MANAGED PRESSURE DRILLING TECHNIQUES, EQUIPMENT & APPLICATIONS

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ABSTRACT

MANAGED PRESSURE DRILLING
TECHNIQUES, EQUIPMENT AND APPLICATIONS

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In the most of the drilling operations it is obvious that a considerable amount of money is spent for drilling related problems; including stuck pipe, lost circulation, and excessive mud cost. In order to decrease the percentage of non-productive time (NPT) caused by these kind of problems, the aim is to control annular frictional pressure losses especially in the fields where pore pressure and fracture pressure gradient is too close which is called narrow drilling window. If we can solve these problems, the budget spent for drilling the wells will fall, therefore enabling the industry to be able to drill wells that were previously uneconomical. Managed Pressure Drilling (MPD) is a new technology that allows us to overcome these kinds of drilling problems by controlling the annular frictional pressure losses. As the industry remains relatively unaware of the full spectrum of benefits, this thesis involves the techniques used in Managed Pressure Drilling with an emphasis upon revealing several of its lesser known and therefore less appreciated applications.

Keywords: Managed Pressure Drilling (MPD), Constant Bottom-Hole Pressure (CBHP), Pressurized Mud Cap Drilling (PMCD), Dual Gradient (DG), Return Flow Control (RFC)

ÖZ

BASINÇ YÖNETİMLİ SONDAJ
TEKNİKLERİ, EKİPMANLARI VE UYGULAMALARI

Tercan, Erdem
Yüksek Lisans, Petrol ve Doğalgaz Mühendisliği Bölümü
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Çoğu sondaj operasyonunda, takım sıkışması, çamur kaçağı ve aşırı çamur maliyetleri gibi sondajla alakalı problemler için önemli miktarlarda para harcandığı açıktır. Bu gibi problemlerden kaynaklanan üretken olmayan zaman yüzdesini azaltmak için özellikle dar sondaj penceresi olarak adlandırılan formasyon gözenek basınç ve çatlatma basınç eğrilerinin fazla yakın olduğu sahalarda amaç sondaj dizisi ile kuyu cidarı arasındaki anülüs olarak tabir edilen bölgedeki sürtünmeye dayalı basınç kayıplarını kontrol etmektir. Bu problemler çözüldüğünde kuyu sondajları için harcanan bütçe azalacak ve böylece önceden endüstrinin ekonomik olarak nitelendirmediği kuyular kazılabilecektir. Basınç Yönetimli Sondaj anülüsteki sürtünmeye dayalı basınç kayıplarını kontrol ederek bunun gibi sondaj problemlerinin üstesinden gelinmesine imkân sağlayan yeni bir teknolojidir. Endüstri tam olarak tüm yararlarından haberdar olmadığından, bu tez henüz tam olarak bilinmeyen ve bu yüzden uygulamalarına önoluşum tam olarak sağlanmamış olan Basınç Yönetimli Sondajdaki tekniklerden bahsetmektedir.

Anahtar Kelimeler: Basınç Yönetimli Sondaj, Sabit Kuyu Dibi Basınç Metodu, Basınçlandırılmış Çamur Örtü Sondajı, Çift Eğim Metodu, Dönen Akış Kontrol Metodu.

TO MY WIFE, THE INSPIRATION OF MY LIFE

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NOMENCLATURE

AFP	: Annular Friction Pressure
AFL	: Annular Friction Loss
API	: American Petroleum Institute
APWD	: Annular Pressure While Drilling
BH	: Bottom Hole
BHA	: Bottom Hole Assembly
BHP	: Bottom Hole Pressure
BOP	: Blow Out Preventer
BP	: Back Pressure
CBHP	: Constant Bottom Hole Pressure
CCS	: Continuous Circulation System
CCV	: Continuous Circulation Valve
CIV	: Casing Isolation Valve
CMC	: Controlled Mud Cap
CMCD	: Controlled Mud Cap Drilling
CPD	: Controlled Pressure Drilling
CTD	: Coiled Tubing Drilling
DAPC	: Dynamic Annular Pressure Control
DDV	: Downhole Deployment Valve
DG	: Dual Gradient
DHAD	: Down Hole Air Diverter
DEA	: Drilling Engineer Association
DIV	: Downhole Isolation Valve
DORS	: Deep Ocean Riser System
DP	: Drill pipe or dynamically positioned
DTTL	: Drill thru the Limits
DwC	: Drilling with Casing
ECD	: Equivalent Circulating Density
ECD-RT	: Equivalent Circulating Density Reduction Tool

EDS	: Emergency Disconnect System
EMW	: Equivalent Mud Weight
ER	: Extended Reach
ERD	: Extended Reach Drilling
ERRCD	: External Riser Rotating Control Device
FMC	: Floating Mud Cap
FMCD	: Floating Mud Cap Drilling
FP	: Fracture Pressure
HAZID	: Hazard Identification Study
HAZOP	: Hazard Operability Study
HCV	: Hydrostatic Control Valve
HH	: Hydrostatic Head
HP	: High Pressure
HPHT	: High Pressure High Temperature
HSE	: Health, Safety and Environment
IADC	: International Association of Drilling Contractors
ICU	: Intelligent Control Unit
IPM	: Integrated Pressure Manager
IRRCH	: Internal Riser Rotating Control Head
LOT	: Leak-off Test
LRR	: Low Riser Return
LRRS	: Low Riser Return System
MFC	: Micro Flux Control
MPD	: Managed Pressure Drilling
MW	: Mud Weight
MWD	: Measurement While Drilling
NGU	: Nitrogen Generation Unit
NPT	: Non-Productive Time
NRV	: Non-Return Valve
OB	: Over Balanced
OBD	: Over Balanced Drilling
PCWD	: Pressure Control While Drilling

PLC	: Programmable Logic Control
PMC	: Pressurized Mud Cap
PMCD	: Pressurized Mud Cap Method
PP	: Pore Pressure
PWD	: Pressure While Drilling
RCD	: Rotating Control Device
RCH	: Rotating Control Head
RFC	: Return Flow Control
ROP	: Rate of Penetration
ROV	: Remotely Operated Vehicle
RTTD	: Rotary Through Tubing Drilling
SAC	: Semi Automated Choke
SAC	: Secondary Annulus Circulation
SBP	: Surface Back Pressure
SDS	: Storm Disconnect System
SMD	: Subsea Mudlift Drilling
SSBP	: Subsea Back Pressure
TD	: Total depth/Target Depth
TTD	: Through Tubing Drilling
TVD	: True Vertical Depth
UB	: Under Balanced
UBD	: Under Balanced Drilling
WR-NRV	: Wireline Retrievable Non-Return Valve

CHAPTER 1

INTRODUCTION

1.1 Introduction

World energy demand is increasing continuously to meet the need of energy of the developing countries. Increase in the energy consumption rates forces the scientists and engineers to discover another ways of gathering energy or better ways to recover the sources that we have been already using for years.

Most of the world's remaining prospects for hydrocarbon resources will be more challenging to drill than those enjoyed in the past. In fact, many would argue that the easy ones have already been drilled. And with oil prices where they are today, drilling safely and cost effectively while producing a good well in the process could not be more important[1].

Considering all these, MPD should now be regarded as a technology that may provide a noteworthy increase in cost-effective drill-ability by reducing excessive drilling-related costs typically related with conventional offshore drilling, if most of the world's remaining vision for oil and gas being economically un-drillable with conventional wisdom casing set points and fluids programs are taken into account[2].

Since the cost of NPT (Non-productive time) has much more economic impact upon offshore drilling and due to offshore operators' portfolios having higher percentages of otherwise un-drillable prospects than those onshore, offshore is the environment where the technology has potential to have greatest overall benefit to the industry as a whole[3].

In addition, as the predominant strengths of MPD are; reducing drilling-related non-productive time and enabling drilling prospects that are technically and/or economically un-drillable with conventional methods, it is inevitable to utilize from the advantages that MPD presents in several conditions and environments.

The abnormally risk-adverse mindset of many drilling decision-makers has contributed to the industry being seen by other industries as laggards in accepting new technology. Relative to the basic hydraulics applied to drilling a well, this is particularly the case. For instance, drilling with weighted mud, open-to-atmosphere annulus returns, and relying upon gravity flow away from under the rig floor was developed over a century ago (Spindletop, Beaumont, Texas, 1901) and remains status quo "conventional-wisdom" in the way we look at the hydraulics of drilling[3].

To date and as one may expect, operators who have practiced MPD for their first time, onshore and offshore, the applications have mostly been on the most challenging and/or otherwise un-drillable prospects, i.e., where conventionally drilled offset wells failed or grossly exceeded their budgets[3].

Beyond these proven strengths of MPD's root concepts, this body of work will strive to address applications that have yet to be fully recognized, appreciated, and practiced. And, in doing so, will further the vision that MPD is the way most wells should be drilled today and will likely have to be drilled at some point in the future due to depletion, overburden and water depths.

1.2 Definition of Basic Concepts

1.2.1 Formation Pore Pressure

The formation fluid pressure, or pore pressure, is the pressure exerted by the fluids within the formations being drilled. The sedimentary rocks, which are of primary importance in the search for, and development of oilfields, contain fluid due to their mode of formation. Most sedimentary rocks are formed as accumulations of rock debris or organic material, underwater. As it is known, over two thirds of the earth's surface is covered with oceans, so the vast majority of sedimentary rocks are laid down as marine sediments in the shallow seas around the land areas. In general, areas of the earth's surface which are above sea level are affected by the processes of erosion (breaking up and wearing down of the land masses). The debris is washed down into the shallow sea basins where it settles out onto the sea floor, the coarser material generally settling out closer to the shore than the fine silts and clays. An illustration of the sedimentary process can be seen in Figure 1[4].

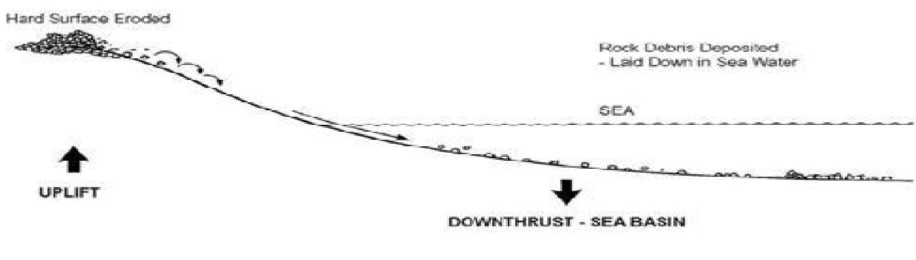


Figure 1 Sedimentary Process[4]

This process may continue for long periods as the earth's surface slowly moves, some areas being pushed up to provide fresh surfaces for erosion, with adjacent sea basins slowly deepening to allow great lengths of sediment to build up. Thus sedimentary rocks contain water, usually sea-water, as an integral part of their make-up. As the depth of sediment increases, the rocks are compacted, squeezing water out. The water contained within the rocks becomes progressively more salty as the relatively small molecules of water move through the pore spaces of the rock, while the larger salt molecule is retained[4].

The result of this is that the formation fluid pressure, or pore pressure, exerted by the water in a normal, open, sedimentary sequence is equivalent to that produced by a free-standing column of salt water, which is rather saltier and heavier than typical sea water. An average figure for normal formation pressure gradient in marine basin sediment was determined some years ago in the U.S. Gulf Coast area is 0.465 psi/foot. This is the pressure gradient produced by a column of water of approximately 100,000 ppm chloride. In comparison, a typical value for seawater is 23,000 ppm chloride[4]. Since the salinity or chloride concentration varies accordingly to the deposited basin, formation pore pressures should be identified according to the interest of area rather than using the specifically estimated pressure gradients of the specific basins.

The pressure gradient of 0.465 psi/foot or, expressed as an equivalent mud weight, 8.94 ppg is generally accepted as a representative figure for normal pore pressures in marine basins. There is some evidence that, worldwide, this figure is a little on the high side and evidence in the North Sea generally supports this view. Overall, this results in a slight over-estimate of anticipated pressure which is the safer option[4]. However, the variations from the normal pressure trend should be clearly identified or estimated in order to make accurate designs to drill the wells where the pressure management is an important issue and subnormal /abnormal pressure profiles exist.

Subnormal pressured formations have pressure gradients less than normally pressured formations. Subnormal pressures can either occur naturally in formations that have undergone a pressure regression because of deeper burial from tectonic movement or, more often as a result of depletion of a formation because of production of formation fluids in an old field[5].

In abnormally pressure formations, which have pressure gradients greater than normally pressured formations, the fluids in the pore spaces are pressurized and exert pressure greater than the pressure gradient of the contained formation fluid. Many abnormally pressured formations are created during the compaction of the impermeable water-filled sediments or adjacent shales (diogenesis). When a massive shale formation is completely sealed, squeezing of the formation fluids causes the fluid in the pore space to pick up some of the overburden pressure. Abnormally pressured formations may form in other ways and may be found in the presence of faults, salt domes, or geologic discontinuities. The transition zone to a higher pressure gradient may vary from a few feet to thousands of feet[5]. In addition, injecting fluid for production purposes might also result in an increase in the existing pressure profile.

In the drilling industry, formation pore pressure is the primary variable while designing a well to drill, since measuring, estimating and predicting pore pressures are important issues that lead the accurate hydraulic design of the well. Estimation and prediction of the formation pressures by using the analyses of seismic, log, production and test data, and evaluation of the drilling parameters are the most common ways. Furthermore, the developing technologies bring the usage of real time evaluation out.

1.2.2 Overburden Pressure

Overburden pressure is the pressure at any point in the formation exerted by the total weight of the overlying sediments. This is a static load and is a function of the height of the rock column and the density of the rock column[6]. However, if we need to consider the offshore and deepwater environments the definition should be revised as mentioned in *Managed Pressure Drilling*[5].

The pressure exerted by the weight of the rocks and contained fluids above the zone of interest is called the overburden pressure. The common range of rock overburden pressure, in equivalent density, varies between 18 and 22 ppg. This range would create an overburden pressure gradient about 1 psi/ft. Nevertheless, 1 psi/ft is not applicable for shallow marine sediments or massive salt[5].

Determination of the overburden pressure is an important concept because the overburden stress distribution varies depending on the assumptions while predicting the pressures. The real values of overburden cannot be predicted since the distributions of the overlying rocks are not homogeneous unlike the assumptions.

1.2.3 Fracture Pressure

Fracture Pressure is the stress which must be overcome for hydraulic fracturing to occur. This stress is known as the minimum lateral stress. When fracturing occurs, the fracture orientation will usually be parallel to the greatest stress (which is normally the over-burden pressure), which means the fractures will be vertical. For horizontal fractures to occur, the overburden pressure will have to be exceeded. This will occur in areas of large horizontal tectonic stresses[6].

It can be also defined as the pressure at which the formation fractures and circulating fluid is lost. Fracture pressure is usually expressed as a gradient, with the common units' psi/ft (kg/m) or ppg (kPa). Deep formations can be highly compacted because of the high overburden pressures and have high fracture gradients. In shallow offshore fields, because of the lower overburden pressure resulting from the sea water gradient, lower fracture gradients are encountered. Many of the formations drilled offshore are young and not as compacted as those onshore, which results in a weaker rock matrix[5]. While drilling the offshore wells the pressure profiles are to be managed more accurately so as to avoid loss circulation.

Fracture pressure (FP), which is the upper boundary of drilling window, is known as the secondary control variable while designing the hydraulics of the well. In order to eliminate the hazards, prediction of the FP is needed. FP can be predicted by using Hubbert and Willis Method, Matthews and Kelly Method and Eaton Model, however, Christman Model is the best suited one for offshore purposes[4]. Moreover, estimation of FP onsite is possible with a commonly used way called Leak off Test (LOT).

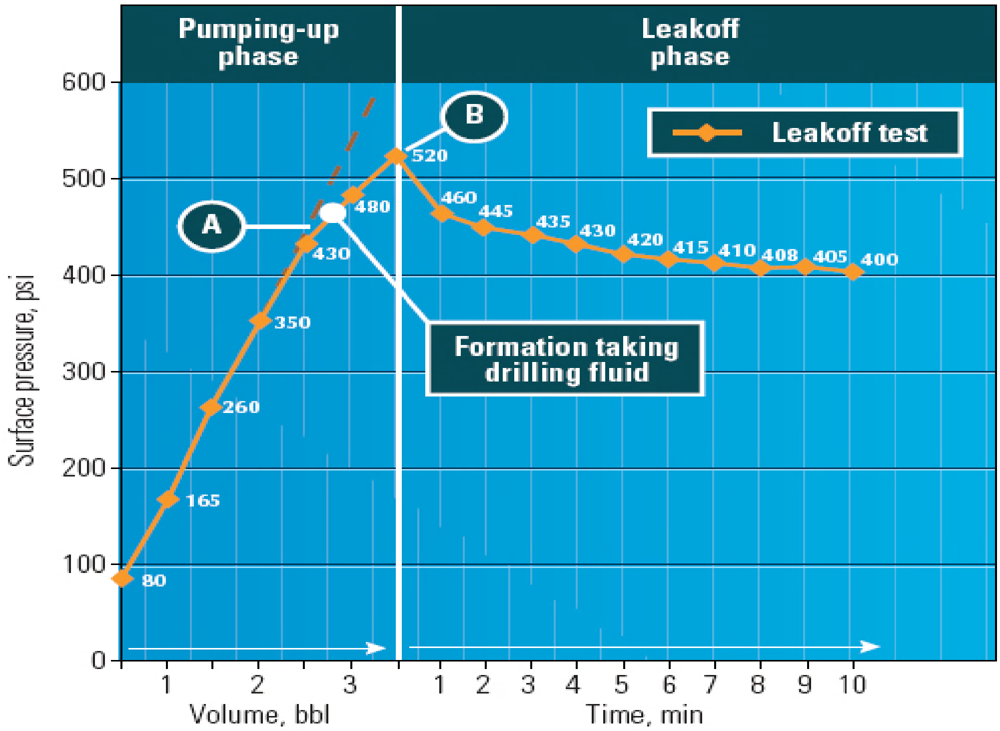


Figure 2 Leak-off Test monitored with APWD[7]

As it is demonstrated on Figure 2, leak-off test data plotted with Annulus Pressure While Drilling (APWD) tool in the BHA is to comprehend formation leak-off behavior after cementing the casing.

1.2.4 Collapse Pressure

Collapse pressure represents the minimum mud weight required to maintain a gun barrel hole and keep the formation "intact" before potential collapse[6]. The formation collapse pressure should not be ignored. In some cases, the collapse pressure is equal to or greater than pore pressure. Drilling operations encroaching on the collapse pressure curve are likely to see large splinters of formation popping off into the wellbore, as opposed to cuttings created by the drill bit. Wellbore instability may cause the drill string to become stuck by packing off the wellbore from collapse of the formation[8].

1.2.5 Conventional Drilling

In the conventional drilling circulation flow path, drilling fluid exits the top of the wellbore open to the atmosphere via a bell nipple, then thorough a flow line to mud-gas separation and solids control equipment, an open vessel approach. Drilling in an open vessel presents difficulties during operations that frustrate every drilling engineer. Annular pressure management is primarily controlled by mud density and mud pump flow rates. In the static condition bottomhole pressure (BHP) is a function of hydrostatic column's pressure. In dynamic condition, when the mud pumps are circulating the hole, BHP is a function of hydrostatic mud pressure and annular friction pressure (AFP) as shown in Fig. 3[9].

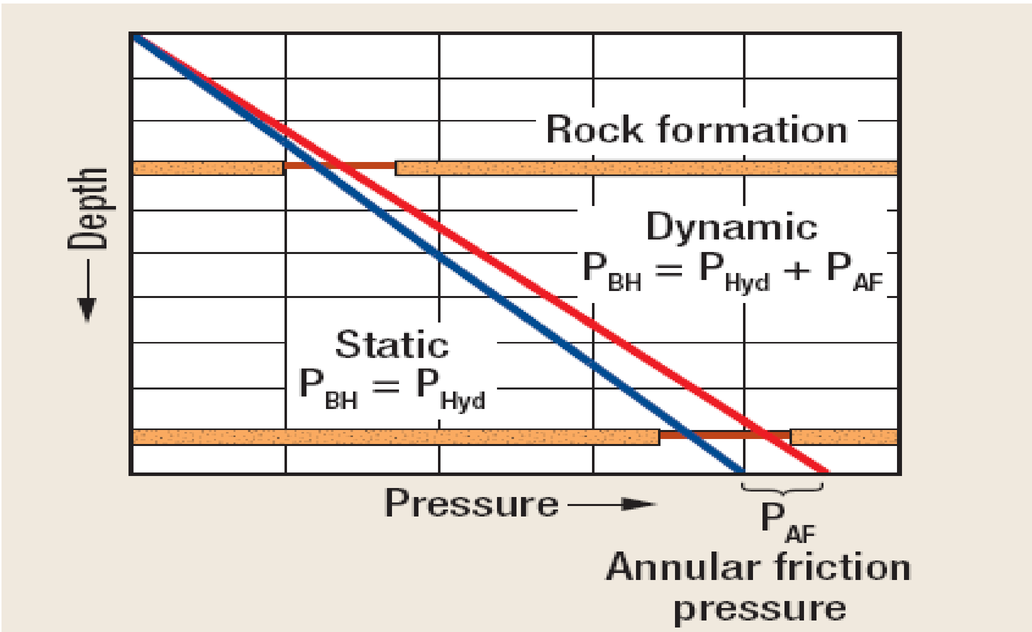


Figure 3 Static and Dynamic Bottomhole Pressure Profile[9]

On land and in some shallow water environments, a comfortable drilling window often exists between the pore pressure and fracture pressure gradient profiles, which the hole can be drilled safely and efficiently[9]. See Fig. 4.

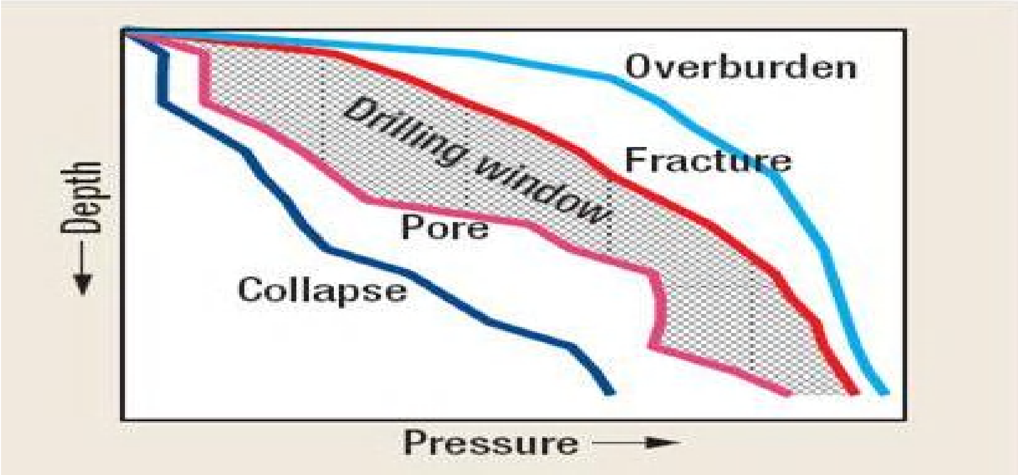


Figure 4 Example of Wide Pressure Window[9]

As it is illustrated in Figure 4, from a hydraulic standpoint, the objective is to drill within the pressure window bounded by the pore pressure on the left and the fracture gradient on the right[8].

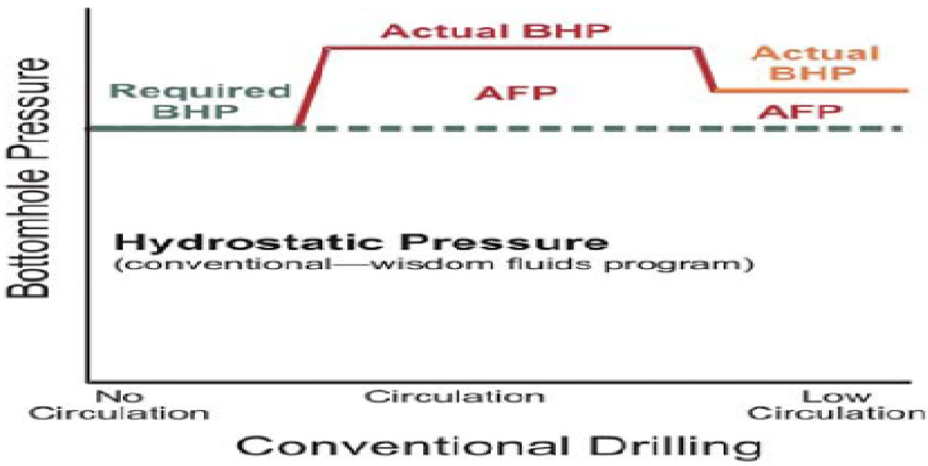


Figure 5 Conventional Drilling BHP Variations[10]

Figure 5 is an illustration of how bottomhole pressure changes depending on whether the system is static or dynamic. In conventional drilling, mud is designed to act statically overbalance or slightly above balance in order to prevent any influx, when the pumps are turned off to make connection or any failure due to the rig equipment.

1.2.6 Underbalanced Drilling

Drilling Engineering Association (DEA) defined Underbalanced (UB) drilling as deliberately drilling into a formation where the formation pressure or pore pressure is greater than the pressure exerted by the annular fluid or gas column. In this respect, “balanced” pressure drilling is a subcategory of underbalanced drilling because the annular pressure is expected to fall below the formation pressure during pipe movement[11]. Originally, underbalanced drilling is using the underbalance condition only if the mud is static and when there is no pipe movement. In other words, the system is overbalanced or near- balanced while drilling continues because in dynamic condition, both annular frictional losses and pipe movement induced pressures are added to the pressure exerted by the column of drilling fluid.

DEA stated that Underbalanced “mud” may be conventional drilling mud, water, oil, aerated systems (aerated mud or foam) or pure air with or without mist. “Air” or aerated systems may use air, natural gas, nitrogen, or a combination of gases[11]. Although the usage of air as an underbalanced mud is defined as Air Drilling (AD) by some of the major companies, lately it is named as Power Drilling (PD) is placed together with UBD and MPD under the sub categories of Control Pressure Drilling (CPD) concept.

As a broad generalization, underbalanced drilling is undertaken for only three reasons[11]:

- To improve the drilling rate.
- To limit lost circulation.
- To protect the reservoir formation.

1.3 The Reason for Narrow Drilling Window

Typically in deepwater prospects, pore pressures are abnormally high at relatively shallow depths below the sea floor due to rapid sedimentation and lack of compaction. On the other hand, the fracture pressures are typically low because of less overburden owing to large column of water instead of denser sediments. This results in a narrow window between the pore pressure and the fracture pressure. See Fig. 6. However, deepwater prospects are generally more rewarding in terms of the size of the field, rate of production and the net reserve in comparison to shallow water prospects[12]. Due to the limitations of the narrow drilling window, conventional methods are leaving its place to the emerging technologies.

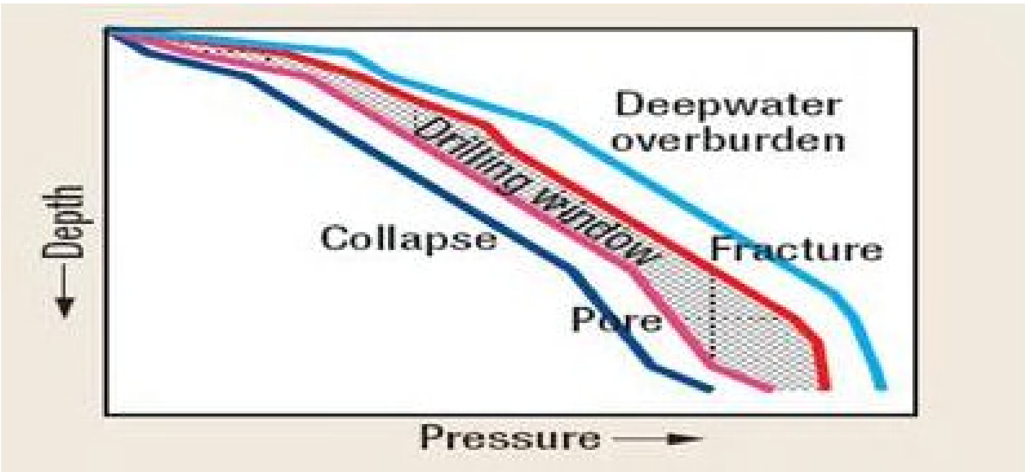


Figure 6 Narrow Drilling Window[9]

From an offshore prospective, MPD was and still is driven by the very narrow margins between formation pore pressure and formation fracture pressure downhole. Narrow margins are most pronounced in deep water drilling, where much of the overburden is seawater. In such cases, it is standard practice to set numerous casing strings at shallow depths to avoid extensive lost circulation[9]. With the help of the variations of MPD, it is possible to solve such problems by controlling the bottomhole pressure.

The collapse, pore pressure, fracture pressure and overburden profiles often change in more mature fields because of production and depletion. The drilling window that was once generous becomes narrower, making it more challenging to "drill within the lines" without losing circulation or inviting influx[9]. In another way, when encountering virgin reservoirs, especially in days past, the drilling window was fairly wide. The challenges of today's environment include re-entry of partially depleted reservoirs or deep water applications where water accounts for a large portion of the overburden[8]. See Fig. 7.

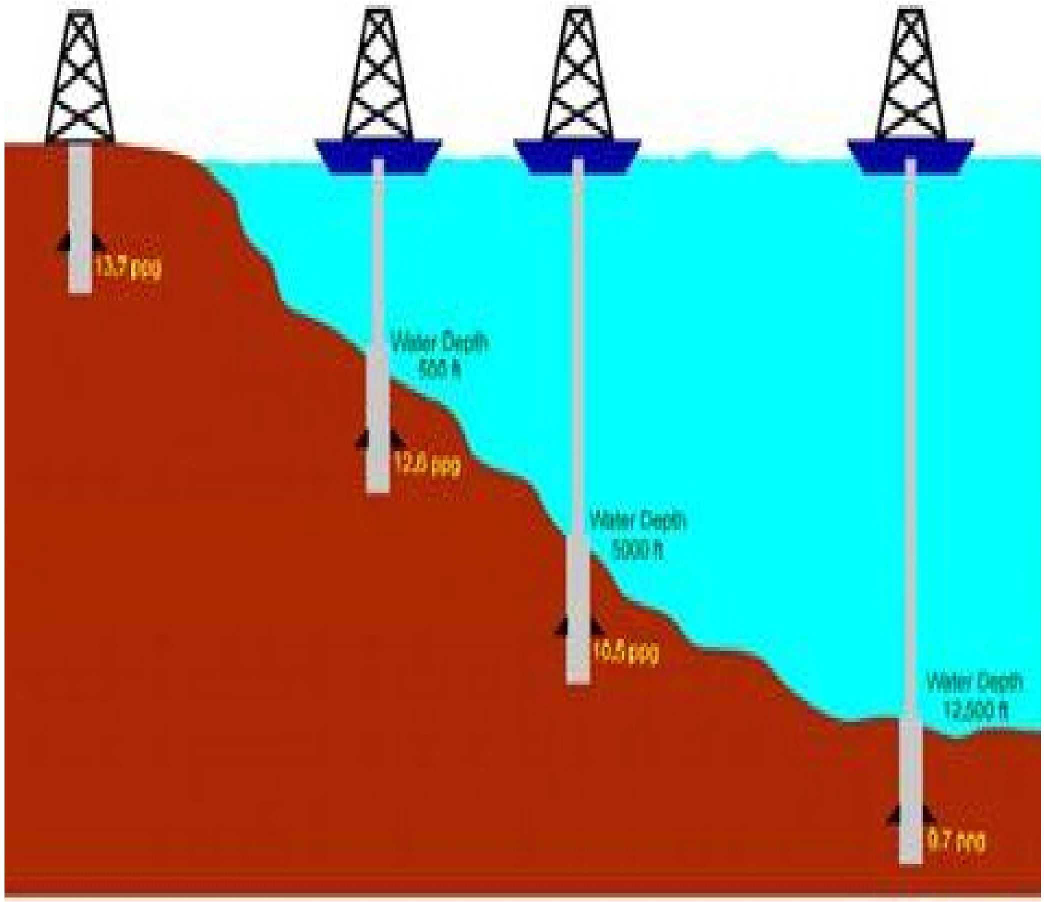


Figure 7 Fracture Gradient due to Water Overburden[8]

The formation collapse pressure should not be ignored. In some cases, the collapse pressure is equal to or greater than pore pressure. Fig. 8 is an example of such a window. Drilling operations encroaching on the collapse pressure curve are likely to see large splinters of formation popping off into the wellbore, as opposed to cuttings created by the drill bit. The mandate of productive drilling operations is to make hole and perform other essential operations contributing to completing the well, such as running casing, logging, and testing, etc. In an open vessel environment, drilling operations are often times subjected to repetitive kick – stuck - kick – stuck scenarios that significantly contribute to non-productive time, an add-on expense too many drilling AFE's (Authorization for Expenditure). This non-productive time is often times protracted, causing the rig crew to deviate from their routine of making hole. The deviation from routine drilling operations can expose the rig personnel to unfamiliar circumstances and if not adequately trained may lead to less than safe practices[8].

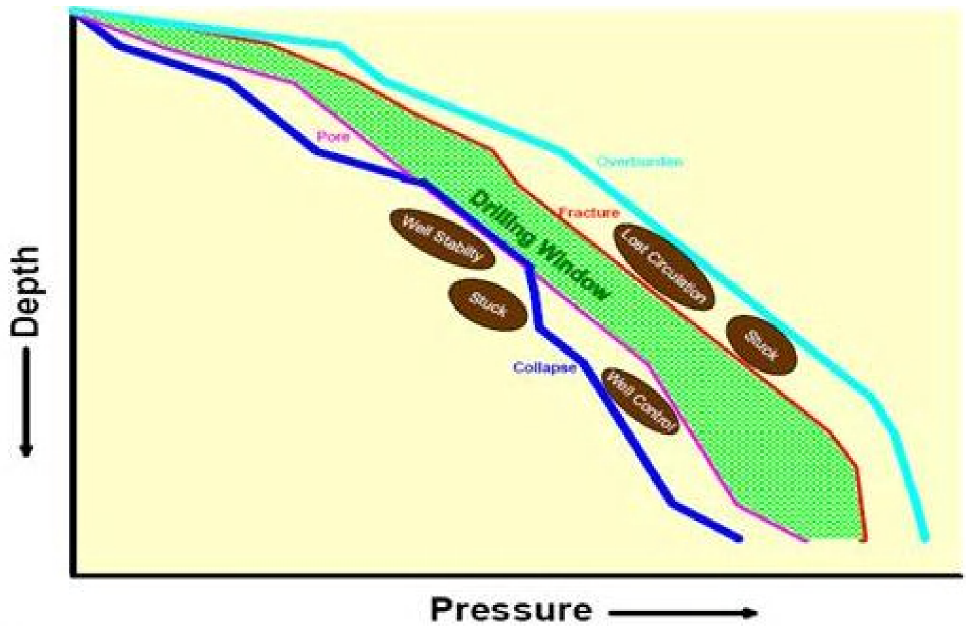


Figure 8 Drilling Window (Collapse Pressure ≥ Pore Pressure)[8]

CHAPTER 2

BASICS OF MANAGED PRESSURE DRILLING

2.1 History & Background of MPD

Managed Pressure Drilling should not only supposed to be a new technology and taking the advantage of new tools available in the industry but also it is an obvious fact that it utilizes from the existing knowledge and tools which are previously discovered and used several times in drilling operations. In order to clarify the evolution of MPD, the history and background behind the technology are to be understood.

In the 1500's Leonardo da Vinci sketch a machine for boring wells. A "spring-pole" cable rig was developed in 1806. In 1859 Drake used a steam engine driven cable tool rig to drill the western hemisphere's first economically viable oil well. In 1901 wells drilled underbalanced in the Spindletop Field of S.E. Texas[13]. After a few decades practicing and understanding the advantages of the underbalanced drilling, the need for better control of influxes were realized as a result of the difficulties faced while controlling influxes.

