is filled with sea water in order to prevent from collapse. So two mud systems are developed, one being the sea water system in the marine riser, other the normal drilling mud below seabed.

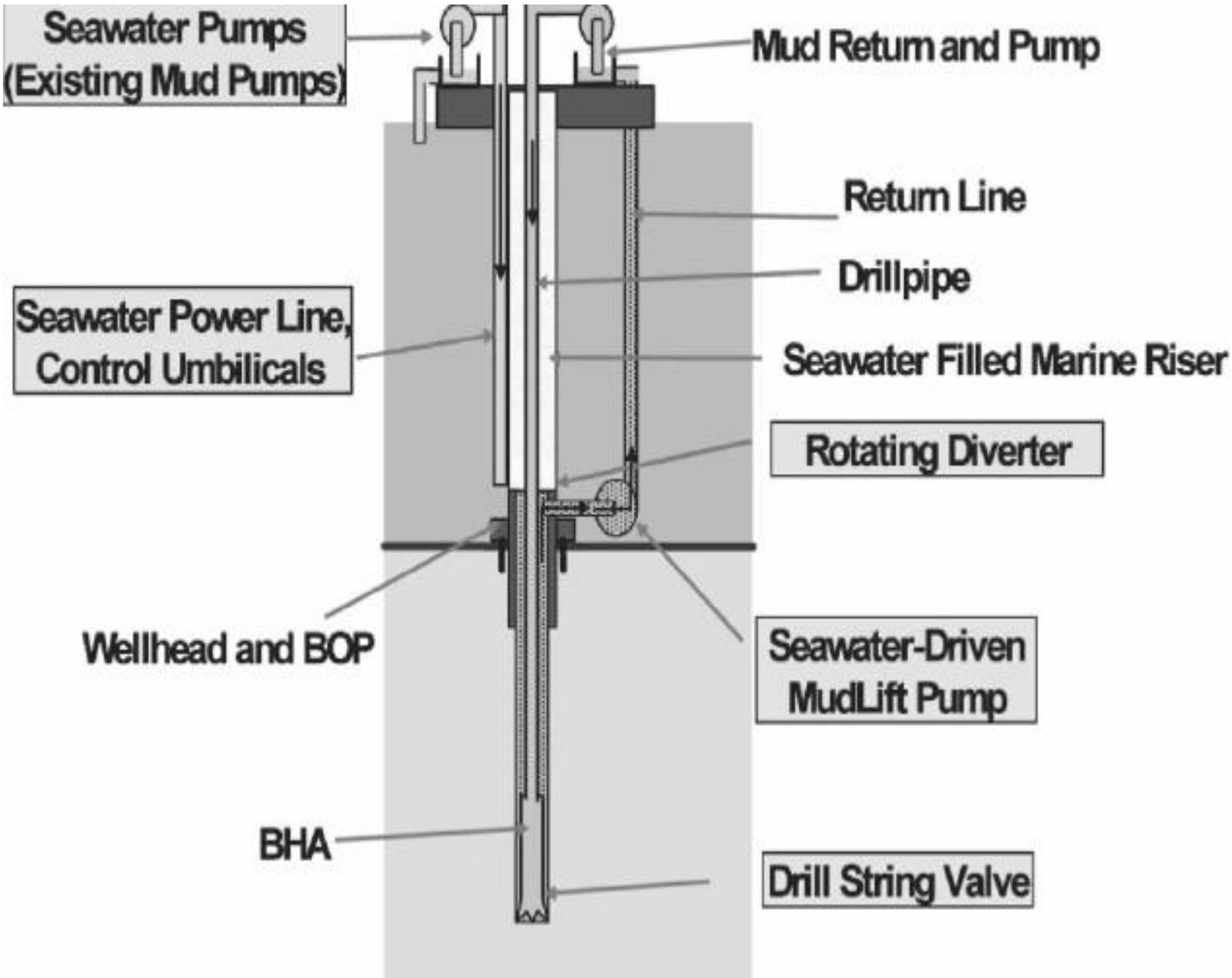


Figure 3.19: Subsea Mud-lifts Drilling system (J. J. Schubert, 2006)

3.6.6 Low Riser Return System (LRRS)

Low riser return system is a method of controlling the annular pressures. This is done by adjusting the riser mud level for enhanced pressure control in wells with narrow operating margins. It works by adjusting the mud level in the marine riser by returning mud and cuttings to surface through a subsea pump in a separate conduit. It is a single mud gradient, open managed pressure drilling (MPD) system, designed for subsea drilling.

With LRRS system, the drilling fluid density and the riser annulus drilling fluid level control the well pressure. Figure 3.20 illustrates LRRS connected to a drilling riser. LRRS has subsea drilling fluid return pump. Pumps can be controlled automatically or manually to obtain the required mud level in the riser. Annular Level is controlled by removing top part with Nitrogen. The Control System monitors the level and controls the pump. By adjusting the level, the BHP changes in short period of time. As illustrated in figure 3.21, the LRRS perfectly fit the drilling window shown in green envelope.

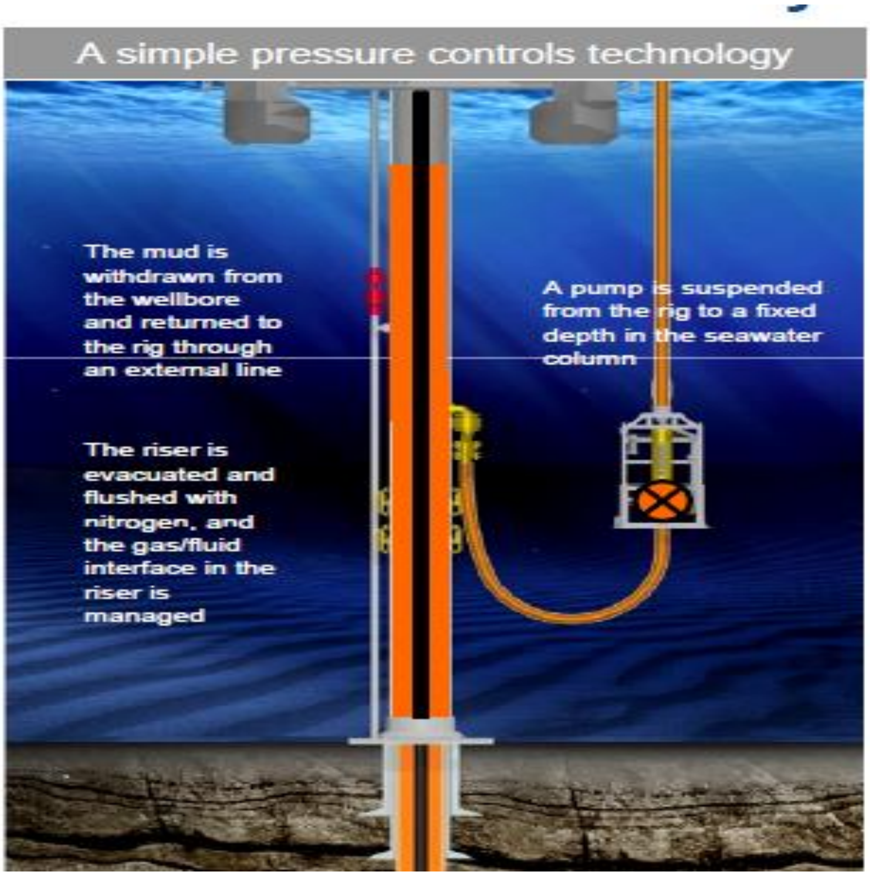


Figure 3.20: Low Riser Return System-Pressure control technology (Jasmin Begagic, 2011)

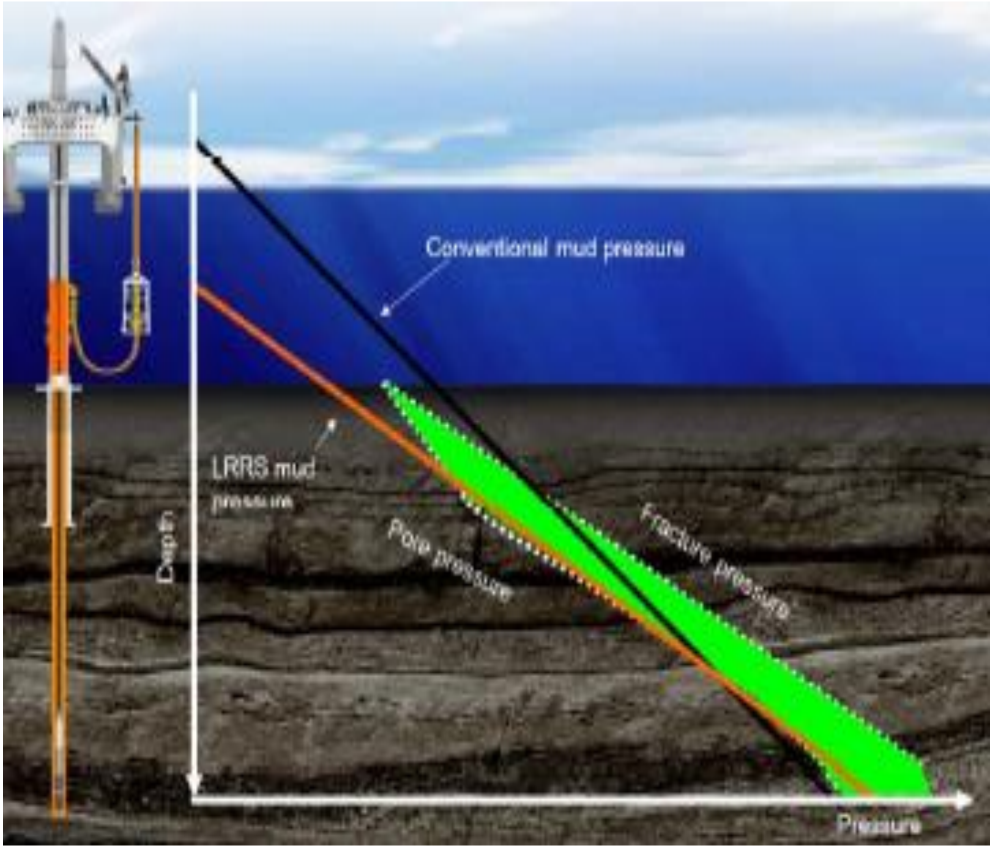


Figure 3.21: Conventional vs LRRS methods drilling envelop (Jasmin Begagic, 2011)

Falk et al (2011) have analyzed the potential application of LRRS by using two wells with different water and total drilling depths. The first case is based on a typical deep-water well in the Gulf of Mexico. The second case is based on BP's Macondo well. However, the parameters they used were not 100% exactly the same as the one encountered in the well.

They used design and analysis simulators for the evaluation of the LRRS method. Their study has shown that:

- LRRS allows lysis, allowing the mud gradient to better fit into the operating window in deep to medium-deep water (Figure 3.21)
- can reduce the risk of kick and fracture loss probabilities (Figure 3.22)
- the system can also improve kick detection and reduce kick size
- as well as improve quality of primary cementing in narrow drilling windows (Figure 3.23)

As a result, this technology can improve safety in drilling of deep-water wells and infill drilling in depleted fields.

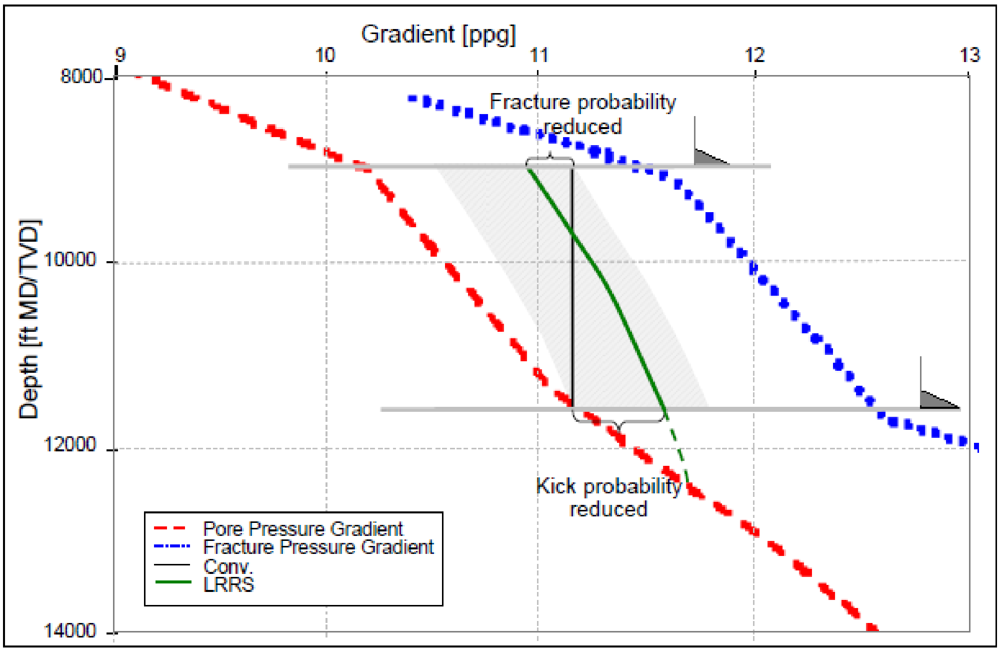


Figure 3.22: Comparisons of LRRS and conventional mud gradients (LRRS method showing a reduced kick and fracture margins) (Kristin Falk & Arne Handal, 2011)

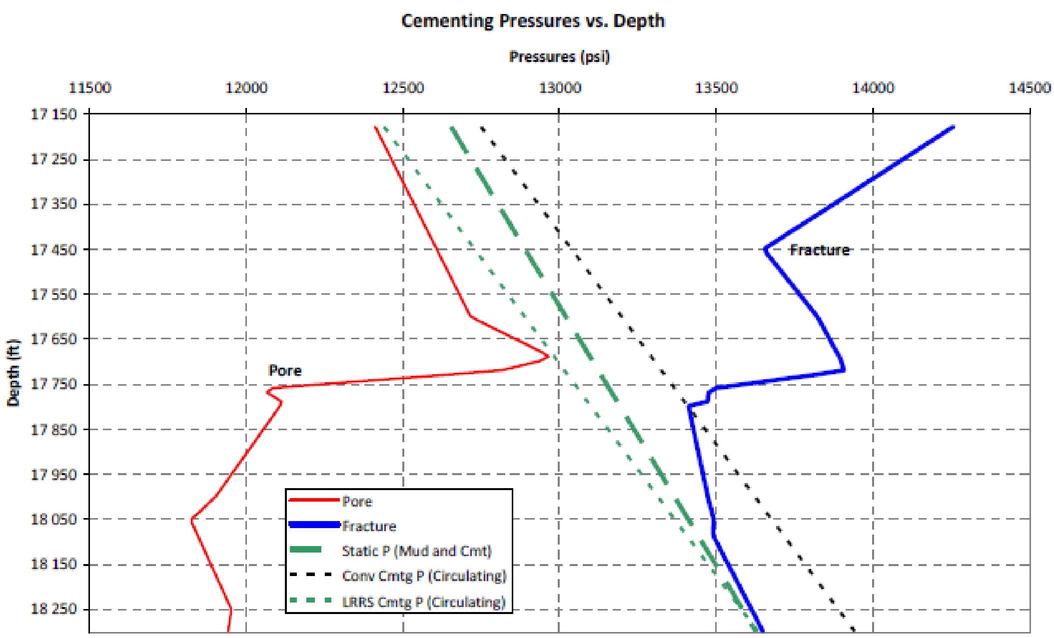


Figure 3.23: Cementing operation with LRRS method (Kristin Falk & Arne Handal, 2011)

3.6.7 Returns Flow Control (HSE)

Also known as return flux control or closed loop system, this method consists of an early detection and avoidance of harmful gases like organic gases overall (methane-ethane, propane, etc) and toxic gases (carbonic and sulfuric gas). It reduces the risk of harm to the operation, rig, personnel, and environment by handling the bottom hole pressure proactively.

The basic HSE system is exemplified on the Figure 3.24 and normally consist of the basic conventional drilling equipment plus the RCD, a choke valve designated to this activity and a valve of the drilling pipe.

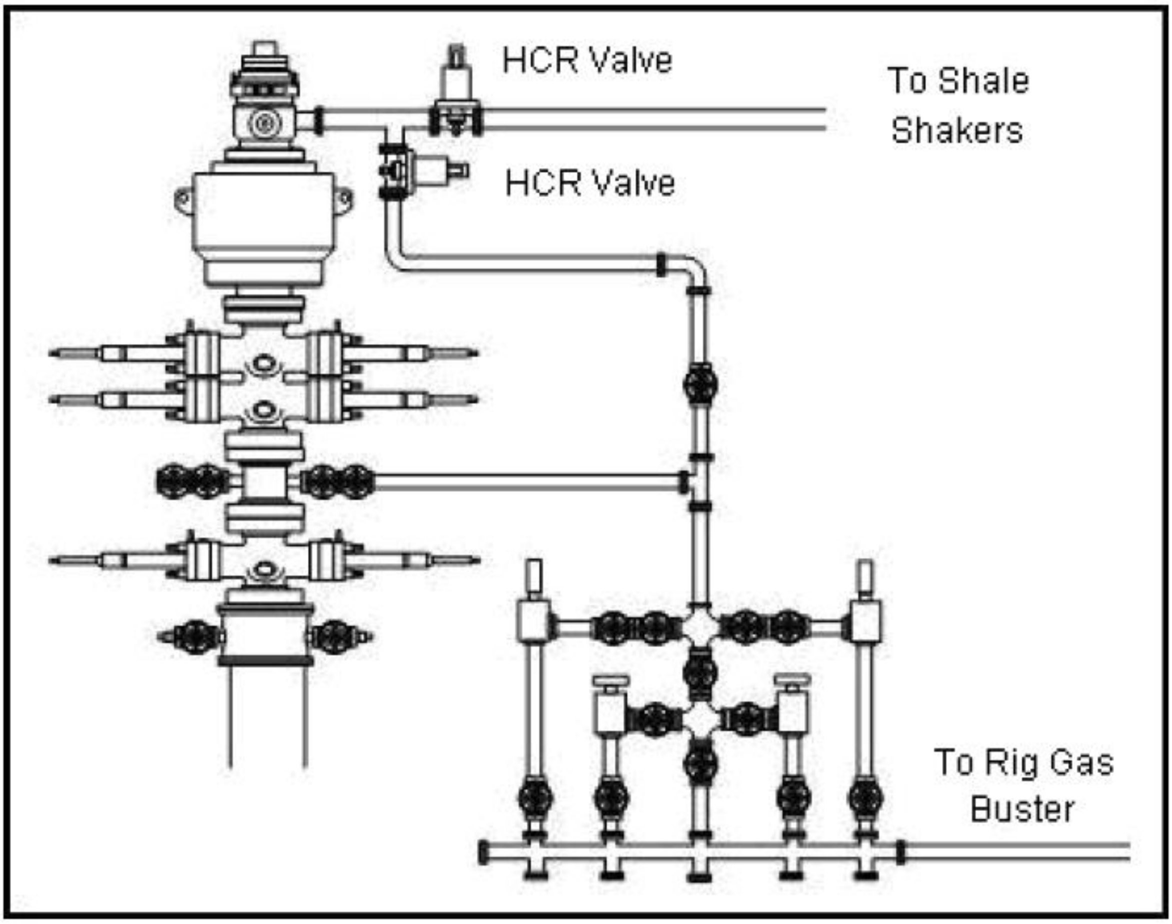


Figure 3.24: MPD rig return flux control (S. Nas, 2009)

4 MPD Field Case Studies

The MPD field case studies presented in this chapter are summarized based on deep-water, horizontal well, and HPHT. However, the well may experience three of the categories and the presentation has no special reasoning, but for simplicity.

4.1 Deep-Water

Xanab field is located off the coast of Tabasco in the south-eastern Gulf of Mexico (GoM). The oil field reserve is concentrated in a dolomitized carbonate rock from the Upper Jurassic formation. Its structure is described as an elongated anticline reservoir with measured depth (MD) deeper than 6000m and limited by two faults. Figure 14a and 14b show the geographic location of Xanab field and a 3D plane of correlative 1DL and 31 wells (Ramirez, 2011).

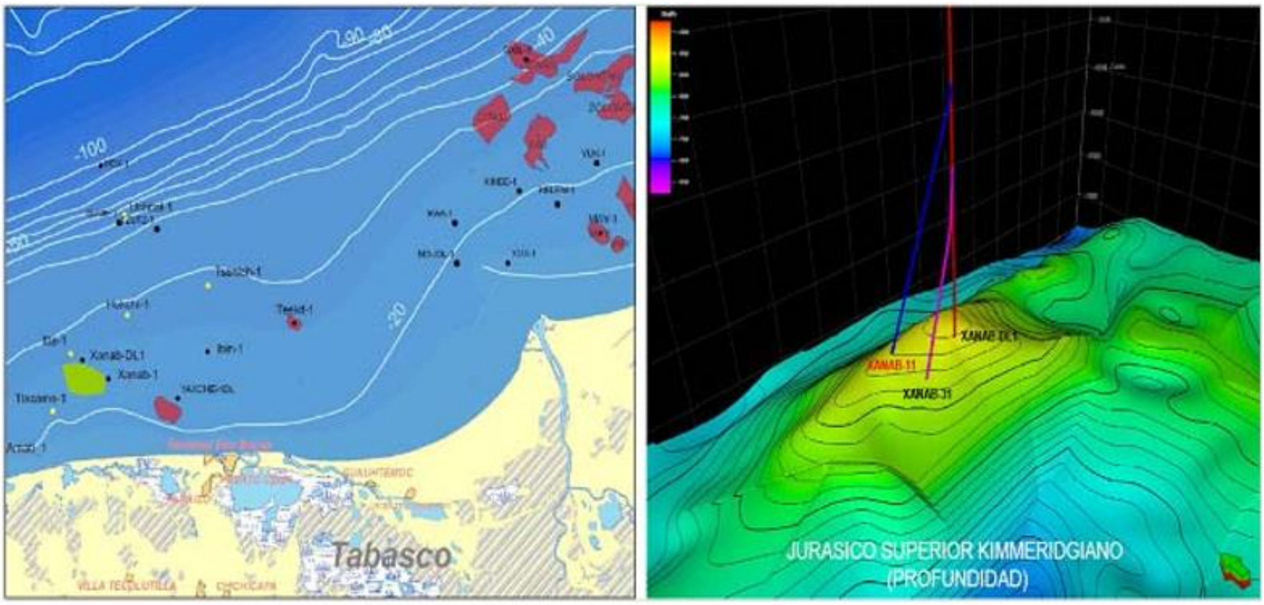


Figure 4.1a: Geographic location of Xanab field   Figure 4.1b: 3D plane path of Xanab 11 well (Ramirez, 2011)

4.1.1 Problem with conventional method

Based on correlative well data and logs run over 31 wells, a narrow operational window of 0.6g/cm^3 was expected at the entrance of the Miocene zone around 4900m depth and due to the circumstances, using conventional drilling methods could cause severe kicks and fluid losses as experienced on the correlative wells.

A review of the events logs and drilling records of the correlative wells for this specific section was made to have a better overview and understanding of well trajectory plan and other important data.

4.1.2 Solution with MPD technique

MPD was then chosen as a solution to drill the 5 -7/8 in. hole section of the well enabling to work within a narrow window and to identify formation tops during drill breaks, which normally wouldn't be possible due to fluid losses and kicks.

The decision for the chosen equipment was based upon the limited operational window expected for the MPD interval. A rotation control device at the wellhead, an automatic chose assembly, a surface three-phase separator as well as a data acquisition system were installed as shown in Figure 4.2.

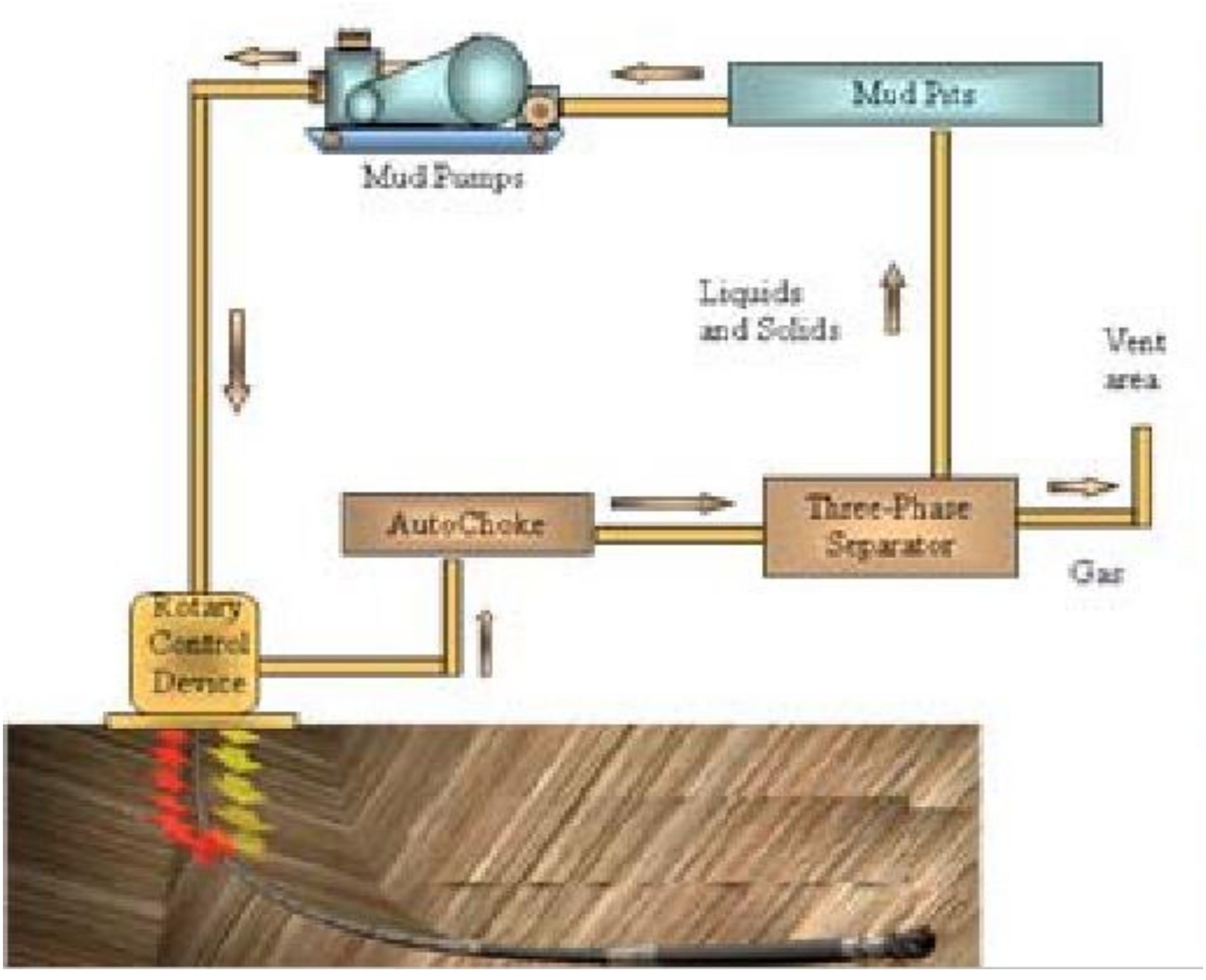


Figure 4.2: Diagram of Equipment Used (Ramirez, 2011).

The 5-7/8 in. section started to be drilled at 6086m MD (Measured Depth) using conventional drilling until severe losses occurred at 6245m. MPD was then introduced by reducing gradually the mud weight and diverting the well flow through an automated choke and the three-phase separator. At 125m further, a drilling break caused a severe mud loss, requiring an even lower mud density. If an influx was detected, automated choke %propitiated the increase of backpressure or decrease if losses were detected.

Constant bottom hole pressure was maintained slightly above the reservoir pressure during the whole operation, even when rig pumps were off during connections and short trips by using backpressure. After loss episodes, the well experienced two kicks which one of them was controlled by pumping with the well shut in until pressure was highly reduced from 3250 psi to 800 psi. The well was then diverted through the automated choke to continue drilling and mud weight was increased to displace the kick volume and surface pressure achieve 200 psi. The well also had six high gas concentration episodes which were all displaced through the three-phase separator.

<u>MPD's main achievements</u>

Overall, MPD was successfully applied to the Xanab field in a well with narrow operational window overcoming the issues presented during conventional drilling.

Despite the loss and kick episodes, MPD improved the average ROP thus reducing the drilling scheduled time of 44%. Also, the total volume of mud loss was reduced by 72% compared to correlative wells.

BHP was maintained slightly overbalanced and adjusted backpressure was possible by an automated choke, which along with the 3 phase separator enabling drilling even on the event of high gas, what would probably request to stop the operation and circulate if using conventional drilling. Obviously, NPT was reduced by all those benefits but also because of the use of a flowmeter downstream from the choke that enables early detection of influx and loss making possible practical decisions in advance.

4.2 Horizontal Well

Samaria field is located on the south-eastern basin in the Chiapas area, 20km from Villahermosa, Tabasco, in Mexico. Oil production comes from Bermudez Complex, the biggest producer in the southern region and number four greatest in Mexico. The complex covers 5 other fields in a total area of 192km². First well drilled in this area was in 1960 by Samaria-2 but only in 1973 that Samaria-101 well confirmed its production potential.

The reservoir is located between 4200m and 4500m TVD in carbonates and dolomites formation from Upper, Medium and Lower Cretaceous. At the beginning of production, reservoir pressure was around 7500psi which suffered depletion after 25 years of production achieving 2300psi.

4.2.1 Problem with conventional method

After 25 years of production, this field has been decreasing formation pressure down to 30% of its initial pressure. Previously, nitrogen concentric injection, an MPD variation, had been used to mitigate problems such as mud loss circulation and differential sticking, but the high volume of nitrogen inside the drillpipe imposed limitations for conventional MWD (Measured While Drilling) and electromagnetic tools due to high BHP or formation resistivity.

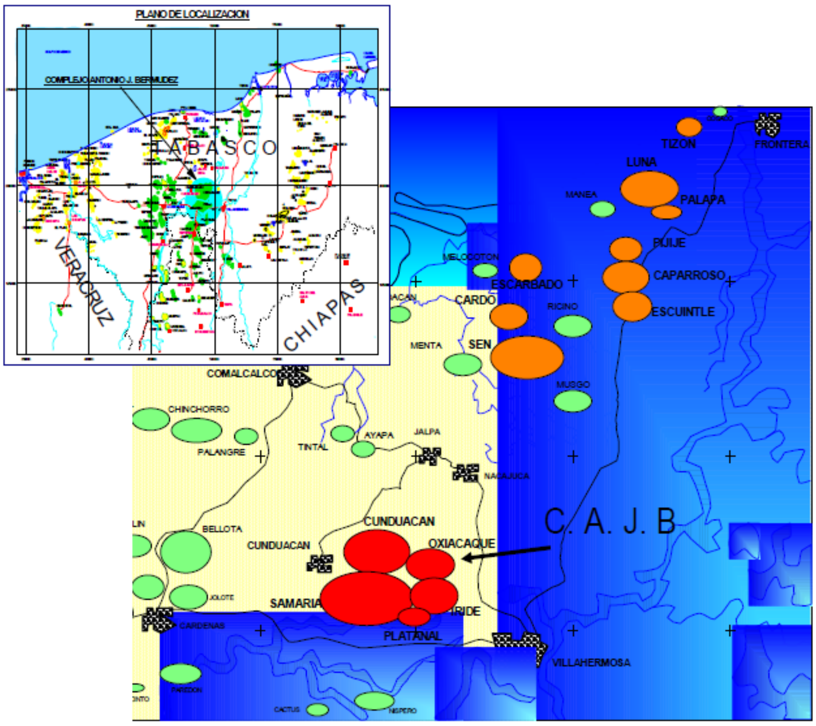


Figure 4.3: Geographical location of the complex A.J. Bermudez (C. Perez-Tellez, 2009)

Based on this scenario, 3 horizontal wells were previously drilled without much success because of the difficulty in controlling their trajectory. Nevertheless, to ensure a production level above the forecast declination, drilling horizontal wells were necessary. Also, offset wells drilled in Samaria field had severe circulation losses, over 3000m³ in some cases, at the upper Cretaceous formation depths.

Technically, the evaluation of this method feasibility was driven by two factors:

- The need for new methods to increase the production field
- The impossibility to build angle and/or to direct into high angle section due to lack of signal when high volumes of nitrogen were injected into the drill string to avoid circulation loss into the production formation

4.2.2 Solution with MPD technique

The Dual Gradient Drilling with riser variation called Nitrogen Injection, was suggested as a solution to make possible the use of conventional mud pulse MWD/LWD (Logging While Drilling) and, at the same time, to keep bottom hole pressure within the operational window avoiding losses, improving hole cleaning and controlling risks of hole instability. The main goal behind the nitrogen injection to drill the 6½" section was to achieve a balanced condition reducing the overbalance pressure against formations by the hydrostatic column of fluids in the annulus. Consequently, mitigating problems occasioned by low pore pressure in the upper Cretaceous when drilling conventionally.