Rotating heads were described in the 1937 Shaffer Tool Company catalog[5]. In the 1960s, Rotating Control Devices (RCDs) enabled the practice of drilling with compressible fluids (gas, air, mist, and foam) to flourish. Now referred to as performance drilling (PD) or simply *air drilling,* value is realized primarily in the form of improved penetration rates, longer life of drilling bits, and reduced overall costs of drilling the prospect[14].

Many of the ideas on which MPD is predicted were first formally presented in three Abnormal Pressure Symposiums at Louisiana State University between 1967 and 1972. These symposiums looked at the origin and extent of abnormal pressures and how to predict pressures and fracture gradients from available data[5].

The Equivalent Circulating Density (ECD) was effectively used in well control practices develop in the 1970's. The present technology combines and formalizes new techniques with those historically used to deal with some of the most common drilling problems, such as well kicks and lost circulation[5].

In the 1970s, a major oil company was drilling from "kick to kick" in offshore Louisiana to increase drilling rate and avoid lost returns. This was a clear case managed pressure drilling in the Gulf of Mexico[5].

At first reluctant, the industry finally accepted of the practice of horizontal drilling in the 70's and 80's. This spurred an exciting and beneficial perspective to drilling technology, however, drilling horizontally into inclined fractures of high pore pressure hydrocarbons occasionally brought unpleasant surprises. The fluid column, the primary well control barrier designed to prevent a blowout, fell downward into the fractures encountered, and a significant number of well control incidents occurred as a result of high pore pressure hydrocarbons entering the wellbore, then flowing to the surface[13].

Mud Cap Drilling (MCD) was common for years as “drilling dry” or “drilling with no returns”. A more formalized version of MCD was tried in Venezuela in the 1980s, in the Hibernia Field of Nova Scotia in the 1990s, and later in Kazakhstan, in the former Soviet Union[5].

Over time, other uses of the RCD evolved—uses other than *air drilling* and *underbalanced operations.* The industry learned to use the RCD to more precisely manipulate the annular hydraulic pressure profile when drilling with a conventional mud system. It also enabled one to drill safely with an EMW nearer the reservoir pore pressure. Although an influx of hydrocarbons during the drilling process is not invited, one is better prepared to safely and efficiently deal with any that may be incidental to the operation. In 2003, the assortment of techniques was recognized as a technology within itself and given the label *managed-pressure drilling*[14].

It was not until 2003 that the enabling characteristics of the technology began to be more fully appreciated by offshore drilling decision makers. MPD is a technology that addresses a litany of drilling-related issues or barriers to conventional methods. The encounter of *drilling trouble zones* is undeniably on the increase. This is due in part to a requirement to drill in greater water depths and through depleted zones or reservoirs. And, as many would argue, most of the *easy* prospects in shallow and deep waters have already been drilled. Those remaining are more likely to be *hydraulically challenged,* requiring more precisely controlled management of the wellbore pressure profile to be drilled safely and efficiently[14].

Since 2005, over 100 wells have been drilled using MPD techniques by a number of operating companies. MPD has delivered direct cost and time savings by eliminating the non-productive time associated with losses and other related well control events. Being able to control wellbore pressures by using a closed wellbore system and introducing the application of some simple techniques has allowed previously “undrillable” wells to be successfully drilled to TD. Operators plan and budget wells for a certain number of days and then find that in the best case some 20% time spent on curing losses and kicks is added to their well times. Yet other operators have encountered losses and well control issues that double or even triple their planned well timings. Exceeding planned well times not only pushes drilling budgets past acceptable limits, but it also has a knock on effect on the rig sequence especially if the rig is shared by other operators in the region. Rigging up MPD equipment has allowed successful drilling of the fractured carbonates on all of the wells where the equipment was rigged up. Not all of the wells encountered losses, and on these wells the equipment was rigged up but not used. On the wells that did encounter the loss / kick scenarios, MPD enabled all of these wells to be drilled to TD without significant delays[15].

Managed Pressure Drilling has gained widespread popularity and a great deal of press coverage in recent years. By applying MPD techniques, it is possible to drill holes that simultaneously expose formations with pore pressures very close to the fracture pressures of other exposed formations with minimal formation influx or mud losses. Complex and expensive systems have been designed and implemented to maintain pressure on the wellbore using hydraulics modeling software, automated chokes, and continuous surface circulating systems, often working in conjunction with each other[16].

2.2 Definition of MPD

Managed-Pressure Drilling (MPD) is an advanced form of primary well control that many times employs a closed and pressurizable drilling fluid system that allows potentially greater and more precise control of the annular wellbore pressure profiles than mud weight and pump rate adjustments alone[17].

The IADC Underbalanced Operations Committee defined MPD as the following[18]:

Managed Pressure Drilling is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly.

Technical Notes:

- MPD employs a collection of tools and techniques that may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.
- MPD may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.
- MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects. *A condition where the pressure exerted in the wellbore is less than the pore*

pressure in any part of the exposed formations (IADC – Updated MPD definition, 2008).

- MPD techniques may be used to avoid formation influx. Any flow incidental to the operation will be safely contained using an appropriate process.

According to Malloy and McDonald[8], the centerpieces of the definition are rooted around the words "intent" and "precisely control". A range of technologies available at present give us a chance to control maintenance of the bottomhole pressure from the surface within a range of 30 – 50 psi. One MPD method does not address all problems. Managed Pressure Drilling is application specific. The drilling engineer will have his choice of many options that will best address the drilling problems he confronts[8].

Medley and Reynolds emphasized that benefits of precise wellbore management can reportedly overcome 80% of conventional drilling-related barriers. MPD having advantageous role such as leading to increased well control, increased ROP, greater bit life, less drilling flat time, fewer casing strings, less mud cost and safer applications can be realized by both offshore and onshore drilling personnel[19].

Brainard[17] claims that the use of MPD technologies can influence many wellbore pressure-related drilling challenges, including lost circulation, kicks, wellbore ballooning, tight pore pressure (PP)/fracture pressure (FP) margins, close tolerance casing programs, wellbore stability problems, shallow water/gas flows, slow ROP, etc. These techniques may also enable future well programs that are currently thought to be conventionally "un-designable" with single gradient mud systems[17].

According to DEA, Managed Pressure Drilling continues to demonstrate its bright future. There has not been any recorded incident of a kick while applying the techniques of managed pressure drilling, despite the fact that MPD can be used to briefly characterize a reservoir by allowing a small momentary influx. This is not to say that there have been no problems, sometimes pipe still gets stuck and lost circulation problems still exist, but not the same magnitude as in conventional drilling. The most impressive aspects of Managed Pressure Drilling are it is as safe or safer than current conventional drilling techniques AND problem wells are being drilled and completed instead of abandoned either with cement plugs or in a file labeled "TOO RISKY TO DRILL – TECHNOLOGY NOT AVAILABLE". MPD is a sophisticated form of well control and deserves a balanced quality appraisal of risks – positive and negative[8].

2.3 Categories of MPD

The MPD subcommittee of IADC separates MPD into two categories -"*reactive*" (the well is designed for conventional drilling, but equipment is rigged up to quickly react to unexpected pressure changes) and "*proactive*" (equipment is rigged up to actively alter the annular pressure profile, potentially extending or eliminating casing points). The reactive option has been implemented on potential problem wells for years, but very few proactive applications were seen until recently, as the need for drilling alternatives increased[19].

2.3.1 Reactive MPD

Malloy[9] stated that reactive MPD uses MPD methods and/or equipment as a contingency to mitigate drilling problems, as they arise. Typically, engineers plan the well conventionally, and MPD equipment and procedures are activated during unexpected developments[9].

One is prepared to practice MPD as a contingency. Hannegan emphasized that a conventional-wisdom well construction and fluids program is planned, but the rig is equipped with at least an RCD, choke, and drillstring float(s) as a means to more safely and efficiently deal with, i.e., unexpected downhole pressure environment limits (e.g., the mud in the hole at the time is not best suited for the drilling window encountered). For example, of the one-in-four US land-drilling programs practicing MPD, many are practicing the reactive-category MPD. As a means of preparing for unexpected developments, the drilling program is equipped or *tooled up* from the beginning to deal more efficiently and safely with downhole surprises. This, in part, explains why some underwriters require that wells they insure be drilled with a closed and pressurizable mud-return system[14].

2.3.2 Proactive MPD

The drilling program is designed from the beginning with a casing, fluids, and open hole drilling plan and/or alternate plans that take full advantage of the ability to more precisely manage the wellbore pressure profile. According to Hannegan, this *walk the line* category of MPD technology offers the greatest benefit to both onshore and offshore drilling programs. Most offshore applications to date have been of this category. Of significance is the fact that a growing percentage of land MPD programs are transitioning from reactive to proactive MPD. This shift requires that the wells be pre-planned more thoroughly, but the benefits to the drilling program typically more than offset the cost of the additional MPD engineering and project management[14].

Malloy explained that proactive MPD[9] uses MPD methods and/or equipment to control the pressure profile actively throughout the exposed wellbore. This approach uses the wide range of tools available to

- Better control placement of casing seats with fewer casing strings
- Better control mud density requirements and mud costs
- Provide finer pressure control for advanced warning of potential well control incidents.

All of these lead to more drilling time and less NPT time. Briefly, proactive MPD drills:

- operationally challenged wells
- economically challenged wells
- "undrillable" wells

2.4 UBD vs. MPD

The incapability to drill the well using conventional overbalanced drilling (OBD) methods led companies to explore alternative drilling techniques such as UBD and MPD. Drilling problems that have driven the adoption of UBD or MPD in the past include[20]:

- the need to eliminate or minimize formation damage
- small formation pressure/fracture gradient window
- desire to minimize well cost by:
  - ✓ minimize fluid losses
  - ✓ eliminate differential sticking
- increasing rate of penetration
- extending bit life, etc.
- increase safety in drilling operations

Under-balanced drilling was initially adopted for resolving drilling problems, but it soon became evident that this technique could also minimize reservoir damage. In spite of its many benefits, UBD has not been embraced by the industry as readily as would have been expected. This reluctance has been due to high equipment rental costs and limitations on application of the technique offshore, either due to regulations limiting hydrocarbon flaring or formation instability. As an intermediary mitigation, MPD was developed[20].

Malloy and McDonald[8] stated addressing the starting point that the origins of Managed Pressure Drilling (MPD) can be found in the utilization of a few specific technologies developed by its forbearer, Underbalanced Drilling. Underbalanced Drilling (UBD) is a drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.

While there are some similarities in equipment selection, as well as similar training needs for personnel, MPD is not a “poor-boy” version of underbalanced drilling. On the contrary, done properly, contingencies need to be explored requiring engineering forethought and planning, even though the equipment footprint is typically not as extensive[9].

The definitions cited in the study of Ostroot et al. are concerned; IADC has defined managed pressure drilling as “an adaptive drilling process used to precisely control the annular profile throughout the wellbore”. The objectives are to ascertain the downhole pressure environment limits and to manage the annular pressure profile accordingly. The definition for a UBD operation is “when the hydrostatic head of a drilling fluid is intentionally designed to be lower than the pressure in the formations being drilled, the operation is considered underbalanced drilling[20].

A comparison of the two methods can be performed by considering the objectives for the project, the equipment requirements and potential benefits/risks of each method. It has been established that MPD is used primarily to resolve drilling-related problems, although some reservoir benefits also may be achieved. This is not surprising as any effort to decrease the degree of overbalance, and thus, the impact of drilling fluid on virgin formations usually will initiate some positive reservoir benefits. UBD, on the other hand, has long been employed to provide solutions to both drilling-related and reservoir-related problems. Thus, one can deduce that the critical difference between UBD and MPD lies in the degree of resolution attainable with each method for both the drilling-related and reservoir / production related problems[20].

Ostroot et al. stated giving the design purpose that even though MPD and UBD offer management of wellbore downhole pressures during drilling, the two methods differ technically in how this is accomplished. Whereas MPD is designed to maintain bottomhole pressure slightly above or equal to the reservoir pore pressure (i.e. overbalanced or at balanced drilling), UBD is designed to ensure that bottomhole pressure (BHP) is always below the reservoir pore pressure (i.e. underbalanced drilling), and thus, induces formation fluid influx into the wellbore, and subsequently, to the surface[20].

Malloy pointed emphasizing the aim that unlike underbalanced drilling, MPD does not actively encourage influx into the wellbore. The primary objectives of MPD are to mitigate drilling hazards and increase operational drilling efficiencies by diminishing NPT[9].

Ostroot et al. also stated emphasizing the goal that MPD cannot match UBD in terms of minimizing formation damage, allowing characterization of the reservoir, or identifying productive zones that were not evident when drilled overbalanced. Nonetheless, when the objective is simply to mitigate drilling problems, MPD can often be as effective and more economically feasible. MPD is also preferable where wellbore instability is a concern, when there are safety concerns due to high H2S release rates, or when there are regulations prohibiting flaring or production while drilling[20,21].

Two of the primary reasons cited[20] for selecting MPD over UBD are 1) wellbore instability concerns during UBD, and 2) desire to reduce equipment requirements to improve cost efficiency. However, basing the decision only on these criteria ignores the possibility that significant reservoir benefits also could be realized with UBD and that equipment requirements really depend on the reservoir to be drilled, since MPD may require an almost equivalent setup as UBD.

MPD is often seen as easier to apply compared with full UBD operations. Often in non reservoir sections, MPD design requirements may determine that a simpler equipment package will satisfy safety considerations for the well, and therefore, the day rate would be reduced compared to using full underbalance. As has been described, depending on the design parameters of the project, equipment requirements for both operations vary considerably. In many instances, the same equipment setup is necessary for UBD as well as MPD methods. The distinguishing difference concerns the fact that smaller-sized separation equipment can be used for the MPD setup, as large fluid influx is not expected during drilling[20].

Furthermore, some level of automation of the surface systems is needed for quick, uninterrupted reaction to changes in downhole conditions, owing to the fact that wellhead pressure changes are used to control MPD operations. This type of automation could be required to enhance UBD operations as well[20].

Medley and Reynolds[19], stressing the influx, clarifies the major difference between the two by stating that MPD will never invite influx into the wellbore. On the contrary, this is identified as UBD's objective. The UBD process involves drilling into any formation, where the pressure exerted by the drilling fluid is less than the formation pressure. The technique reduces the hydrostatic pressure of the drilling fluid column, so that the pressure in the wellbore is less than the formation pressure. Consequently, the formation pressure will cause permeable zones to flow, if conditions allow flow at the surface.

Additionally, by the use of lower-priced, lighter fluid systems, and riddance or significant reduction of mud losses, both UBD and MPD have the potential to lessen drilling-fluid costs notably[20].

It is important to mention here that while UBD has the potential to eliminate formation damage; MPD can be designed only to reduce it compared to conventional overbalanced drilling. Nonetheless, residual damage in the near-wellbore area after drilling is still likely. Residual formation damage of a MPD well can be as high as that of a conventionally-drilled overbalanced well[20].

The reservoir-related or production-related benefits of UBD (and to a much lesser extent MPD) are significant when compared with conventional OBD. Primarily, these benefits are seen through higher productivity of UBD wells[20]. See Fig. 9.

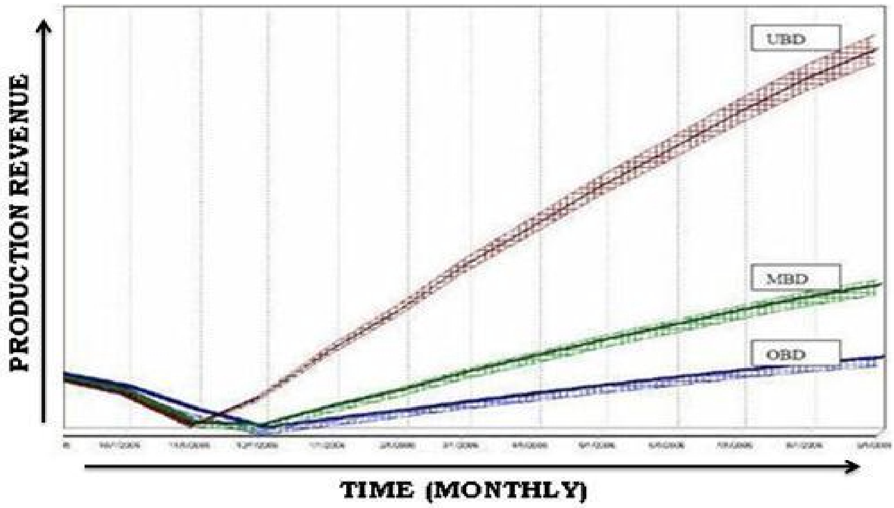


Figure 9 Production Revenue Comparison: UBD, MPD, OBD[20]

In fact, reduction in damage to the reservoir compared with conventional OBD in some MPD wells has been recognized in the industry only recently. UBD, on the other hand, has had a much longer track record for maximizing well productivity, thereby ensuring higher sustained production rates compared to conventional wells. Historically, many wells that have been classified as UBD have in fact actually been MPD wells where some portion of the drilling was underbalanced; however, overbalanced conditions occurred often or were used for completing a well drilled underbalanced. This had the effect of reducing or even eliminating any productivity gains from UBD, and therefore, in many instances, it appeared that UBD had little or no impact on reduction of formation damage and improved productivity[20].

2.5 The Need for Managed Pressure Drilling

It is important, almost vital that MPD become widely and comfortably used in the offshore market. Coker[22] stated that this technology can, and will, lead to many offshore resources becoming available. Some industry professionals would quote figures that as much as 70% of current offshore hydrocarbon resources are economically undrillable using conventional drilling methods. With the techniques and equipment that are addressed in the index (see Appendix A) more and more of these offshore resources will become available in an economic sense. Therein lies the importance of the MPD, without this technology much of the world resources will be neglected.

Hannegan[13] stated highlighting the drawbacks that about one-half of the remaining offshore resources of hydrocarbons, gas hydrates excluded are economically undrillable with conventional tools and methods. The percentage "undrillable" increases with water depth. Drilling related obstacles to greater economic viability include:

- Loss circulation/differentially stuck pipe
- Slow ROP
- Narrow pore-to-fracture pressure margins necessitating excessive casing programs and requiring larger, more expensive drill ships to buy
- Shallow geohazards when drilling top holes riserless
- Flat time spent circulating out riser gas, kicks, etc.
- Failure to reach TD objective with large enough hole

Das[12], considering the loss of revenue due to reduced casing size at the total depth, affirms that the cost of the well increases as a result of longer drilling time and the higher cost of casing and accessories. Owing to the requirement for a large number of protective intermediate casing strings in the well, the size of the production casing becomes very small in a conventional well design with a narrow PP-FP window. The lower production rate consequent to the small production casing size may be uneconomical in a high capital and operating cost environment.

High circulating pressure, difficulties in drill bit torque transmission, high drag in the open hole, susceptibility to drillstring sticking etc. are among the various technical and operational limitations, for the reason that drilling a small diameter hole is difficult. Additionally, operations such as wireline logging, running and cementing casing, and running completion equipment also experience great difficulties in small size holes.

2.6 Drilling Hazards

According to Malloy and McDonald[8], to alleviate drilling hazards and increase drilling operations efficiencies by reducing non-productive time (NPT) are the principal objectives of Managed Pressure Drilling. The operational drilling problems mostly related with non-productive time include:

- Lost Circulation
- Stuck Pipe
- Wellbore Instability
- Well Control Incidents

Figure 10 Drilling Hazards[8]

Hoyer[23] stated emphasizing the importance of hazard mitigation that successful hazard management and mitigation begins with a clear understanding of known drilling hazards and appreciation of those at risk to be encountered. Careful analysis of well data provides the basis for planning that identifies best practices and technologies based on performance, not habit. This approach requires listening to the well. Making the correct decisions while drilling is a matter of recognizing, integrating, and correctly interpreting all the drilling dynamics— including but not limited to weight on bit, revolutions per minute, vibration, downhole pressure, temperature, hole cleaning, shale shaker cuttings, etc. The downside of this is well understood. Misinterpreting any of these dynamics has broad ranging repercussions. Interpreting them singularly, outside the context of the other dynamics, carries the danger of actually contributing to instability and inducing further hazards.

In JPT July 2009, three DHM technologies were mentioned for the fact that good drilling practices provide the process through which these hazards can be recognized, understood, managed, and either avoided or mitigated effectively. Three well construction technologies stand out as highly effective, but underutilized means of managing and mitigating drilling hazards. The technologies which deal with the solution to the drilling hazards are Managed Pressure Drilling (MPD), Drilling with Casing (DwC) and Solid Expandable Systems (SES)[23].

Hoyer emphasized another technology mitigating the hazards along with MPD by stating that drilling-with-casing or liner technology also provides an effective means of dealing with instability and lost circulation that conventional drilling systems are unable to provide. This has been demonstrated in such demanding applications as the Banuwati field offshore Sumatra, Indonesia, where the Lower Baturaja limestone is infamous for severe lost circulation conditions. In this difficult environment, the drilling-with-casing system overcame severe wellbore instability and lost circulation challenges that had resulted in three sidetracks in just one well. Compared to anticipated costs for conventional methods, the system saved three days of rig time equating to almost USD 1 million. A key factor in this achievement was the technology's so called smear effect, in which the close proximity of the casing wall to the borehole spreads ground cuttings against the formation to create an impermeable filter cake[23].

In addition, Hoyer informed about the other technology referring to the necessity of MPD in reducing drilling problems by explaining the fact that solid expandable casing or liner being a proven method of isolating trouble zones with zero or minimal loss of hole size compared to conventional telescoping casing designs. Hole size conservation is often critical in reaching TD with optimal hole size for evaluation and completion—or even reaching TD at all. Further advantages in managing and mitigating drilling hazards are coming from recent advances in high-collapse resistant expendables and monobore technologies that help prepare for trouble rather than react to it[23].

2.6.1 Well Control Incidents

Kick tolerance is an important concept that can be applied both in drilling operations and in casing program design. For the wells currently drilled by oil industry, more multifaceted planning and execution are required. Application of kick tolerance concept is especially helpful in. Taking kick tolerance into consideration made drilling execution safer and more economical by reducing the probability to have an incident. It is crucial to keep an eye on the kick tolerance in real time, by updating the calculation every time there is a variation of parameters which influence its value. In deepwater, choke and kill line friction is an important factor, particularly when the threshold between mud density and casing shoe fracture gradient is really narrow[24].

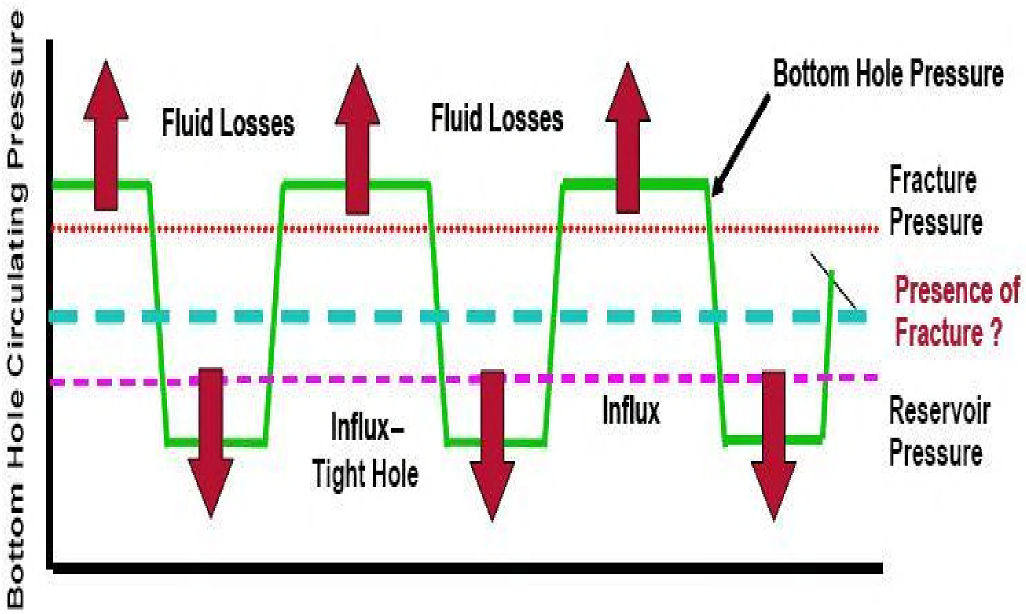


Figure 11 Kick Occurrences due to Narrow Drilling Window[25]

Figure 11 illustrates that taking kick is faced while stopping the pumps to make connection in conventional wells which have narrow drilling window. Dynamically overbalance system turns statically underbalance which allows kicks to the well.

Malloy and McDonald[8] stated disadvantages of conventional drilling while dealing with kicks by emphasizing that annular pressures cannot be adequately monitored in an open vessel unless and until the well is shut in. Well control incidents during conventional drilling are predicated on increased flow, where precious time is often wasted pulling the inner bushings to "check for flow”. In that time the influx volume becomes larger. The larger the influx volume becomes, the more difficult it is to manage the kick. Correspondingly, during conventional drilling operations it is required to cease the drilling and shutting in the well. While the influx volume is being circulated out of the wellbore and the drilling fluid is more adequately weighted to compensate for the increased bottomhole pressure, the hole is not being drilled and casing is not being run. The non-productive time is mounting, exposing time sensitive formations to drilling fluids that will cause other problems leading to increased nonproductive time. The effects of non-productive time are iterative and costly.

2.6.2 Lost Circulation

Continued loss of drilling mud to the formation not only damages future production potential, but could also lead to a well control issue. The hydrostatic pressure throughout the wellbore decreases when the (static) mud column in the annulus decreases in height, hence the loss of drilling mud in the wellbore will have to be refilled. The decreased height of the mud hydrostatic column sets the stage for a pressure imbalance between the hydrostatic mud column and the fluid contained in the exposed rock formation. An influx of some magnitude will arise once the bottomhole pressure exceeds the hydrostatic pressure created by the static mud column. On condition that there is not an intervention, that influx can grow in volume leading to a kick, and if it is not monitored it may result in a blow-out[8].

Smith[26] stated the importance of casing in conventional operations by suggesting the only way of extending the drilling window by running casing to isolate the potential hazard section, in order to prevent these kinds of preceding drilling hazards that might occur in tight margins. This is one of the common ways of conventional drilling. The figure below illustrates the situation.

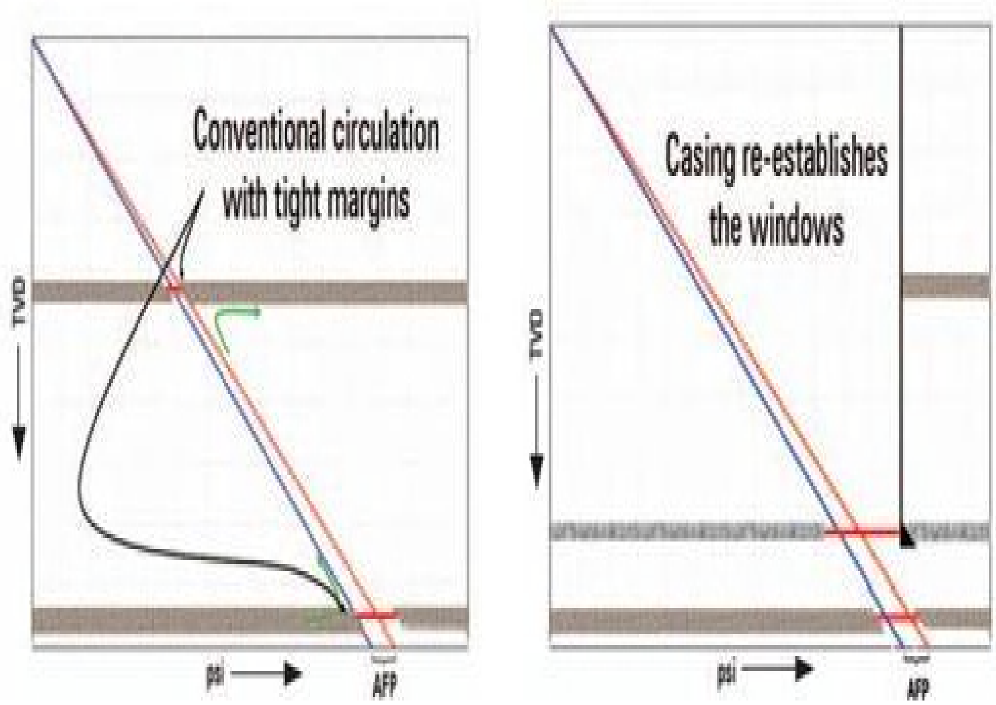


Figure 12 Traditional Response to Extend Tight Margins[26]

2.6.3 Stuck Pipe

As it is published in the underbalanced drilling and completion manual of DEA, the most common sticking mechanism in conventional drilling is the differential sticking. When drilling fluid leaks into the formation, leaving a fairly impermeable layer of solids on the wellbore, differential sticking occurs. If the drill pipe or tubing is in contact with the wellbore, the filtrate can leak away from behind the pipe and create a low-pressure zone. Pressure sticking or differential sticking of the pipe is seen when the differential pressure over the area involved creates forces. This cannot happen if the well is underbalanced. Stuck pipe can be freed by changing the well condition to underbalance[11].

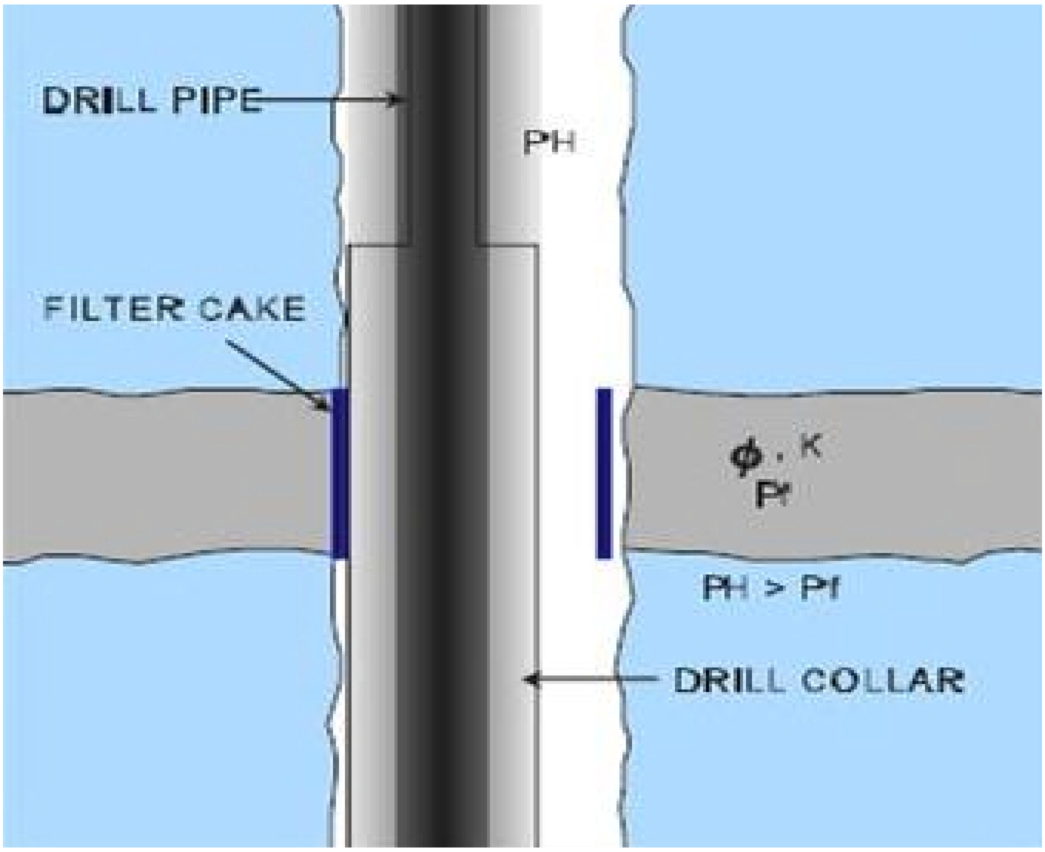


Figure 13 Illustration of Differential Sticking[11]

Figure 13 is an example of differential sticking due to the pressure difference between wellbore and formation. Overbalance of the static mud column can be reduced by using the back pressure instead of using a dense mud. In addition, this situation occurs mostly in static conditions because of not having circulation and rotation.

2.6.4 Wellbore Instability

Once the mud column pressure against the formation is reduced there are important setbacks to consider. In order to function as a close up against well kicks or blowouts, heaving shales (geo-pressured shale), broken or fractured formations, general borehole instability due to tectonic stresses or weak formations and salt, most of the drilling procedures exploit the mud column pressure[11]. The wellbore pressure differential should be controlled very accurately to mitigate wellbore instability problems. MPD methods and tools are used to manage the pressure profiles in the wellbore to reduce the likelihood of the unwanted pressure differential. The effect of the differential pressures is clearly shown in the following figure.

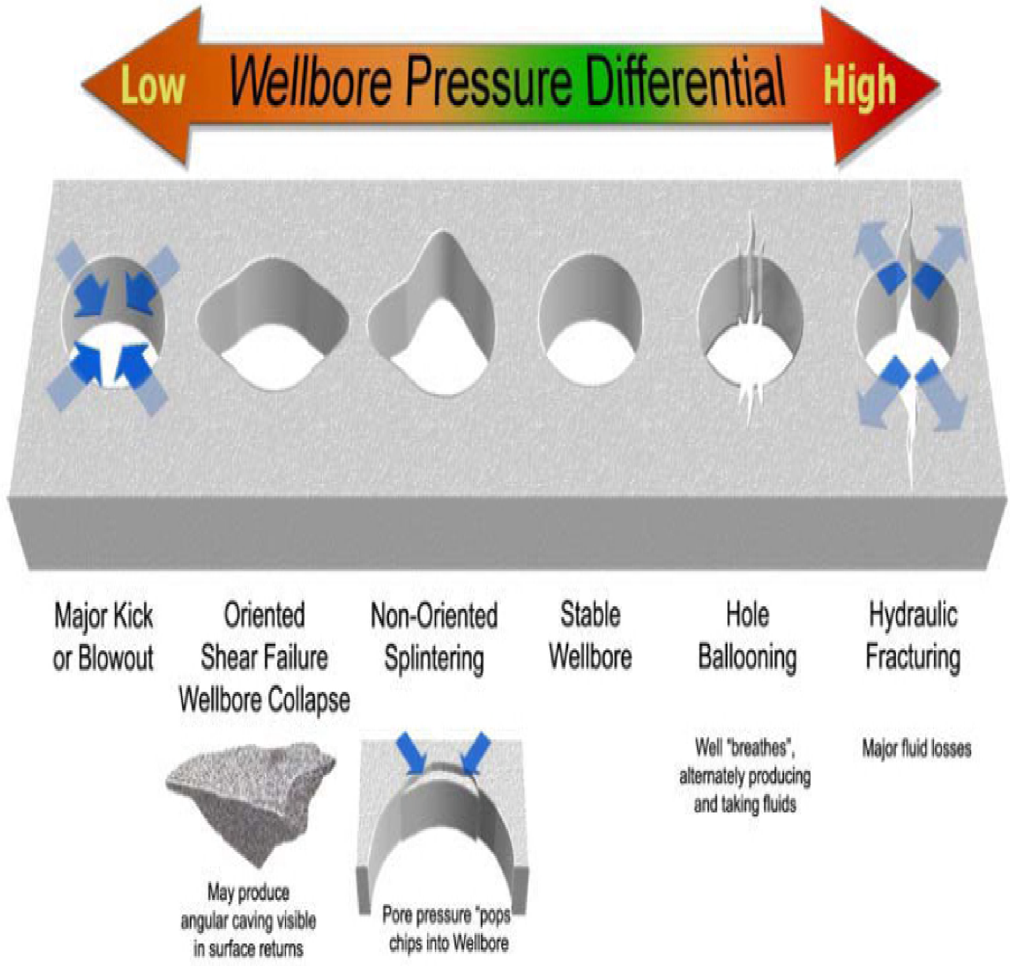


Figure 14 Effect of Wellbore Pressure Differential[27]

Figure 14 is an illustration of the wellbore behavior due to the differential pressures across the well. Increase in wellbore pressure causes hole ballooning and hydraulic fracturing, then again a decrease in the wellbore pressure causes well collapse and kicks.