Once its feasibility was approved, a series of planning to design the required operational procedures were done and it was determined that the method would be based on a steady state and transient flow modeling with different operational parameters in order to analyze its performance. From the modeling results, the minimum equipment requirements were defined which included a RDC, a hydraulic choke manifold, a horizontal 4 phases separator and a nitrogen generating equipment among other conventional tools.

As both for conventional drilling as for MPD/UBD, the BOP serves as a secondary barrier for the well control. In this case, the designed BOP had to have three additional elements to apply the

MPD using a concentric casing to inject nitrogen. The RDC used to deviate the returning fluids from the well to the MPD choke and separator. A temporary wellhead used to hang the 7⅝" tieback and seals around the 9⅝" casing, forming a concentric annulus used to pump the nitrogen down hole; and last a spacer spool that allowed taking the fluid level in the main annulus when tripping out of hole (TOOH).

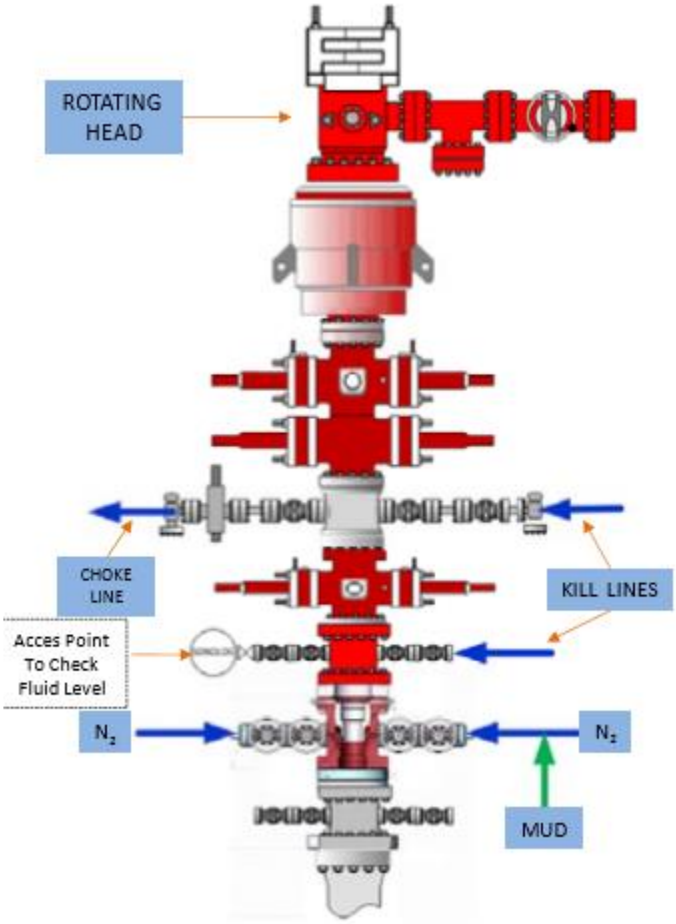
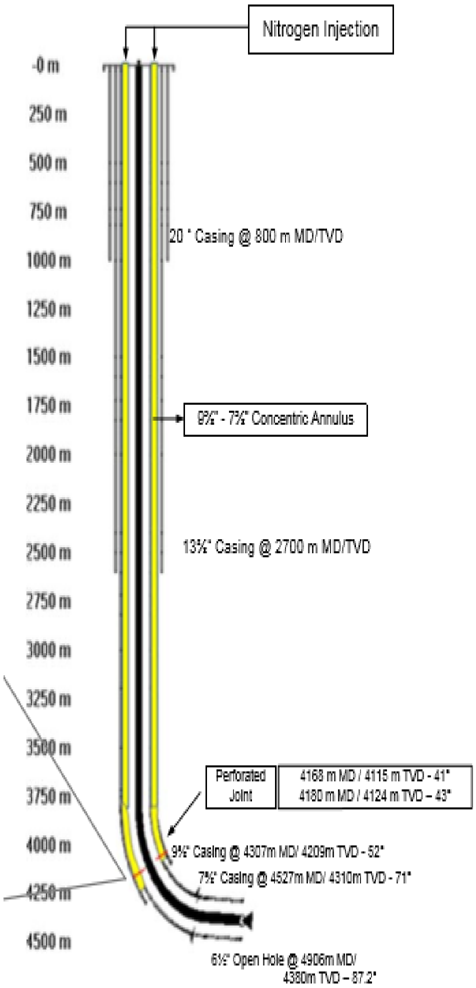
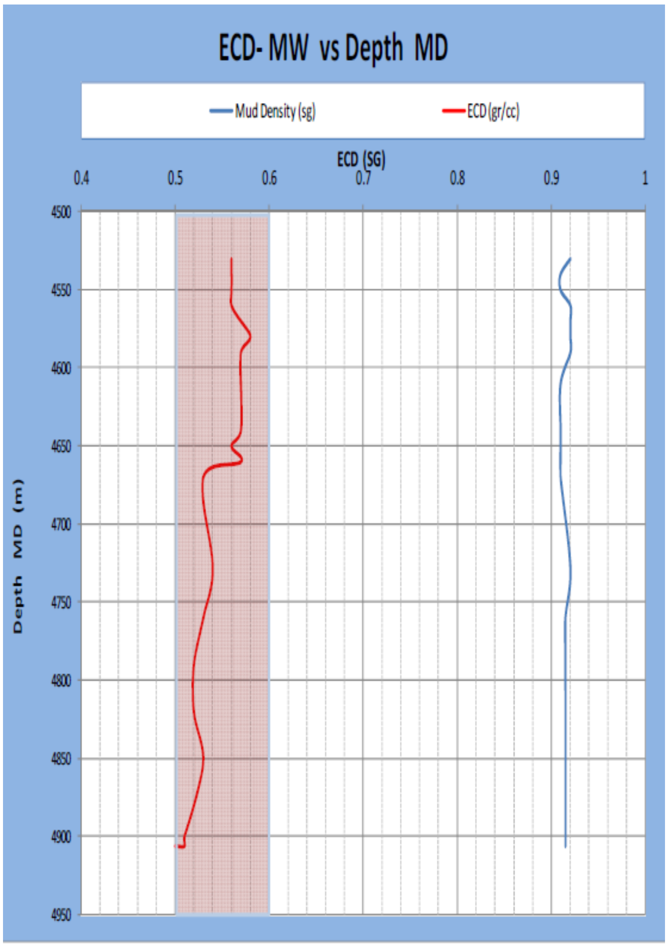


Figure 4.4: Configuration of Nitrogen Injection Well Head (C. Perez-Tellez, 2009)

The main objective was to directional drill 378m between 4338m to 4390m TVD building an angle from 73 to 85 degrees, and that's when the importance of signal from the directional tools was indispensable. Hence, the MPD application for this section faced an extra challenge to obtain a design that could tolerate in terms of injection, the maximum circulation stability as possible at bottom hole and wellhead pressures, and also the inflow and outflow volumes. Figure 4.5 shows the well configuration used in this case.





ıre A.4. Real Operational Window – Equivalent Circulation

Figure 4.5: Well Configuration for Concentric String Nitrogen Injection (C. Perez-Tellez, 2009)

The procedure was done by pumping mud and nitrogen through the concentric annulus at the same time to decrease injection pressure and liquid flow return. A volume of mud arrived at the surface corresponding to the liquid displaced from the concentric annulus and the liquid replaced by nitrogen in the primary annular.

Initially, connections stability was interfered by different factors i.e. pump/ compressor failures, excessive volume of mud pumped for surveys purpose etc., but despite nitrogen rate was over the critical injection, the circulation stability was achieved after 4th connection. The section of 379m was drilled using only 1 bit instead of 3 as previously planned, and directional control of the well was successfully achieved maintaining a controlled ROP thus a better hole cleaning efficiency. ECD (Equivalent Circulation Density) was kept within the operational window reducing mud losses.

MPD's main achievements

This case study recorded a world record for the deepest injection point, drilling a high angle well in the ultra-depleted fractured carbonates reservoir.

Managed Pressure Drilling using Dual Gradient with nitrogen injection was overall successfully applied in this well. Operational results indicated:

- reduction of fluid loss to the formations when compared to offset wells
- avoided differential sticking by keeping bottom hole circulation pressure close to pore pressure
- accurate and strong signal through MWD mud pulse telemetry and cooler downhole temperature by lower injection rates of N_2
- the well was drilled with just one trip, which reduced undesired NPT
- increased productivity and production rate as well as less formation damage, as a result, produced with natural pressure instead of using gas lift, as it was common in the field

4.3 Pre-Salt

Sen field is located in southern Mexico and is surrounded by several other producing fields as shown in Figure 4.6. The productive formations are Upper, Medium, and Lower Cretaceous, mainly formed by mudstones, and the Jurassic which produces from dolomites. The production of HC in its majority comes from the Upper Medium Cretaceous fractured reservoirs.

4.3.1 Problem with conventional method

The main operational concerns while drilling this field, such as stuck pipe, ballooning effect[3], influx of salt water and fluid losses, were founded on the tertiary salt diapir in the 12 ¼" section. Due to those issues, NPT achieved 240 hours on top of the preview schedule time encouraging

[3] Balloning effect occurs when there's fluid migration into the formation while or after drilling, due to any perturbation or hydraulic change in the well. This volume of fluid returns into the well and is possibly mistaken as a kick.

the drilling service company to investigate an alternative to the usual solution used for the wells drilled in the past, which was a rotary head as a diverter.

As part of the well design procedure, some analysis is necessary to prevent some non-desired events and for better design of the well, to do so correlation with other wells could show that the best flat times during drilling operations were observed while drilling the salt layer between 14¾” and 12¼” sections. Also, when analyzing the time spent during such sections in details it was possible to identify that salt water kicks and loss circulation were the most contributors for non-productive time in the 12” section with 9 ⅝” casing.

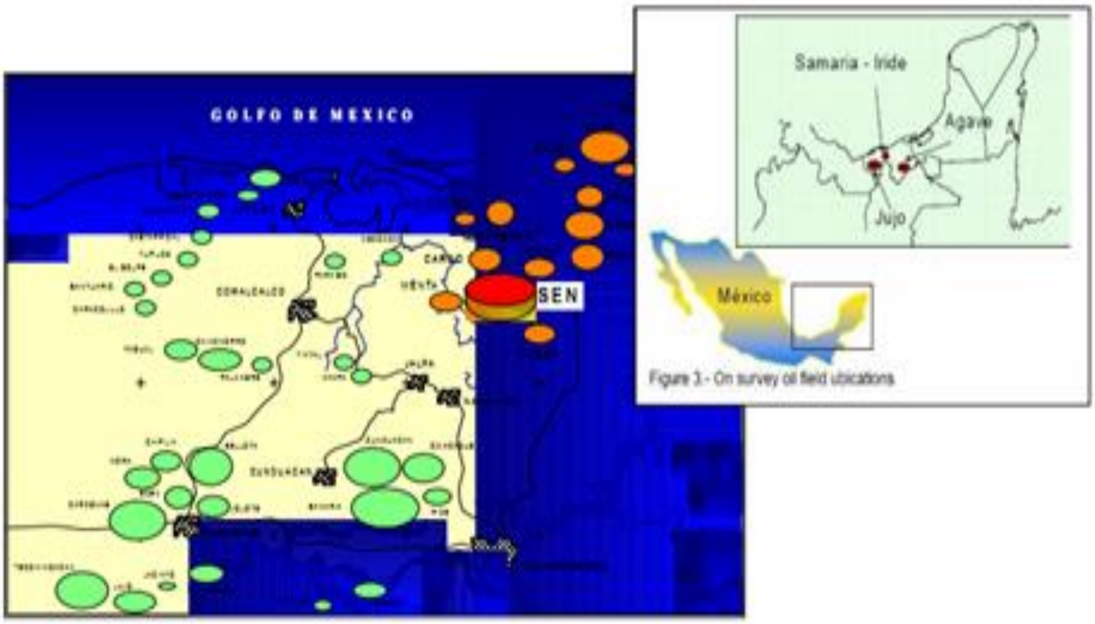


Figure 4.6: San Field Geographic Location in Southern Mexico (Hernandez, Tellez, & Lupo, 2009)

4.3.2 Solution with MPD technique

The MPD technique selected was CBHP driven by the objective of early detection and prevention of any salty water influxes avoiding mud contamination and related NPT and costs. The system chosen was also used to avoid high-pressure overbalances responsible for mud loss into the salt dome. The use of a dynamic annular pressure control device (DAPC) allows adjusting circulation rates to an optimal range by keeping low mud weight and low bottom hole pressure as needed, hence reducing or eliminating LCM (Lost Circulation Material) treatments.

A contingency liner was set at the top of the salt diapir to avoid the mud losses while reaming while drilling the 12 ¼” x 14 ¾” section. The next section (10 ⅝” x 12 ¼”) was drilled along 938m using CBHP with DAPC system with mud weight overbalanced for the salt layer but at the same time, slightly underbalanced in the water-bearing sands. In order to avoid water influxes and reduce losses, a minimal backpressure was applied while drilling.

Starting the diapir salt section, small influxes due to a mud gradient lower than the pore pressure and due to ballooning effect were detected and controlled by the DAPC system and its auxiliary pump and automatic choke. The use of a sensitivity flow meter also contributed to normalizing the mud rate during pressure changes.

MPD’s main achievements

The application of CBHP technique along with DAPC system reduced drilling time of 938m of salt from 30 to 11 days (i.e. by 63.3%), without experiencing drilling problems. Before interpreted as a kick, ballooning effect was recognized for the first time in the field enabling appropriated solutions and reducing associated NPT. In general, constant bottom hole pressure was found as a problem-solving technique to drill the salt diapir. It was the first time that an automated choke system equipment was used, not only in this field but also in Mexico, in order to reduce or eliminate the high NPT associated with mud contamination, fluid losses and stuck pipe.

4.4 HPHT

An exploration well drilled in Southwest Louisiana in 2016 using MPD technique reached new targets of depth, pressure, and temperature being classified as an ultra-HPHT wellbore. The well achieved 8969m of total depth with bottom hole pressure around 30000psi and a temperature of 500°F. (260°C)

4.4.1 Problem

Depths below 4572m presented high solubility of gas which hinders the detection of risk for kick events. The requirement for precise kick detection also increased by the uncertainty around the pore pressure gradient, the reduced kick tolerance for deep depths, and well instability leading to swabbing when tripping operations occurred.

4.4.2 Solution with MPD technique

MPD technique was applied using constant bottom hole pressure to reduce well instability, whereas in this case, the proposed application aimed to facilitate the identification of influxes and further kick events and also increase wellbore stability with the proviso that MPD equipment should not be used as a BOP (blow out preventer).

Prior to its implementation, procedures and planning were settled in order to align the well objectives and contingency plans for challenges detected in a high-pressure high-temperature scenario while drilling with managed pressure. The varied options that MPD offers during connection, flow check, well control and stripping make it necessary evaluation and decision chart to be followed while execution.