CHAPTER 3

MANAGED PRESSURE DRILLING TECHNIQUES

There are four key variations of MPD. Each is addressed in the context of the drilling hazards to which it has proved applicable. Occasionally, combinations of variations are practiced on the same challenging prospect. Combining several variations on the same prospect is expected to become more frequent as the technology becomes more status quo in the minds of drilling decision makers and as prospects become increasingly more difficult to drill[14]. The four key variations of MPD with sub-categories according to their application areas and different strengths they have are listed as below;

- Constant Bottom Hole Pressure (CBHP)
    - Friction Management Method
    - Continuous Circulation Method
    - Drill thru the Limits (DTTL) Method
- Mud Cap Drilling (MCD)
    - Pressurized Mud Cap Drilling (PMCD)
        - Floating Mud Cap Drilling (FMCD)
        - Controlled Mud Cap Drilling (CMCD)
- Dual Gradient Drilling (DGD)
    - Annulus Injection Method
    - Riserless Dual Gradient Method
- Return Flow Control (RFC) or HSE Method

Although there are lots of emergent combinations, the ones added to the list are expected to be used in near future along with the commonly used ones.

3.1 Constant Bottom-Hole Pressure (CBHP)

Many drilling and wellbore stability related issues stem from the significant fluctuations in bottomhole pressure that are inherent to conventional drilling practices. According to Hannegan, these fluctuations in bottomhole pressure are root causes of a litany of excessive costs to a conventional land-drilling program. Such pressure "spikes" are caused by stopping and starting of circulation for drillstring connections in jointed-pipe operations. Specifically, they result from a change in equivalent circulating density (ECD) or annulus friction pressure (AFP), which occurs when the pumps are turned on and off. The AFP additive to bottomhole pressure is present when circulating and absent when not circulating[10].

CBHP is the term generally used to describe actions taken to correct or reduce the effect of circulating friction loss or equivalent circulating density (ECD) in an effort to stay within the limits imposed by the pore pressure and fracture pressure[5]. In order to reduce the effect of AFL or ECD, the need for backpressure (BP) is to be understood.

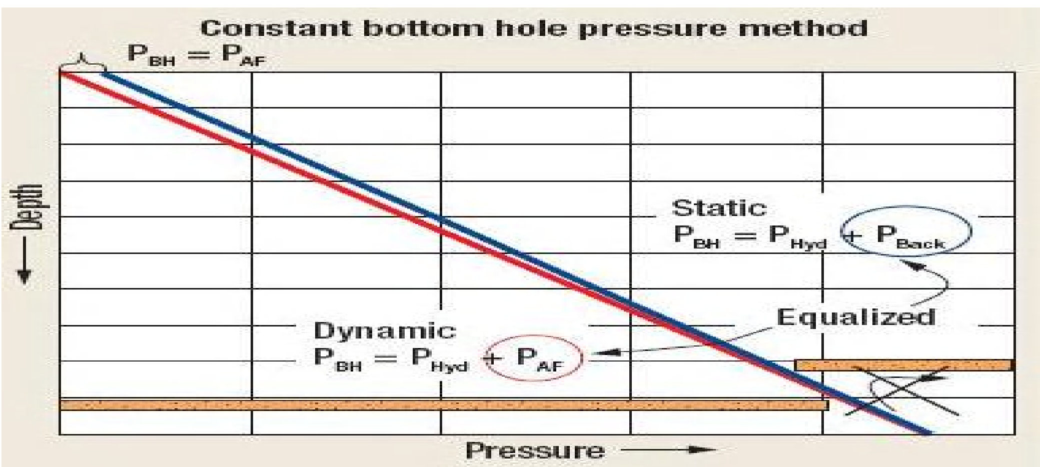


Figure 15 CBHP when BP usage only in connection[9]

In this variation, the objective is to "walk the pore pressure line" with a nearer-balanced-than-conventional wisdom fluids program as a means of overcoming kick-loss issues associated with narrow margins between formation pore pressure and fracture gradient. When drilling ahead, surface annulus pressure is near zero. During shut-in for jointed pipe connections, a few hundred psi backpressure is required[28]. Using of backpressure shows the industry the capability to use a less dense mud.

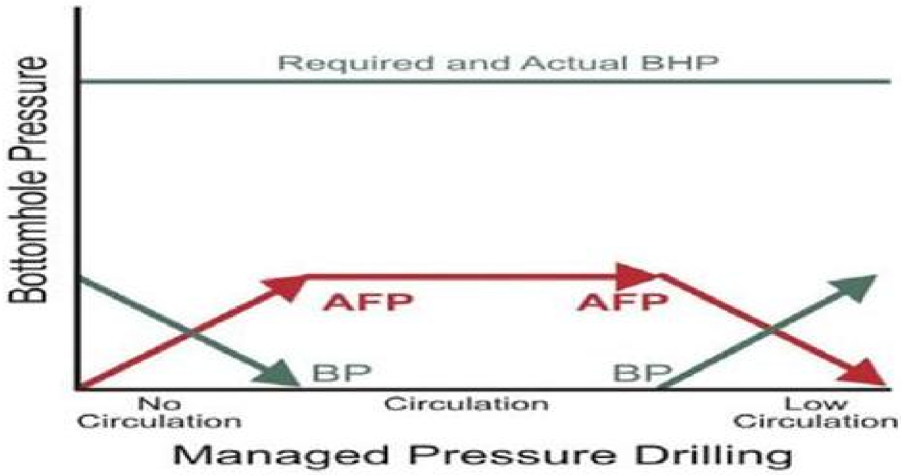


Figure 16 The usage of Back Pressure in CBHP Method[10]

Figure 16 is a simple illustration of how ECD or AFL can be compensated. Theoretically, compensation of decreasing amount of AFL with the same amount of increasing BP is possible while stopping circulation which allows the control of BHP.

Despite the fact that the actual aim of Constant Bottomhole Pressure Method (CBHP) is to control the most difficult pressure anomalies within the exposed wellbore, the name implies control of the bottomhole pressure at the bottom of the hole. Typically, the drilling fluid is lighter than "normal", so the hydrostatic column is statically underbalanced[9]. Using less dense mud showed industry one of the management strengths of MPD and improved the use of this new concept.

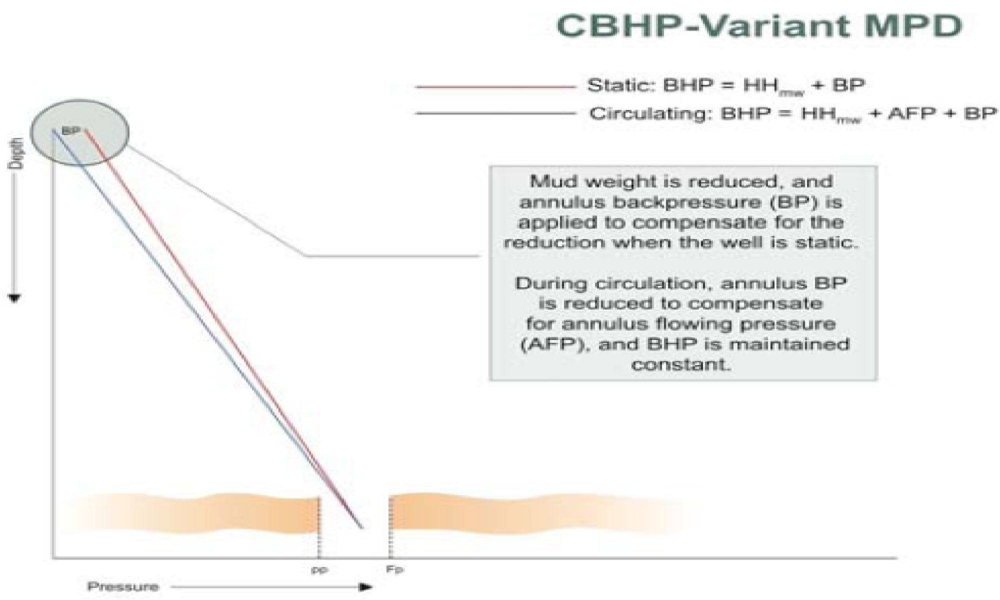


Figure 17 CBHP - BP usage both in connection and drilling[10]

Hannegan[14] clarified the purpose that this method is distinctively applicable to drilling in narrow or relatively unknown margins between the pore and fracture gradients. Whether the rig's mud pumps are on or off, the objective is to maintain a constant EMW. Typically, a lighter-than-conventional-wisdom fluids program is implemented, nearer balanced, perhaps even hydrostatically underbalanced. When shut in to make jointed pipe connections, surface backpressure (BP) contributes to the HH pressure to maintain a desired degree of overbalance, preventing an influx of reservoir fluids.

MPD replaces the pressure exerted by static mud weight with dynamic friction pressure to maintain control of the well without losing returns. The objective of the technique is to maintain wellbore pressure between the pore pressure of the highest pressured formation and the fracture pressure of the weakest. This is usually done by drilling with a mud weight whose hydrostatic gradient is less than what is required to balance the highest pore pressure, with the difference made up using dynamic friction while circulating. That sounds quite simple but has been made extremely complicated[16].

The first issue that must be addressed is how to go from static balance to dynamic (circulating) balance without either losing returns or taking a kick. This can be done by gradually reducing pump speed while simultaneously closing a surface choke to increase surface annular pressure until the rig pumps are completely stopped and surface pressure on the annulus is such that the formation "sees" the exact same pressure it saw from ECD while circulating. It has to be taken into consideration that the bottomhole pressure is constant at only one point in the annulus[16].

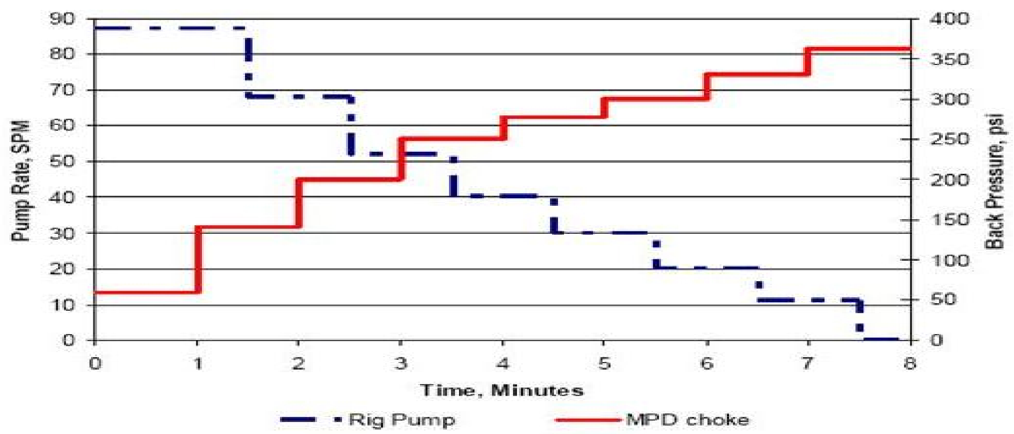


Figure 18 Back Pressure/Pump Speed Curve for Connection[16]

A range of methods have been utilized from to keep bottomhole pressure constant during this transition from dynamic to static (or from static to dynamic). Hydraulics models have been used to calculate a casing pressure schedule to follow while decreasing the pump rate. Computer controlled chokes have been developed that can be employed to automate following the required pressure schedule. Circulating loops have been constructed with dedicated pumps to maintain continuous surface circulation through a choke in an attempt to make it easier to precisely control annular surface pressure. In certain cases a conventional rig pump has been utilized as the dedicated pump giving the added benefit of pump redundancy. Equipment has been developed to maintain continuous circulation through the drill string during connections thus eliminating the transition by eliminating the static situation altogether. With these methods the well is typically never completely shut in, as any required surface pressure is imposed through a partially closed choke[16]. In addition to surface equipments, Malloy[9] emphasized that during drilling, influx is avoided with the increase in annular friction pressure from pumping. During connections, drillers control influx by imposing back pressure or by trapping pressure in the wellbore. At the least, a non return valve (NRV), placed inside the drill string, stops mud flowing up the drillpipe to the surface.

Hannegan[10], emphasizing the importance of CBHP, states that the advantages of this variation of MPD include:

- Less drilling non-productive time
- Enhanced control of the well
- More precise wellbore pressure management
- Increased rate of penetration
- Less invasive mud and cuttings damage to well productivity
- Deeper casing set points
- Fewer mud density changes to total depth objective
- Increased recoverable assets[10]

In an attempt to ensure that any influx can be detected early, a flow meter is often installed as an integral part of the choke manifold in critical CBHP operations. The rig up for a CBHP set-up is shown in Figure 19[15].

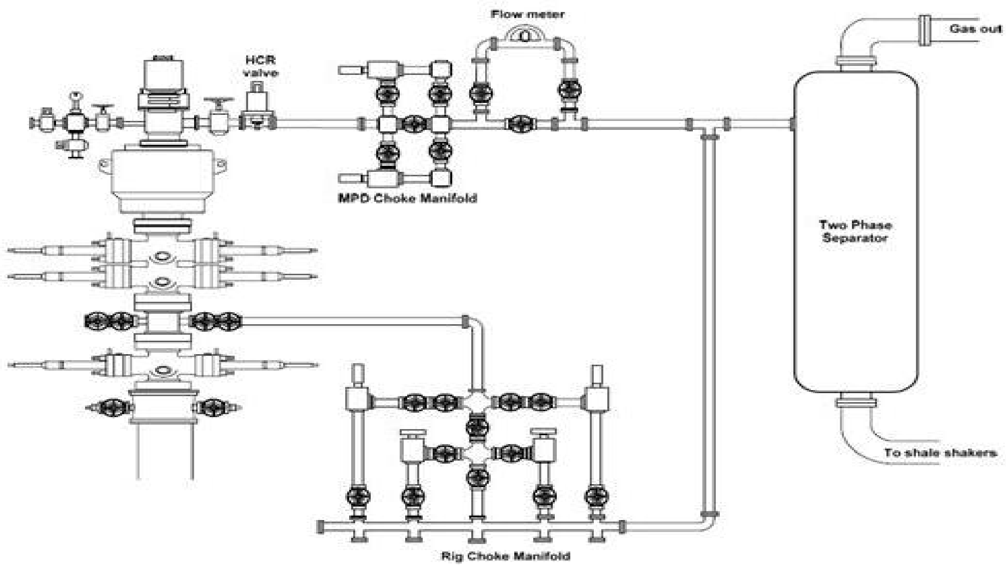


Figure 19 Rig up for CBHP applications[15]

3.1.1 Friction Management

Friction management techniques are used in HPHT or in Extended Reach wells, where the annular pressure is maintained to keep the bottomhole pressure as constant as possible. Hannegan explained that in HPHT wells, this is done by maintaining some kind of annular circulation through the use of a concentric casing string. In ERD wells, the annular pressure loss often needs to be reduced to achieve the required length and reach of the well. This can now be achieved through the use of an annular pump. The pump is placed in the cased section of the well and pumps annular fluid back to surface thus reducing the annular friction pressures. These friction management techniques are considered part of the CBHP variation[15].

3.1.2 Continuous Circulation Systems

Considered under the CBHP variation as well, Hannegan stated that Continuous Circulation Systems technique keeps the ECD constant by not interrupting circulation during drilling operations. The method is used on wells where the annular friction pressure needs to be constant and/or to prevent cuttings settling in extended reach horizontal sections of the wellbore. The circulation can be maintained during connections or other interruptions to drilling progress by using a special circulating BOP system or via continuous circulating subs being added to the drill string[15].

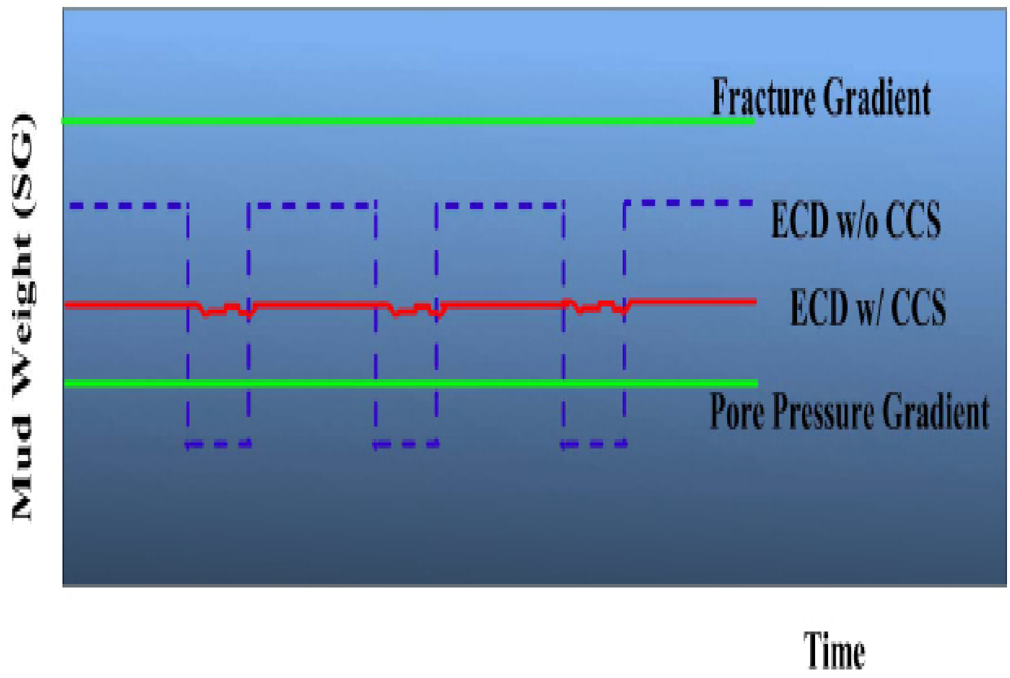


Figure 20 Continuous Circulation System used under CBHP[29]

Figure 20 is an illustration of controlling the BHP without interrupting the circulation by using the advantages of Continuous Circulation Systems. Some slight fluctuations are seen while making up connections. BHP maintained nearly constant by keeping the ECD constant in the same way.

3.2 Mud Cap Drilling (MCD)

3.2.1 Pressurized Mud Cap Drilling (PMCD)

A technique to safely drill with total loss returns, PMCD refers to drilling without returns the surface and with a full annular fluid column maintained above a formation that is taking injected fluid and drilled cuttings. The annular fluid column requires an impressed and observable surface pressure to balance the downhole pressure[5].

Malloy[9] stated that this method also addresses lost circulation issues, but by using two drilling fluids. A heavy, viscous mud is pumped down the backside in the annular space to some height. This “mud cap” serves as an annular barrier, while the driller uses a lighter, less damaging and less expensive fluid to drill into the weak zone.

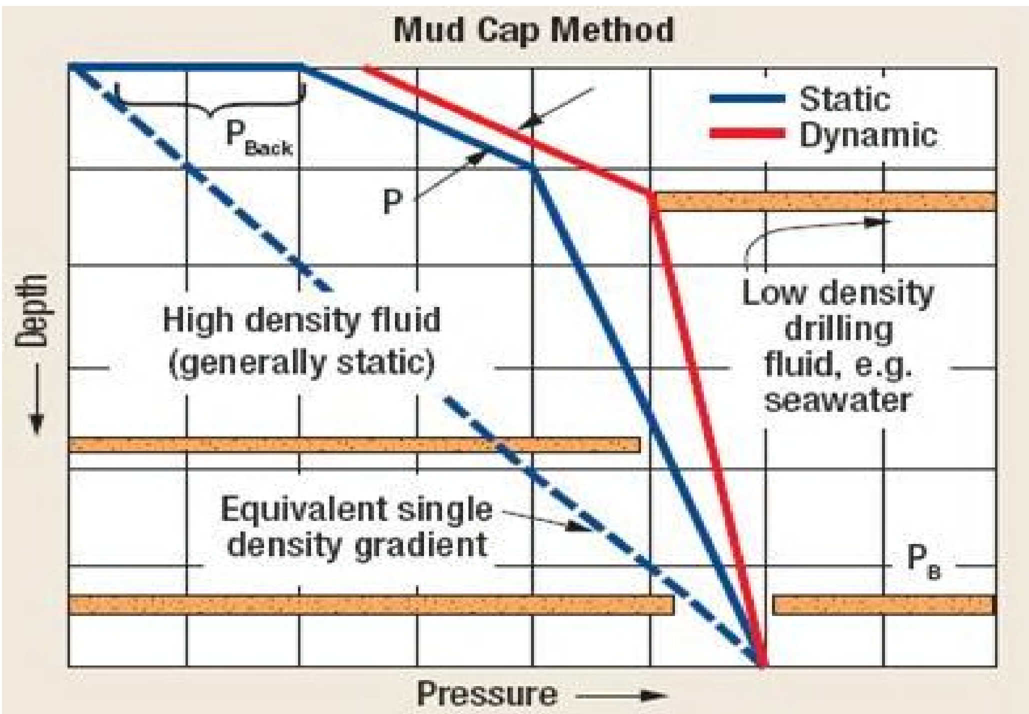


Figure 21 Pressurized Mud Cap Method[9]

The Figure 21 is an illustration of PMCD method. The driller pumps the lightweight scavenger fluid down the drillpipe. After circulating around the bit, the fluid and cuttings are injected into a weak zone uphole below the last casing shoe. The heavy, viscous mud remains in the annulus as a mud cap above the weak zone. The driller can apply optional backpressure if needed to maintain annular pressure control. The lighter drilling fluid improves ROP because of increased hydraulic horsepower and less chip hold-down[9].

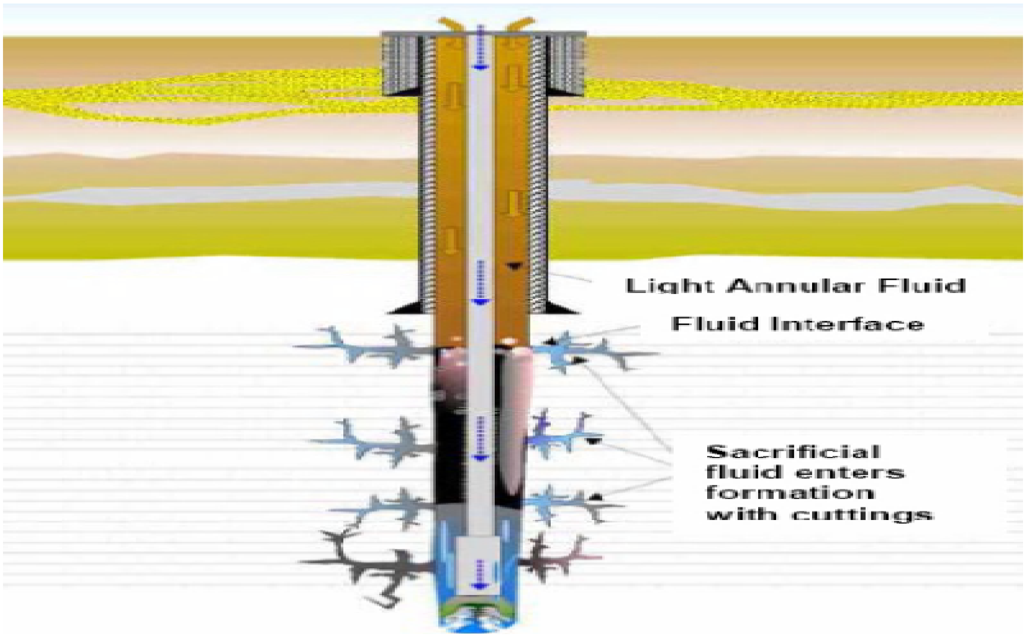


Figure 22 Illustration of how PMCD works[30]

In zones with a proven ability to readily accept mud and cuttings, and where offset wells have indicated depleted pressure; a "cap" of heavy mud is pumped down the backside, into the annulus, where it remains stationary providing the hydrostatic column to control formation fluids. Meanwhile, drilling "blind" with no returns continues with a lighter than conventional drilling fluid. This inexpensive fluid and the cuttings are single-passed into the loss zone[28].

Hannegan[15] suggested that considering the restrictions to use PMCD, total losses must be experienced. The losses must be large enough to take all of the fluids pumped down the drillstring and all of the cuttings generated during the drilling process to use this technique. If circulation, even partial circulation, was to be established, the mud cap would be circulated out of the well. If circulation is possible, a well cannot use the PMCD method, and the CBHP method will have to be used.

In addition, Hannegan[15], unlike the others, proposed that PMCD may be practiced in some situations where a total loss scenario is not encountered, but where total losses can be induced by increasing the wellbore pressure profile. Ultimately, this variation is expected to be used in deep water where heavily depleted old pay zones must be drilled to reach deeper pay zones of virgin pressure. It may allow safe drilling of these zones where the depleted zone above the target has rock characteristics that are capable of receiving the sacrificial fluid and drilled cuttings. The mud cap plus backpressure forces the "returns" into the zone of least resistance, the depleted zone above.

Malloy and McDonald[8] claimed, drawing the industry's attention to tripping, that when the drill pipe is tripped out of the hole a weighted mud slug can either be pumped as a pill to balance the bottomhole pressure to compensate for the loss of backpressure when the bottomhole assembly is out of the hole. Since returns are not normally seen at the surface, the volume of mud required to kill the well sufficiently will be predicated in large part to the gauge of the hole and the proximity of the fractures or wormholes.

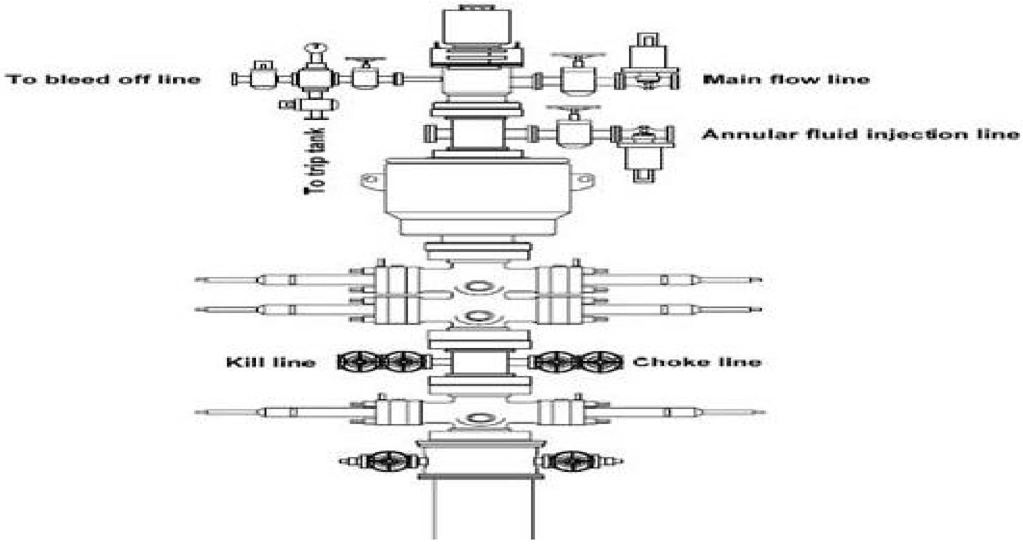


Figure 23 Rig up for Pressurized Mud Cap Drilling Operations[15]

For PMCD operations, a flow spool must be installed below the RCD to allow fluid to be pumped into the annulus. The rig up for this set up is shown in Figure 23-24. The manifold on the left hand side of the RCD is the bleed off manifold that is used to be able to keep the well full from the trip tank. It also allows any pressure to bled off from the stack should this be required when changing RCD packers[15].

Figure 24 Photo of Flow Spool used in PMCD[15]

3.2.1.1 Floating Mud Cap Drilling (FMCD)

Floating mud cap drilling (FMCD) is considered as a sub category of the PMCD technique. FMCD operations are used if the annular fluid cannot be designed to provide surface pressure in the annulus, in which case the mud cap is called floating. In an FMCD operation, sacrificial fluid (normally water) is pumped down the drillpipe, as in PMCD[15].

Malloy and McDonald[8] marked the usage of surface fluctuations to estimate three downhole conditions by taking floating mud cap as the start point, the pressures throughout the wellbore are stable. Once drilling begins again and the hole becomes deeper, assuming that the reservoir pressure will increase with depth, the high density annular mud cap loses its ability to contain the bottomhole pressure by itself. Over time and distance an annular pressure differential between 200 – 300 psi; well below the pressure ratings for RCD tools, is not unremarkable. As the annular pressure becomes higher, the mud cap fluid density is often increased to keep the annular pressure within comfortable limits. Surface pressure fluctuations are used to monitor 3 downhole conditions:

- ➢ Gas migration to the annulus
    - ✓ Produced fluid is injected back into the formation at a prescribed rate and volume
- ➢ Pore pressure increase
    - ✓ Annular hydrostatic fluid density is increased to maintain the surface pressure within a comfortable range
- ➢ Fracture plugging
    - ✓ Should the cuttings plug off the fractures, pressurized mud cap may have to be suspended in favor of conventional drilling operations.

On the other hand Hannegan[15] stresses, considering difficulties while monitoring mud level in the annulus that the pressure of the reservoir can be below hydrostatic so that the annulus cannot be kept full of fluid. The annulus fluid level will drop down to a balance point in the well. The top of the fluid in the well may be too deep to monitor and this will make it very difficult to monitor any influx or gas migration. The FMCD method is in effect drilling blind and there is only limited annular pressure control.

By allowing pressure monitoring along the drillstring, thus providing enhanced well control options, some new technology such as wired drillpipe may unlock FMCD techniques. Fluid technologies using lightweight solid additives such as glass beads are also being considered to achieve mud cap operations when drilling sub-hydrostatically pressured reservoirs[15].

Floating Mud Cap Drilling differs from the PMCD as the name "Floating" is an explanation of dynamically balanced condition. Since there are two opposite ways of spoiling the balanced system, the balance can be maintained either increasing or decreasing the pressure of the mud cap. The first one can be maintained by increasing the density of mud cap or applying back pressure. The second can be managed by decreasing the density of mud cap or using a downhole pressure-boost tool (in case of surface equipment limitations) to increase ECD.

3.2.1.2 Controlled Mud Cap Drilling (CMCD)

The Controlled Mud Cap Drilling (CMCD) method is officially called Pressurized Mud Cap Drilling (PMCD). Although there are some important differences between them, comparing the equipments mostly designed for offshore purposes and applicable without losses in CMCD, IADC and SPE have both adopted this label for this variation of MPD.

As cited in Grottheim's study[31], another method that uses pumps below sea level to bring the returns to the surface is the Low Riser Return and Mud-Lift System (LRRS). There are similarities between LRRS and SMD, but there are also major differences. The principle behind LRRS is to use a smaller high pressures riser combined with surface and subsea BOPs. A mud cap situation is created, where the mud level in the riser can be adjusted with the pump, by connecting a subsea pump to the riser below sea level and taking returns from the lower parts of the riser. See Figure 25.

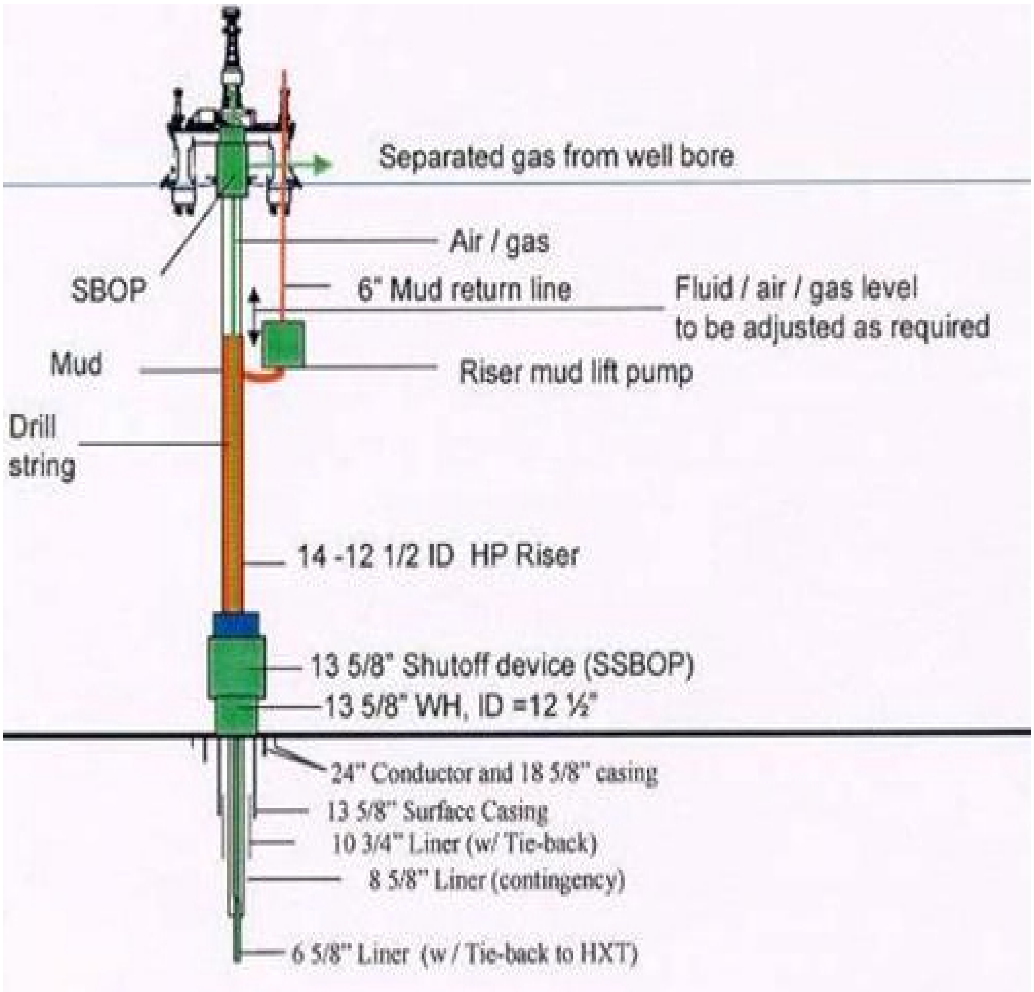


Figure 25 CMCD Low Riser Return and Mud-Lift System[31]

Fossil and Sungesland[32] further explained that the subsea BOP will contain a ram configuration with pipe and shear rams for safe disconnect and reconnect of the riser. The surface BOP will contain a Rotating Control Device (RCD) and an annular BOP. At a pre-determined depth between surface and sea bed, a specially designed instrumented riser joint is placed so that the return fluids can be drawn from the main drilling riser into a separate return line where a submerged drilling fluid pump (mud lift) system is located at approximately the same depth as the outlet from the drilling riser. The low riser return (LRR) joint also contains high pressure valves to isolate the pump system from the drilling riser, in addition to pressure sensors at different intervals to accurately determine the mud level inside the drilling riser. In the mud lift return system running back to the drilling unit there is a separate line parallel to the return line which is coupled to the mud suction line running from the drilling riser to the subsea mud lift pumps, for filling and fluid level control within the drilling riser. The actual drilling fluid level will be actively controlled within the riser (controlled mud cap) by the subsea pump system. Figure 26 is a comparison of both LRRS and conventional riser system.

As cited in Grottheim's study, conventional pressure control involves adjusting the mud weight of the system to increase the hydrostatic pressure in the well, as well as controlling the friction pressures. The Deep Ocean Riser System with a Low Riser Return System (DORS w/ LRRS) is able to adjust the mud level in the high-pressure riser, thus adjusting the bottomhole pressure accordingly[31]. This new mud level control system is an advance form of the one discussed in the FMCD method. One of the differences is that the mud cap is pressurized instead of floating- this is why IADC refer this method as a PMCD. The other difference is being able to use air or gas in the riser while controlling BHP, in addition to PMCD which uses only mud in riser.

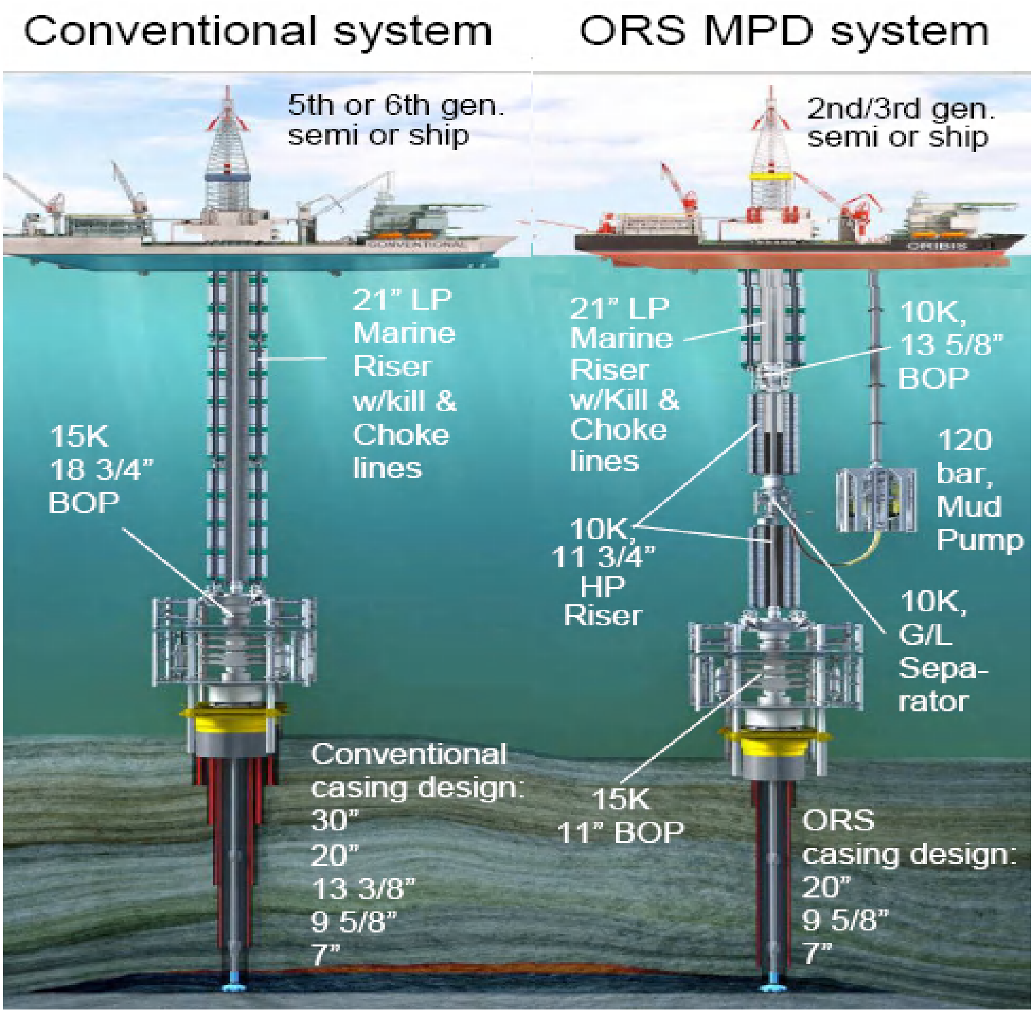


Figure 26 Conventional Riser System vs. CMCD system[33]

The advantages of the Controlled Mud Cap (CMC) method as cited in Grottheim's study[31] are given below.

- During conventional drilling in ultra deep water it is impossible to achieve a riser margin. On the contrary, the LRRS even makes it possible to drill ultra deep water well underbalanced, and still have a riser margin. This is beneficial in that an emergency disconnect would actually increase the bottomhole pressure of the well, and help minimize the consequences of the blowing formation fluids.

- As the top part of the riser will be filled with air and gas, this portion of the riser will act as gas knock-out separator due to the low pressures. The use of heavier mud at a lower level in the riser will in fact reduce the pressure at the mudline. Hydration formation is dependent on temperature and pressure, and because of this pressure reduction, the probabilities of hydrates forming are reduced.

- Well control with this system is greatly improved compared to conventional riser drilling. The use of heavier drilling fluid with a lower level in the riser enables kicks to be circulated out of the well without experiencing added frictional pressures. There are no choke or kill lines, and the annulus between the drillpipe and the riser will act as the return path for the fluids.

- Many conventional kick indicators are still valid. Kick detection is improved, however, due to fact that formation flow will affect the pump speed, much like in Subsea Mudlift Drilling. Additionally, the mud level in the riser will be monitored, and it will in fact serve as a very accurate trip tank when pumps are shut off, and flow can be detected easier than in a conventional scenario. After a kick has been detected, there is no need to wait for fluids to be weighted up to kill the well. An almost instantaneous increase of the mud level in the riser will bring the hydrostatic pressure into overbalance, and the flow is arrested. Since the well has been killed, the influx can be circulated out of the well in a manner similar to conventional circulation methods.

3.3 Dual Gradient Drilling (DGD)

Through managing ECD in deepwater marine drilling, Dual Gradient Drilling (DG) is the general term for a number of different approaches to control the up-hole annular pressure[5]. DG has been utilized successfully in primarily offshore applications, where water provides a significant portion of the overburden[8]. Since this liquid overburden is less dense that the typical formation overburden, the drilling window is small because the margin between pore pressure and fracture pressure is narrow. Because of the weak formation strength, deepwater conventional drilling applications usually require multiple casing strings to avoid severe lost circulation at shallow depths using single density drilling fluids[8,9]. In order to reduce the effect of deep water overburden, drilling system should be balanced by reducing mud density in the upper parts of marine riser or filling the marine riser with sea water or dividing the system at the sea bed into two parts.

The intent of the dual-gradient variation is to mimic the saltwater overburden with a lighter-density fluid. Through injecting less-dense media, such as inert gas, plastic pellets or glass beads, into the drilling fluid within the marine riser, drillers can accomplish bottomhole pressure adjustment. Another method is to fill the marine riser with salt water, while diverting and pumping the mud and cuttings from the seabed floor to the surface[9]. In this case, the drilling riser may be filled with seawater to prevent collapse. The intent is not to reduce the EMW or effective BHP to a point less than formation pore pressure. Instead, the intent is most often to avoid gross overbalance and not exceed the fracture gradient[14].

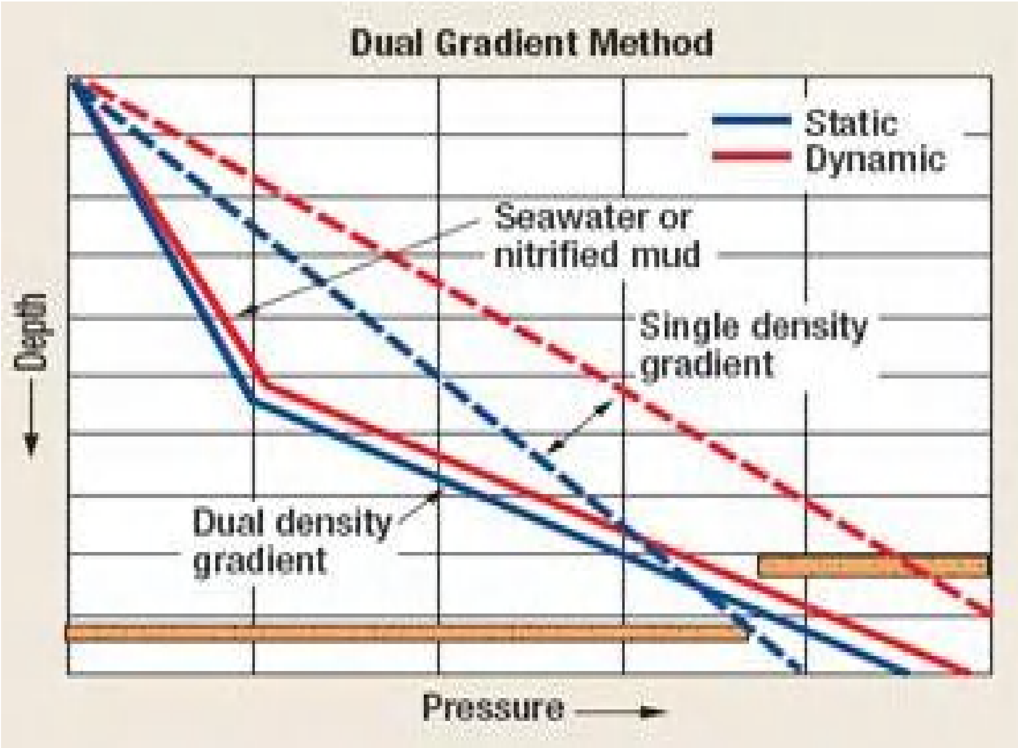


Figure 27 Dual Gradient Method Pressure Profile[9]

Figure 27 is an illustration of comparison of pressure profiles between dual gradient method and the conventional method. Especially in deep water where fracture pressure is one of the limitation, by changing the system from conventional to dual gradient, the risk of fracturing the weak zones is reduced in dynamic condition.

Both of these methods alter the fluid density near the mud line. Two different fluids produce the overall hydrostatic pressure in the wellbore, which avoids exceeding the fracture gradient and breaking down the formation. This saves drilling operations from spending NPT addressing lost circulation issues and associated costs[9]. This form of MPD can be practiced with or without a subsea RCD, although there are advantages of having the subsea RCD (Forrest et al. 2001). In the case of gas injection into the riser, a surface RCD must be run[14].

3.3.1 Injecting Less Dense Media Method

As the Dual Density Drilling is a technique commonly used in deep water offshore, one of the common methods used in the industry is aerating the mud. In order to protect shallow unconsolidated sands, the fluid in the annulus from the sea floor to the pitcher nipple is aerated to reduce the hydrostatic, allowing higher mud weights to control deeper pressures without lost circulation at shallow depths. Land rigs rarely face this sort of problem, but occasionally there is a case where a shallow weak formation may be protected by aerating the mud above it while using weighted mud below[28].

Another method used in DG to reduce the hydrostatic is Nitrogen Injection. A predetermined quantity of nitrogen is injected at some predetermined depth into the casing or marine riser. The mud gradient is determined by gas, mud, and cuttings from the injection point to the surface. Below the injection point, only mud and cuttings determine the gradient; thus the term dual-gradient. This technique is helpful as a means of adjusting the effective bottomhole pressure without having to change base fluid density and with fewer interruptions to drilling ahead, usually to avoid lost circulation in a thief zone or to minimize differential sticking of the drillstring. Nitrogen may be injected by concentric casing, concentric riser, and parasite line or, on fourth or fifth- generation deepwater rigs, by way of the rig's existing booster pump and line. In order for this system to work, the pressures must be carefully managed with attention to the circulating pressure at the shoe as well as at TD. In some cases, a rotating head is used to impart additional pressure on the system to prevent flow and this, used in conjunction with injected air (or nitrogen), allows for a very precise control over what the formation actually sees[28].

Hannegan stated the origin of the method by expressing that nitrogen injection is based on air drilling procedures and underbalanced drilling techniques. This technique uses nitrogen to reduce the weight of the mud in the riser. A detailed explanation as it is cited in Elieff's study[34] would be that in an effort to reduce the amount of nitrogen required to lower the mud pressure gradient in the riser, a concentric riser system is considered the most economical. In this system a casing string is placed inside the riser with a rotating BOP at the top of the riser (in the moon pool) to control the returning flow. The mud is held in the annulus between the casing string and the riser, and nitrogen is injected at the bottom of the riser into the annulus. Buoyancy causes the nitrogen to flow up the annulus which reduces the density and pressure gradient of the drilling fluid as a result of nitrogen's liquid holdup properties. The injection of nitrogen can reduce the weight of a 16.2 ppg mud to 6.9 ppg. This is can be applied when the second gradient is desired to be even lower than that of seawater, which has a typical pressure gradient of 8.55 ppg.

The most noteworthy characteristic about this method of using nitrogen injection to create two gradients is that the formation is not underbalanced, as one might initially conclude. The cased hole is underbalanced to a depth, but below the casing, in the open hole, the wellbore is actually overbalanced, which prevent an influx of fluids from the formation into the wellbore. One serious concern with this method of creating a dual density system is the uncertainty as to whether or not well control and kick recognition will be more difficult. In this case, the system is very dynamic and well control and kick detection are definitely more complex, however, not necessarily unsafe[34].

Another method of creating a dual gradient system is similar to that of the nitrogen injection. A Department of Energy (DOE) project was done to test how the injection of hollow spheres into the mud returning through the riser can create a dual gradient system. This system is similar to the nitrogen injection method, but separating the gas from the mud at the rig floor is simplified because dissolved gas in the drilling fluid is not a concern. The glass spheres are separated from the mud and re-injected at the base of the riser[34].

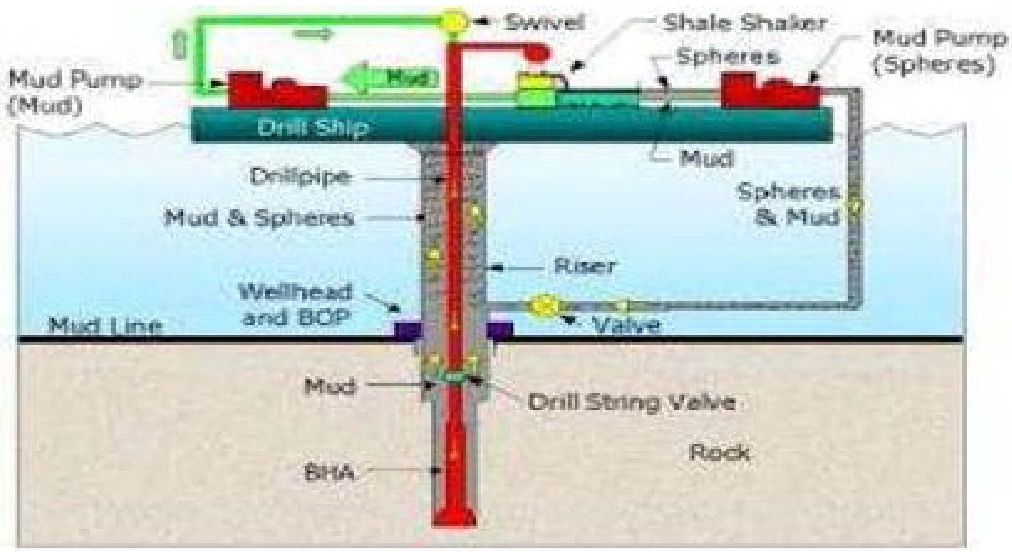


Figure 28 Illustration of Hollow Sphere Injection in DG[34]

3.3.2 Subsea Mudlift Drilling (SMD)

Another method of creating a dual gradient system is to begin by drilling the upper portions of the well without a riser and by simply returning the drilling mud to the sea floor. In this setup the pressure inside the wellbore at the seafloor is the same as the pressure at the sea floor. In other words the pressure gradient from the ocean surface to the sea floor is that of the seawater pressure gradient. Then, inside the wellbore a heavier than typical mud is used to maintain proper pressures while drilling[34].

Once the initial spudding has taken place and the structural pipe has been set, the subsea BOP stack is installed with some variation on a typical system. The mud returns are moved, from the wellhead by a rotating diverter, to a subsea pump which returns the mud to the rig floor through a 6” ID return line. Drilling continues with this setup and the remaining casing strings are set using this dual gradient system where mud returns, to the rig, through a separate line[34].

As it is cited in Grottheim’s study[31], another system creating DG which has been proven in field tests is the Subsea Mudlift Drilling (SMD) system. This system achieves dual-gradients through the use of pumps at the seafloor which circulate the fluids and cuttings back to the surface through a small diameter return line (RL). By letting the inlet pressure of the subsea pumps equal the hydrostatic pressure of seawater at the mudline, a heavier mud can be circulated downhole to stay in the window between pore and fracture pressure for a greater depth interval compared to conventional riser drilling.

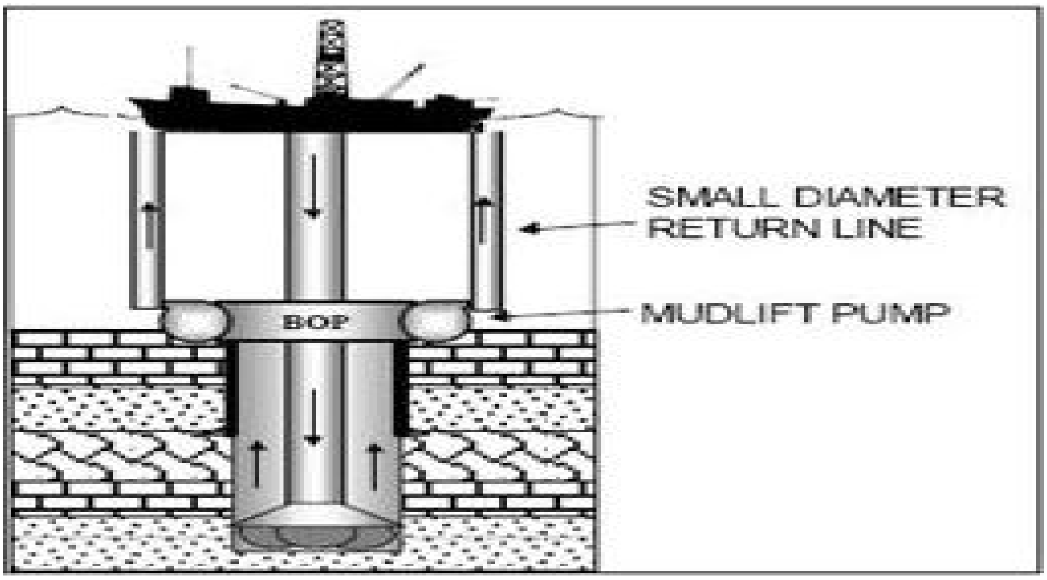


Figure 29 Subsea Mudlift Drilling (SMD) DG system[31]

3.4 Return Flow Control (RFC) / HSE Method

For the reason that we are tooling up to securely and more efficiently react to any downhole surprises, RFC can be regarded as an crucial part of the MPD definition in spite of the fact that technique does not control any annular pressure. In Hannegans's point of view, we also positively divert annulus returns away from the rig floor, to prevent any gas, including and especially H_2S from spilling onto the rig floor. It is used as a safety measure. If an influx is taken whilst drilling the well, or trip gas or connection gas spills onto the rig floor, the flow line to the shakers is closed and flow is immediately diverted to the rig choke manifold, where the influx is safely controlled and circulated out of the hole. The use of the rotating control device (RCD) avoids the need for the closing of the BOP minimizes the potential for hydrocarbon release onto the drill floor, and it allows pipe movement whilst circulating out an influx or dealing with gas cut mud[15].

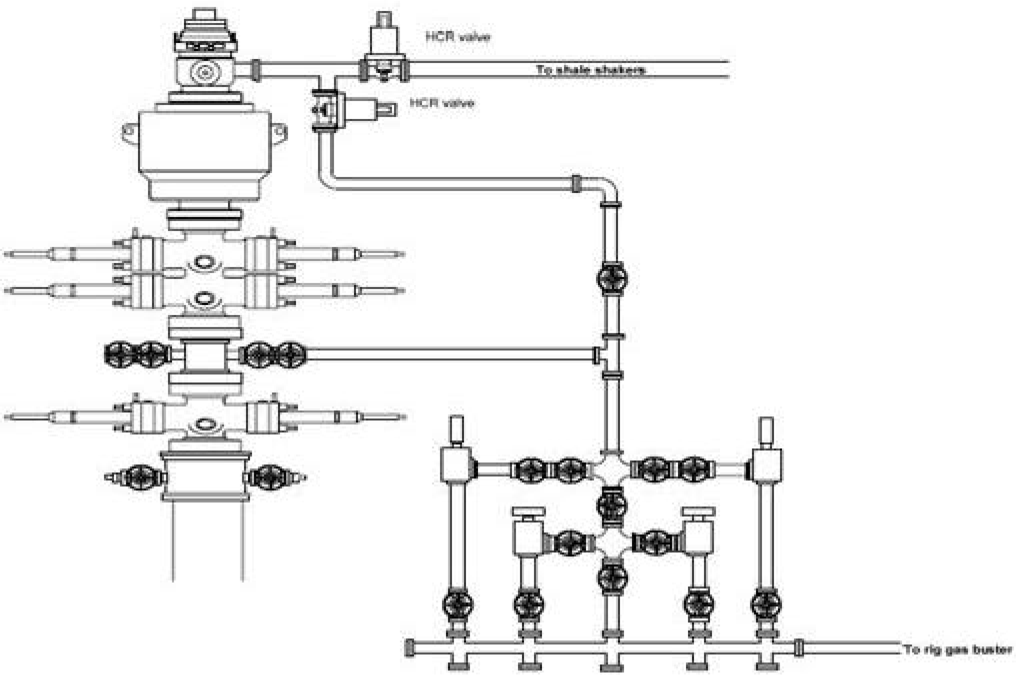


Figure 30 MPD rig up for Return Flow Control[15]

For RFC operations, two hydraulic valves, a conventional flow line to the shakers and a flow line to the rig choke manifold are installed. This allows any influx to be handled by the rig choke manifold and in normal operations the conventional flow line is used to circulate fluids. Fig 31 provides an overview of the rig up. The hydraulically operated valves allow the flow of returns to be diverted to the rig choke manifold or to the shale shakers[15].

Figure 31 Photo of Rig Gas Booster[15]

The objective is to drill with a closed annulus return system for HSE reasons only. For example, a conventional production platform drilling operation with an open-to-atmosphere system may allow explosive vapors to escape from drilled cuttings and trigger atmospheric monitors and/or automatically shut down production elsewhere on the platform. Other applications of this variation include toxicological ramifications of drilling with fluids emitting harmful vapors onto the rig floor, as a precaution wherever there is a risk of a shallow-gas hazards, and when drilling in populated areas. Typically only an RCD is added to the drilling operation to accomplish this variation[14].

3.5 Intentions of the Variations

In order to understand the usage of MPD, it is important to appreciate the purposes of the variations of MPD. Although the variations are introduced with specifically different purposes, subcategories of the variations can be used in different goals in addition to their primary aim. Therefore, the industry has some misapprehension about the MPD. That is the reason why some authors feel the need to express the intent of the variations.

Accordingly, Hannegan[1] stated that there is often some initial confusion about what constitutes MPD. The reason is there are a number of variations in the technology – four primary and several subcategories. These variations must be understood in context of the type of nonproductive drilling time each is intended to address.
If the challenge is a narrow or a relatively unknown drilling window, constant bottomhole pressure (CBHP) MPD is used. This variation includes two subcategories – friction management, used in HPHT or extended-reach wells, and continuous circulation methods for wells where the annular friction pressure must be constant and to prevent cuttings settling in extended-reach horizontal wellbore sections. CBHP MPD is uniquely applicable for subsalt and other drilling prospects where formation and fracture pressures are a relative unknown.

Pressurized mud cap drilling (PMCD) is the most common MPD method used in Asia Pacific. It is used to control wells that experience, or have a likelihood of, total losses and kicks in the same wellbore. To use this technique, the losses must be large enough to take all of the fluids pumped down the drillstring and all of the cuttings generated during the drilling process. If even partial circulation is possible, the CBHP method should be used instead.

Ultimately, this variation is expected to be used in deepwater where heavily depleted old pay zones must be drilled to reach deeper pay zones of virgin pressure[1].

The dual gradient (DG) concept is most applicable to deepwater drilling because all but the most robust of pay zones would be grossly overbalanced from the tall column of heavy mud and cuttings in a marine riser. Hydraulically speaking, true DG (with a subsea BOP and marine riser system) tricks the wellbore into thinking the rig is closer by a means of subsea artificial lift, typically via subsea pumps or an injection of lighter liquids or gas in the annulus returns path. Riserless mud recovery is another application of DG technology showing great promise. The use of subsea RCDs is required in the former and advisable in some of the latter DG methods[1].

HSE or returns flow control (RFC) techniques are a crucial part of MPD that proficiently diverts annulus returns away from the rig floor, where annular pressure control is not the objective. If the insurance underwriter requires a RCD on location for HSE reasons only, the technique to consider is the HSE variation. The RFC system minimizes unnecessary operations of the BOP, provides assurance in presence of shallow geohazards, and allows pipe movement while circulating out tight-gas influx or dealing with gas-cut mud[1].

3.6 Promising Concepts Mentioned under MPD

3.6.1 Continuous Circulating Concentric Casing MPD

Continuous Circulating Concentric Casing MDP is a key example of combining MPD techniques and DHM technologies. The method will become more popular after proving its ability to control pressures in a more accurate way and mitigate drilling hazards.

Hannegan[14] stated, targeting at the stable annular frictional losses, that this process involves more precise and almost instantaneous BHP management by using hydraulic friction control on the return annulus through continuous annular fluid circulation. The bottomhole AFP is manipulated into seeing a more steady-state condition by pumping additional volumes of drilling fluid through a concentric casing or drillstring. By increasing the annular fluid rate down the concentric casing during connections by a volume equal to the normal standpipe rate, the downhole environment in the wellbore sees a more constant AFP. With this method, Pressure spikes typically associated with making jointed pipe connections may be eliminated or reduced significantly.

The authors[18] advised considering the other advantage of the system as synergistic to MPD and UBD is one-trip casing drilling technology that may address the requirement to avoid pulsating the fragile and frozen wellbore unnecessarily. Robust casing could be one-trip set and cemented to a sufficiently deep depth to minimize the risk of seafloor collapse from the thermal, pressure, or chemical quasi-mining process of producing the methane hydrates over time. DwC may also enable drilling with a less expensive floating rig because of reduced weight of casing.

3.6.2 Riserless MPD

Riserless MPD in short is *riserless pumping and dumping* with subsea well control. A subsea rotating device is used when establishing a subsea location via riserless drilling with seawater or other fluids compatible to be discharged onto the seafloor. Hannegan emphasized both pressure control and economics of floating rigs by clarifying that the purpose of the technique typically is to establish deepwater locations by batch drilling, because there is no marine riser and subsea BOP to buoy, smaller and less expensive rigs can be used to establish locations in water depths greater than those for which the rig was originally intended. A remotely operated vehicle (ROV) or subsea automatic choke adjusts BP at the flow line outlet of the subsea RCD. Closing the subsea choke increases BHP, virtually as if the subsea location were being drilled with a marine riser filled with mud and cuttings. As a result, a degree of overbalance greater than the drilling fluid would impart and beneficial for subsea well control in the presence of shallow water flow or shallow gas hazards. Fig. 32 is an illustration of the effect of subsea back pressure[14].

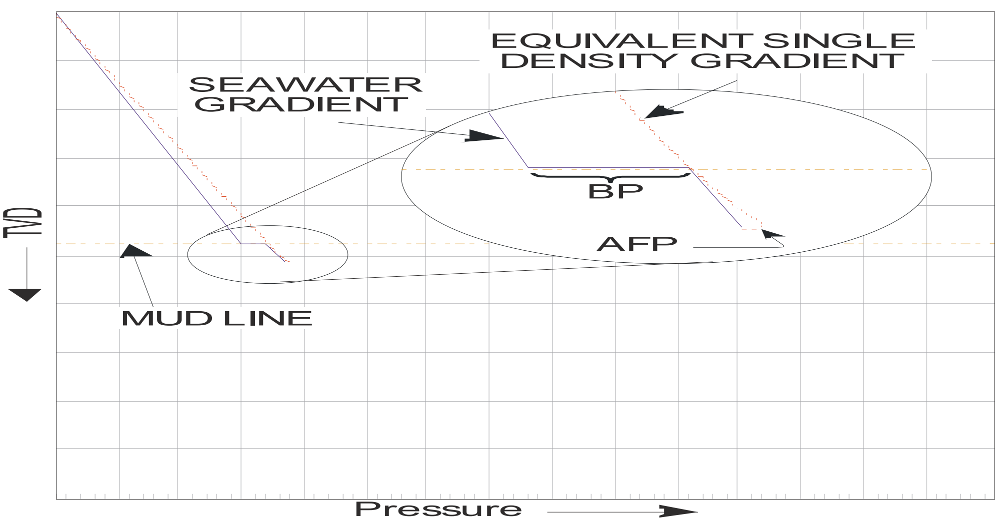


Figure 32 Pressure Profile of Riserless MPD[14]

3.6.3 Dual Gradient Riserless Drilling

Hannegan explained a combination of riserless system with one of the MPD variations, also known as *riserless mud recovery.* For analysis and proper handling, a subsea pump returns mud and cuttings to the rig. Effective BHP may be adjusted via subsea annulus BP and speed of both the rig and subsea pump(s). See Fig. 33[14].

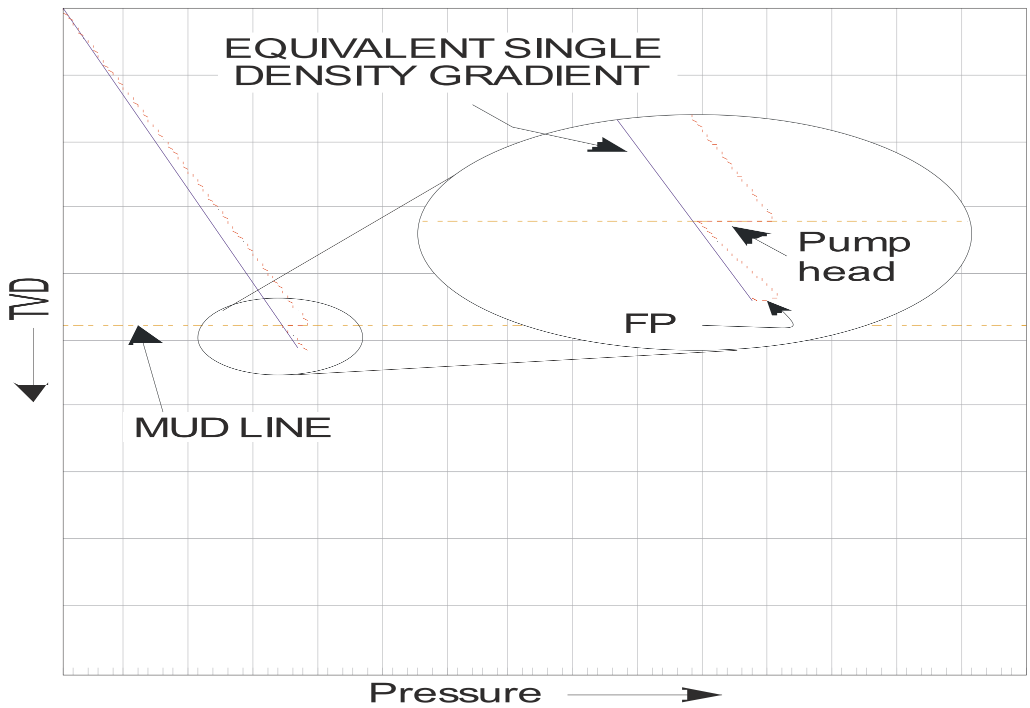


Figure 33 Pressure Profile of Dual Gradient Riserless Drilling[14]

Figure 33 is an illustration of variation of pressure profiles with the usage of subsea pump in dual gradient riserless drilling. Annular frictional pressure losses in the riserless system are smaller than the losses in marine risers systems. The intent of the system is accurate control of BHP by using the subsea pump. With a subsea pump, Equivalent Circulating Density (ECD) or Annular Friction Losses (AFL) is reduced.

3.6.4 Deepwater Surface BOP Application of MPD

The initial purpose of drilling from a moored semisubmersible or dynamically positioned drillship with a surface BOP was to enable wells to be drilled in water depths greater than the depth rating of the rig when using a subsea BOP stack. However, drilling with a surface BOP enables many of the same MPD technologies otherwise available only to fixed rigs to be exploited in deep water. High pressure and usually smaller-diameter casing serves as the marine riser[14].

Surface BOP applications are one of the ways of adapting MPD techniques to the deep water prospects. Surface BOP stacks allow the usage of back pressure which is the exploited strength of MPD; however, there are limitations in offshore operations especially in deep water wells since some of the challenges cannot be controllable, such as wave loadings on the floating vessel. Especially in heavy seas, the wave forces can be reduced by using a moored semisubmersibles or dynamically positioned drillships up to a point. High pressure and smaller diameter casing usage as a marine riser is not possible since the wave heave forces are one of the limitations. Therefore, the usage of MPD especially in heavy seas is limited depending on the technology available. There are two important technology gaps of using MPD in deep water prospects due to harsh weather conditions. The first one is, while applying back pressure if emergency disconnect is needed, there is no other way of compensating the surface back pressure- which will be discussed in the case study chapter. The second one is, BHP fluctuations caused by rig heave movement while applying surface back pressure.

According to Fossil and Sangesland[32], particularly in harsh environment with considerable rig movement (heave), the pressure transients created by rig heave can affect the downhole pressure control. This effect will particularly come into play every time slips are set on the drillpipe, for example during a pipe connection. In theory it will be possible to compensate for the surge and swab effect with the pump system. However in practical terms it will be difficult to compensate for the entire surge/swab effect due to rig heave. It will depend on the amplitude and frequency of the rig movement and the capacity of the subsea pumps.

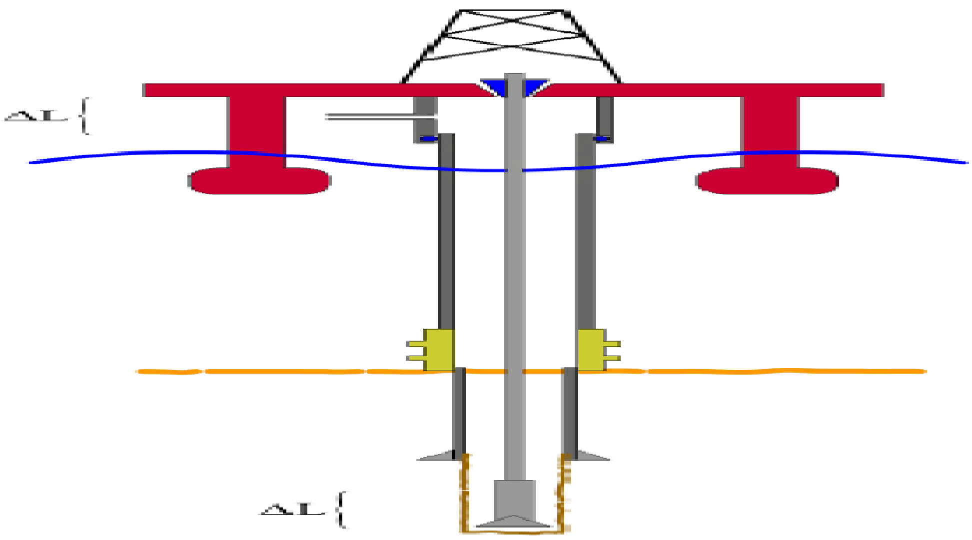


Figure 34 Heave Movement of Platform due to Wave Loadings[29]

Figure 34 is an illustration of heave movement of a floating drilling platform. The magnitude of upward movement of the rig can be compensated by the automated systems that are capable of adjusting the pipe movement speed. However, when the string is on the slip, the drilling string becomes a part of the platform so the effect of the wave loading is directed to the string. This is also a problem for DP drillships since the position can be kept only in the parallel plane to the sea floor. That is one of the reasons for developing more stable platforms or using moored platforms.