Figure 4.7 illustrates an example of the effect of tripping on well pressure with conventional and MPD technique. As displayed with conventional method, where backpressure is zero, the effective mud weight is nearly approaching the pore pressure. The operation resulting in an estimated 31.3 hours to completely pool out of the hole. One other truck as shown the application MPD, with 300psi backpressure, one can observe two important results a) the effective well pressure is within the safe window and b) the POOH operation completed in 24.2 hours. This means that the MPD operation reduced the tripping time in this case by 22.7%

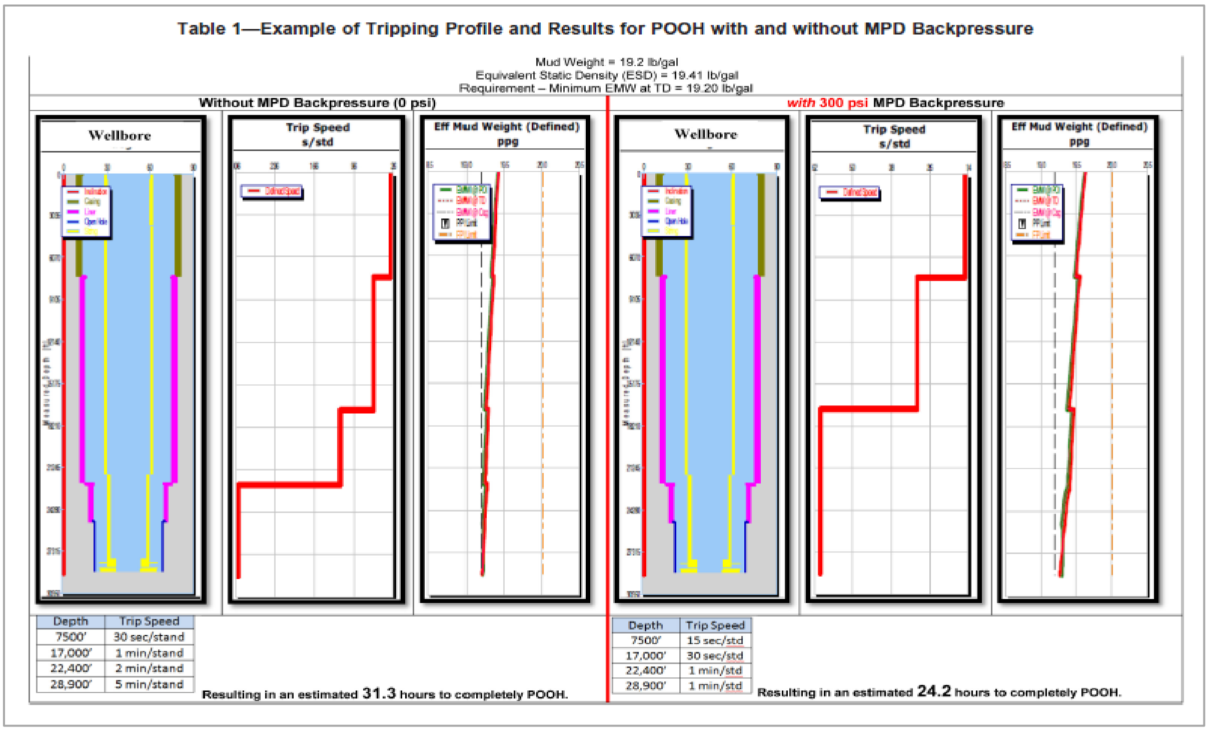


Figure 4.7: Tripping profiles and the resulting POOH with and without backpressure (Craig Starkey and Travis Webre & Mike Rafferly, 2016)

MPD's main achievements

MPD technique and the selected equipment were successfully applied in this ultra-deep HPHT exploratory well with three main important achievements. The first one is the detection of small kick: an influx of less than 3 barrels in a challenging kick detection environment. The second one is tripping efficiency: the main achievement by implementing managed pressure drilling was saving considerable rig time due to higher trip efficiency and less time used for circulating and managing gas at the surface. The third one is manage entrained gases: MPD manage to control entrained gasses that breakout of the solution when reaching to the surface.

4.5 Fractured Carbonate Reservoir

The wells in Soka field are located on the Musi Platform, in onshore South Sumatra Basin, Indonesia.

4.5.1 Problem

Type of formation: fracture carbonate reservoir (Baturaja formation). Severe circulation losses and kicks are quite common. It is reported that due to total losses combined with gas kicks, in the upper section of the Baturaja Formation, drilling activity was suspended for 2 years.

4.5.2 Solution with MPD technique

To overcome the operational related problems, the best MPD technique, which is suitable for the fractured carbonate formation, is the Pressurized Mud Cap Drilling (PMCD). The working principle is reviewed and presented in section § 3.5.2.

Normally, drilling operations conducted until losses encountered. If the losses are critical, making the operation unfeasible, operations change to PCMD. The PMCD system for the Soka 2006-6 and 2006-1 were set up in stages. The RCD, valves and pipework were installed before the 6" hole section was drilled and used while drilling this section to divert the flow of returns.

A river, located two kilometers away from the rig site, was used as a source of sacrificial fluid and water trucks were on standby at the rig site for additional water if needed.

For Soka 2006-6, the DIV and RCD were installed before drilling the reservoir section at 2780 feet depth. The 6" hole section was drilled conventionally because at that point circulation losses and gas kicks events were not severe.

During operation, the field experienced severe losses and kick influx. However, after the application of PMCD and injecting annular fluid, operators managed to control gas migration. Moreover, despite the difficulties encountered, the liner was successfully installed and cemented in PMCD mode.

MPD's main achievements

The PMCD technology allowed re-entry operation in Soka 2006-1 and target reaching. There was no NPT associated with PMCD. There was sufficient hole-cleaning and good ROP performance during the re-entry operation. Rather than curing the drilling fluid loss, PMCD manage the job by drilling through the loss zone.

4.6 Coral Reefs

The well PL 591 is located approximately 220km West of Brønnøysund in the Norwegian Sea surrounded by an area of coral reefs. Drilling stopped at 2,875 m below sea level.

4.6.1 Problem

Once stated the potential well location in 2010, environmental assessment work was previously done and in 2011 it was necessary to do a site survey in order to identify operational challenges associated to potential harms on the environmental habitat and fisheries. The survey reported "a number of relief and/or high reflectivity features that maybe be of conservational interest or biogenic origin including indications of distinct morphology similar to that found around cold-water coral communities such as that created by the hard branched coral "Lophelia Pertusa" (Macdonald & Oil, 2016). Even though not confirming that these occurrences were within the license area, they were confirmed proximately to its boundary.

Based on the site survey, an initial and final coral risk assessment was done aiming to identify possible hazards caused by drilling cuttings to the coral formation and results showed that possibly 76 coral structures were in risk of being harmed. By the results, a visual map survey was made and a ROV (Remotely Operated Vehicle) inspection took place to certify the presence and condition of the corals and sponges and also to identify a suitable anchor for the drilling rig as well as a location for discharge of drill cuttings.

Following the surveys and seabed mapping, the well location had to be moved 90m to guarantee a maximum distance from the nearest coral and to ensure that the type of anchor chose wouldn't impact it. The risks for the corals were damage caused by sedimentation from the drilling discharges and partially burying/ damage due to the contact with the rig anchor chains. A risk matrix was then created to set the level of risk of sedimentation for each coral structural.

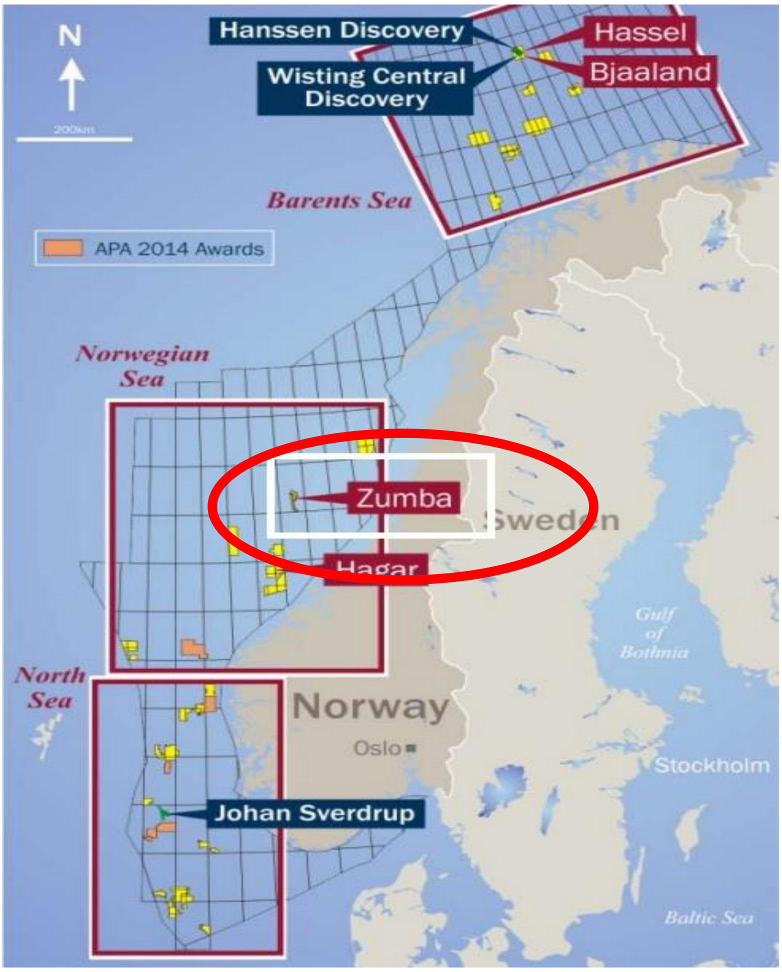


Figure 4.8: Location of well PL 591 (Derrick, u.d.)

4.6.2 Solution with MPD technique

The main concern behind all those alternatives were the possibilities for the hole cuttings discharges. That's where Riserless Mud Recovery (RMR) was indicated as the best environmental alternative to protect the corals along with shipping the drilling cuttings, from the top hole and further hole sequences, to shore for treatment and disposal, implementing a zero cuttings discharge strategy.

Normally, when using RMR, the conductor is placed before the RMR system and the suction module (SMO) is installed on the conductor via an adaptor but in this case, it was also desired to contain the cuttings from drilling the 36” hole section. The challenge here was that there was no fixed structure on the seabed to install the SMO so an alternative was using a spud base with a spud pile inside to ensure the system would be in place while drilling the top hole as shown in Figure 4.9.

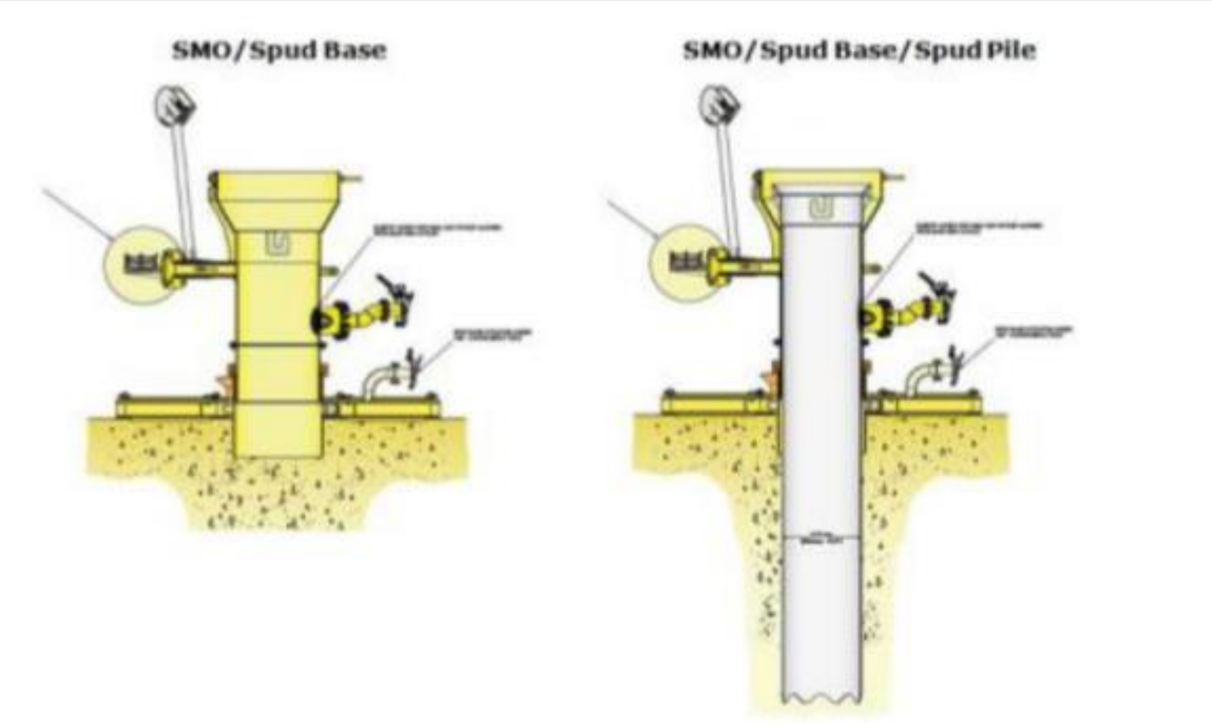


Figure 4.9: SMO/ Spud base with and without Spud Pile installed (Macdonald & Oil, 2016)

The pre spud installation was done by vessels prior to the rig arriving on the location hence minimizing the rig time (thus the rental costs) used for the rig up of the RMR system.

One of the concerns using this MPD variation was the time delay while drilling the 36” and 26” sections due to a large amount of drilling cuttings generated and the various processes it had to pass by before arriving onshore. Also, the chances of having equipment failure by the amount of cuttings would affect the rate of penetration controlled by the lower capacity of the system components.

The decision to contain and ship the cuttings made possible using an engineering oil-based mud in a closed loop system for the intermediate and reservoir sections. Cuttings were pumped to the surface by RMR system directly to shale shakers and mud cleaners and posteriorly transferred and stored in a rig based tank before going to the ISO tanks on the vessel. There was no decrease on ROP due to the handling capacity of RMR but because of boulders while drilling. Some delay on the operations happened due to weather conditions making it hard for the transfer of cuttings to the vessel.

This well took 2.9 days of rig time to rig up the RMR system in parallel with the ISO tank cuttings handling system, and other third part services 2 weeks prior to the drilling operation began avoiding time and cost exposure associated to the systems. An estimation shows that the use of RMR system together with cuttings containment to drill the top hole sections added a cost of $6.000.000,00 without taking into account the invisible cost savings.

<u>MPD's main achievements</u>

Zumba well was drilled within the top 10% for m/day when compared to similar exploration wells in Norway drilled in 2014 and 2015 showing a high efficiency and successful application. The application of RMR system together with the ship to shore avoid cuttings discharge to the sea, hence not harming the cold water corals achieving the main objective of the well without undesirable harm to the environment.

4.7 Highly Porous Formation

Goodwyn-10 well is located in Dampier Sub-Basin offshore in Australia. The reservoir rock is Bare Sands. The drilling of the well started in March 2006.

4.7.1 Problem

The formation where it's located is composed of highly porous sand and circulation loss often occurs. It is also interbedded with soft sand and hard cemented layers, causing severe torsional vibration and twistoff in the bottom hole assembly (BHA). Hard drilling problems, stuck pipe, packoff and large non-productive time are common. Figure 4.10 below shows the time lost due to stuck pipe in the Bare formation.

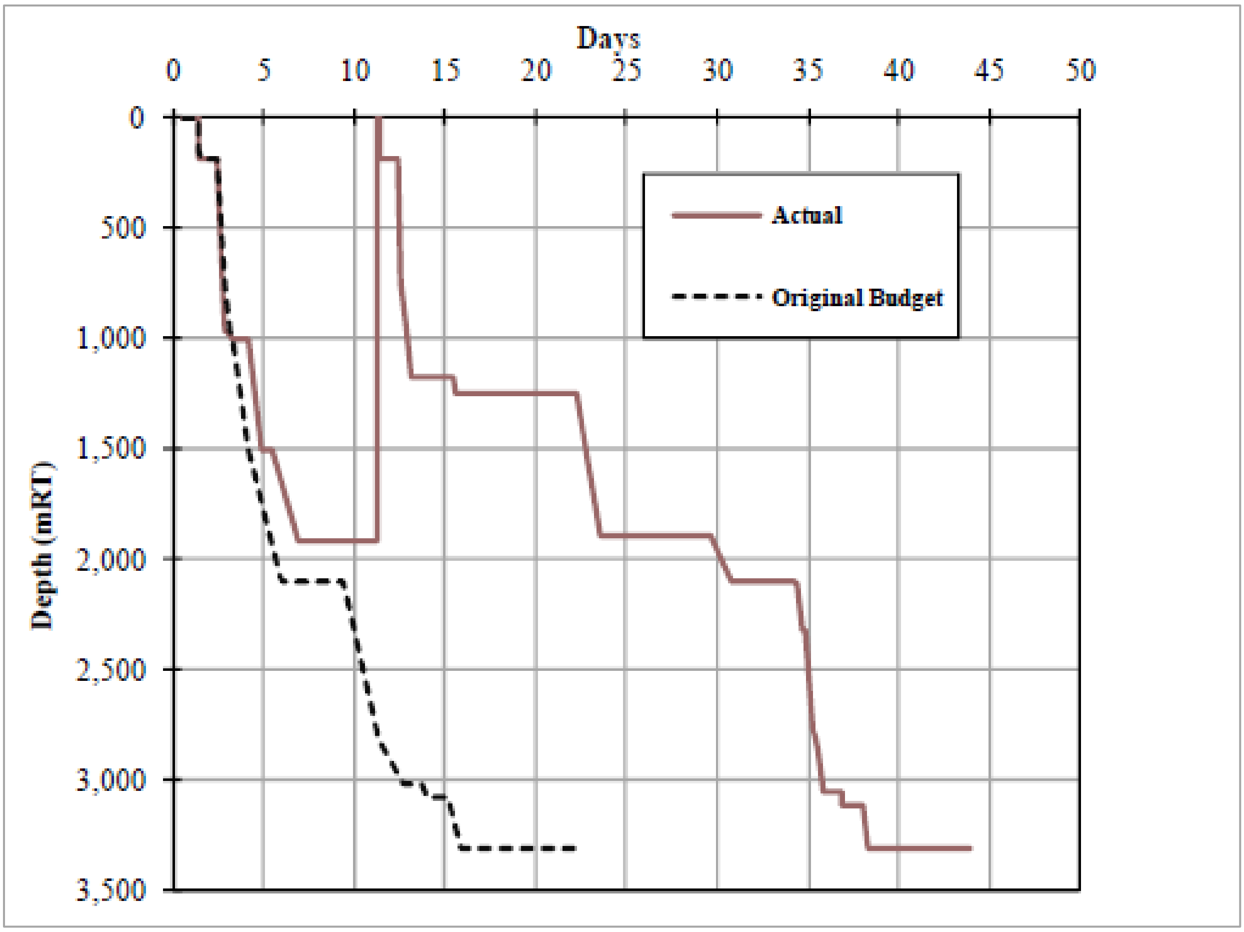


Figure 4.10: Days X Depth chart for the Goodwyn-10 well showing the lost time due to stuck pipe in the Bare formation (J. Peyton and A. McPhee, 2013)

4.7.2 Solution with MPD technique

In order to overcome vibration and hole stability problems, the company decided to implement Riserless Mud Recovery (RMR). The operation was performed from a sub-submersible rig. The design of the operation in this scenario incorporated larger hole sizes and control drilling to reduce packoff risks.

When drilling Goodwyn-10 through the Bare formation, the ROP had to be reduced to control vibration. The well was then packed off, only being freed after working the pipe for 24 hours. A second pack off occurred but this time with no rotation or movement. A washdown string was used in an attempt to clear the packoff but the washdown string also became stuck, in the first two attempts.

To avoid the typical drilling problems encountered in Bare sands, changes to the drilling operation were made. To avoid vibrations the drilling was performed using a tungsten carbide insert (TCI) roller cone bit. As the formation below the Bare Sand is not so prone to vibrations, at this stage the bit was tripped for a PDC that improves ROP compared to the roller-cone bit.

Cutting samples from Goodwyn were evaluated together with seismic data to identify the areas, thickness, and risk of unconsolidated sections of Bare. The strategy adopted was to set a casing above the Bare to improve hole cleaning capacity and hole stability.

MPD's main achievements

The use of RMR is believed to have a key role in the success of the operation, once no losses were observed and stable pump pressure indicated that no packoffs occurred. RMR offered a cost-effective method of enhancing hole cleaning to avoid stuck pipe, minimizing vibration, stabilizing the hole and enabling the interval to be drilled in a single run.

5 Simulation

This chapter presents the simulation results of managed pressure drilling and cementing operation. For MPD drilling, the model reviewed in section §2.2 was implemented in Microsoft Excel and simulation were conducted for connection scenario by employing both conventional and MPD methods. For Managed pressure cementing, a deep-water well Gulf of Mexico constructed in Wellplan / Landmark and cementing job performed comparing with conventional cement job.

5.1 Managed pressure drilling-MPD simulation

5.1.1 Simulation set up

A 10000ft vertical well having drill string and BHA considered for the experimental simulation. The drill string has three 28/32in sized nozzles. Table 5.1 shows the well and string data. Figure 5.1 shows the experimental well.

	Annulus	
Length	Well bore	OD Pipe
9500	**8.53**	**5.00**
300	**8.50**	**5.00**
200	**8.50**	**5.00**

Length	ID Pipe
9800	**4.80**
200	**2.50**

Table 5.1: Well and String data

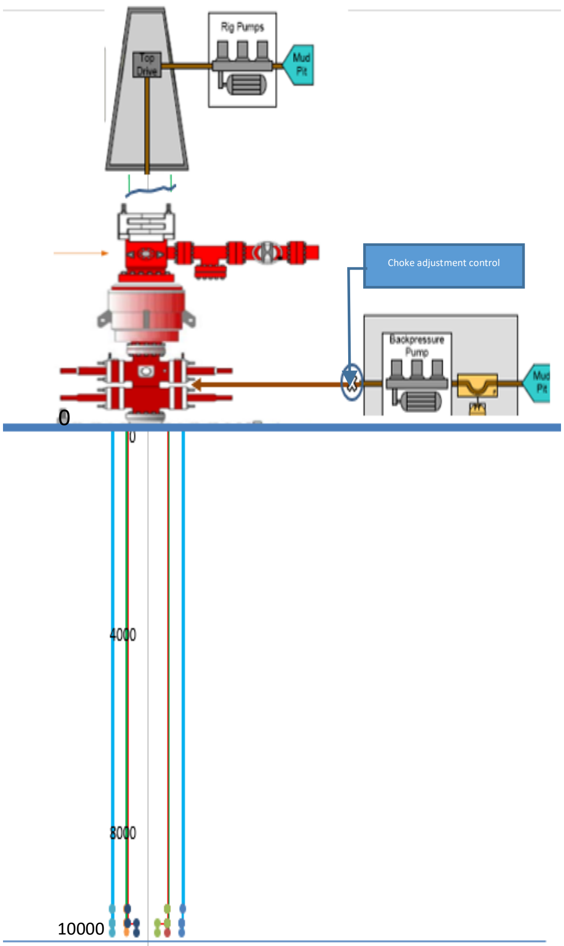


Figure 5.1: Experimental well

The drilling fluid rheology used for drilling is shown below.

Reading	Value
R600	24.5
R300	19.0
R200	16.5
R100	13.5
R6	8.5
R3	7.5

Table 5.2: Viscometer data of drilling fluid

5.1.2 Simulation result

Figure 5.2 shows the simulation calculator for activating MPD choke. The idea here is to illustrate how one can use a simple spreadsheet in order to calculate a quick choke opening for a given backflow rate.

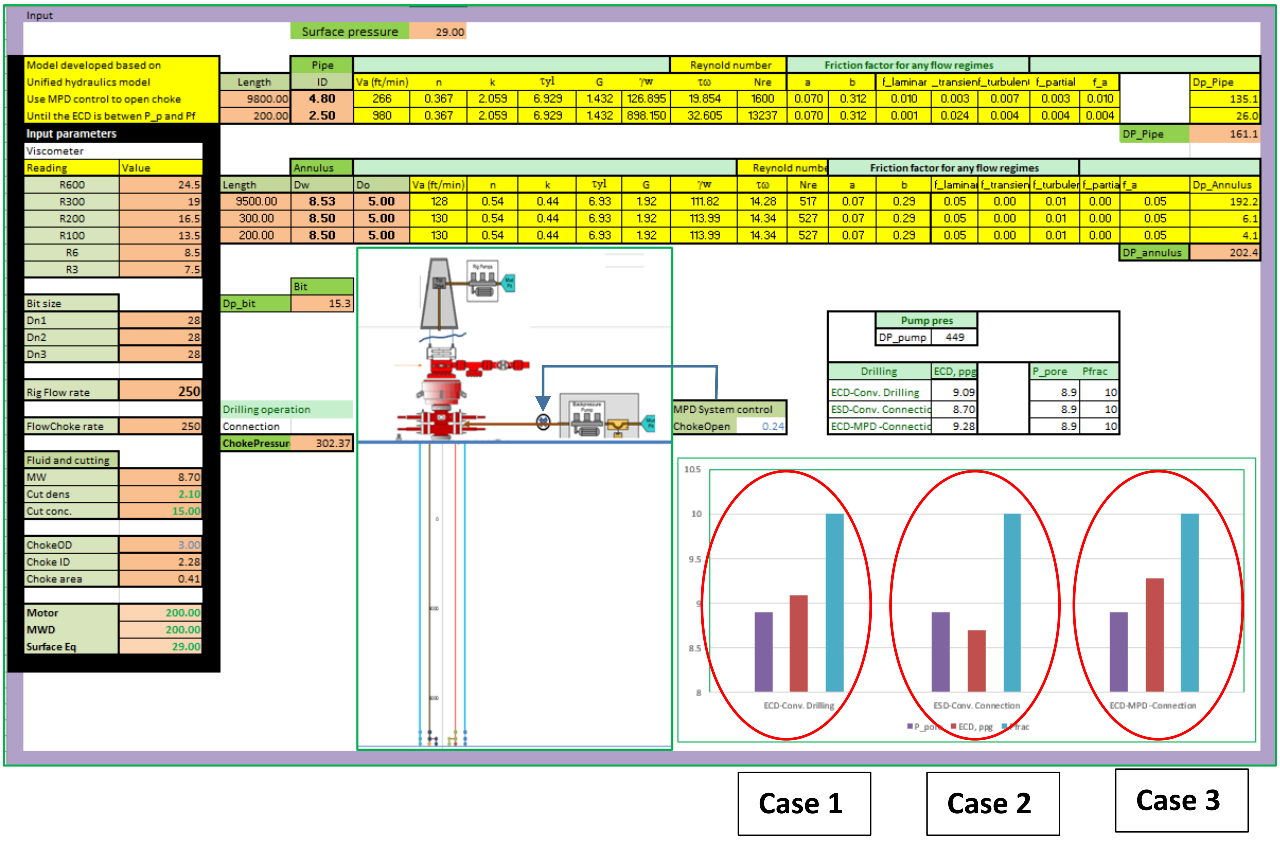


Figure 5.2: MPD control setup view

Case 1: ECD-Conventional drilling mode.

As shown, for 250gpm circulation rate the ECD in red bar shows within the pore pressure (pink) and the fracture pressure. This ECD is near over pressure and controlled by the hydrostatic pressure and the annular friction loss.

Case 2: ESD-Conventional static mode

In this case, rig pump is shut down due to connection operation. The friction part of the equation will disappear and the equivalent static density is governed only by the hydrostatic pressure. As shown the red bar reduced below the pore pressure. Due to the lower well pressure, one could expect kick if the drilling formation is in reservoir or well collapse issue. This is the main challenging when drilling with conventional drilling method, especially in narrow window.

Case 3: ECD -MPD connection mode:

To overcome the issue of well collapse and kick, just before rig pump shut down, operators should calculate the right choke size opening for a given flow choke rate. This can be done by consulting the calculator shown in Figure 5.3. For instance, if the 250gpm back flow rate, 24% choke opening size maintain the well pressure to be within the narrow window. Once the calculation is down, engineers can do a quick action by opening choke, activating backpressure pump and shut down the rig pump until the connection process is done.

Example 1: Choke opening vs flow rate for a given desired target density while connection

This first example is designed to illustrate the choke opening vs flow rate curve. For this, a higher viscous oil based drilling fluid with 9ppg density was injected through 10000ft well at the rate of 600gpm while drilling. The choke size, the drill bit and the size of the well, drill string and BHA is the same as the one provided in section §5.1.1. Table 5.2 provides the viscometer measured data. The operational window is bounded by pore pressure and fracture pressure are 9.1ppg and 9.8pg, respectively. At around 8 min, connection was going to be made. For this, rig pump will be shut down and the back pressure will be activated. The target ECD as MPD system would be activated is assumed to be 9.3ppg.

5.1.2.1 Conventional drilling Connection mode-Problem

Figure 5.3 displays the conventional drilling connection mode result. As shown during connection, the shutdown of the rig pump reduced the well pressure below the pore pressure in the region of light green shaded area, which is not desirable.

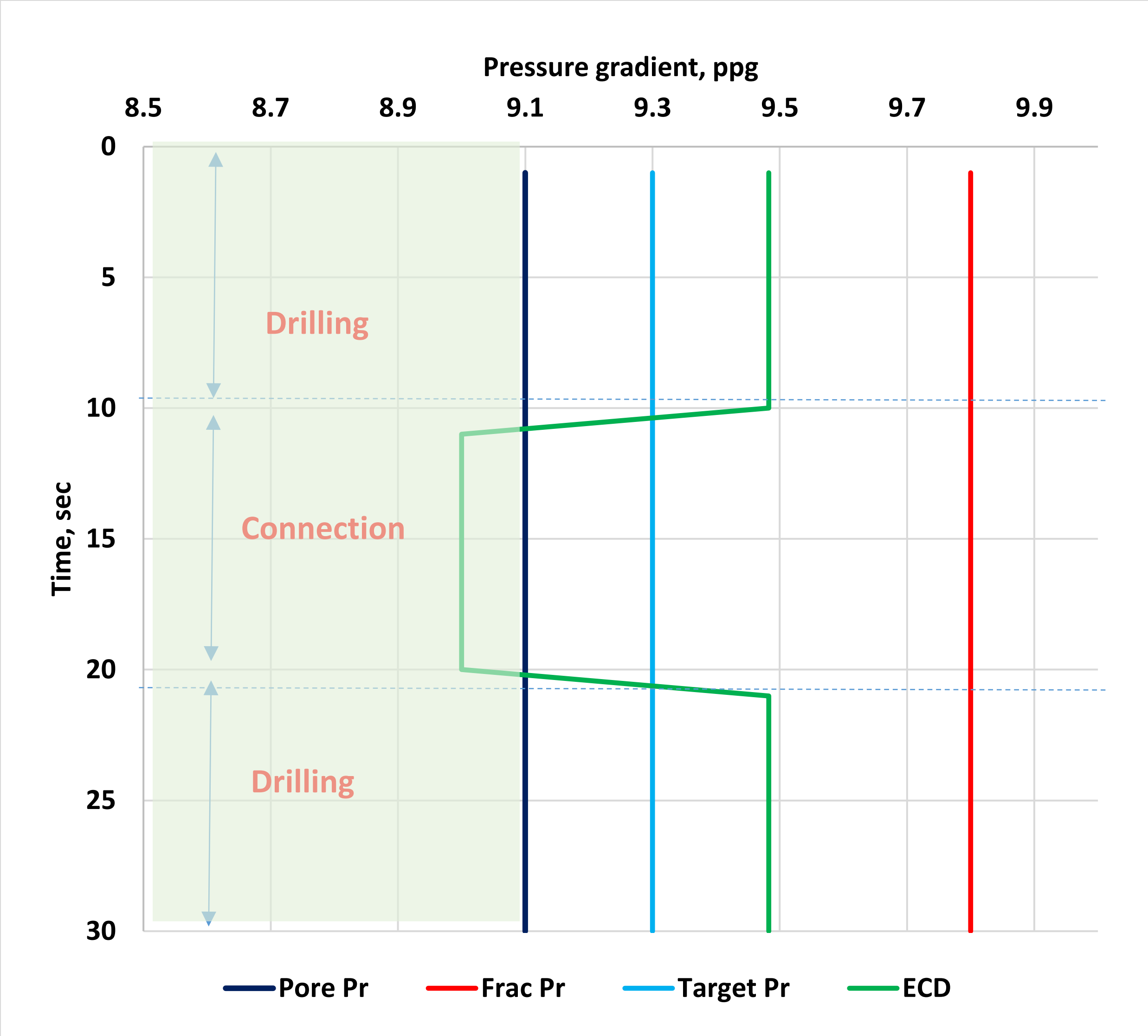


Figure 5.3: ESD- Conventional drilling connection mode

5.1.2.2 MPD drilling Connection mode-Solution

In order to achieve the desired target well pressure, the right operational activities are activating the back pressure to circulate flow 200ppg while opening the choke by 26%. The results displayed in figure xx solved the problem of the conventional drilling model presented in Figure 5.4. For backflow rates ranging from 50ppg to 600ppg, the simulated corresponding choke opening to achieve target ECD during connection is displayed as in Figure 5.5.