Amplitude ±(m)	Period (sec)	Max Velocity ±(m/s)	Surge/swab pressures ±(bar)
0.5	11	0.29	10.18
1.0	14	0.45	14.00
1.5	11	0.86	24.32
3.0	13	1.45	55.63

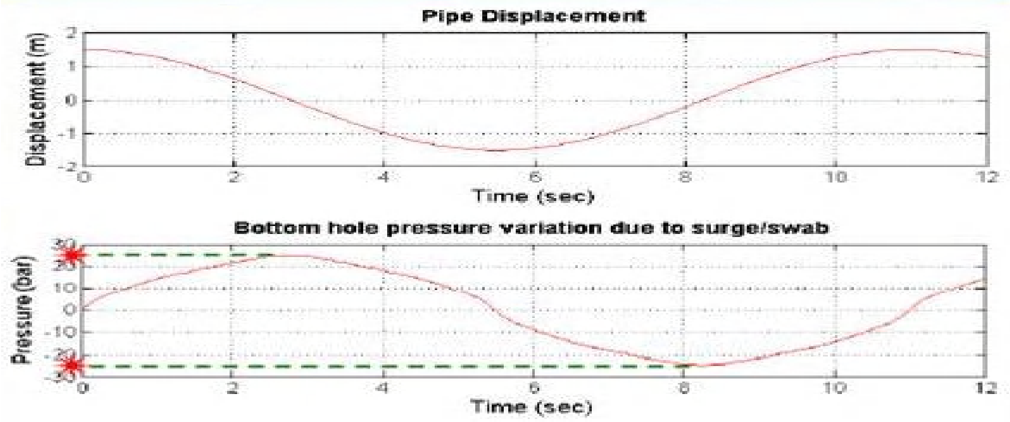


Figure 35 BHP variations due to wave heave movement[29]

Figure 35 is an illustration of BHP variations due to the wave loadings which is taken from the study of Sangesland[29]. Pipe movement induced pressures are defined as surge and swab pressures which are functions of time. Therefore, heave amplitude and wave period are the variables which determine the velocity of the pipe movement in both upward and downward directions. In order to clarify 1.5 meter change in amplitude in a period of 11 seconds results from BHP change with an amount of 24 bars, this means nearly 350 psi. Although one of the intents for using MPD is managing pressures accurately, especially in tight/narrow margins, such a considerable amount of change in pressures should be prevented in order to eliminate a technology gap for further MPD applications in ultra deep waters where mooring is not possible. Indeed, Through Tubing Drilling (TTD) and Coiled Tubing Drilling (CTD) applications on floating rigs are the promising available ways to reduce the effect of wave heave.

3.6.5 Downhole Pumping MPD

A newly emerging variation of MPD is through the use of a drilling-fluid-powered pump in the drillstring and within the casing that adds energy to the annulus fluid returns. Diminishing or eliminating the impact of the friction pressures on the BHP, such an *ECD reduction tool* has the effect of creating a important change in differential pressure at the point of the pump[14]. See Fig. 36.

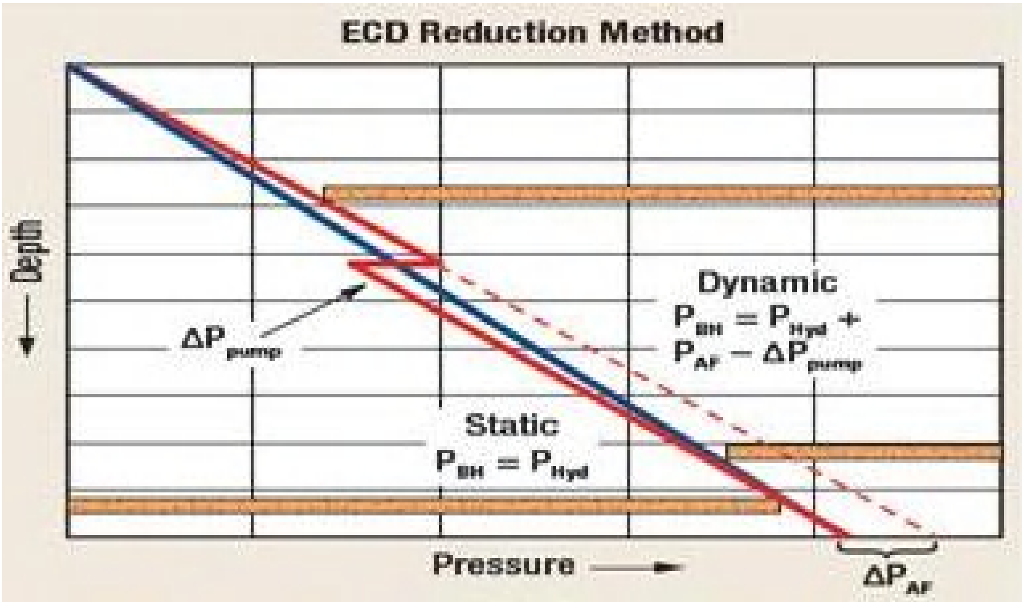


Figure 36 Downhole Pump usage in MPD[9]

Figure 36 is an illustration of the usage of downhole pumps while controlling the downhole pressure profile. The pump can be used to eliminate the narrow drilling window in the sections where the upper pressure boundary is fracture gradient of the previously drilled section and the lower pressure boundary is pore pressure of formation to be drilled or already being drilled. Ideally, the reduction of the pressure at the pump is equal to the annular frictional losses so the BHP is to be maintained to be constant.

3.6.6 Hydraulic Flow Modeling and Process Control Computers

Hannegan[14] emphasized, considering the proven use of process-control computers that process industries (e.g., chemical, refineries, pulp and paper) have benefited from the use of closed and pressurizable systems for many decades. Today, few are found to be operating those systems without the aid of process-control computers. The results such as greatly improved safety, more consistent product quality, reduction of waste, lower energy consumption, and a more positive environmental impact have been observed.

Hannegan also mentioned the idea of corrections in the measurements that the closed-loop characteristics of MPD have enabled the development of a technology that enables time- and temperature-corrected mass balance accuracy of measurement and analysis of flow and pressure profile data. The technology enables control of the circulating-fluids system with process-industries capability. Very small amounts of fluids influx and mud losses are detected, allowing the actual, not predicted, drilling window to be revealed and responded to safely, efficiently, and typically with less NPT[14].

Two of the most practiced technologies in the field have proven their strengths of controlling the pressure profiles are Dynamic Annular Pressure Control (DAPC) and Micro Flux Control, which belongs to two of the major companies in the oil industry. Although the systems are functioning in the same way in general, there are some differences depending on their abilities and their rig set up.

3.6.6.1 Dynamic Annular Pressure Control (DAPC)

As the overview of the system is described in the study of Chustz et al., to uphold the desired BHP set point or ECD, the DAPC system is a fully automated backpressure control system that uses a hydraulics model running in real time. The set point is entered into the DAPC system along with drilling assembly, well geometry, mud properties, planned directional data and temperature. In real time, the model calculates BHP as changes occur, and updates are received for bit depth, drill string revolution (rpm) and pump flow rate (gpm). A proprietary process calibrates the hydraulics model if downhole pressures while drilling data are available for MWD tools[35].

The working basics of the system are introduced as the DAPC system relies on a RCD to seal and allows pressurization of the wellbore annulus. Drilling returns are diverted by the RCD and routed into a choke manifold independent of the rig BOP. The MPD choke manifold imposes backpressure of the annulus during connections and trips to replace the friction pressure component of ECD. The backpressure pump energizes the annular fluid and more precisely controls the applied pressure. Applied by the choke to maintain the desired bottomhole pressure, a computerized system establishes the required backpressure set point[35].

Chustz et al. stated the three major pieces of equipment that DAPC system consisted of as: a choke manifold, a backpressure pump, and an Integrated Pressure Manager (IPM). The choke manifold makes continuous backpressure adjustments to maintain the BHP at the programmed set point, under the control of the IPM. By using continuous flow into the choke manifold from the backpressure pump while the rig pumps are off, precise BHP control is accomplished[36]. Figure is an illustration of rig up for DAPC system.

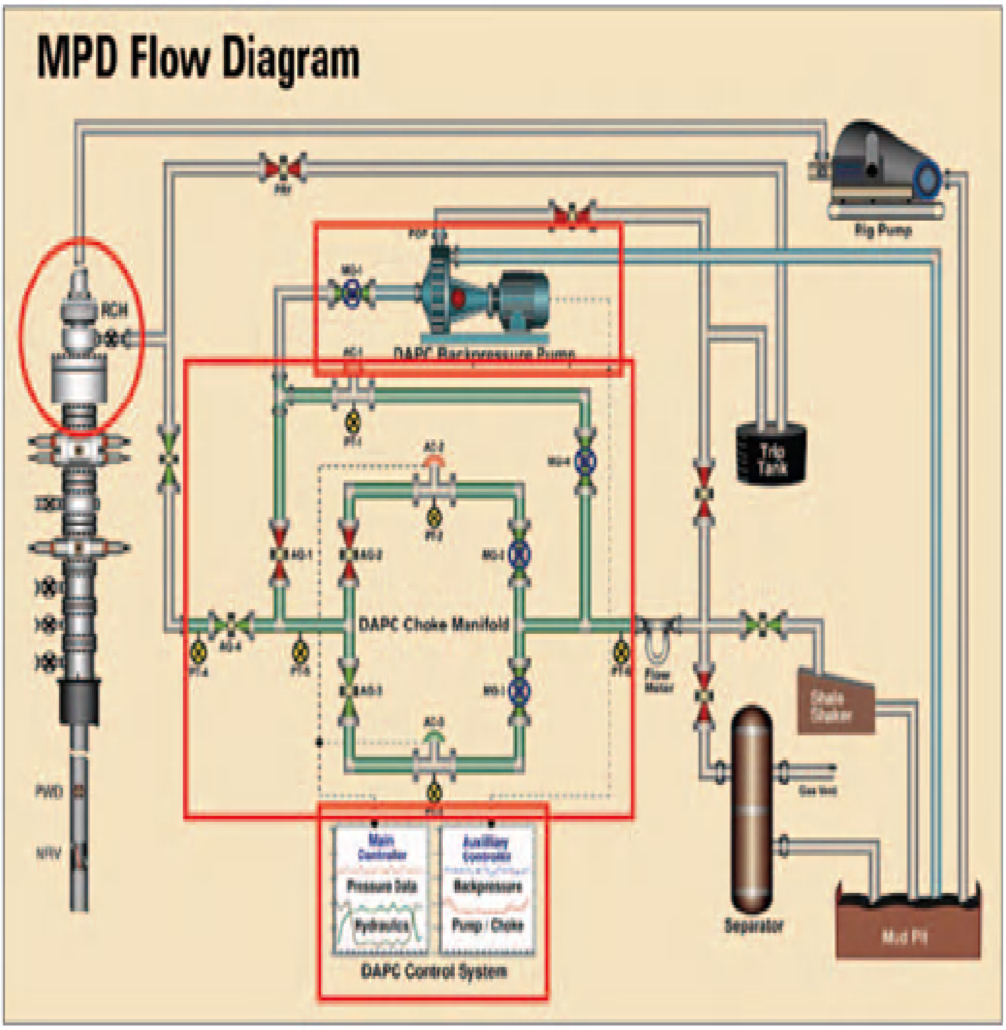


Figure 37 MPD Flow Diagram of DAPC[35]

The DAPC choke manifold consisted of two primary 4" hydraulic choke legs and one 2" secondary hydraulic choke leg. Under normal operation only one primary choke is active, with the other acting as backup. The backup 4" choke leg was programmed for static high-level pressure relief to protect the wellbore against over pressure events. All three chokes are hydraulically gear driven position chokes activated by a hydraulic power unit (HPU) mounted on the manifold. Another redundant feature of the manifold allows the HPU to be powered from multiple sources in case of malfunction or failure. Primary power is supplied by an electric motor and secondary power by the rig air supply. In the unlikely event both fail, then manual power is available by recharging the designated accumulators while still maintaining the programmed BHP set point under automated control[36].

The second component of the DAPC system is the backpressure pump. Similar to the choke manifold, operation is under full control of the IPM. The pump provides a dedicated, on-demand supply of backpressure whenever the rig pump drilling flow rate drops below a defined threshold. This is accomplished by delivery of a steady flow of mud into the choke manifold providing the ability to actively stabilize BHP during connection transitions, from rig pumps-on to rig pumps-off and back. By simply changing the set point in the IPM, BHP can also be increased or decreased during a connection[36]. In addition to the use of dedicated manifold especially designed to maintain BHP while making connection, supporting the rig pumps incase of any fluctuations while drilling is an improving technology.

Chustz et al. explained further about the software control system, third component of the DAPC system, the Integrated Pressure Manager, that measurement, monitoring, analysis, and control are all integrated into. The IPM consists of a control computer, a programmable logic control system, a real-time hydraulics model, and data communications network. Together, these provide the automated software control and data acquisition necessary to maintain constant bottomhole pressure through the DAPC choke manifold. A human machine interface (HMI) provides the means for a control system technician to configure and adjust the operation of the IPM and the entire DAPC system. Accurate BHP control requires a steady stream of accurate data. The IPM relies on this stream of data to maintain its accurate control of the BHP throughout the drilling interval. Regularly updated drilling parameters and real-time data from the PWD tool are transmitted over a data communications network to the IPM. Of particular importance is the rig pump stroke counter, which is a crucial parameter for the operation of the DAPC system. The Integrated Pressure Manager uses the pump strokes as its primary indicator that the pumps are working, mud is flowing, and that there is annular friction in the wellbore. Two independent rig pump stroke counters are used to reduce the chance of data interruption or mechanical failure and ensure an uninterrupted supply of data. The IPM is programmed to alert the system technician if one of the stroke counters went down or showed erratic flow allowing a manual switch to the alternate sensor[36].

As a contingency, in the event that all rig data being transmitted was severed the control system technician could manually enter the stroke rate. The hydraulics model runs continuously to provide the IPM with the necessary calculated data to maintain the set point. Using the model and the manually entered stroke rate, the IPM will still generate the required DAPC system configuration and continuously control the BHP[36].

In a closed loop, it is not possible for the driller to monitor flow-out of the well during connections. Also, the hydraulics model requires the actual flow-out to accurately calculate the BHP. While pump rate is typically used in the hydraulics model, it is also possible to calibrate the model based on actual flow out values. A Coriolis flow meter was installed downstream of the choke manifold to monitor flow-out of the well. Alarms were set to alert the driller of a developing kick or losses event[35].

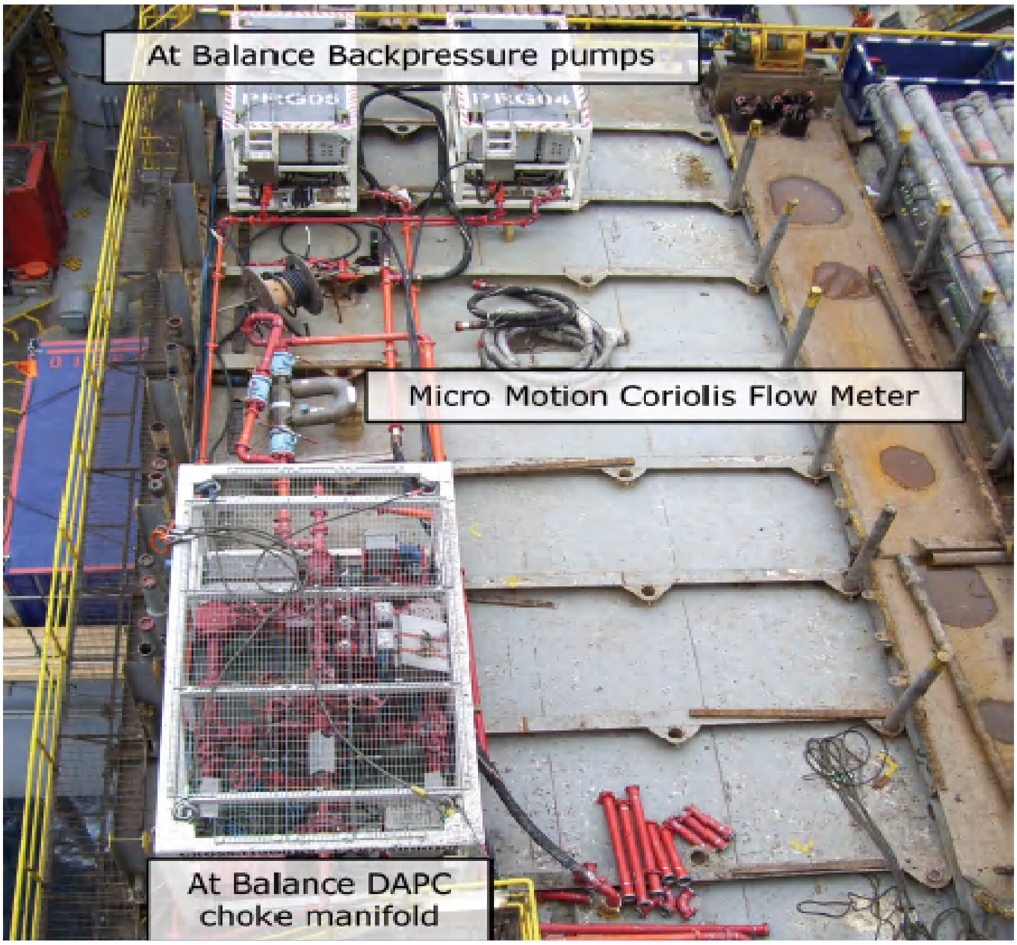


Figure 38 DAPC System set up in the field[37]

Fredericks and Reitsma[38] emphasized an important feature of the DAPC system that it has integration of control and hydraulics modeling. It enables BHP control at a depth and within limits specified by the operator, which delivers improved safety, well control and reservoir integrity. The hydraulics model has been in continuous use and development since 1998, in conventional and unconventional fields. It performs more than 60 pressure calculations a minute, uses the real-time pressure while drilling (PWD) data to calibrate itself, and its accuracy is continuously monitored through real time graphical trend analyses displayed on drilling monitors throughout the rig or in remote data centers.

3.6.6.2 Micro Flux Control (MFC)

The industry has made significant progress in the last few years with Managed Pressure Drilling (MPD). Early users succeeded at solving critical problems, reducing downtime, lowering the risks of drilling challenging wells, and reaching TD when it was not possible using conventional drilling[39].

Since the first well was drilled with MFC MPD in August 2006, the method has been used on many wells in both the standard (when the mud weight is hydrostatically overbalanced) and special (when the mud weight is hydrostatically underbalanced) modes. The wells were drilled with water- and oil-based fluids with densities up to 18 ppg, offshore and onshore, for both exploration and development. The flexibility and simplicity to change from one mode to the other allows the operator to select the proper configuration depending on well conditions, well problems, rig capability, crew competency and other conditions. One interesting finding is that the standard mode can provide unique value in understanding more accurately the downhole events, leading to a clearer identification of the problems faced[39].

The MFC MPD system uses a Rotating Control Device (RCD) to keep the well closed to the atmosphere at all times, and a specialized manifold with a very small footprint that includes redundant chokes, a flow-meter, and data acquisition and control electronics. The simplicity of this standard MPD system makes it attractive for use on many wells[39]. Fig 39 is an illustration of rig update for Secure Drilling Micro Flux Control (MFC) system.

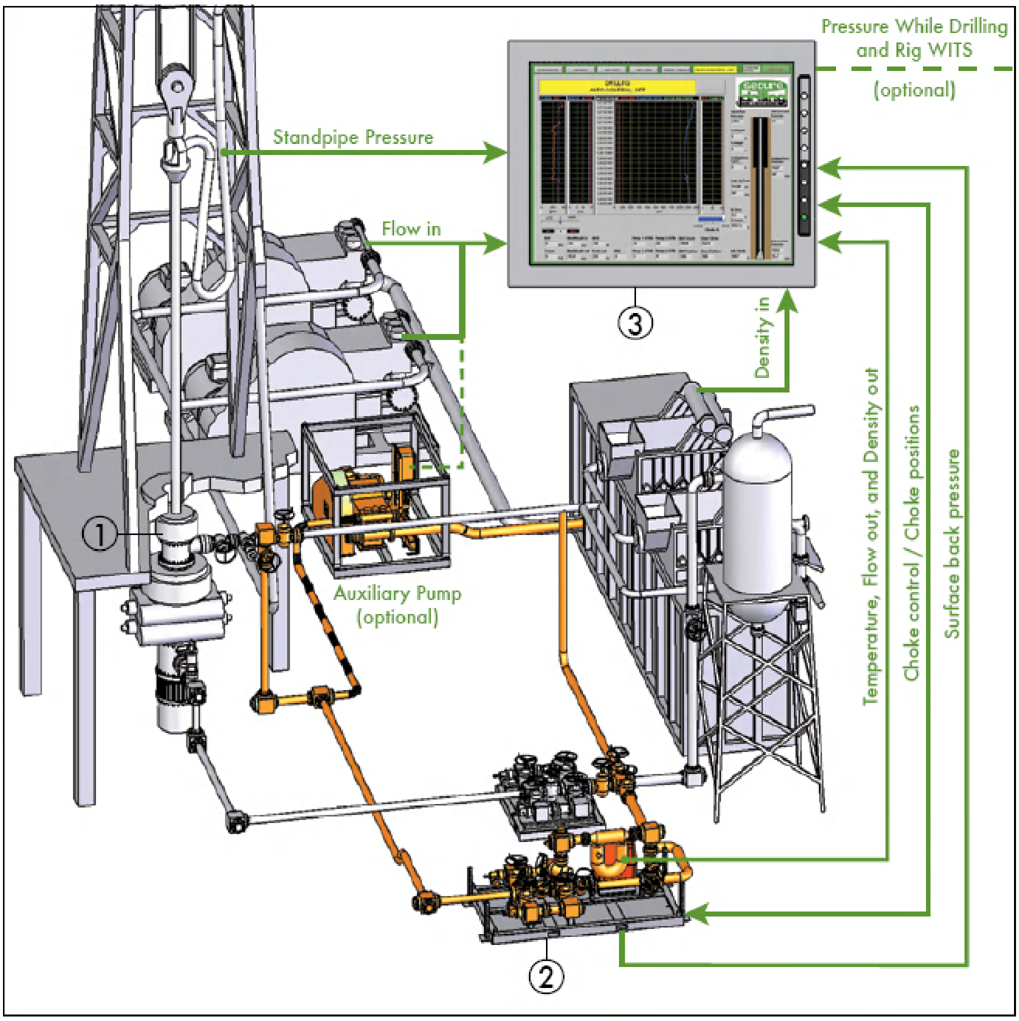


Figure 39 MPD Rig Upgrade for the Secure Drilling System[40]

A few years ago, the industry thought that MPD would be useful only on narrow-margin wells where mud weight is below the pore pressure. On many narrow-margin wells, mud losses begin as soon as the mud pumps are turned on. One option to avoid the losses is to have a hydrostatically underbalanced mud weight such that, with the friction generated when the fluid is in circulation, the final pressure inside the wellbore would be smaller than the fracture gradient. As there is a need to compensate the hydrostatically reduced mud weight to avoid influx when the pumps are off, this MPD application is called the constant bottomhole pressure variation. The MFC special mode provides this drilling option[39].

Continuous circulation devices have been developed and are already in use to avoid the pressure oscillations due to stop/start of the mud pumps. These devices can also be used for CBHP, as there is no need to stop the circulation during connections. However, it is crucial to have a contingency plan in case problems arise with mud pumps or with the equipment itself[39].

Applying CBHP is relatively easy using any of several options. The main challenge is to define the correct bottomhole pressure to be applied. This is where the accuracy and automatic response of the MFC standard mode enters the equation[39].

Wells are drilled based on predicted pore and fracture pressures. The mud weight program is based on these estimated curves and adjusted as drilling progresses. No matter how well the estimated pressures have been defined, reality will always deviate from the estimated curves. Casing depth and the mud weight programs are based on the pore and fracture pressures, and to optimize drilling it is essential to know the actual values[39].

Problems associated with drilling conventionally include the risk involved in taking kicks and the inaccuracy on flows, mud volumes and pressure measurements. Based on offset well data from conventionally drilled wells, many wells today are classified as narrow margin due to indications of kicks and losses within a very narrow pressure window. In these cases, the MFC special mode has been used to achieve the CBHP variation[39].

From experience on other wells using the MFC standard mode, it was observed that rather than using the special mode at all times on a section, the optimal solution would often be to begin in the standard mode. With the mud weight as close as possible to the estimated pore pressure, or even slightly below if possible, commencing drilling with the MFC standard mode would allow confirmation of whether the mud weight is hydrostatically underbalanced. Based on the leak-off test obtained at the shoe, and periodic dynamic leak-off tests or dynamic Formation Integrity Tests (FITs), the hydrostatic mud weight and the bottomhole pressure to be used can now be more accurately defined[39].

Another advantage of the system is that wells can be significantly optimized compared with drilling conventionally by knowing the correct margin available in real time, and permanently adjusting the margins as indications of kicks and losses are automatically confirmed by MFC. Casing strings can be eliminated; as contingency casings will be necessary only when it is determined that they are actually necessary. Mud weight will need to be increased only when there is a confirmation of increased pore pressure, rather than by the fear factor when drilling conventionally. Sections will be drilled to the limit safely, providing a substantial reduction in cost and risk[39].

Automatic system software runs in the ICU with the interface running at the HMI. The advantages of the system software are tracking all available data from the well, analyzing and trending the parameters, defining whether many problems are happening, displaying warnings to the driller, taking automatic action as necessary to correct the situation in some cases, providing data acquisition[41].

Automatic System software consists of two independent processes: Drilling Events Detection and Control Process which allows for kick and loss detection and automatic control and circulation of influxes with computer driven automated choke; and the MPD

Process which allows for manipulating the standpipe pressure or surface back pressure as necessary[41].

In order to provide a better, smoother and more reliable control, several “MODEs” were developed and run under the Automatic System software. Main Operational Modes and Kick Modes are the main modes that the software is running detection and control process. The main operational modes include drilling/not drilling, auto control on/off and the detection mode. There are five kick modes which are influx detected, reaching circulating pressure, circulating influx out, kill mud falling and kill mud rising mode. The figure shows the schematic of the modes[41].

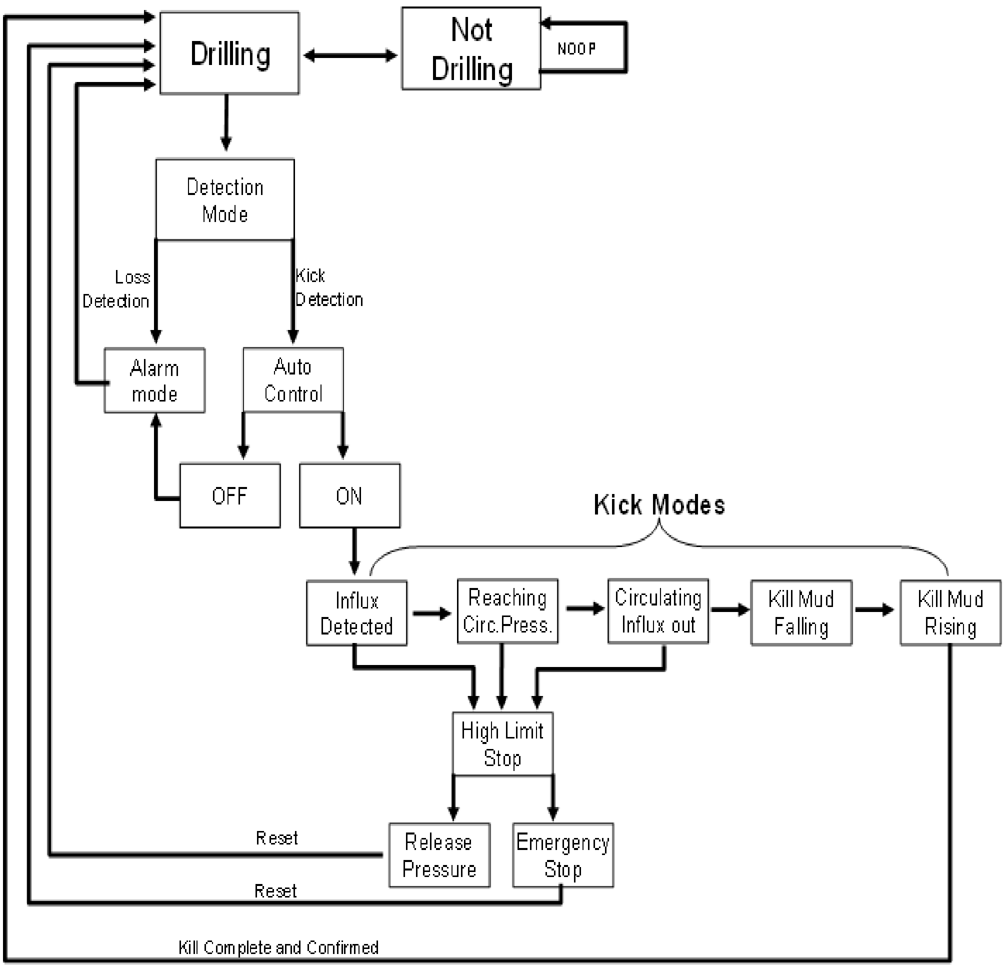


Figure 40 MFC Automatic System Software Modes[41]

3.6.7 Secondary Annulus Circulation (SAC)

Rasmussen and Sangesland[42] stated that the SAC method acts in accordance with the Continuous Circulation System. The difference is the location of the injection point which will have an impact on the annulus pressure drop. Typical injection point(s) can be in the riser section and/or below the seabed through a casing annulus. Figure 41 is an illustration of the typical injection points.

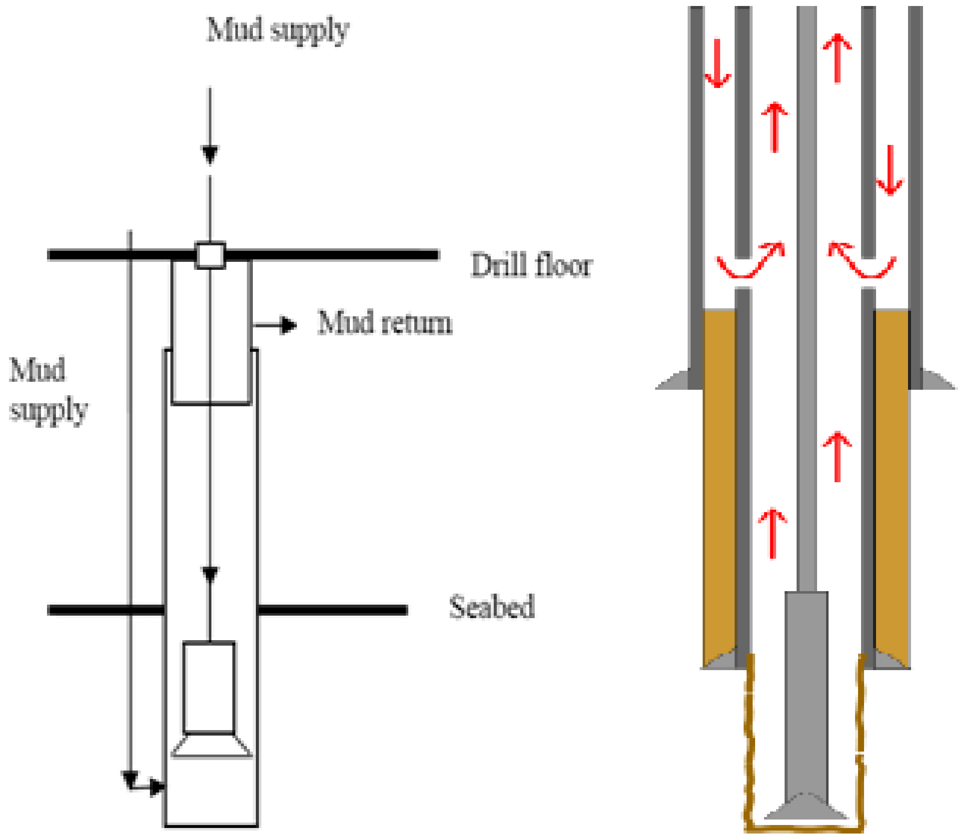


Figure 41 Secondary Annulus Circulation[42,29]

The system is designed to circulate down the secondary annulus during connections, which enable to keep constant BHP. One of the advantages of the system is that the circulation allows for faster trip speeds while tripping out with drillstring[29]. The use of secondary annulus circulation is used together with continuous circulation valve or continuous circulation device to control downhole pressure profiles. The concept is usually mentioned together with tubing drilling indeed Through Tubing Rotary Drilling (TTRD).

Through Tubing Drilling (TTD) is a method that eliminates the need for expensive conventional (new) wells or sidetracks. Avoid drilling the “transport distance” down to the reservoir reduces the costs significantly. Although Coiled Tubing Drilling (CTD) has been preferred and dominating TTD technique from fixed installations, when a drilling rig is available, the use of jointed pipe and rotary drilling operations has gradually become the more attractive option. The main advantage of using Through Tubing Rotary Drilling (TTRD) is the ability to rotate the drillpipe which improves hole cleaning, drilling mechanics and ultimately increases the reach capability. Thus an obvious potential application of TTRD is infill drilling to access new reserves in subsea wells[43].

Increasing demand for energy sources and developing technologies lead the industry to combine the alternatives which are designed for specific applications. Using the advantages of TTRD, SAC and CCS are one of the examples of this concept. However, combinations are limited depending on the comparison between available technology or the cost for developing and applying a new technology considering the benefits. Therefore, the possibility of applications of SAC is applicable for fixed rigs. In addition, stiffness of well control, riser margin, kick margin and kick detection should be improved especially in closed systems according to the aim of use. See Appendix C.

3.6.8 Compressible-Fluids MPD

Mellot stated that reducing the annular bottomhole pressure in wells using incompressible fluids as the cuttings removal medium is not new. Many innovative ways have been used in the past 30 years to accomplish this task[44]. However, the use of compressive fluids in MPD applications is the new part of the concept. Since MPD has the strengths of accurate managing of wellbore pressures, the compressible fluids can be used in challenging wells more effectively.

Hannegan[14] stated the advantages increasing with the usage of downhole tools under MPD by emphasizing that the concept of more precise wellbore pressure management has application to air, mist, foam, and gas drilling mediums. An example is a downhole air diverter (DHAD) subbed into the drillstring. The tool responds to a preset differential between drillstring and annulus pressure. An amount of cuttings-free compressed air is diverted into the annulus.

By diverting the surplus air traveling down the drillstring before it reaches the bottomhole assembly, the energy that would normally be wasted as friction is used to provide lift in the annulus, reducing BHP. Secondly, by reducing the annular friction hole erosion and sloughing can be minimized[44]. Improved hole cleaning and a corresponding decrease in BHP increases the differential pressure across a percussion hammer, typically improving its performance. ROP increases and in some cases allows drilling to a greater depth in a *wet hole* than otherwise possible[14]. With the improvement in both hole cleaning and drilling performance, the hazards related with wellbore stability are reduced.

3.6.9 Wellbore-Strengthening MPD

One method for strengthening the wellbore is stated by Hannegan[14]. In the early 1990s, work was done to investigate the impact of strengthening the wellbore by maintaining a sized solids content in the mud, effectively plugging the microfractures that occurred in weaker formations as the mud density was increased. While this is not MPD in the sense of requiring a closed and pressurizable mud-return system, it achieves similar goals by widening the margin between pore pressure and fracture pressure in the wellbore[14].

Another way of improving the drilling window is proven to form a very low permeability protective barrier that prevents fluid and the mud overbalance pressure from invading rock formations. Hence the low invasion fluids can be used to increase the fracture gradient and so open the safe mud weight window. In addition, these low invasion properties help reduce formation damage and so increase well productivity, as well as reducing the risk of differential sticking and some wellbore instability problems[45].