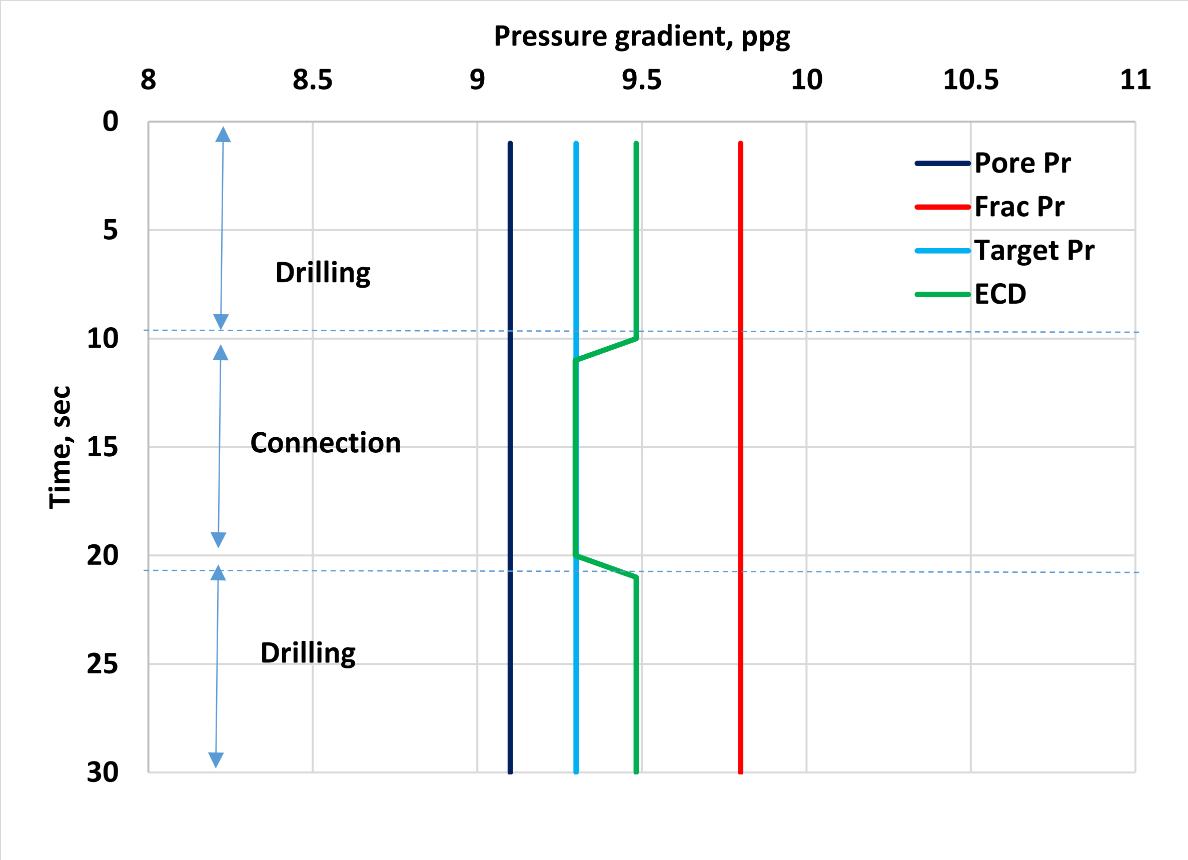


Figure 5.4: MPD-connection mode

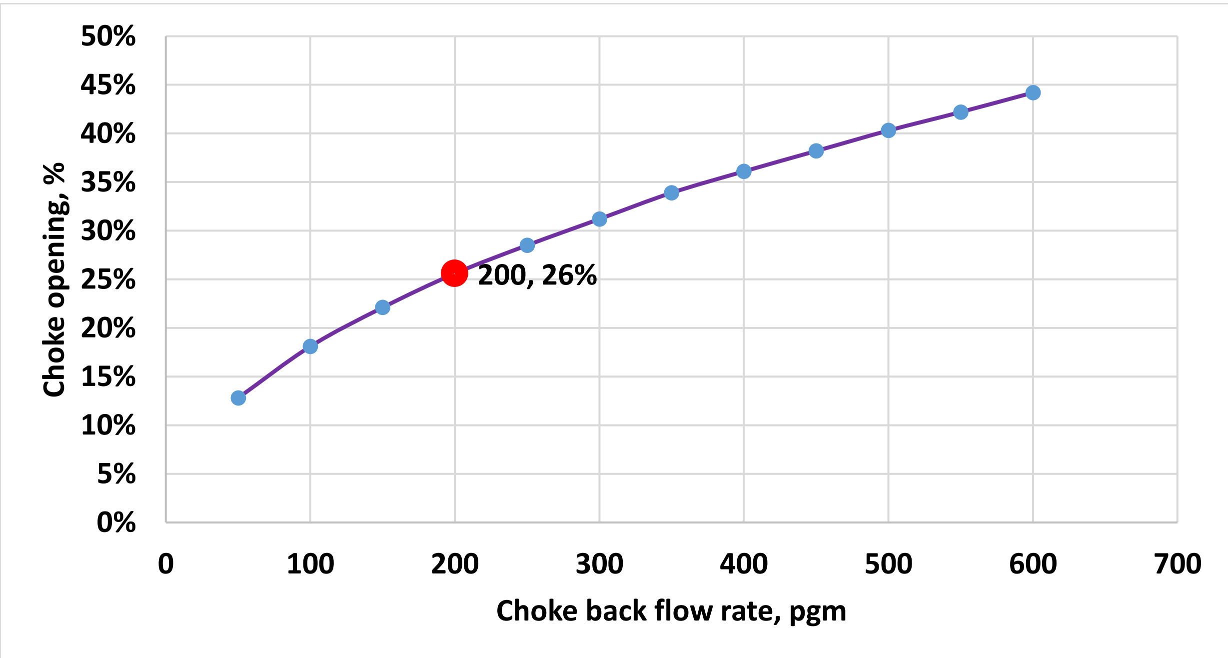


Figure 5.5: Simulated Choke opening vs flow rate for MPD drilling connection mode for 1.68 target ECD

5.1.2.3 MPD connection case scenario for High and Low viscous drilling fluid

Assume that the effect of temperature and pressure the rheology of the drilling fluid (DF-1) is reduced by 50% as provided in Table 5.3. The density is controlled by weighting material and assumed to be constant (12.8ppg). The main reason for this case scenario is to look at the effect of rheology alone on the choke opening

	DF-1	DF-2
RPM	Viscometer reading	
Q600	98	49
Q300	60	30
Q200	46	23
Q100	25	13.5
Q6	12	6
Q3	9	4.5

Table 5.3: High viscous (DF-1) and lower viscus (DF-2) drilling fluids

Drilling with DF1, the flowrate required to achieve a well pressure of 13.4 was 250gpm. This is due to high viscosity. On the other hand, for 13.4gpm, drilling with DF2 required 600gmp. During connection phases, the choke flow rate was varied in order to obtain a target well pressure of 13.3 ppg for both drilling fluids. Figure 5.6 shows simulated MPD connection mode for the two drilling fluids.

As shown in Figure 5.7, the choke opening when operating with drilling fluid is the same proved that both are designed to attain the same as the target well pressure. Backpressure is not a function of the drilling fluid rheology when doing connection. However, rheology and density are factors when drilling with MPD mode. The statement is valid provided that during connection there is no flow, but the backpressure is activated to compensate the pressure that has been lost during dynamic flow.

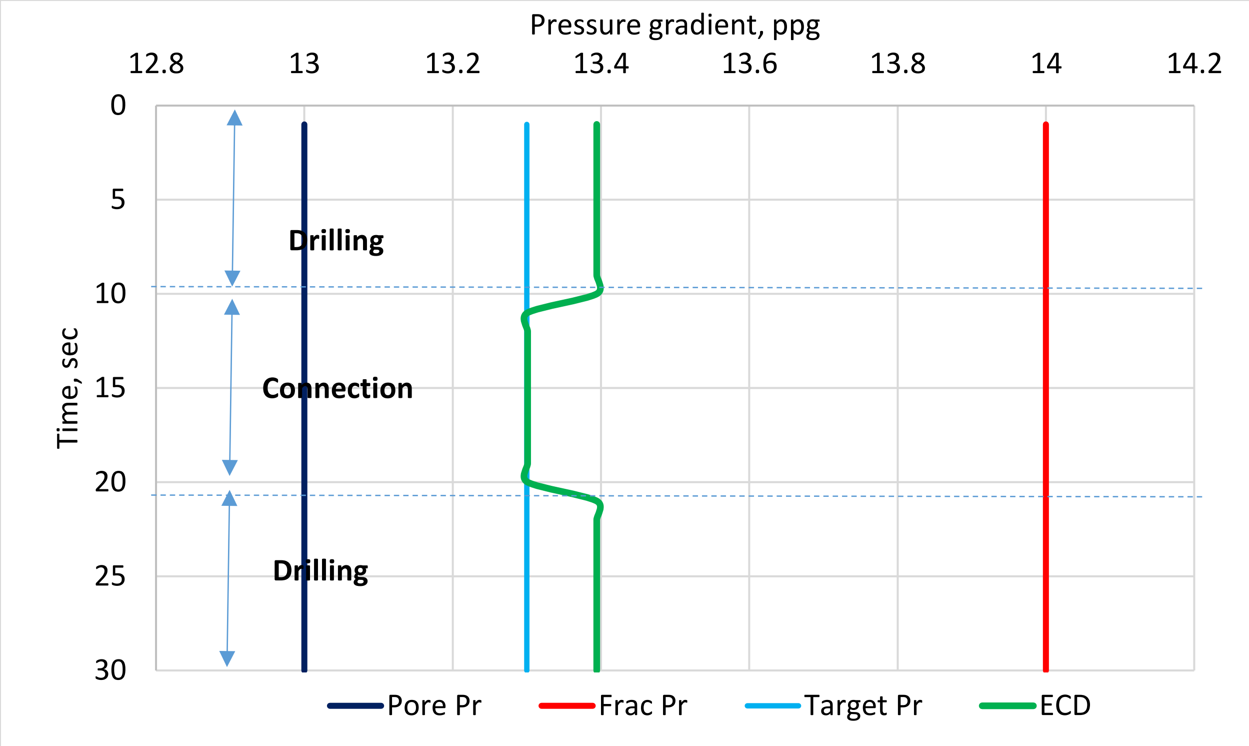


Figure 5.6: MPD connection case scenario for drilling fluids DF-1 and DF-2 at target ECD

Figure 5.7: Choke opening during MPD connection case scenario for drilling fluids DF-1 and DF-2 at target ECD

5.2 Managed pressure cementing-MPC simulation

Properly designed well structure prolong the life of the production period. Among others, cementing job is part of the well construction process. Both cementing and the cement quality are the primary factor for successful structural integrity.

Cementing in narrow window with conventional method is also an issue and may results in well collapse and fracturing. These problems result in casing sticking and cement into formation. Like managed pressure drilling, managed pressure cementing also is a solution for operation in narrow window. Here also back pressure is a key to control the annular pressure profile along with the rheological and density of cement slurry.

5.2.1 Simulation set up

A deep-water case experimental setup is designed in Well plan. The well pressure profiles are obtained from (Khan, 2012). However, the depth in this thesis setup was allowed to extend ultra-deep well. A 30000ft well is planned to cement, where the casing shoe is located at 20000ft. Table 5.4 shows the cement, drilling fluid and spacer viscometer data, which determine the hydraulics of cementing job.

RPM	Spacer	Luize Drilling fluid	Cement
	Dial Reading	**Dial Reading**	**Dial Reading**
600	-	70	-
300	47	40	61
200	40	29	45
100	30	19	31
6	15	6	15
3	14	5	14
Density, ppg	13.00	13.00	14.00

Table 5.4: Cement job fluid’s rheology data

Table 5.5 also provides the cement job design, which consists of spacer, drilling fluid and cement. For better visualization, Figure 5.8 presents the viscometer reading of the fluid systems.

	Type	Fluid
1	Drilling Fld (Mud)	Luize Drilling Fluid, 13.00 ppg
2	Spacer/Flush	Spacer, 13.00 ppg
3	Cement	Cem, 14.00 ppg
4	Top Plug*	
5	Mud	Luize Drilling Fluid, 13.00 ppg

Table 5.5: Cement job fluid sequence

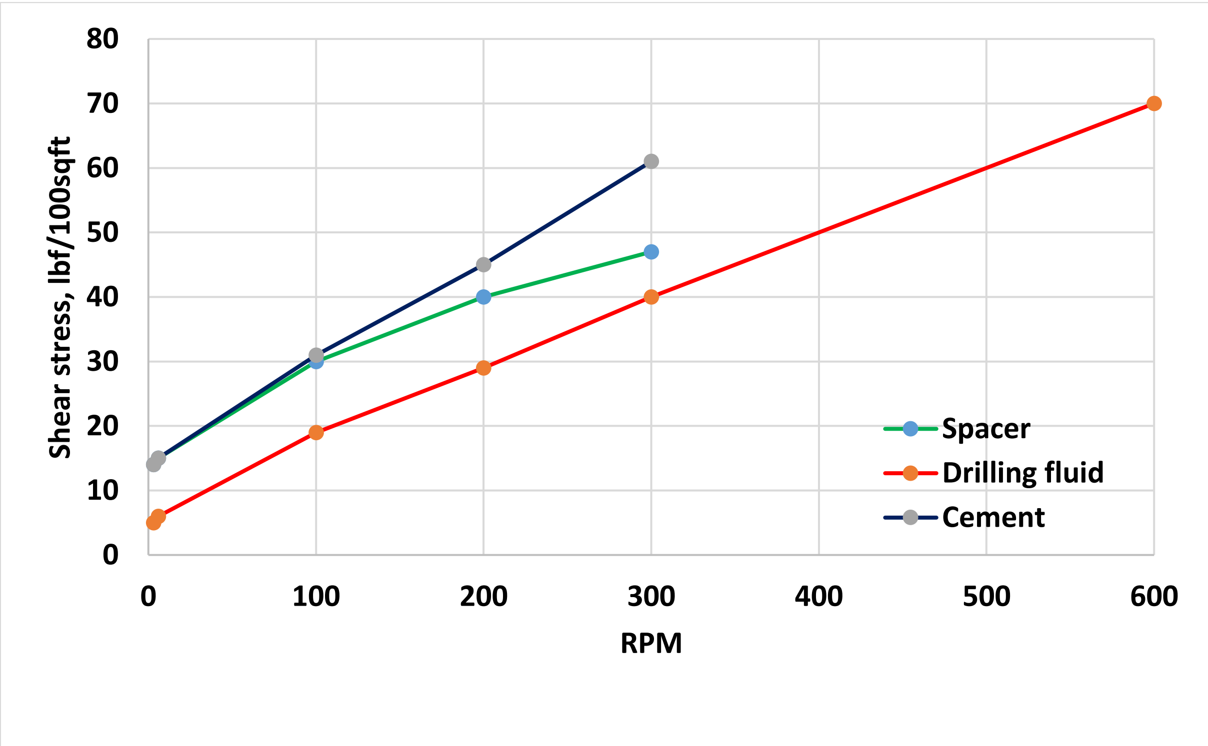


Figure 5.8: Viscometer shear stress-RPM of cement job fluids

Figure 5.9A displays the wellbore being completely filled with drilling fluid, which is before cementing job. Figure 5.9B illustrates the wellbore with fluids after cementing job. As shown, the green fluid is the cement, which is completely placed within 2000-3000ft open hole-section. The yellow and blue fluids are spacer and drilling fluids respectively.

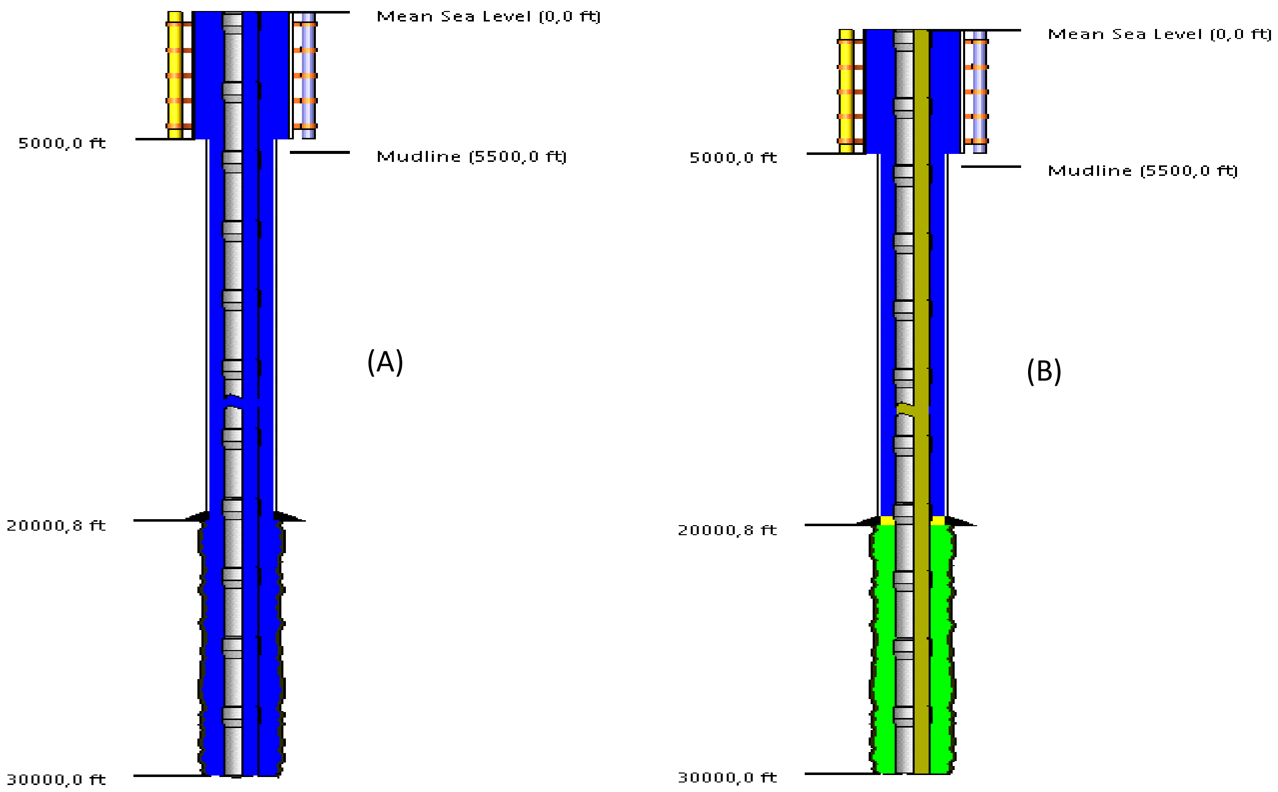


Figure 5.9: MPC experimental well schematic before (A) and after (B) primary cementing job

5.2.2 Simulation result

The following section presents the simulated results of well pressure and cement job time for a range of injection rates.

5.2.2.1 Well pressure

Cementing job simulation were conducted with conventional and managed pressure cementing methods. The circulation rates were varied from 2bbl/min to 14bbl/min. Table 5.6 shows the simulation rates in three different units.

bbl/min	l/min	pgm
2	318	84
4	636	168
6	954	252
8	1272	336
10	1590	420
12	1908	504
14	2226	588

Table 5.6: Cementing injection rates used for cementing job

Figure 5.10 shows the well pressure results as cementing job was performed with conventional method, as shown for considered flow rates, the well pressure below the casing show is below the pore pressure. This indicates two possible challenges, namely influx or well collapse. To solve the problem, MPC was employed by applying 519-psi backpressure. Figure 5.11 shows the result. As shown, all the pressure profiles are within the safe operational window. This illustrates the application of MPC in narrow operational window.

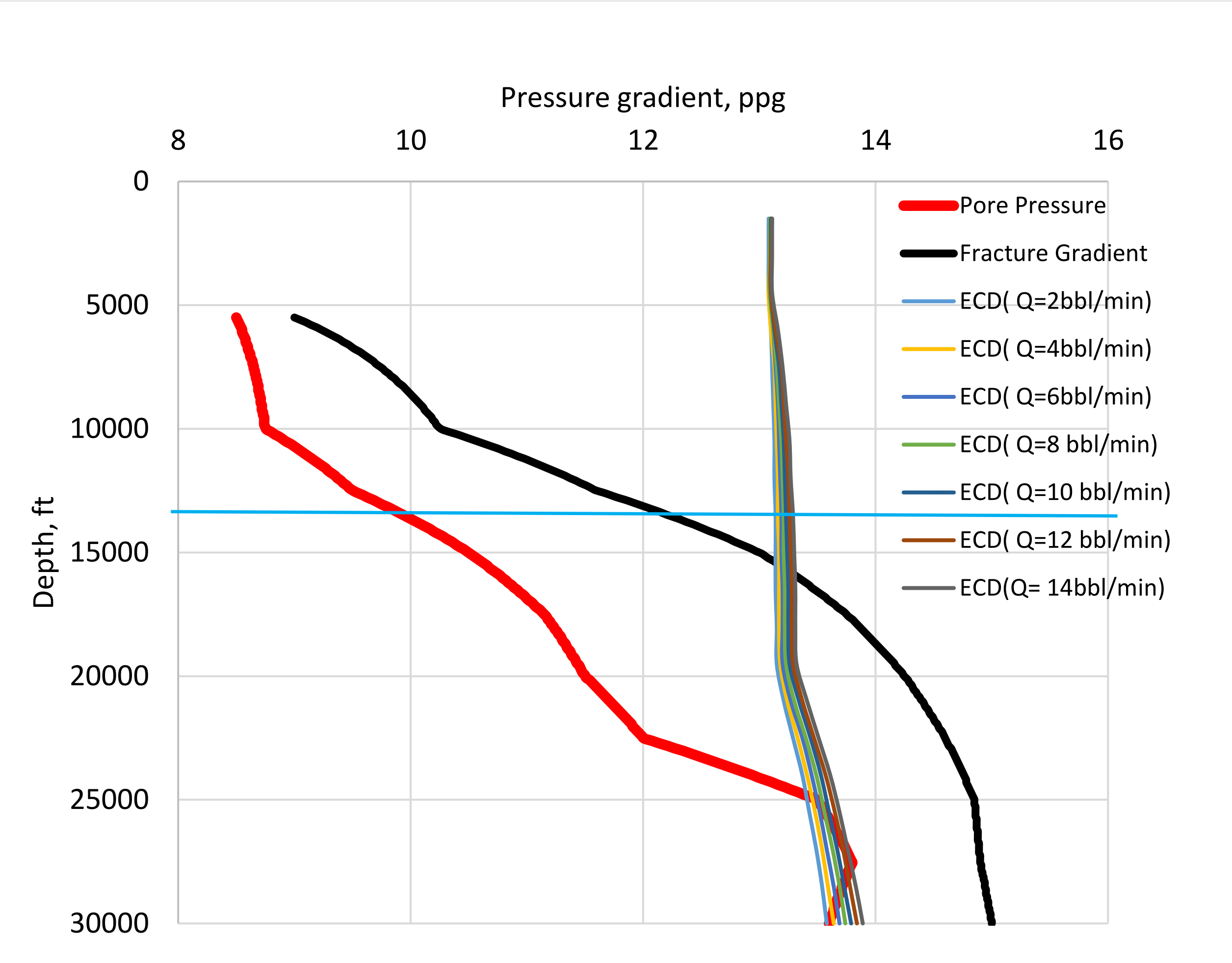


Figure 5.10: Conventional cementing job

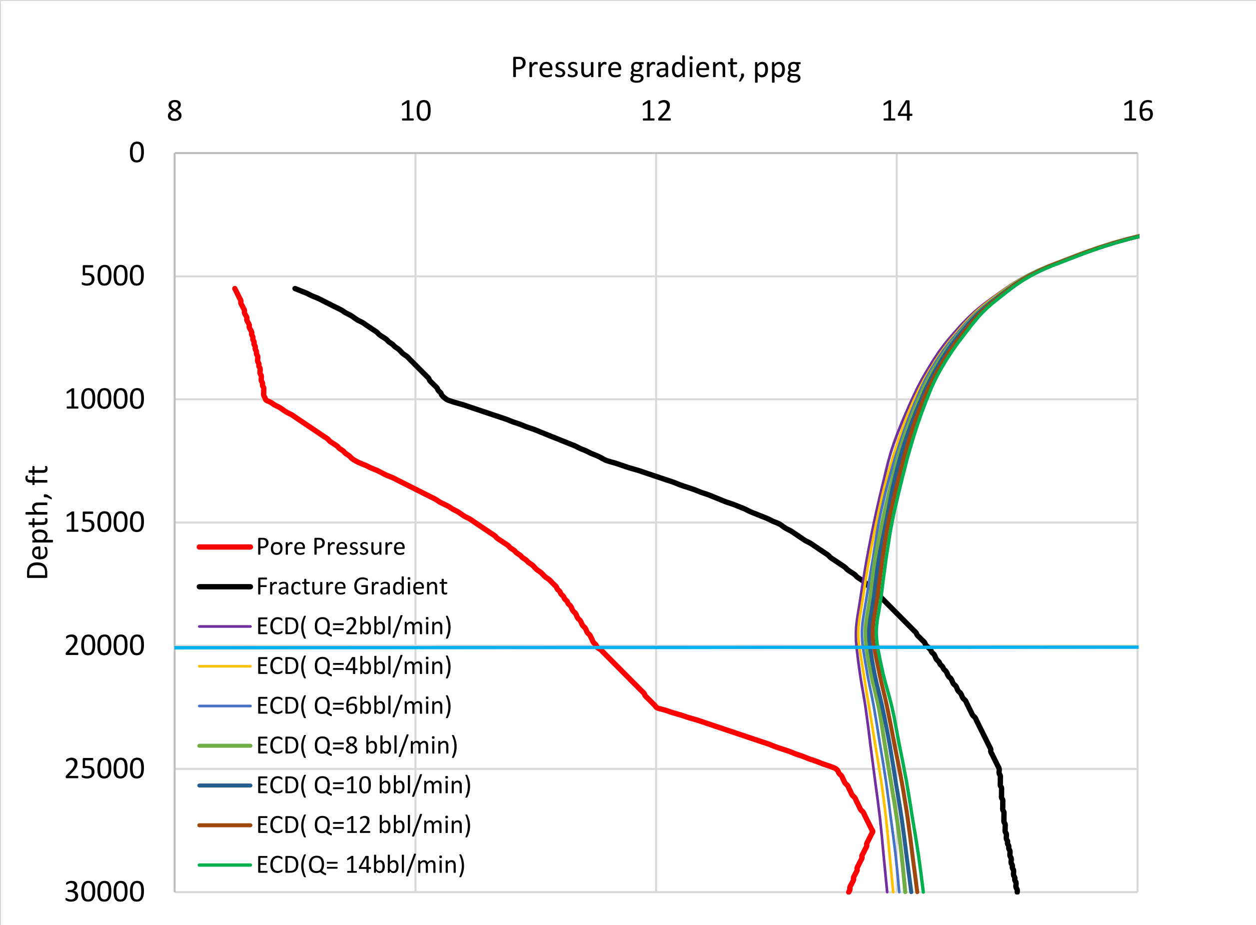


Figure 5.11: MPC cementing job

5.2.2.2 Circulation time

Cement circulation time is an important factor when performing the cementing job, which is determined by the circulation rate. The higher the circulation rate is the lower cementing placement. However, the higher flow rate increased well pressure and may have an effect on the well fracturing or casing collapse. This needs to be evaluated through simulation studies. As displayed in Figure 5.11, for the considered circulation rates (i.e. 2-14bbl/min), all the well pressures are within the operational safe window. For these flow rates, Figure 5.12 displays the circulation time.

For instance, as shown, time taken for the 4bbl/min and 8bb/min circulate rates to fill annular spacing are 133min and 67min, respectively.

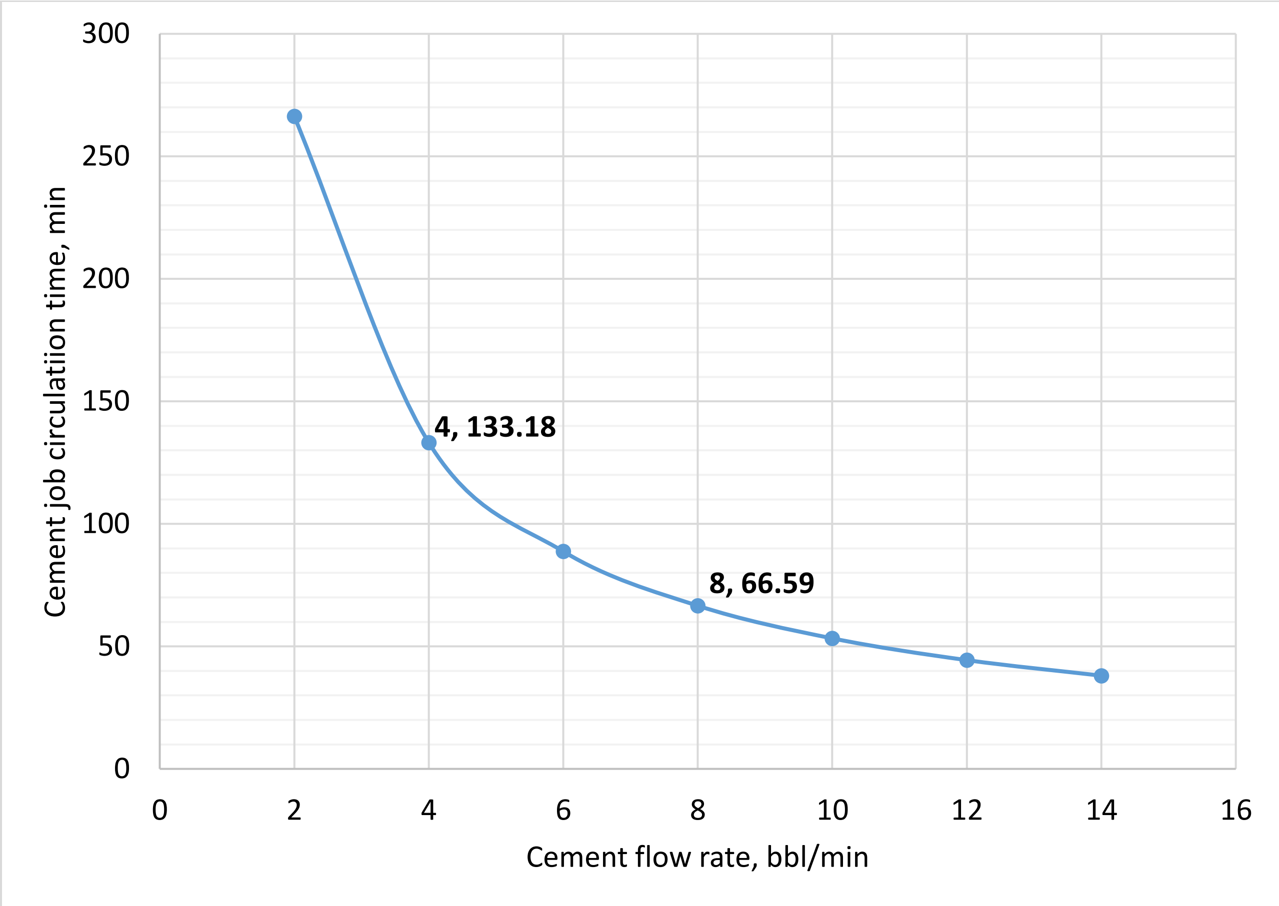


Figure 5.12: Circulation rate vs time take to complete primary cementing job

6 Results discussion

Since the introduction of petroleum exploration, the drilling technology development is improving in terms of safety and efficiency as well. However, reports show that NPT associated with conventional drilling-related problems is higher especially as one drill in deep-water. MPD is one of the newly developed drilling methods, which is considered as a solution for challenges with conventional drilling method. This chapter presents the summary of the results obtained from the field case and simulation studies

6.1 Based on field case studies

The cases presented are examples of successful cases of MPD application. In these cases, engineers have made evaluations and correctly selected a proper methodology for the respective operational challenging area. The following discusses the applications of MPD and main achievement.

6.1.1 HPHT well

The main concern in the HPHT well is the impact of HPHT on drilling fluid rheology and density changes along the wellbore profile and wear on RCD seal element, RCD bearing assemblies and MPD dynamic annular pressure control pump. Therefore, before the implementation of MPD system in HPHT well, it is important to select tools and accessories, which satisfies the API specification to tolerate the operational conditions safely.

Field case studies in HPHT well has shown that by applying backpressure, one can control ECD to be within the window and allows an increase tripping speed. By this, one can reduce rig time, but tripping speed is limited with conventional method since swabbing is an issue.

Apart from the backpressure, designing of a drilling fluid which tolerate high temperature and pressure contributed for the success of MPD operation.

6.1.2 Issue to pre-salt

From the field case studies, the concern of drilling at the top of the salt includes diapir loss circulation, stuck pipe, ballooning effect, and salty water influxes. The overall consequences increased the NPT significantly.

The application of CBHP along with liner casing and controlled mud weight manage the well pressure and hence avoid water influxes and reduce losses with minimal backpressure while drilling. Dynamic annular pressure control device (DAPC) system and its auxiliary pump and automatic choke detect and controlled minor influxes occurrence due to underbalanced well pressure and ballooning. DAPC allows adjusting circulation rates to an optimal range by keeping low mud weight and low bottom hole pressure as needed, hence reducing or eliminating LCM (Lost Circulation Material) treatments. Moreover, the drilling time reduced significantly.

6.1.3 Horizontal well

Well instability is an issue during drilling operation. It is reported that well instability problem increases the operation budget by over 10%. Well collapse and fracturing results in undesired drilling-related problems and hence increase NPT. The well instability problem is more challenging when drilling in horizontal well than vertical well. The window in horizontal is narrow.

From field case studies, it is shown that constant bottomhole pressure with dynamic annular pressure control method able to drill by controlling the well pressure with injection of Nitrogen. Results showed the reduction of mud loss; reduction of total operational cost; improved productivity and flow rate.