As a result, welbore strengthening improves the upper boundary of the drilling window and MPD improves the control of pressures while keeping the BHP in the drilling window. Therefore, the combination of wellbore strengthening and MPD methods allows us drill within a wide window with the precise control of bottom hole pressures. That means the challenges due to narrow window can be easily eliminated by considering such a combination. In addition, with the capability of real time estimation in the applications of MPD, invasion fluid additives can be used when needed without increasing the total mud costs.

3.6.10 Drill thru the Limits (DTTL) MPD

The various techniques now labeled MPD have been evolving over the past 2 decades, mostly on U.S. land drilling programs. In 2004 they were “packaged” for global consumption and defined as a technology within themselves. The MPD label was coined and variations upon its common theme of drilling overbalanced with more precise wellbore pressure management was introduced to the world’s drilling decision-makers with an emphasis upon technology transference offshore where its benefits are more profound[46]. For instance; it is known by the industry that most of the un-conventional sources such as methane hydrates which is the most pronounced one, are still waiting to be drilled especially in the deeper seas.

Hannegan[46] emphasized the proven effect of MPD usage on the drilling fluids. Land drilling programs have learned that MPD increases the margin of error relative to planning the fluids and well construction programs. More precise and real-time adjustments to the Equivalent Mud Weight, in effect, broadens the drilling window even when the mud in the hole at the time and at that depth is otherwise un-suitable for the open-hole pressure environment encountered. In other words, MPD “dumbs-down” the fluids program and extends the range of drilling fluids options, typically towards less expensive and/or more readily available fluids[46]. As a result, MPD widens the restricted window of fluid dynamics.

DTTL is one of the emerging concepts under MPD which requires improvement of the equipments depending on the application. Indeed, it is the advance form of CBHP MPD which enables usage of the surface back pressure not only in connections but also in drilling operations. In the applications of DTTL MPD, drilling fluid is designed not only to act statically underbalanced and dynamically overbalanced like CBHP MPD but also to act both statically and dynamically underbalanced. The difference is the surface back pressure amount with the help of the improving tools. The higher back pressure means the higher ECD and hydrostatic head can be compensated which leads to drill with simple and less dense drilling fluids.

The difference between CBHP MPD and DTTL MPD should be understood clearly to provide better BHP control. The mathematics behind the methods can be explained more clearly by giving the equations for bottomhole conditions both under static conditions (USC) and under dynamic conditions (UDC).

<u>CBHP MPD equations;</u>

$$HH\ (psi) < PP\ (psi) < FP\ (psi) \qquad \text{(USC)}$$

$$PP\ (psi) < HH\ (psi) + ECD\ (psi) < FP\ (psi) \qquad \text{(UDC)}$$

BP can be applied in case of need.

$$PP\ (psi) < HH\ (psi) + ECD\ (psi) + BP\ (psi) < FP\ (psi) \qquad \text{(UDC)}$$

<u>DTTL MPD equations;</u>

$$HH\ (psi) < PP\ (psi) < FP\ (psi) \qquad \text{(USC)}$$

$$HH\ (psi) + ECD\ (psi) < PP\ (psi) < FP\ (psi) \qquad \text{(UDC)}$$

BP has to be applied to mitigate drilling hazards.

$$PP\ (psi) < HH\ (psi) + ECD\ (psi) + BP\ (psi) < FP\ (psi) \qquad \text{(UDC)}$$

The concept of using less dense mud in DTTL MPD applications requires some additional considerations. As it is known ECD or AFL can be managed by adjusting the flow rate or changing the drilling fluid density in conventional drilling operations. One of the limitations for adjusting flow rate is pressure rating of the rig equipments such as rig pumps, manifolds etc. Another limitation for changing the mud density is the pressure profiles in the wellbore. In the applications of DTTL MPD, less dense mud causes less ECD. Although ECD can be increased by increasing the flow rates, it is restricted by the pump capabilities. Therefore, application of back pressure is a must in DTTL MPD applications in order to prevent any influx or wellbore collapse. Due to the usage of less dense mud and reduced ECD rates, especially when circulation is stopped to make connection, wellbore is possibly under underbalanced condition, or in fact gross underbalanced condition, which requires greater back pressure requirements unlike other MPD methods.

In order to eliminate or reduce the limitations in the applications of DTTL MPD, Hannegan[46] suggested additional considerations such as;

- Application of surface backpressure becomes the primary barrier. Equipment can be pre-tested and qualified to contain the maximum surface backpressures that may be needed to prevent or limit an influx of reservoir fluids. (Conventional mud programs cannot be pre-tested and qualified to deal with unexpected downhole pressure environments that may be encountered.)
- Less risk of the well drinking the secondary barrier, the column of mud and cuttings in the annulus.

- Upon approaching the safety factor of the pressure containment capability of surface equipment, integrity of casing, casing shoe LOT's, open-hole FIT's, etc., it's time to consider adding weight to the mud.
- Conventional well control principals apply.
- Demand for High pressure capable DDV's will be fostered.

The benefits of the Drill thru the Limits (DTTL) MPD according to Hannegan[46] are;

- Enjoy broader drilling window, maximum ROP, simplified and less expensive fluids program, simplified casing program and/or deeper casing set points, less NPT, etc.
- Uniquely applicable to HT/HP, "high ECD" wells, exploratory wells, and where the formation pressure is a relative unknown, such as sub-salt.
- Reservoir pressures will continue to deplete, assuring a growing percentage of prospects may be drilled with this approach to the hydraulics of drilling a well.

CHAPTER 4

MANAGED PRESSURE DRILLING TOOLS

Discovering or improving innovative ideas is the primary deal; however, these ideas can only come true only if the equipments that enable the concept are used. That is the reason why MPD is defined as a tooled up technique. As cited in *Advanced Drilling and Well Technology*[14], a closed and pressurizable circulating mud system in its most basic configuration includes a rotating control device (RCD), dedicated drilling choke, and drillstring non-return valves [e.g., floats. The RCD is the key enabling tool for a closed-loop circulating fluids system, and the technologies based upon that concept have evolved in harmony with the evolution of its numerous onshore and offshore designs.

4.1 Key Tools of MPD

According to Hannegan[47] key tools for most techniques of MPD are;

- Rotating Control Device on Floating Rigs (wave heave)
  - ✓ External Riser RCD
  - ✓ Subsea RCD
  - ✓ Internal Riser RCD (IRRCH)
- Rotating Control Device on Fixed Rigs (no wave heave)
  - ✓ Passive & Active annular seal design “land” models
  - ✓ Marine Diverter Converter RCD
  - ✓ Bell Nipple Insert RCD
  - ✓ IRRCH (in marine diverter or surface annular)
- Non Return Valves

- Choke Options (dedicated recommended, except HSE)
    - ✓ Manual
    - ✓ Semi-automatic
    - ✓ PC Controlled Automatic

4.1.1 Rotating Control Device (RCD)

Malloy stated considering the wide range of usage of RCD that using an RCD alone does not necessarily constitute MPD operations. An RCD is an excellent supplemental safety device and adjunct to the BOP stack above the annular preventer. Used alone, it is at best a highly effective reactionary tool, which can be used to safely mitigate hydrocarbons escaping from the wellbore to the rig floor[9]. The reactive usage of RCD is one of the strengths of MPD which enables the control of the flow more safely.

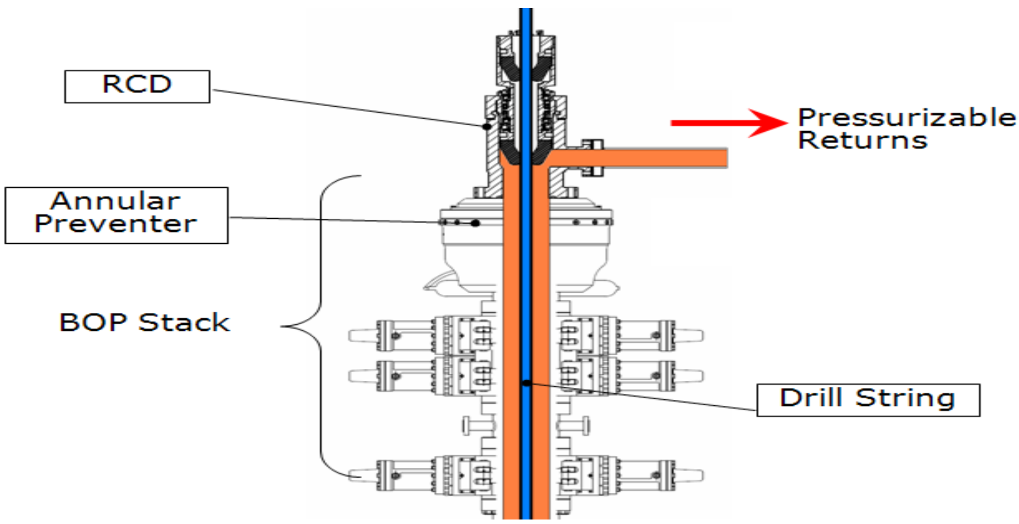


Figure 42 Typical Alignment of RCD[48]

Malloy and McDonald[8] stated emphasizing supplementary use of RCD and design criteria that the location for the RCD is most typically atop the annular preventer as shown in figure 42. The RCD is not intended to replace the Blowout Preventer stack as a primary well control device, but only as a supplement to the BOP stack to give it more range and flexibility. The size and design of the Rotating Control Device for a specific drilling operation is application driven, including:

- Rig substructure geometry
- Seal elements
  - Single
  - Dual
- Pressure rating
  - Static
  - Dynamic
- Flange connections
- Operator preference

Aside from a work-over stripper head, there are four basic types of Rotating Control Devices.

- Single element (see fig. 43 left side)
- Dual element (see fig. 43 right side)
- Rotating Annular Preventer (see fig. 44 left side)
- Rotating Blowout Preventer (see fig. 44 right side)[8]

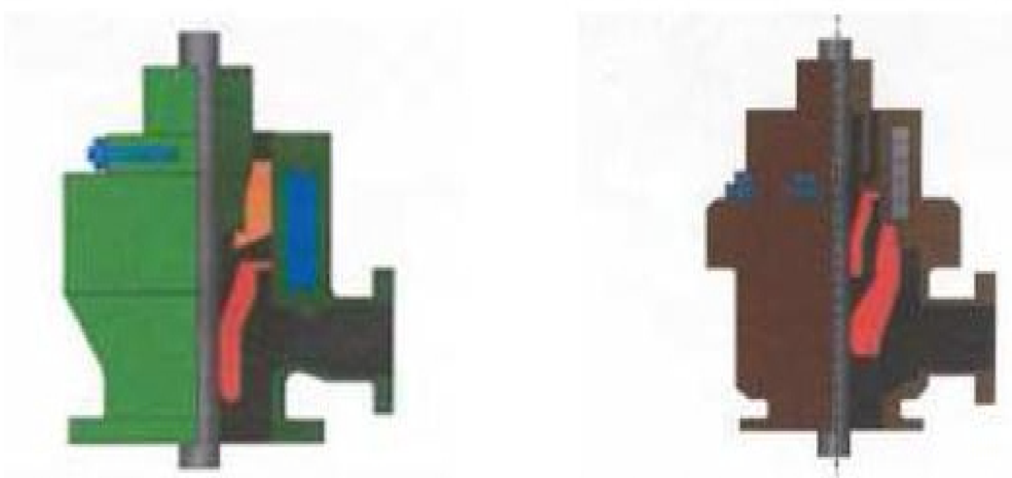


Figure 43 Single element RCD and Dual element RCD[8]

Figure 44 Rotating Annular Preventer and Rotating BOP[8]

API Specification 16RCD describes manufacturing and testing specification for these devices. Rotating Control Devices for land, jack-up, and barge drilling operations can have 2,500 psi capability for rotating and stripping, and is rated at 5,000 psi in the static mode. With light density annular fluids, the RCD can routinely maintain pressure differentials in excess of 1,000 psi. Most operations are performed within a lower pressure differential range between 200 – 300 psi[8]. Its competence of working with higher differential pressures allows the use of less dense fluid that facilitates improving the drilling performance. Indeed, MPD performance is directly proportional with the RCD pressure ratings.

Typical and unique alignment of RCD as cited and stated in *Advanced Drilling and Well Technology*[14] informs that onshore and offshore applications of RCDs from fixed rigs such as jack-up and platform-mounted rigs often use *surface models* that usually are mounted atop or on the head of a typical blowout preventer (BOP) stack (Hannegan and Wanzer, 2003). One RCD design allows its bearing and seal assembly to be remotely latched within a fixed rig's existing bell nipple. Another allows the RCD to be secured within the rig's existing marine diverter or within a dedicated annular or pipe ram BOP.

The alignment of RCDs, as cited in *Advanced Drilling and Well Technology*[14],differ from the fixed rigs in that floating rigs such as semisubmersibles and drillships use RCD designs that may be configured to be atop a typical marine riser in the moon pool area (Terwogt et al. 2005). A recently introduced design facilitates *docking* the RCD bearing and annular seal assembly in the upper marine riser system, typically under the upper telescoping slip joint. This design requires minimum modifications to the rig's conventional mud-return system and enables rapid transition from conventional returns to pressured returns, and vice versa. All RCD designs for floating rigs incorporate flexible flow lines to compensate for the relative movement between the rig and the riser[14]. Figure 45 is an illustration of RCD docking station prior to the installation of flexible flowlines.

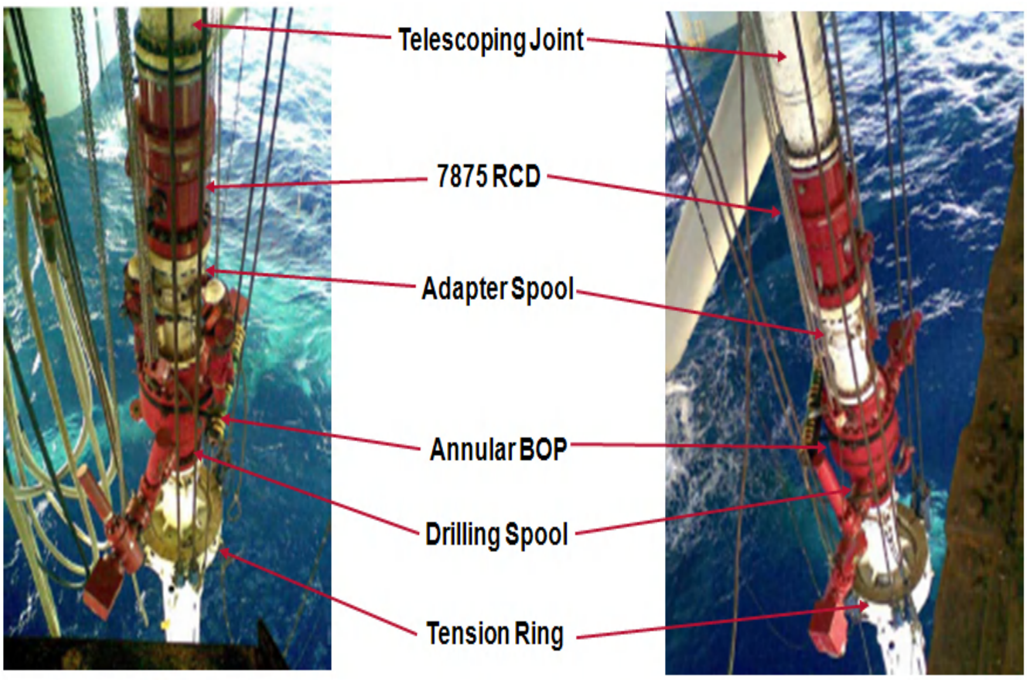


Figure 45 RCD Docking Stations installed in semi-subs[49]

As referred in the manual named “MPD operations from Floating Rigs” prepared by Weatherford, the rig up of an MPD system on a floating rig requires a little more forward planning. With the high spread costs of deepwater rigs, an MPD system should be rigged up once the BOP and riser systems are installed. This requires a novel concept in RCD design which allows the RCD seals and bearing to be installed through the rotary table. The so called RCD docking system in installed in the marine riser system and remains connected to the rig at the diverter housing all times. The RCD bearing and packer assembly is installed through the diverter housing and marine riser system. The slip joint is placed higher in the riser string with the RCD and an annular preventer with flow spool below the slipjoint. These RCD docking stations are now being used by early adaptors on floating installations[50]. An illustration of RCD docking station is shown in fig. 46.

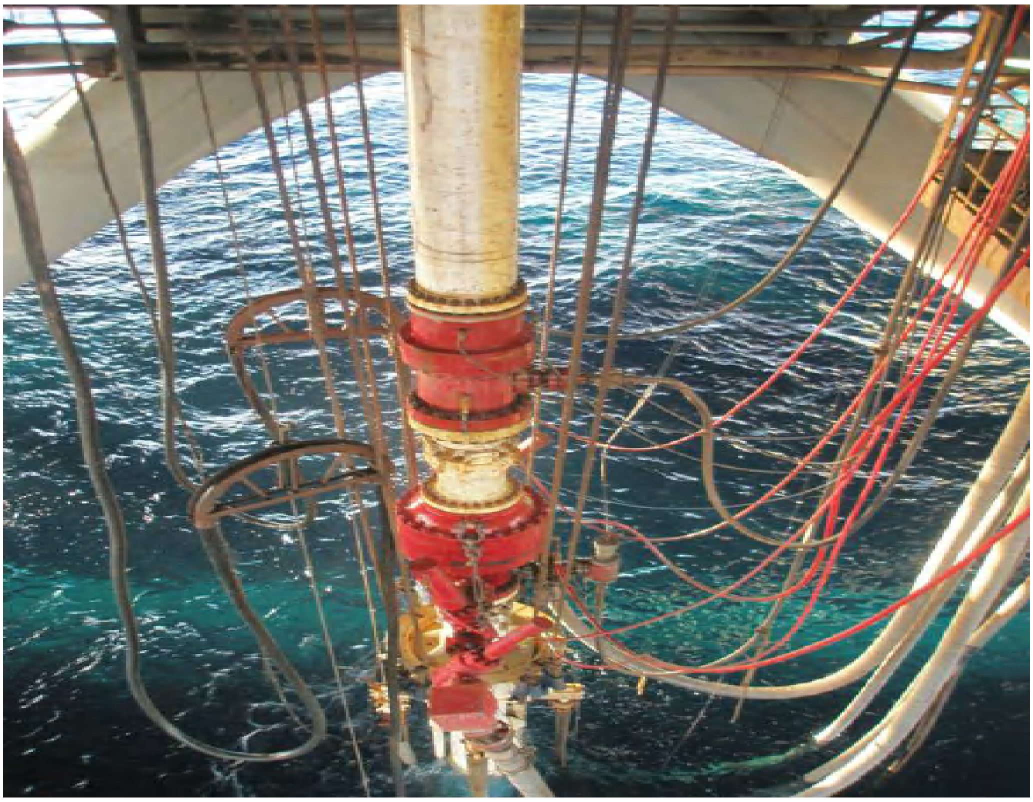


Figure 46 RCD Docking Station with flexible flowlines[50]

4.1.1.1 External Riser RCD (ERRCD)

As Hannegan pointed out the essential importance of External Riser RCD, it is designed to be used in MPD applications on floating drilling vessels which is subjected to hydrodynamic upward loadings due to waves. Maximum possible wave heave determines length of flexible flowlines. Moreover maximum return flow rate determines size of flexible flowlines[51].

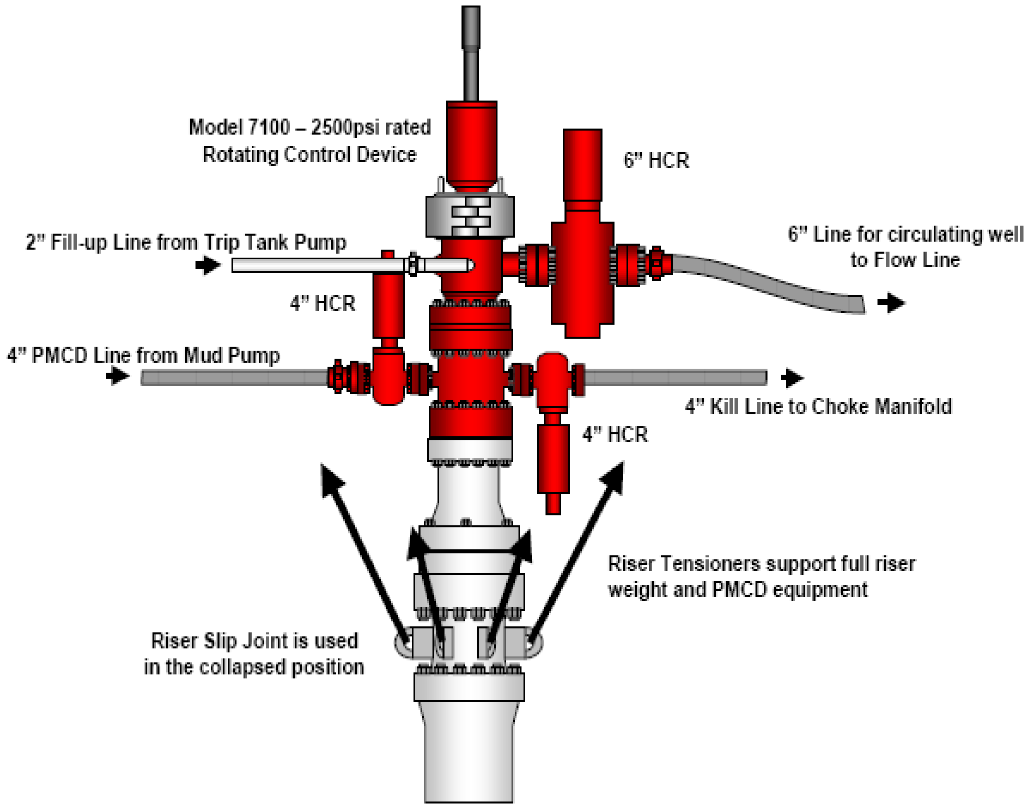


Figure 47 External Riser RCD (ERRCD) on a Riser Cap[36]

Figure 47 is an illustration of External Riser RCD used in floating drilling applications. ERRCD is a part of Riser Cap which enables the applications of PMCD. With the usage of Riser Cap, high viscous fluids can be pumped down to the annulus with the purpose of creating a mud cap condition.

4.1.1.2 Subsea RCD (SSRCD)

Considering the usage of design in various applications Hannegan explained further that Subsea RCD designs are applicable to riserless drilling, with or without riserless mud recovery, and to several variations of dual-gradient drilling with a marine riser system[14]. In addition, taller spool or swivel flange may be required on drill ships to accommodate changes in heading. It is important that hoses are clear riser tensioner cables in catenaries swing[47].

Figure 48 Subsea RCD (SSRCD) installation in moon pool[36]

Figure 48 is an illustration of Subsea RCD or External Riser RCD with Subsea BOP installation in the moon pool area. The name is derived from the usage of the RCD with Subsea BOPs.

4.1.1.3 Internal Riser RCD (IRRCH)

One way to allow MPD from a floating rig is through the use of a surface BOP. With the installation of a high pressure riser or internal riser, a conventional BOP stack can be nippled up on the marine riser and the RCD and flow spool can be rigged up on top of the surface BOP. In this set-up, the entire system works more like a surface stack on a platform or a jack-up. The rig up of the MPD system would be very similar when compared to fixed surface stacks, with the only difference being the use of hoses instead of fixed pipe work. The issues with surface BOP stacks on semi-submersible rigs are mainly associated with stack alignment[15]. Hannegan added that IRRCH is designed for several methods of DG. Tool serves as a subsea annulus barrier[51]. IRRCH can be used in marine diverter for specific purposes. Figure 49 is an illustration of both design and virtual view of IRRCH.

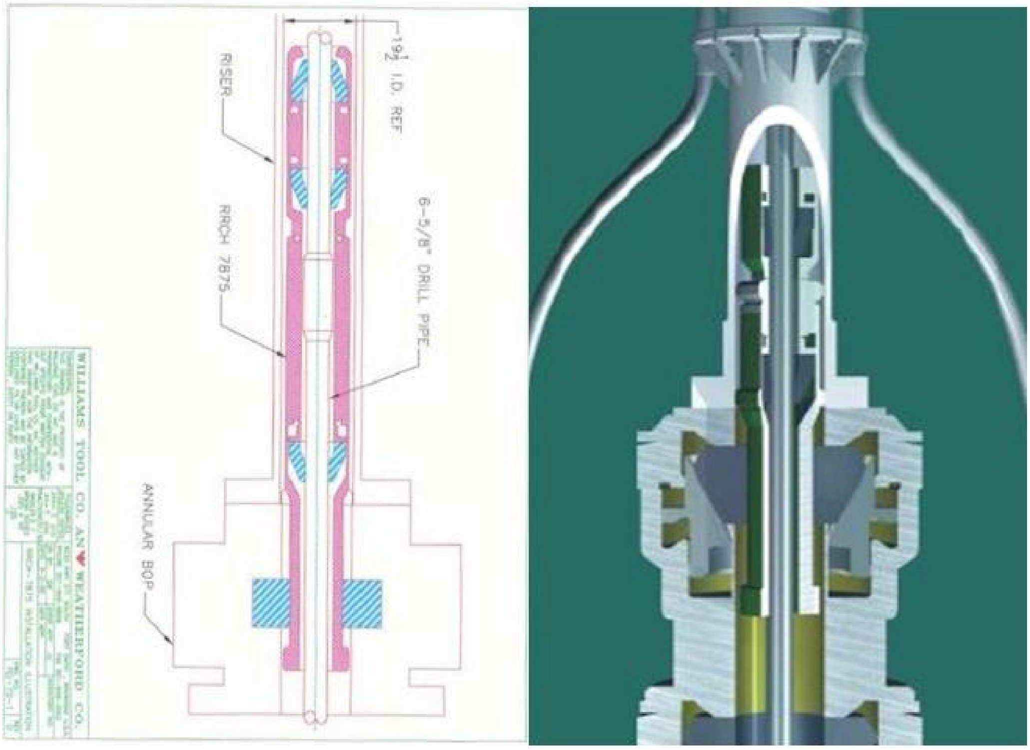


Figure 49 Alignment of Internal Riser RCD[51,13]

4.1.1.4 Active annular seal design RCD

Hannegan mentioned that active annular seal design requires external-to-tool source of hydraulic energy. The design typically requires dedicated technicians[51]. In addition, its electro-mechanical-hydraulic circuits and piping tend to be trouble prone on drilling locations, and the inflated element does not handle stripping out under pressure very well[3]. Figure 50 is an illustration of typical surface stack illustrating an active rotating control device. The design compatibility with API specs. of the active annular seal RCD is shown in the figure as well.

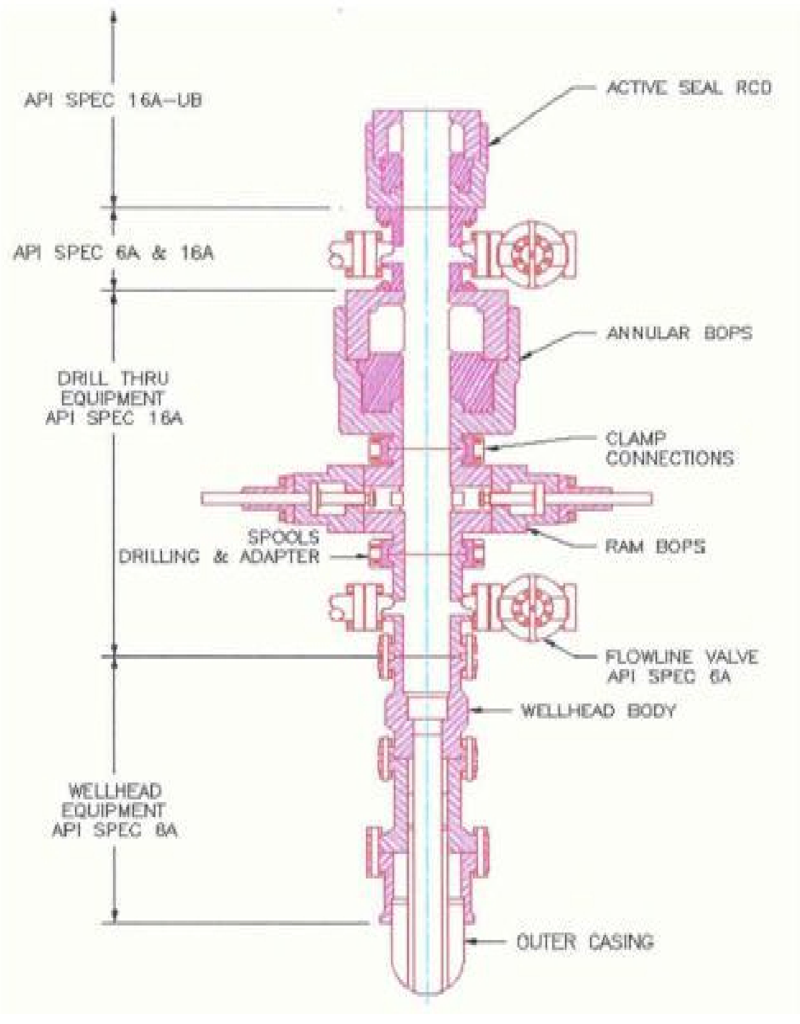


Figure 50 Active RCD in Typical Surface Stack[51]

4.1.1.5 Passive annular seal design RCD

Hannegan, emphasizing the advantages of the design in MPD applications, claimed that passive annular seal design (see fig. 51) is most commonly used on MPD applications. One of the advantages of this design is not requiring a dedicated technician. Other advantage is requiring no external-to-tool source of energy to function. The design allows higher differential pressure which leads tighter annular seal[51]. Indeed, higher differential pressures across the RCD are commonly confronted in MPD applications, due to the usage of less dense drilling fluid.

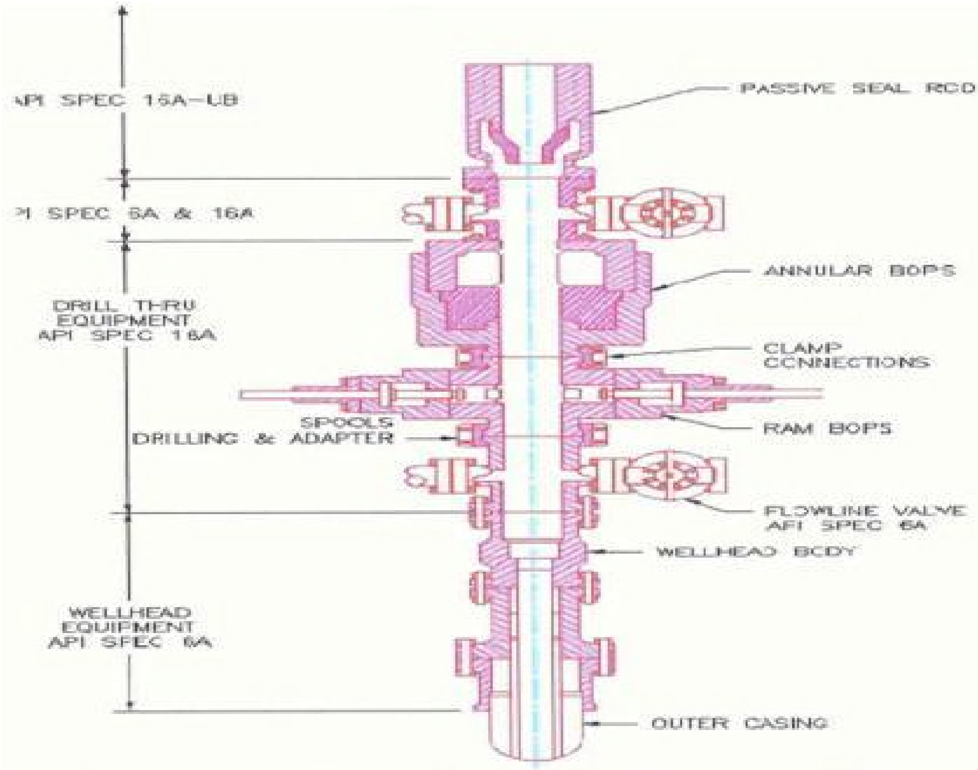


Figure 51 Passive RCD in Typical Surface Stack[51,47]

The reason for describing the system under the name “passive” is that the rotating packer that uses an annular seal element or “stripper rubber,” which is ½ in. to 7/8 in. diameter undersize to drill pipe and is force fit onto the pipe. This forms a seal in zero-pressure conditions. The element is exposed to wellbore pressure and further sealing is done by the annular pressure (well pressure actuation). The buildup of annular pressure against the element exerts a direct sealing pressure on per unit area basis against the stripper rubber. On the other hand, the failure mode for the passive RCD in most cases is a leak in the seal around the pipe or drill collars at low pressure. As the packers or strippers wear, they reach the point where they do not seal tight at low pressures[5].

4.1.1.6 Passive over active annular seal design

This design is the combination of the seal designs of the passive and the active ones. Passive seals are on the upper part, whereas active ones are on the lower. Design failed commercially, because when they were tested to API 16 RCD and failed to meet minimum test criteria; differential pressure vs. number of tool joints stripped before failure[3]. See Fig. 52.

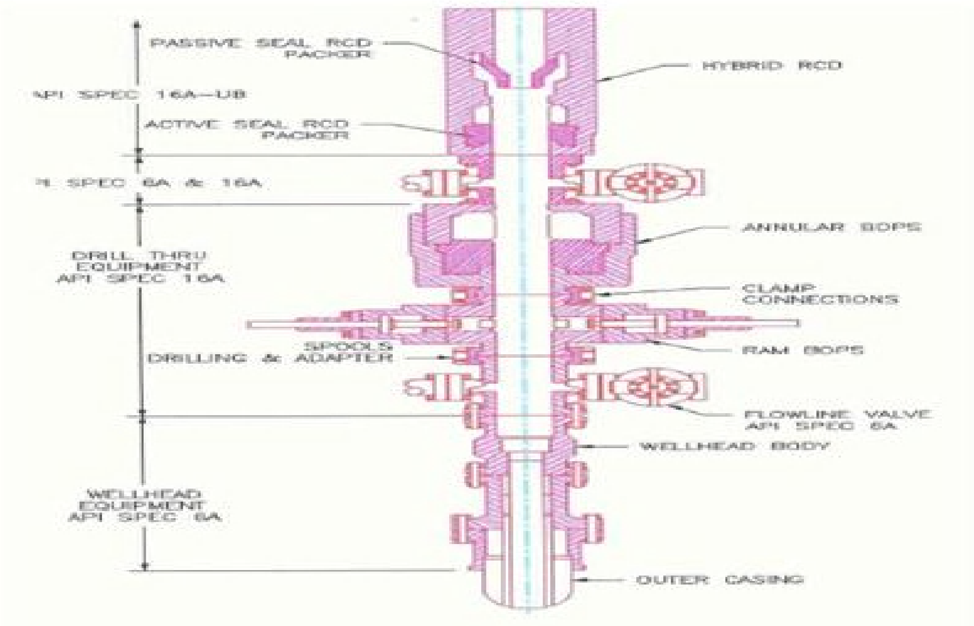


Figure 52 Passive over Active Design Hybrid RCD[51]

4.1.1.7 Marine Diverter Converter RCD

The marine diverter converter RCD converts typical marine diverter to rotating diverter. This type of RCD can be used in MPD applications where there is little or no relative movement between rig and drillstring[51]. Marine Diverter Converter housing is clamped or latched to a RCD. The housing assembled with the RCD is inserted into a marine diverter above the water surface to allow conversion between conventional open and non-pressurized mud-return system drilling, and a closed and pressurized mud return system used in managed pressure or underbalanced drilling[52].