6.1.4 Deep-water drilling

Deep-water drilling environment has shown about 41% NPT due to drilling-related problems. Field case studies have shown that the application of constant BHP enables to reduce drilling time and mud loss by several percent.

Flat rheology drilling fluid system is a good solution for deep-water application and has been used in difficult regions of GOM since 2004 (Schlemmer, Oiltools, Sheldon, & Miri, January

2010). Flat rheology keeps fluid properties of density and viscosity constant. Figure 6.1 shows the effect of temperature on the flat rheology drilling fluid. As shown, FR maintain the yield stress and plastic viscosity for higher temperature than the conventional drilling fluid. However, more research and development are required to develop a better flat rheology drilling fluid including relatively constant density properties.

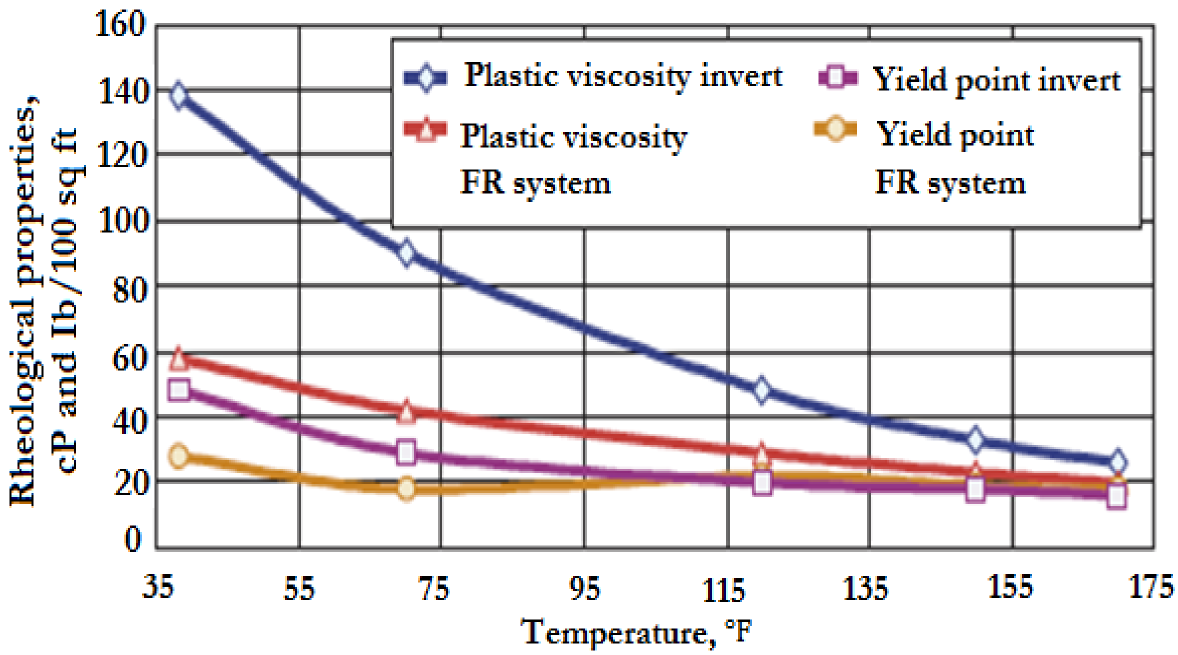


Figure 6.1: The effect of temperature on the rheological properties of a conventional and Flat rheology drilling fluids (Schlemmer, Oiltools, Sheldon, & Miri, January 2010)

6.2 Based on MPD-MPC simulation studies

Among the main key factors for the MPD/MPC achievement is the use of good hydraulics model along with temperature and pressure dependent model which determine the rheology and density of drilling fluid. Physics-based models are better than empirically derived models.

The drilling mode MPD sensitivity simulation indicated that when the rheology of the drilling fluid decreased by 50%, the circulation rate required to attain the required ECD was found out to be reduced by 2.4 times. This shows that the correct knowledge of the drilling fluid properties along the wellbore profile is the key for the determination of the pressure profile.

7 Summary and Conclusion

The primary objective of this thesis was to analyze and describe the issues addressed in section §1.2. For this, the activities listed in section §1.3 has been implemented, which are field case studies, modeling and simulation studies. Based on the overall evaluation, this chapter presents the major key findings and concluding remarks.

7.1 Summary of the key findings

The performance and efficiency of different MPD techniques reviewed in Chapter 3 were evaluated through field case studies. The challenging areas for conventional drilling methods were categorized into namely deep-water, HPHT, horizontal, depleted, highly fractured and pre-salt formation.

Key elements for successful MPD implementation and performance are among others:

- Well planning and design
    - Identify problem and select the right MPD system according to the operational challenges included
    - by considering all activities to be conducted, such as drilling, tripping, displacement, and completion operations
- Proper design – hydraulics, equipment selection and generation of detailed operational procedures as well as contingency procedures for the success of MPD
- Real-time measurement along with models calibrated with measurement
- Since the MPD technique is not yet standardized, it is important to provide crew training, driller training, and constant communication among engineering team, meeting to achieve precise pressure control.
- Real-time control system, both hydraulics and mechanical to control downhole condition (Eg. Flow in, Out, SPP, ECD, surface pit management with respect of displacement and trilling, Torque, WOB, Bit position, HL..++etc)
- The combined effect of MPD with conventional is a key factor for successful operation (Eg. MPD+LCM, Liner casing can be mentioned)

Table 7.1 provides the main investigations obtained from the field cases studies. As shown MPD able to solve problems associated with the conventional drilling methods.

Field Environment	Field Name	Location	Main Field Problems	MPD Application	Success / Failure	Challenges using MPD	MPD Application Results
Deep-water	i)Xanab	South-east of GoM	Circulation loss due to narrow operational window	CBHP	Success	Severe mud loss solved by reducing mud density; Two kicks controlled by pumping w/ well shut in and increased mud weight; Six high gas concentration solved by displacement through three-phase separator.	44% reduction of drilling time and 72% reduction of mud loss
Horizontal Well	ii)Samaria Field	Mexico	Circulation loss; differential sticking; Impossibility to use directional tools to drill horizontal wells.	DGD with riser: Nitrogen injection	Success	Nitrogen bubble pushing mud out of the hole solved by stop pumping mud through the concentric annulus and start pumping through drill pipe; Fluid loss to run logs, controlled by decreasing mud weight; Circulation was established only after 4th connection.	72% to 86% reduction of total mud loss; Reduction of total operational cost; Reservoir productivity increased.
HPHT	iii)Exploratory Gas field	Southwest Louisiana	High solubility of gas implying risk for kick detection; Uncertainty of pore pressure; swabbing	CBHP with DAPC	Success	Small influxes detected mitigated by MPD equipment and well shut-in whenever necessary; Wear of RCD sealing elements due to	Increased trip efficiency when POOH; Saved rig-time; Early detection of influxes; Reduced time circulating;

			during tripping operations.			its inadequate pressure rates for the necessary backpressure; RCD bearing stopped rotating while drilling and replaced at certain point, but analyses concluded that it was only missing torque.	and managing gas at surface.
Pre - Salt	iv)Sen	Southern of GoM	Mud contamination, Fluid losses and Stuck pipe due to salt diapir	CBHP with DAPC	Success	Small influx at the beginning due to ballooning & lower PP than set point detected by MPD sensors and controlled by the DAPC system; Mud losses before reach the salt diaper controlled by setting up a contingency liner at the top of the salt	37% reduction of drilling time of 938m of salt; Reduction of NPT associated with ballooning effect; Zero mud contamination
Fractured Carbonate Reservoir	v)Soka Field	South Sumatra, Indonesia	Severe circulation loss; Gas kick	PMCD	Success	LCM pill was pumped to plug zone of potential circulation losses without success and casing pressure increased considerably. Isolation of casing from gas migration zone was achieved by the injection of 3 BDO plug.	No NPD associated to PMCD; Good ROP and hole cleaning; 19hrs versus one and a half months spent (in correlated wells) to achieve target

Coral Reefs	vi)Zumba well	Norwegian Sea	Restriction for cuttings discharge on corals; Excess rig time costs	RMR	Success	NPT due to waiting on weather (WOW) harsh conditions and cuttings tanks couldn't offload their capacity through hoses to the boat.	Primary well control prior to riser installation; Improved hole stability; Downhole losses monitoring and Zero cuttings discharge to seabed.
Bare Sands (Highly porous formation)	vii)Dampier Sub-Basin	Australia	Challenge to drill tophole in bare formation; Loss of circulation; Bad hole cleaning; Stuck pipe	RMR	Success	Annular pressure drop and increased standpipe pressure while drilling Mandu formation caused rupture of the burst disc on the drillshoe. The decision was made to continue drilling with reduced flow through the bit nozzles.	Cost-effective solution for tophole drilling; Enhanced hole cleaning; Reduced vibration in dolomitic stringers zone; Eliminated stuck pipe

Table 7.1: Analysis of MPD techniques application in different cases studies

7.2 Concluding remarks

Based on field case studies, and MPD/MPC simulation studies, the work finally concludes that:

- Good planning, selection of materials which tolerate and appropriate work procedure along with realtime downhole and surface measurements are key for the success of MPD/MPC operation
- During planning phase, good hydraulics model which are based on physics rather than correlation along with realtime data
- Drilling fluid having good tolerance for HP/HT such as flat rheology drilling fluid reduces any effect on the fluid

- MPD is proved to manage kick, allow higher tipping out speed hence reduced tripping time.
- MPD equipment should be considered as a well-control equipment but not as a BOP
- Managed Pressure Cementing allows cementing job safely in narrow window.
- MPD allows increasing ROP, improved good hole cleaning, reduces formation damage, improve productivity and production rates
- MPD in horizontal well, highly fracture formation proved to be successful in safe operation and flow reduces loss and reduces drilling time.
- MPD manage to drill in pre-salt formation good ROP and hole cleaning
- RMR cost-effective solution for tophole drilling; enhanced hole cleaning; eliminated stuck pipe

Finally, this thesis concludes that due to the potential application of MPD in an oil field, industry needs to standardize and automate MPD operations. For this, more research and developments are required.

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Appendix A: Managed Pressure Drilling Applications Index

(Coker, OTC 16621 Managed Pressure Drilling Applications Index, 2004)

A1-Riserless Drilling Top Holes

2. **Table A-1**

Riserless Drilling Top Holes																		
Specialized Equipment	Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Surface Separator	Flare Line and Stack	Continuous Circulation System	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modelling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Casing
Conventional Drilling Obstacles																		
Narrow Pore/Fracture Gradient Margins				x		x	x			x			x	x	x	x		x
Heavy Viscous Mud Cost (Environmental Considerations)							x			x	x		x					x
Excessive Casing Program										x			x		x			x
Poor Cement Jobs				x														
Well Bore Instability				x		x	x	x		x			x		x			x
Shallow Gas Kicks				x		x	x	x	x	x	x		x					
Shallow Water Flow Hazards				x			x	x					x	x				x
Shallow Geo-Hazards				x			x	x	x				x					x
Underground Blowouts				x						x	x		x					x
	Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Separator	Flare Line and Stack	Continuous Circulation Device	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modelling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Casing

A2-Shallow water Jack-up

Table A-2

Shallow Water - Jack Up / Platform / Barge Mounted (Surface BOP)																		
Conventional Drilling Obstacles / Specialized Equipment	Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Surface Separator	Flare Line and Stack	Continuous Circulation Device	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modeling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Casing
Lost Circulation (Excessive Mud Cost)	X		X		X	X	X	X	X	X	X	X		X			X	X
Differentially Stuck Pipe	X		X		X	X	X	X	X	X		X		X			X	X
Slow ROP / Short Bit Life	X		X		X	X	X	X	X	X						X		
Narrow Pore/Fracture Gradient Margins	X				X	X	X			X		X		X	X	X	X	x
Shallow Gas Kicks	X		X				X	X	X	X	X	X		X				
Excessive Casing Program	X				X	X				X					X	X	X	X
Poor Cement Jobs						X				X								
Well Bore Instability	X		X		X	X	X			X		X		X			X	X
Shallow Geo-Hazards	X		X				X	X	X									
Shallow Water Flow Hazards	X		X				X	X						X				X
Skin Damage (Grossly Over-Balanced)	X		X		X	X				X		X		X			X	
Underground Blowouts	X		X		X	X	X			X	X			X			X	
Ballooning					X	X				X								X
High-Temperature High-Pressure	X		X			X	X	X	X		X	X		X		X		
Extended Reach Issues (I.e. Hole Cleaning, High Torque)	X				X	X	X			X				X			X	
Flat Time Circulation Out Kicks	X		X		X	X	X	X	X	X	X			X				X
	Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Separator	Flare Line and Stack	Continuous Circulation Device	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modeling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Casing

A3-Deep Water - Drill ships / Moored Semi Submersibles / etc. (Sub-Sea BOP)

Table A-3

Deep Water - Drill ships / Moored Semi Submersibles / etc. (Sub-Sea BOP)

Specialized Equipment / Conventional Drilling Obstacles	Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Separator	Flare Line and Stack	Continuous Circulation Device	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modeling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Liners
Lost Circulation (Excessive Mud Cost)		X			X	X	X	X	X	X	X			X	X	X	X	X
Differentially Stuck Pipe		X			X	X	X	X	X	X				X	X	X	X	X
Slow ROP / Short Bit Life		X			X	X	X	X	X	X				X	X	X	X	
Narrow Pore/Fracture Gradient Margins		X			X	X	X		X	X				X	X			X
Shallow Gas Kicks		X				X	X	X	X	X	X							
Excessive Casing Program		X			X	X	X	X	X	X				X	X	X		X
Poor Cement Jobs		X																
Well Bore Instability		X			X	X	X	X		X	X	X		X	X	X	X	X
Shallow Geo-Hazards		X				X	X	X			X			X		X		
Skin Damage (Grossly Over-Balanced)		X			X	X				X				X	X	X	X	X
Underground Blowouts		X			X	X	X			X	X			X		X	X	
RSR Gas Burping		X			X						X							
Ballooning		X			X	X	X	X		X	X							X
High-Temperature High-Pressure		X				X	X	X	X		X	X		X		X		
Extended Reach Issues (i.e. Hole Cleaning, High Torque)		X			X	X	X	X		X				X	X		X	
Flat Time Circulating Out Kicks		X			X	X	X	X	X	X	X	X		X	X	X		X
	Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Separator	Flare Line and Stack	Continuous Circulation Device	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modeling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Liners

A4-Emerging Technologies

Table A-4

Emerging Technologies (i.e. Dual Gradient, Slim Riser (Surface BOP), Pressurized MudCap, Drilling with Casing, Nitrogen Gas Lift)																				
	Specialized Equipment	Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Separator	Flare Line and Stack	Continuous Circulation Device	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modeling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Casing	Drilling With Liners
Conventional Drilling Obstacles																				
Lost Circulation (Excessive Mud Cost)			X	X	X	X	X				X	X		X	X	X	X	X	X	X
Differentially Stuck Pipe			X		X	X	X	X			X			X	X	X		X	X	X
Slow ROP / Short Bit Life			X			X	X	X			X			X		X		X		
Narrow Pore/Fracture Gradient Margins			X		X	X	X				X			X	X	X	X	X	X	X
Shallow Gas Kicks			X			X	X	X	X	X	X	X	X	X	X			X	X	
Excessive Casing Program			X		X	X					X			X	X	X			X	X
Poor Cement Jobs					X		X							X	X			X		
Well Bore Instability			X		X	X		X			X			X	X	X	X		X	X
Shallow Geo-Hazards			X		X				X					X	X			X	X	
Skin Damage (Grossly Over-Balanced)			X		X	X	X	X	X	X	X	X	X	X	X	X	X	X		
Underground Blowouts			X		X	X	X				X	X		X	X		X	X	X	X
RSR Gas Burping			X			X						X							X	X
Ballooning			X			X	X		X		X			X	X	X		X	X	X
High-Temperature High-Pressure			X					X	X	X		X	X		X				X	X
Extended Reach Issues (i.e. Hole Cleaning, High Torque)			X			X	X		X		X	X		X	X	X		X		
Flat Time Circulating Out Kicks			X			X		X	X		X	X		X			X	X	X	X
		Surface Rotating Control Device (RCD)	External Riser RCD	Marine Diverter RCD	Sub-Sea RCD	Internal Riser RCD	Nitrogen Generation Systems	Choke Manifold	Separator	Flare Line and Stack	Continuous Circulation Device	Down hole Isolation Valve	Non-Return Valve (Drill String Isolation Device)	Top Hole Drilling Package	Flow Modeling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Casing	Drilling With Liners