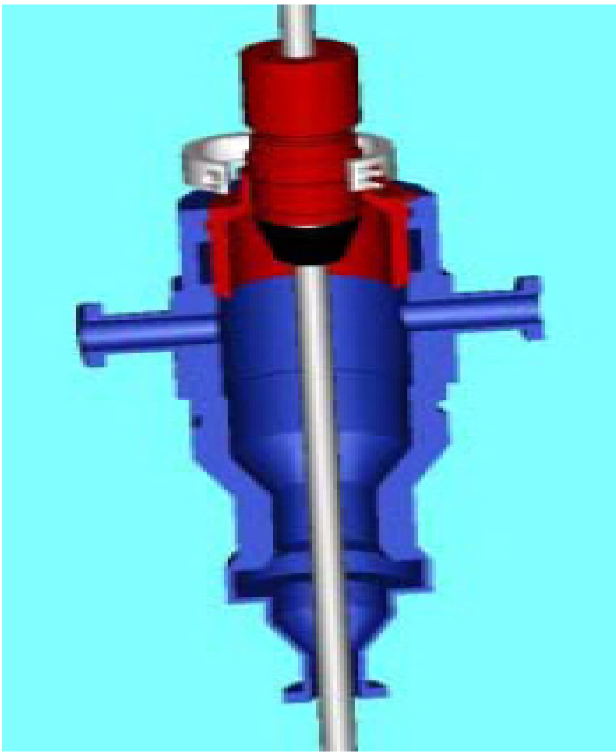


Figure 53 Marine Diverter Converter RCD[51,47]

As shown in Figure 53, RCD is installed in a marine diverter which enables diverting of any influx effectively while drilling. Commonly, the usage of this type of RCD is limited to the fixed rigs.

4.1.1.8 Bell Nipple Insert RCD

Bell nipple insert RCD is one of the upper marine riser rotating control device. Because of this type of RCD has a fixed design, there should be no wave heave while used[51].

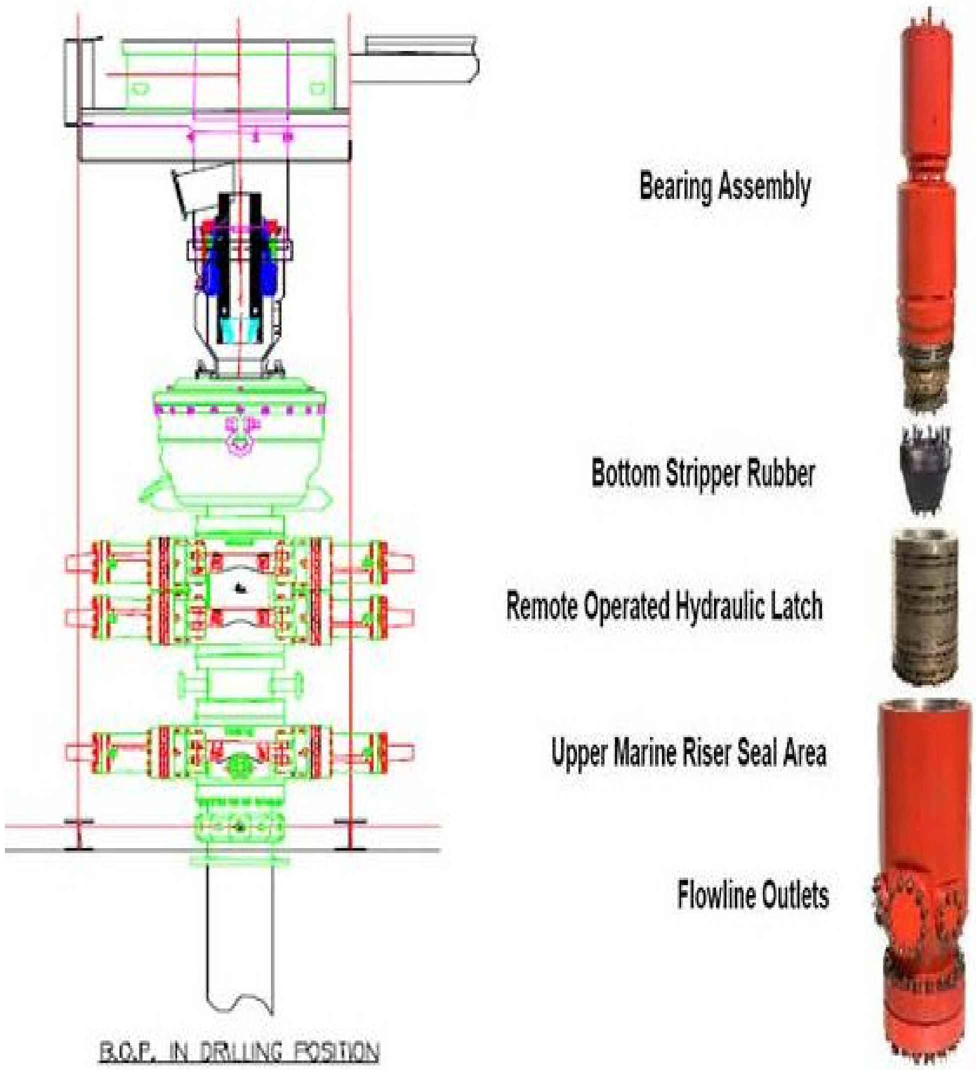


Figure 54 Alignment & Components-Bell Nipple Insert RCD[51,47]

Figure 54 is an illustration of Bell Nipple Insert RCD in a typical BOP stack in drilling position (left side) and components of Bell Nipple Insert RCD (right side) of which pressure ratings are 5000 psi static/2500 psi dynamic.

4.1.2 Non-return Valves (NRV)

The non-return valve, or one-way valve in the drillpipe, was originally called a float. That term is still in use in older literature and some of the equipment description catalogs. Within last several years, the term non-return valve or NRV has replaced float as a primary descriptor of the drillpipe one-way valve[5].

The drillpipe non-return valve (NRV) is essential to any MPD operations. MPD operations often require annulus back pressure. Looking at the U-tube principle so commonly discussed in well control activities, it is evident that any positive unbalance in the annulus forces drilling fluid back up the drillpipe. The drilling fluid may carry cuttings that plug the motor or MWD or, in the worst case, blow out the drillpipe[5]. That is the reason why NRV is a key in MPD applications, since most of the time some amount of back pressure is applied to compensate the annular friction losses.

4.1.2.1 Basic Piston Type Float

The primary line of defense against backflow problems has been the type-G Baker float, also called piston float. The piston NRV has a simple piston driven closed by a spring that looks a bit like an engine valve system. Drilling fluid pressure forces the valve open against the spring when circulating; and when the pump is turned off, the spring and any well bore pressure force the valve closed. This type of NRV has proven very reliable and rugged. Failures of this valve have been rare and generally the result of no maintenance or very high-volume pumping of an abrasive fluid. The valve is housed in a special sub above the bit, and it is common and prudent for critical wells to use dual NRVs[5]. Housing of the valve was also named as *float bit sub* in the older literature.

The primary two problems with the type-G float are that it blocks the drillpipe for wireline and the use of the float blocks back pressure or shut-in drillpipe pressure from a well kick. As long as the NRV is located just above the bit, it limits the need to pass a wireline. The shut-in pressure problem is overcome by slowly increasing the pump pressure until it levels out, indicating that the valve is open and the pressure is equivalent of shut-in pressure[5]. Conversely, the Baker Model "F" Drill Pipe Float Valve provides a positive and instantaneous shut-off against high or low pressure, assuring continuous control of fluid flow during drilling[41]. Figure 55 is an illustration of “G” (left side) and “F” (right side) type non-return valves.

Figure 55 The Baker Model “G” and “F” Type NRV[41]

4.1.2.2 Hydrostatic Control Valve (HCV)

The hydrostatic control valve (HCV) is a subsea version of the bit float valve used in dual gradient drilling. It is used to hold up a column of drilling fluid in the drillpipe to avoid the U-tube effect when the pump is turned off. This would be the equivalent of pressure of a full column of mud in the riser minus the pressure of an equivalent column of seawater, regardless of the depth of the hole. The HCV does not restrict the use of an NRV at the bit to prevent backflow and plugging. The HCV is a longer tool than the type-G float, to accommodate the spring calibrated to hold the piston closed against the equivalent pressure of a full column of drilling fluid in the riser[5]. In brief, HCV is a reverse control valve adjusting mud level in the riser to eliminate the pressure difference due to sea water column.

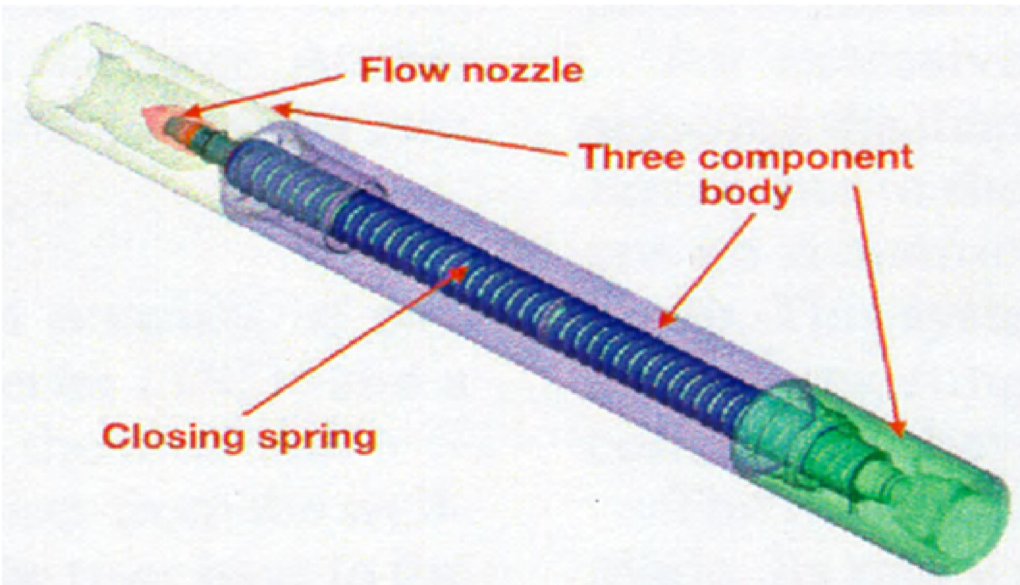


Figure 56 Hydrostatic Control Valve (HCV)[53]

Figure 56 is an illustration that displays HCV is made up of three body components; bottom body, middle body with closing spring and top body with flow nozzle.

4.1.2.3 Inside BOP (Pump-Down Check Valve)

The inside BOP is an older tool, from the generation of the piston float. The inside BOP is designed as a pump-down tool seated in a sub above the bottomhole assembly and acting as a check valve against upward flow. The original use of the inside BOP was during a period when there were objections to running an NRV at the bit because of the chance of increasing lost circulation. It is now used as a backup to the bit float[5]. On the other hand, a special release tool allows the valve to be held open to permit stabbing into position against a backflow of fluid. This optional release tool can be installed on the float valve and the entire assembly kept ready on the rig floor for quick installation at the first signs of serious backflow when drill pipe is pulled from the well[4].

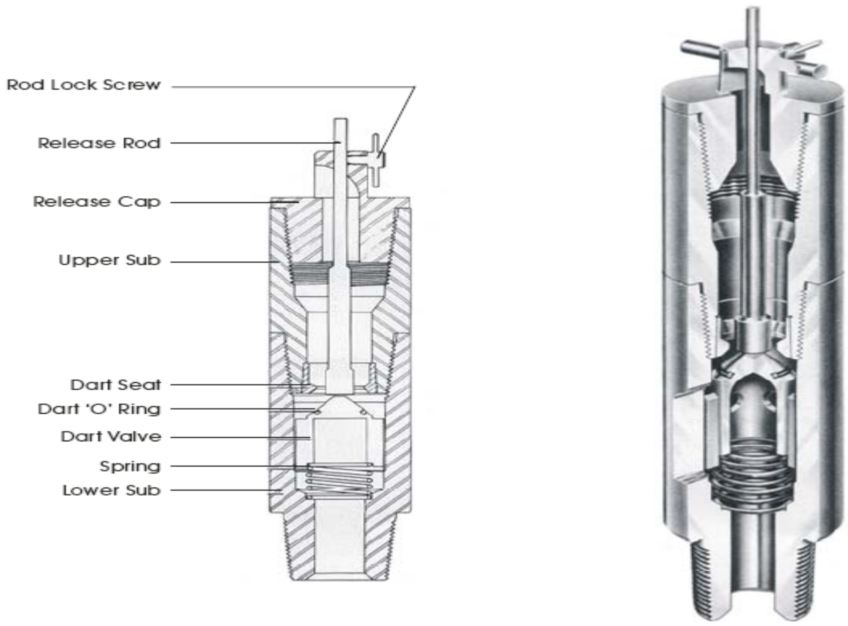


Figure 57 Pump-Down Check Valve (IBOP)[4]

Figure 57 is an illustration of the components of the Inside BOP with the optional release tool that consists of release cap, release rod and rod lock screw.

4.1.2.4 Wireline Retrievable Non-return Valve (WR-NRV)

Wireline Retrievable Non-return Valve is a newly introduced NRV type which is placed in the drillstring; this flapper-style drill-float valve prevents pressure from entering the string above it. The high-pressure valve enhances safety by allowing pressure above the valve in the drillstring to be bleed off when making and breaking connections. Efficiency is improved and risk is reduced because, unlike a fixed-float valve, the WR-NRV can be changed out or removed on wireline, eliminating the need to trip the pipe[54]. That is the primary advantage of the WR-NRV when comparing fixed-float valves.

One of the advantages that make difference is the usage of multiple valves which are typically positioned at intervals of about 500 ft (150 m) in the string to enable incremental bleed back of any existing pressure and later incremental re-pressurization. This procedure eliminates the time associated with bleeding pressure off the entire drillstring, as required with fixed valves positioned in or near the bottomhole assembly (BHA)[54]. The WR-NRV arrangement in the drill string provides elimination of unnecessary time caused by complete pull out of hole in case of logging.

In contrast to fixed-float valves those are made up as part of the drillstring, the Gateway WR-NRV makes up to an industry standard X-lock assembly that is latched into a drillstring profile sub. Using this common industry connection facilitates quick recovery by wireline, which enables valve replacement without killing the well. It also makes it possible for fishing operations to reach the BHA, which is prevented with fixed-valve configurations[54].

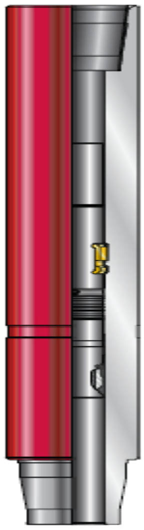


Figure 58 Wireline Retrievable Non-Return Valve[54]

Figure 58 is an illustration of Weatherford's Gateway Wireline Retrievable Non-Return Valve which can be used in Managed Pressure Drilling applications.

Features, advantages and benefits of WR-NRV are as follows[54];

- Easy access on wireline means the Gateway WR-NRV can be changed or removed without tripping the drillstring or killing the well. Eliminating the trips required to retrieve a fixed valve saves valuable rig time.
- Designed for high-pressure applications, the valve ensures pressure control integrity, even with extremely high pressured hydrocarbons.
- A large bore ID minimizes friction when pumping gas and fluid into the drillstring for maximum drilling performance. The valve only restricts flow when fluids or gas travel up the drillstring.
- The large bore design does not preclude the pumping of balls or darts, which provides options not available with fixed float valves.

4.1.3 Choke Manifold Systems

Choke Manifold System is one of the key tools of enabling MPD applications. Indeed, Nas et al.[15] emphasized the need for choke in CBHP operations emphasizing that a choke must be installed in the return flow line to allow back pressure to be applied during the drilling process. If a choke is used and surface pressure is to be applied during connections, then the ability to energize the choke by pumping across the wellhead may also have to be incorporated. Whenever possible, a separate MPD choke manifold should be used as this will ensure that secondary well control equipment is not used for routine drilling operations[15]. This is the reason why using a dedicated choke manifold is a must considering the primary usage of a choke manifold in well control operations. There are three choke options in the applications of MPD; manual choke, semi-automatic choke and PC controlled automatic choke.

4.1.3.1 Manual Choke

As the name suggests, the manual choke system can be operated by manual control of the choke position, moreover, supported with monitoring of flow in and out, remote transmission of data and remote visualization using website, as long as an internet connection at the well site is provided[41]. Although downhole pressures can be controlled with the usage of manual choke system, the utilization of automated choke systems are more preferable to eliminate human related mistakes while using the system in critical applications of MPD- where narrow window situations are possibly confronted.

4.1.3.2 Semi-Automatic Choke

In addition to the manual choke features, semi automatic chokes are capable of automatic surface back pressure set point control. Arnone presented the advantages of using semi automatic chokes as follows; maintaining stable BHP during connections, instantaneous change in BHP compared to increasing mud weight, improving kick detection, continuing drilling through High Pressure Low Volume (HPLV) nuisance gas zones, optimizing mud weight for ROP, reducing effect of gas-cut mud on lightening fluid column in well[41]. Figure 59 is an illustration of Semi-Automatic Choke Manifold used in MPD applications which is hydraulically operated by applying the back pressure according to the set point.

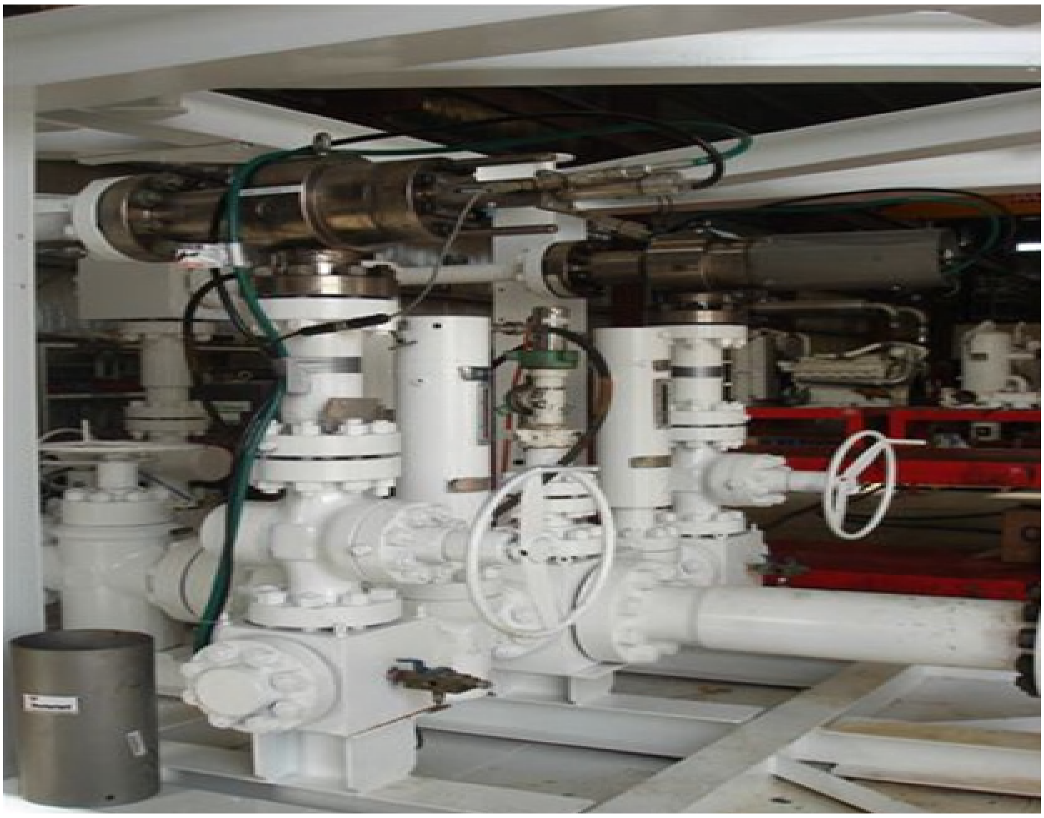


Figure 59 Semi-Automatic Choke Manifold System[41]

The manifold has semi-automatic choke valves which enable accurate control of back pressure. Operation principles were explained in the presentation of Arnone. The system is designed with sliding shuttle within the choke connected to a dynamic trim sleeve. The shuttle assembly slides back and forth into a static trim sleeve to form a circular orifice to control the flow from casing. The hydraulic control pressure (set point) applied to the back side of the shuttle is adjusted by the set point regulator and measured in the hydraulic set point gauge. Casing pressure is applied to the front side of the shuttle[41].

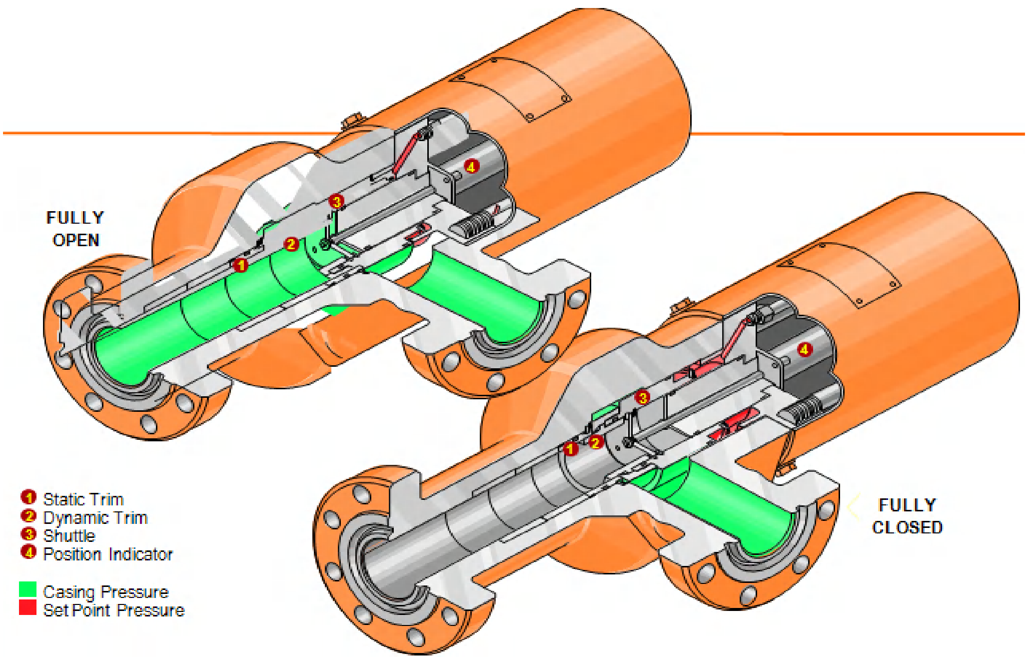


Figure 60 Operation Principle of Semi Auto Choke[41]

Figure 60 is an illustration of operational schematics of semi-automated choke valve both in fully open and fully closed position. Position of the static trim, dynamic trim and shuttle is shown in the figure for better understanding and visualizing the inside of the choke valve. According to the position of the dynamic trim, application of set point pressure can be seen.

4.1.3.3 PLC Automatic Choke

PC controlled choke system is an advance form of other choke systems. The choke has capability of automatic control of any pressure variable desired such as BHP, stand pipe pressure (SPP), surface back pressure (SBP). PC controlled chokes are commonly used in CBHP applications to control BHP while making up new connections in order to prevent pressure related drilling hazards up to a point. The concept is applying back pressure by closing the choke manifold to compensate reduction of AFP while gradually decreasing the pump rate[41].

Step	Choke Pressure (psi)	Pump Rate (gpm)	Pump (spm)	Pump Press (psi)	Friction DP (psi)	BHP (psi)
Pump Rate while drilling	20	196	70	2995	393	1566
Increase choke pressure	48	197	70	3003	393	1617
Decrease pump rate	48	183	65	2646	345	1566
Increase choke pressure	113	183	65	2691	345	1611
Decrease pump rate	113	170	60	2395	300	1566
Increase chore pressure	155	170	60	2397	258	1608
Decrease pump rate	155	155	55	2081	258	1566
And continue with steps until pumps are stopped						
Decrease pump rate	323	85	30	990	90	1566
Increase chore pressure	347	85	30	1014	90	1590
Decrease pump rate	347	71	25	931	66	1566
Increase choke pressure	359	71	25	843	66	1578
Decrease pump rate	359	45	16	596	54	1566
Increase chore pressure	413	45	16	650	54	1620
Decrease pump rate	413	0	0	413	0	1566

50psi range

Figure 61 BHP control with PC Controlled Choke[55]

Figure 61 is an illustration of back pressure control steps to make a connection in CBHP application with the usage of PC controlled automated choke system. BHP can be controlled precisely within a 50 psi range.

The automated choke manifold which includes mass flow meter, precision quartz pressure sensors, Hydraulic Power Unit (HPU), and Intelligent Control Unit (ICU), is an advanced version of the semi automatic choke. The manifold has two drilling chokes, so that one can be used at all times with the second one to be used as contingency. The mass flow meter is installed at the manifold, just downstream the chokes. The Intelligent Control Unit (ICU) is the brains of the Automatic Choke system. All data is acquired and directed to it, and the operation is monitored and controlled from this unit. All the critical controls, algorithms and data acquisition are installed at the manifold, to avoid any potential problem with communication and to increase the reliability of the system[41].

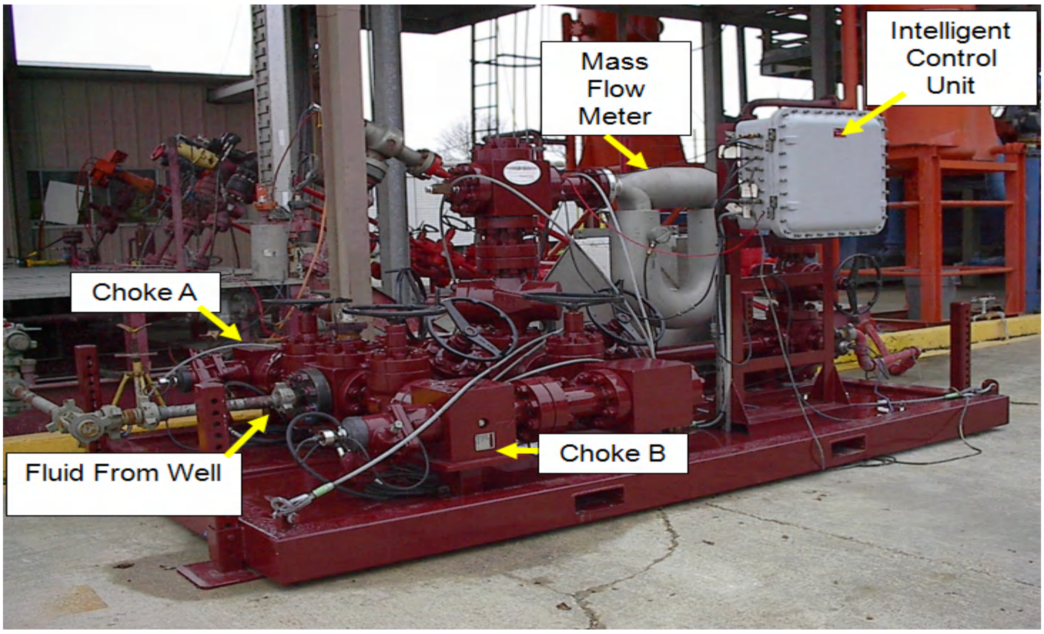


Figure 62 PC Controlled Automated Choke Manifold[41]

Figure 62 is an illustration of Secure Drilling's automated choke manifold. It is different from the semi-automated MPD chokes since the manifold has integrated mass flow meter and intelligent control unit together which enables early detection of any influx or any BHP variations.

4.2 Other Tools of MPD

In addition to the key tools of MPD, some applications of the MPD require additional or supplementary equipment which makes different variations of control possible. According to the Hannegan[47], other tools of MPD are listed below;

- Downhole Casing Isolation Valve (Downhole Deployment Valve)
- Nitrogen Production Unit
- ECD Reduction Tool
- Real time Pressure & Flow Rate Monitoring
- Continuous Circulating Valve
- Continuous Circulating System
- Downhole air diverter[44]
- Multiphase Separation Unit[56]

4.2.1 Downhole Deployment Valve (DDV)

Downhole Deployment Valve (DDV) is a downhole valve which allows tripping without killing the well. The tool has different names in the industry although the purpose of the downhole valve is nearly the same. The other names of the valve are Downhole Isolation Valve (DIV), Casing Isolation Valve (CIV) and Quick Trip Valve (QTV).

The industry has fully embraced and adopted the true benefits of underbalanced operations in the Southern North Sea. Sutherland and Grayson[57] mentioned about tripping that, since 1996, the critical steps have been undertaken to advance from a low-head drilling operation, where the well was killed during trips, to the current fully underbalanced operation, which encompasses drilling through to the completion of the well[57]. In addition to UBD, tripping is an important barrier in MPD applications as well because drilling fluid is designed to provide dynamic overbalance and static underbalance condition. As a result, the increasing demand for MPD applications leads the usage of downhole valves since they eliminate the time spent for tripping and killing the well.

A solution to some of the financial and technical challenges has been found in a newly developed technology called the downhole isolation valve (DIV). See Figure 63. DIV technology is based on a casing-deployed downhole valve system that is used to shut in the well at a predetermined depth and allows for lubrication of the drillstring or completion assembly into the well[57].

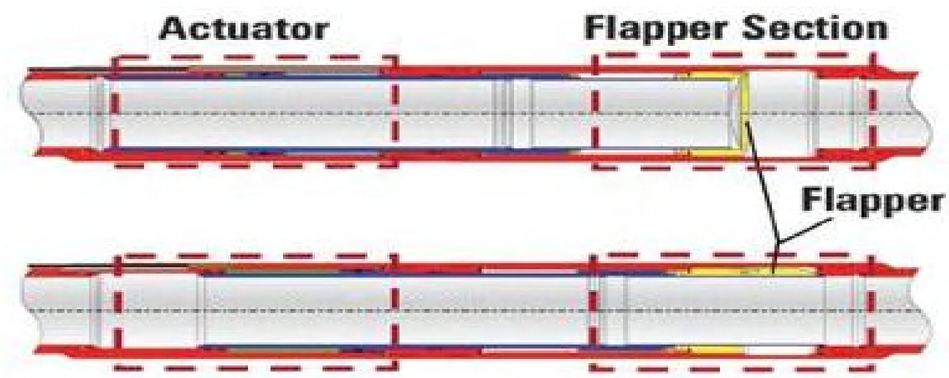


Figure 63 Downhole Isolation Valve (DIV)[57]

Figure 63 is an illustration of Downhole Isolation Valve (DIV) which is designed for safe tripping especially in underbalanced conditions. The top part of the tool has an actuator controlling the flapper movement in the flapper section which is the bottom part of the tool.

The CIV offers the most positive solution to the MPD problem of trips. With a casing isolation valve, the pipe is stripped up into the casing until the bit is above the valve. The CIV is then closed, trapping any pressure below it, which allows the trip to continue in a normal mode without stripping or killing the well. The wellbore pressure below the CIV comes to equilibrium with the reservoir pressure. So, in a high pressure well, the valve needs to be set as deep as practical. This also has the advantage of limiting stripping distance up to the valve level[5].

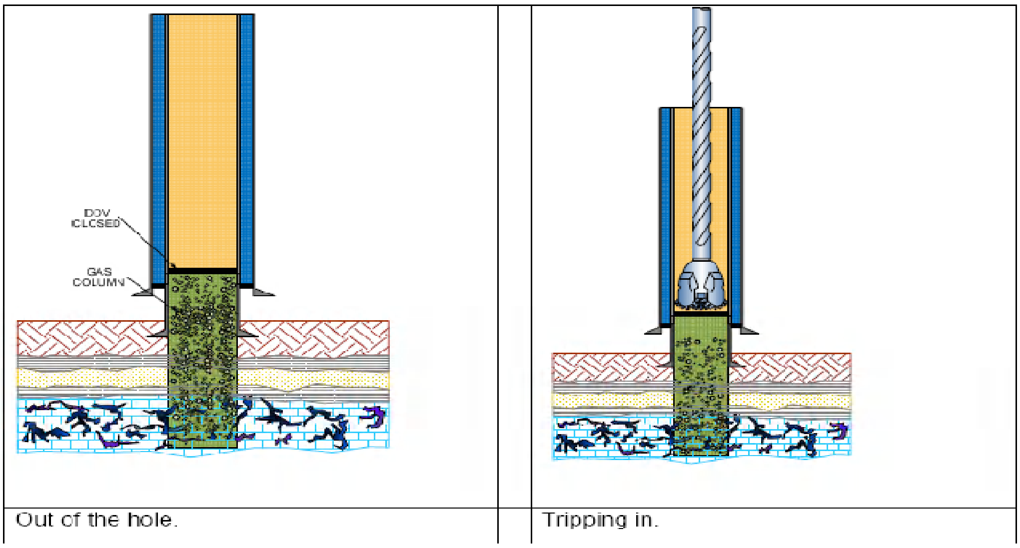


Figure 64 Tripping with Downhole Deployment Valve (DDV)[8]

Figure 64 is an illustration of the usage of DDV in MPD applications. Since DDV is a kind of downhole isolation tool, it is opened and closed by equalizing the pressures below and above the tool.

Going back in the hole, the pipe or tubing is run in to just above the valve. The rams are closed and the upper well bore is pressurized up to equal to the annulus below DDV valve and fluid pumps through the valve. At this point hydraulic pressure is applied to the “open” line, driving down the protective seal mandrel and opening the valve. It is important to note that the tool is not pressure equalized, but the DDV tool is a power-open, power-closed device. The pressures must be equalized before opening[5]. Therefore, power-open feature of the device prevents the risk of sudden expanding of pressurized gas below the DDV.

According to Morales[30], the advantages of Downhole Deployment Valve (DDV) are given below;

- There's no need to kill the well so formation damage is minimized.
- Eliminates time required to circulate kill fluid into and then out of the well
- Protect against potential swabbing and kick while tripping
- No fluid loss
- Eliminates the need for snubbing operations, enhancing safety
- Pipe can be tripped at conventional tripping speeds, reducing rig-time requirements and improving personnel safety.
- Allow for installation of long complex assemblies, such as whipstocks, slotted liners, and expandable sand screens.

On the other hand, there are some limitations of Downhole Deployment Valve given in *Managed Pressure Drilling*[5] such as;

- The DDV should not be used on long term basis (for production). It contains elastomeric seals that can deteriorate over time when exposed to well effluent
- The hole size or previous casings needs to be a size larger
- Pressure limits on the tool must be considered
- The umbilical cord must be protected during cementing, which may limit pipe reciprocation

4.2.2 Downhole Air Diverter (DHAD)

The Downhole Air Diverter (DHAD) is a drillpipe or drill collar sub equipped with two sonic nozzled valves strategically placed in the drillstring to divert a portion of the compressed pneumatic fluid from inside the drillstring into the annulus. Depending on the application and the specific goal there may be one or more of these diverter subs in the drillstring[44]. Although it is mostly used in Air Drilling applications; according to the Mellott, it can be classified as a MPD tool, considering the definition of MPD.

DHAD (see Figure 65) has been able to increase the efficiency of the compressed air system improving drilling performance in most drilling situations where pneumatic fluid is used for cuttings removal by a more efficient use of the compressed air's energy[44]. Since the tool reduces the losses in BHA by diverting the flow, the efficient use of energy is gained.

Figure 65 Downhole Air Diverter (DHAD)[44]

Mellott[44] stated the benefits of the DHAD as;

- Less annular bottom hole pressure
- Less surface drill pipe pressure
- Reduction or elimination of low velocity zones
- Reduction of erosion potential through BHA
- Reduction of downhole fire potential
- Aids in use of hammer tool and flat bottom bit to control angle

4.2.3 Nitrogen Generation Unit (NGU)

The Corporation's membrane Nitrogen Generation Units (NGU) or Nitrogen Production Units (NPU) produce nitrogen from air using a filtering process. Atmospheric air is compressed and then cooled. The air then enters a series of filters designed to remove particulates, hydrocarbons, and water vapor from the flow stream. The dried and particulate-free air proceeds to an oxygen filter membrane that separates the nitrogen from the flow stream and vents the oxygen to the atmosphere. The approximately pure nitrogen then enters a gas booster where the pressure is increased to working pressure. These systems are best used for remote locations where the cost of delivered liquid nitrogen is high, when scheduling and delivery of nitrogen takes a long time, or when the requirement calls for continuous mobility[58]. The primary usage of the NPU (see Figure 66) is in DG MPD applications where there is a need for continuous supply of nitrogen to reduce the upper riser mud density.

Figure 66 Nitrogen Generation/Production Unit (NGU/NPU)[59]

4.2.4 Multiphase Separation System

The use of the separators is a need especially in DG MPD applications where the separation of gas is an obvious issue or can be used in case of any influx to condition the mud. There are different separator designs consistent with their purpose. Vertical separators are the optimum design for separating gas from liquid, and horizontal separators are the optimum design for the separation of liquids of various densities. A dual purpose separator for the separation of formation fluids consists of an underbalanced drilling separator and a MPD separator. The dual purpose process reduces the separation costs of the current four phase (oil, gas, water and solids) horizontal UBD separator[58]. Multiphase separation systems offer advantages for some offshore MPD applications[56].

Figure 67 Multiphase Separation System for MPD[56]

Figure 67 is a photo of Multiphase Separation System for MPD purposes, taken in an offshore platform.

4.2.5 Coriolis Flowmeter

Coriolis Flowmeter is one of the important tools in MPD applications since measurements provide a supplementary data while using with automated pressure control systems. Measuring principle is based on control generation of coriolis forces. It has specifically designed meter body, so only fluid properties influence measurement intrusive type meter. Measurements have accuracy of the order of 0.15 % of reading. Change in fluid properties has minimum impact on (taken care of) measurement. Mass flow and density measurements are possible. Proper installation of meter avoids the gas/solid accumulation and it is ideal for slurry flow measurements. Coriolis force is not affected by external forces (noises). Risk of erosion, during high flow rates specially with solids, should not be disregarded[41].

Malloy and McDonald[8] explains that the fluid density can be accurately determined directly with great precision by measuring the time it takes to complete one oscillation (wave period) (see Fig. 68). Since the oscillations happen in the range of tens of thousands per second, it does not take more than an instant to sense the change in fluid density.

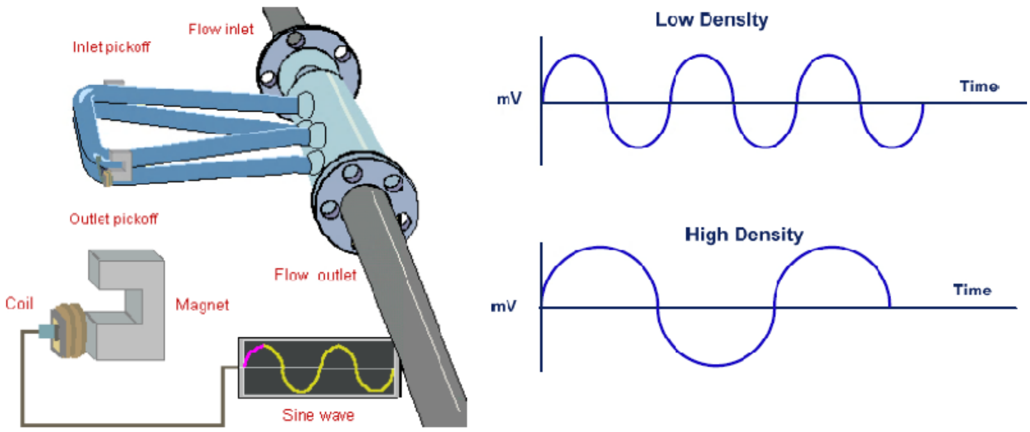


Figure 68 Working Scheme of Coriolis Flowmeter[8]

4.2.6 ECD Reduction Tool (ECD-RT)

ECD Reduction Tool (ECD-RT) is one of the downhole tools that enable the applications of MPD. Malloy and McDonald[8] stated that Equivalent Circulating Density (ECD) can be altered by modifying the annular pressure profile directly. Using a single density drilling fluid, a downhole motor can be used to add energy that creates an abrupt change in the annular pressure profile[8]. Reduction of the ECD acts as if drilling with the hydrostatic head of mud column, which allows no need of back pressure when the system is static. In brief, BHP is equal in both static and dynamic conditions.

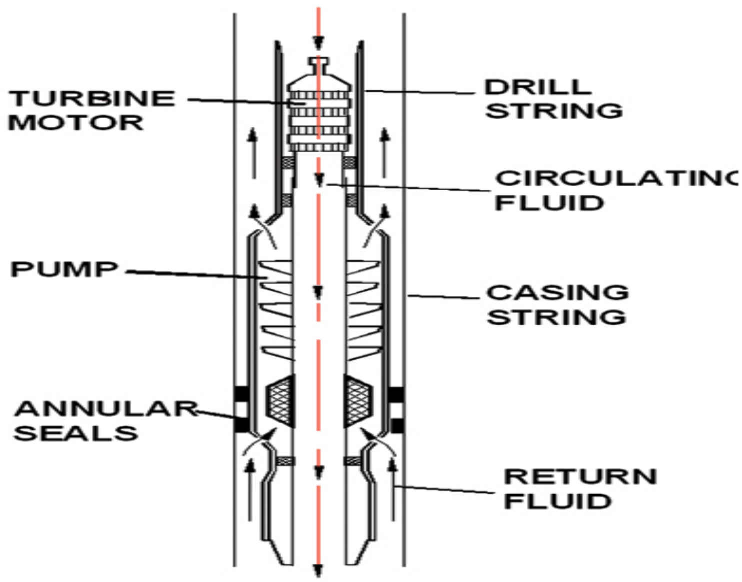


Figure 69 Flow path and Components of ECD RT[60]

The ECD reduction tool is expected to have application in deepwater drilling (where drillers are historically forced to run several casing strings to reach target depth, therefore progressively reducing the hole size) and extended-reach wells (where the length of the well increases frictional pressure loss, thereby increasing ECD and causing fracturing and/or mud loss)[60].

4.2.7 Real Time Pressure & Flow Rate Monitoring

Real time measurements are one of the appreciated technologies not only providing invaluable data to the automated control systems, but also monitoring the results of the applications of emerging concepts. Managing the BHP accurately within a narrow window or margin helps to mitigate the risk of critical drilling events and improves drilling performance and well control. In managed pressure drilling, flow rate measurements are used to mitigate potential well control risks through[37]:

- ✓ Early kick detection, which involves detecting, as early as possible, the influx of fluids from permeable or fractured formations into the wellbore[37].

Figure 70 Real time detection and monitoring of influx[41]

Figure 70 is an illustration of influx detection. Basically, Red line in the first column shows the increase in return flow. Blue and Green line in the third column shows the increase in SPP and BHP.

✓ Detection of lost circulation, which involves detecting the loss of drilling fluid from the wellbore into permeable or fractured formations[37].

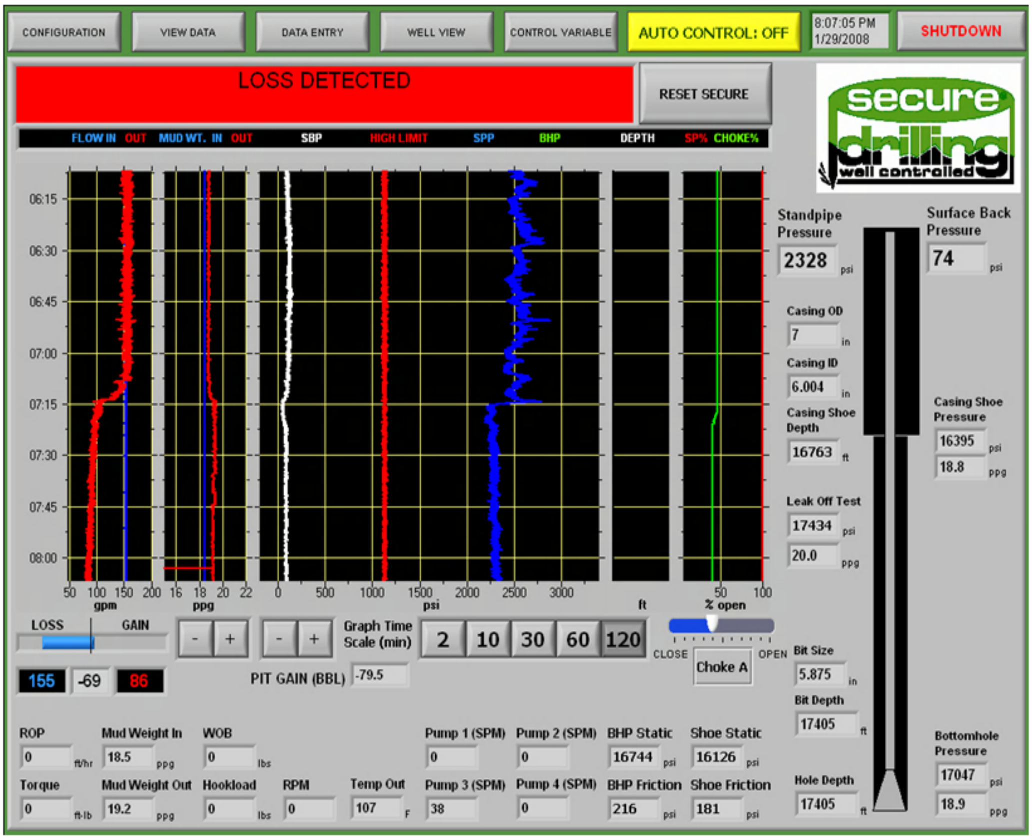


Figure 71 Real time detection and monitoring of loss[61]

Figure 71 is an illustration of loss circulation detection and monitoring. In the first column, return flow rate (red line) is decreasing while circulation rate (blue line) is constant. This is the primary indicator of a fluid loss situation which can be seen also in the bar below the first column. In the third column, decrease in the SPP (blue line) is shown. In the second column, return flow density (red line) is slightly increased comparing with inflow density (blue line). The increase in the return flow density might be caused by the cuttings in the mud which results in BHP increase due to the increase in ECD caused by cutting loadings. As a result, loss circulation is confronted since the dynamic pressures would exceed the leak-off test pressure. The simple discussion is a proof that such kind of an invaluable real time data provides better understanding on the well dynamics which leads to better control.

Eliminating or minimizing drilling fluid influx and losses reduces costs, improves safety, increases wellbore stability, and decreases formation damage. Increasing stability and decreasing damage enables oil companies to drill difficult and or otherwise impossible-to-reach targets with less cost[37].

The system is controlled remotely by the driller or MPD operational personnel through a remote control panel, which houses the user interface. This device is a computer that is mounted in a box, and has a touch screen monitor. Ideally, the remote control and display unit should be mounted on the rig floor in a convenient place where the driller can have easy access[41]. See Figure 72.

Figure 72 Real Time Monitoring Screen on driller's console[41]

4.2.8 Continuous Circulating Valve (CCV)

Continuous Circulation Valve (CCV) is also known as Continuous Circulation Device (CCD). CCV is one of the tools enabling Continuous Circulation Method which is a sub category mentioned under CBHP MDP. A Continuous Circulation Valve (CCV) was developed for enabling drilling in depleted reservoirs at HP/HT fields in the Norwegian sector of the North Sea. By utilizing a system to obtain circulation through the whole drilling operation, the downhole pressure will remain constant even during drillpipe connections. By balancing this downhole pressure between a maximum pore pressure and a minimum fracture pressure, drilling can be performed properly even through narrow drilling windows[62]. As a result, the mud can be designed for dynamic conditions since the wellbore is never under static condition due to continuous circulation.

Figure 73 Continuous Circulation Valve (CCV)[24]

Figure 73 is an illustration of CCV. As it is cited in Rasmussen and Sangesland's study[42], short drill pipe joints with a valve arrangement are integrated in the drill string. During drill string connection, the valve arrangement allows drilling fluid to be injected through a side port in the drill string joint and into the drill string[42]. Figure 74 is an illustration of Continuous Circulation Method considered under CBHP MPD with the usage of CCV.

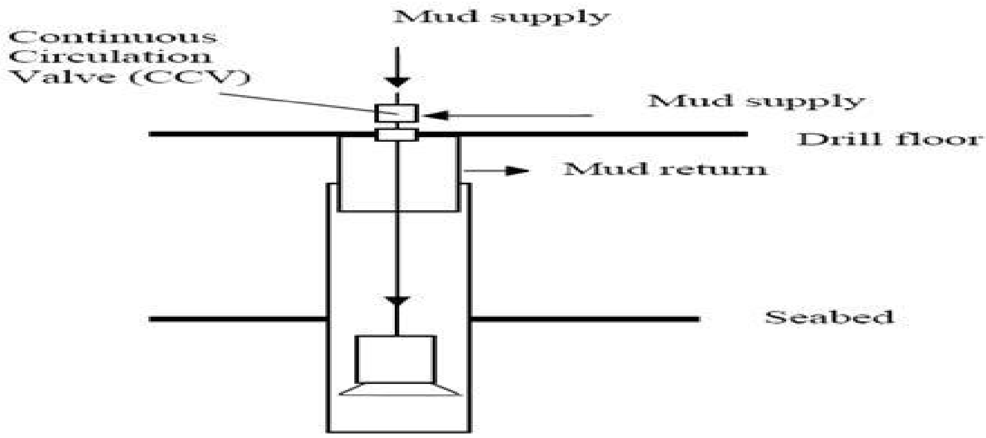


Figure 74 Continuous Circulation Method with CCV[42]

Torsvoll et al.[62] informed about how to operate the CCV. The valve is a two-position, three-way ball valve. It is possible to circulate through the valve from the top drive down the drill string or through a side port and down the drill string. Such a valve must be installed at the top of each drill pipe stand before the continuous circulation operation starts. When a connection is to be performed, a hose must be connected to the side inlet of the valve, the flow from the mud pumps will then be switched from the top inlet to the side inlet, and top drive can then be disconnected and a new stand installed. To continue drilling, the operation is reversed. The valve is designed to withstand HP/HT pressures, including gas-filled casings, bull heading and maximum pressure during standard drilling operation[62]. The maintenance and inspection of the CCV should be done before using in the operation since there are various numbers of CCV in the wellbore.

4.2.9 Continuous Circulation System

Continuous Circulation System (CCS) allows for continuous circulation in the well when using jointed pipe. As it is cited in the Rasmussen and Sangesland's study[42], the system was developed by a joint industry project managed by Maris International. During connection, the drill pipe is suspended from a pressurized chamber that comprises two pipe rams and one blind ram. This arrangement enables the circulation of mud down the drill string to be maintained throughout the entire section[42]. CCS is one of the appreciated technologies in CBHP MPD applications since system has a wide range of usage to mitigate drilling hazards. See Appendix A.

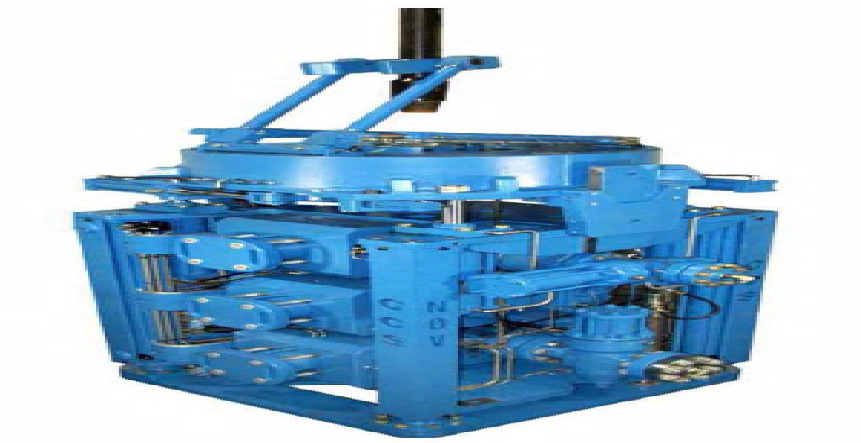


Figure 75 Continuous Circulation System[8]

Continuous circulation system (CCS) which is shown in Figure 75 permits full circulation during drill pipe connections. In HPHT wells, it is only by maintaining full circulation at all times that we can control the impact of downhole temperature changes. By maintaining the downhole temperature profile with minimum variations, we can achieve something close to hydraulic stability in the well. This is a great benefit to choke control and improves the sensitivity for detecting trends in other parameters. Once installed and commissioned, the CCS requires aligning and tuning to the rig systems. However, once this has been completed, the system can perform reliably for extended periods of operation[63].

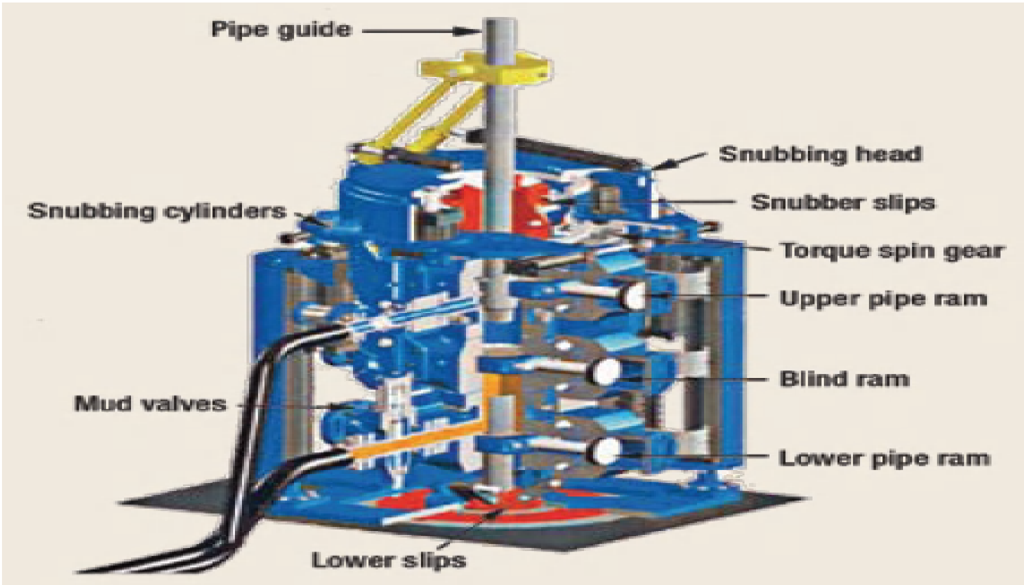


Figure 76 Components of Continuous Circulation System[9]

Figure 76 is an illustration of the components of the system. Combination of two pipe rams and a blind ram allow pressurization of the system by injecting fluid through mud valves while breaking out or making up a connection. Snubbing components and torque spin gear provide appropriate connection eliminating any damage.

Malloy[9] mentioned about another feature of the system by giving information about the procedure as; the continuous circulating device breaks the drillstring connection and, through a sequence of operations, diverts the fluid flow across the open connection. The device makes up the new connection to the appropriate torque and drilling continues[9]. Schematic view of the sequenced operations of CCS was finalized by Elkins (2005) to clarify how the device works[8].

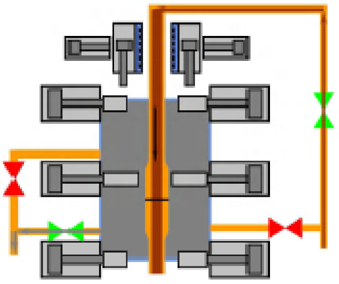
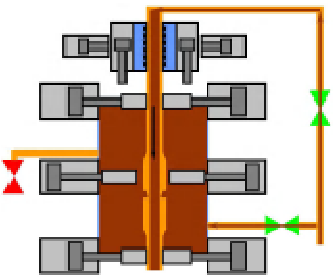
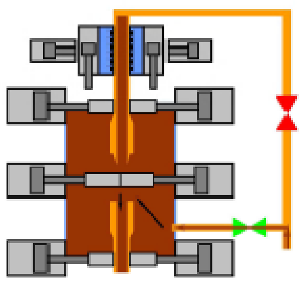
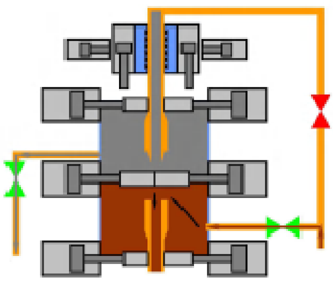
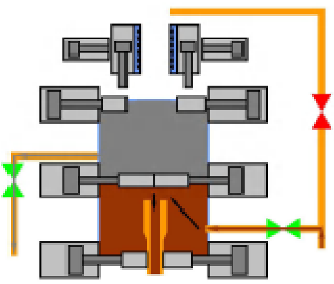
• DRILLING • Standpipe mud flow open • Lower chamber mud drain open START	 DRILLING	FINISH • Close lower chamber mud flow • Open lower chamber drain • Release pressure in chambers • Release upper and lower pipe rams • Disengage snubber • DRILLING
• Close upper and lower pipe rams • Engage snubber • Standpipe mud flow open • Mud flow into upper and lower chamber and pressurize • Contain force from mud pressure with snubber • Break out saver sub		• Close upper chamber drain • Open standpipe to mud flow • Open middle blind rams • Lower drill pipe • Make connection • Torque connection with snubber
• Raise saver sub • Close middle blind rams • Mud flow into chamber and pressurize lower chamber • Close standpipe mud flow • Mud pumped through drill string via pressurized lower chamber		• Mud pumped through drill string via pressurized lower chamber
• Mud pumped through drill string via pressurized lower chamber • Depressurize upper chamber • Drain upper chamber		• Mud pumped through drill string via pressurized lower chamber • Engage snubber • Close upper pipe rams
• Mud pumped through drill string via pressurized lower chamber • Open upper pipe rams • Disengage snubber • Remove saver sub		• Mud pumped through drill string via pressurized lower chamber • Pipe dope pin connection • Pick up stand for connection

Figure 77 Sequence of Operations of CCS[8]

CHAPTER 5

MPD APPLICATIONS

With respect to professional judgment and absolutes, Managed Pressure Drilling operations are application dependent. A successful Managed Pressure Drilling operation requires a certain minimum amount of equipment, technology, and know-how. Managed Pressure Drilling is not unlike a lot of other projects. Not only do you have to have tools, you have to have the correct tools and use them in an appropriate manner. Having a Rotating Control Device installed above the Annular Preventer does not constitute a MPD operation, unless that device is augmented with a drilling choke manifold (separate from the rig choke manifold), Non-return Valves (NRV) in the drill string, and a "what-to-do-if" or troubleshooting guideline for those operating the equipment[8].

On the other hand, drilling a well is not only a technical concept but also an economical issue. Therefore, feasibility of a drilling process should be determined. Most of the remaining hydrocarbon reserves which are invaluable to drill are lying in the deeper parts of the sea. That is the reason for offshore projects or deep water projects require more budget than the land projects. However, it is very hard to mitigate drilling hazards in deep water applications which force the companies to develop their existing techniques and tools. Nowadays, MPD is one of the evolving technologies in the drilling industry, promising to overcome the challenges of deep water environment. Among the most pronounced applications, which are more challenging, are depleted reservoirs, methane hydrates, high pressure high temperature and extended reach wells.

5.1 Depleted Reservoir Drilling

Conventional drilling through a depleted zone with an overlying high pressure formation in a typical PP-FP window may cause lost returns due to high wellbore pressure against the depleted zone while overbalance is maintained at the high pressure formation. This problem may be mitigated by controlling the wellbore pressure precisely by CBHP operation so that the fracture pressure at the depleted zone is not exceeded while overbalance at the high pressure zone is still maintained[12].

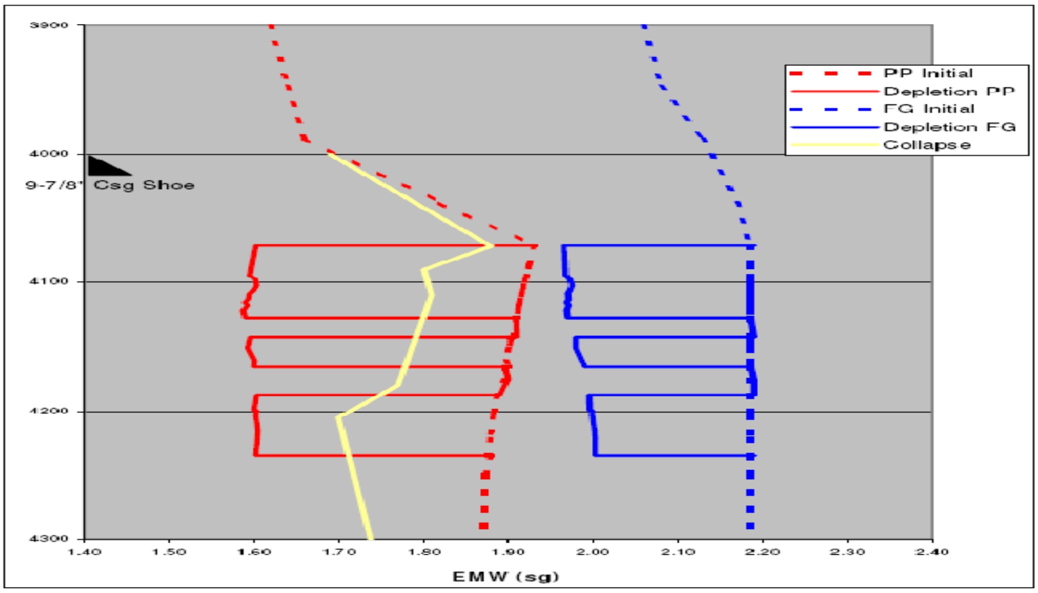


Figure 78 Change in Pressure Profiles in Depleted Sections[64]

Figure 78 is an illustration of the variation of the pressure profiles in the wellbore especially in the heavily depleted sections. Dash lines demonstrate the initial formation pressures and solid lines demonstrate the reduced pressures due to production. Narrow drilling window is the chronic challenge faced in depleted wells.

Similarly, if a high pressure formation is penetrated with an overlying depleted zone, CBHP operation may be able to maintain the well bore pressure within the required window that doesn't exceed the fracture pressure at the depleted zone and maintains overbalance at the high pressure zone. A proper combination of hydrostatic pressure, AFP and back pressure will be required for such precise control of the wellbore pressure[12]. To sum up, accurate control of downhole pressures is an important issue since drilling hazards can be confronted both at the top of the depleted section and at the top of section just below the depleted section.

The main prospective drilling hazards confronted in depleted wells are cited in the study of Kulakovsky et al. Industry studies have shown that drilling costs and nonproductive time (NPT) increase as reservoirs become depleted. The top two causes of NPT and the related additional costs associated with drilling depleted areas are: (1) differential sticking and (2) lost circulation incidents. With UB or MPD, related incidents and associated costs may be avoided[65]. In fact, mitigating drilling hazards is the primary aim of MPD variations.

In addition to two main drilling hazards, Hannegan[10] emphasized the possibility of another drilling hazard. These prospects are "hydraulically challenged" because it is often a requirement to drill through production zones which no longer possess their virgin pore pressure. With the mud in the hole at the time, these zones of depleted pressure often result in lost circulation of drilling fluids. This causes excessive mud costs and higher risks of differentially stuck pipe and twist-offs. It is also not uncommon to experience kicks (influx of hydrocarbons) within that same open hole from "energized stringers of near-virgin pore pressure[10]. While trying to avoid overbalanced condition to eliminate two main hazards, drilling with a slightly overbalanced mud depending on the narrow window may cause incident kicks.

As it is pointed out by Hannegan as well, if mud density is reduced to avoid exceeding the formation fracture pressure and experiencing lost circulation at one depth with depleted pressure, kicks may occur a stand of pipe or two further down if stringers of abnormal pressure are encountered. This is the classic “kick-loss” scenario that results in drilling non-productive time, excessive mud cost, and quite frequent well control issues[10].

Although CBHP MPD is the most mentioned variation, another variation of MPD can be used in the depleted sections of the well. Mud Cap Method (MCM) might be an alternative to drill depleted sections since its primary strength is coping with loss circulation. Malloy and McDonald[8] stated that this method also addresses lost circulation issues, but in another manner using two drilling fluids. A heavy, viscous mud is pumped down the backside in the annular space to some height. This “mud cap” serves as an annular barrier, while a lighter, less damaging, and less expensive fluid is used to drill into the weak zone. Improved rate of penetration (ROP) would be expected using the lighter drilling fluid because of more available hydraulic horsepower and less chip hold-down. The less expensive sacrificial mud and cuttings are pumped away into the depleted zone below the last casing shoe, leaving the heavier mud in the annulus as a “mud cap”.

Hannegan[1] extended the usage of mud cap by stating that ultimately PMCD variation is expected to be used in deep water where heavily depleted old pay zones must be drilled to reach deeper pay zones of virgin pressure. It may allow safe drilling of these zones where the depleted zone above the target has rock characteristics that are capable of receiving the sacrificial fluid and drilled cuttings. The mud cap plus backpressure forces the "returns" into the zone of least resistance, the depleted zone above[1].

While penetration rates increase as bottomhole pressure decreases, the savings in drilling days with MPD are often negated by the increased spread rate cost associated with the extra safety equipment required (i.e., if NPT issues do not need to be mitigated at the same time). Because many of the problems of drilling depleted zones (and the associated extra costs) are avoided with MPD, the real advantage of this method is observed later in the life of a field, after reservoir depletion has occurred. This can be best observed in Figure 79. When the reservoir life cycle has advanced and we start operating on the right side of the dashed line, the additional spread rate associated with MPD is often greatly overshadowed by the increase in trouble-drilling cost[65].

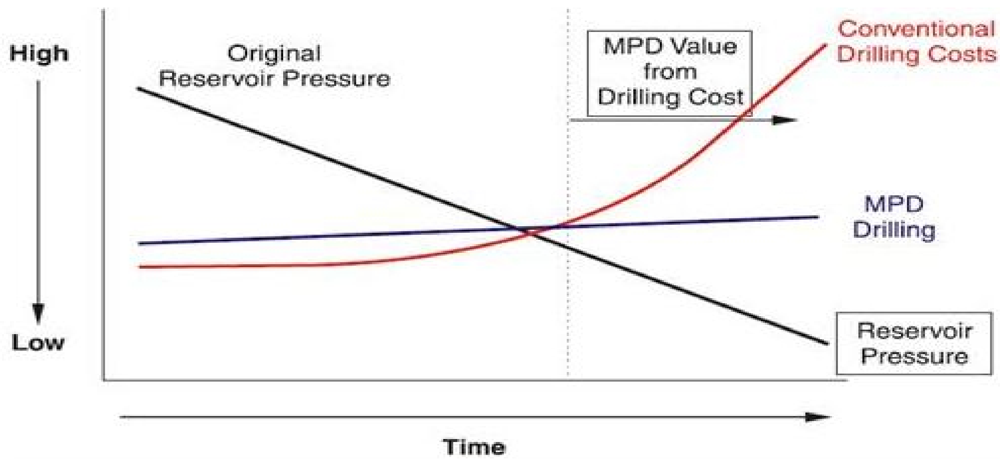


Figure 79 Relative field development drilling costs[65]

Figure 79 is an illustration that comprises of relative field development drilling costs. It is obvious that although relative drilling costs of MPD are higher than the conventional costs, in depleted reservoirs nobody denies the cost-related advantages of MPD methods.

5.2 HPHT Drilling

High Pressure High Temperature (HPHT) wells are one of the most challenging wells to drill since primary control variable of MPD applications, annular frictional pressures, are directly affected by temperatures. Therefore, HPHT drilling requires an advanced level of control supported with both equipments and planning.

During MPD operations in general, and especially in HPHT wells, relatively small failures can ultimately cause loss of the well. Hence, it is of utmost importance that everyone has the skills and motivation to do their work properly. This is a management responsibility. MPD must not commence until all personnel are competent for the upcoming tasks. This includes working as a team, as well as performing their individual responsibilities[63].

In challenging deep HPHT wells, where kick tolerance is very narrow or doesn't exist at all, it is necessary to use innovative Technologies in order to be able to drill on[24]. Therefore, an extensive series of hazard identifications (HAZIDs), hazard and operability studies (HAZOPs), peer reviews and workshops were conducted, covering every aspect of the proposed operation. These consultations refined the methods, configurations and procedures that were employed and proved an important contributor to the success of the project[63]. Once the project is clarified in all means, the next step is choosing the effective equipments to eliminate discussed hazards or contingencies.

Key to the adaptation of MPD for HPHT applications is the retention of the high-pressure (HP) blowout preventer (BOP) system below the MPD control stack. This met all well control requirements for HPHT wells. At any time the HP BOP system could be engaged and the established HPHT well-control procedures applied. There is scope for the use of the MPD control stack for low-pressure well control incidents (by far the most common event on HPHT wells), but, in this instance, a demarcation was made between well control and operational control[63]. As a result, well control procedures should be applied with the usage of HP BOP, independent from volume and pressure of the influx, since there is no or little the kick tolerance.

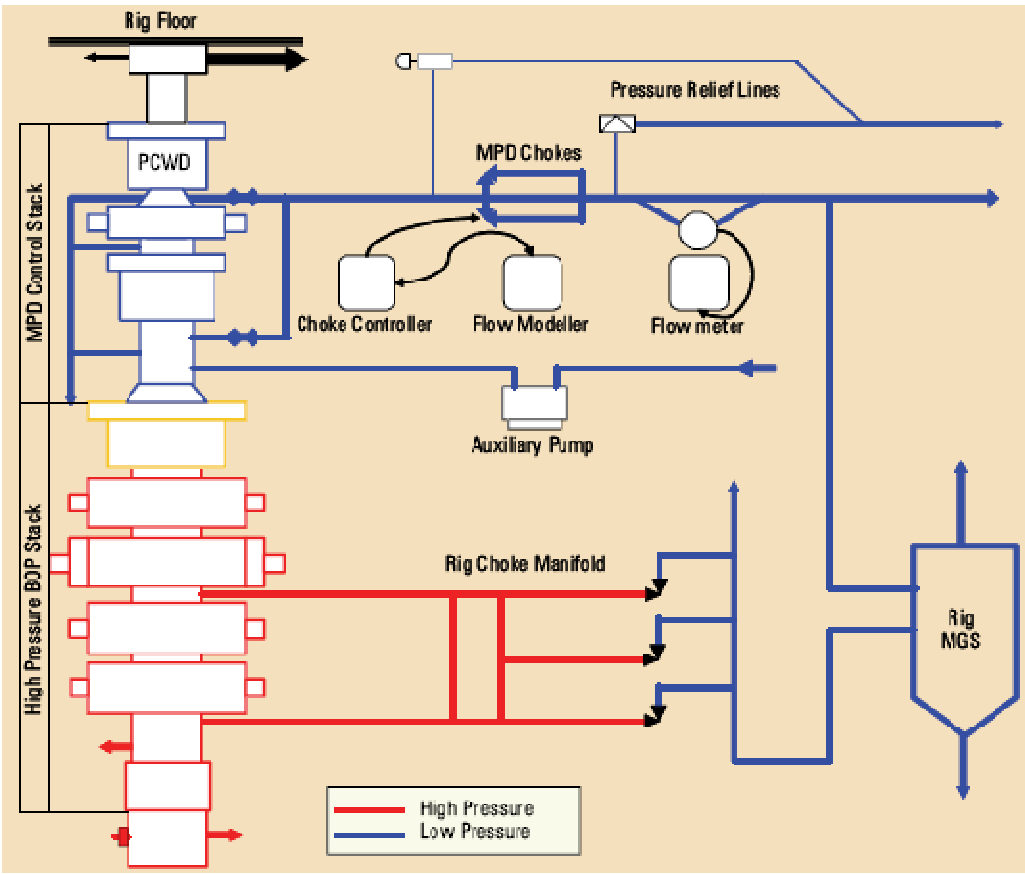


Figure 80 Equipment layout of MPD for HPHT applications[63]

Figure 80 is an illustration of equipment schema for HPHT applications. Red lines shows the high pressure lines for well control and blue lines shows the low pressure lines for operational control. In brief, upper stack is installed for MPD purposes; lower stack is installed for well control purposes.

At the heart of the MPD control system is a pressure control while drilling (PCWD) rotating control head. This item has a long history of successful field use and benefits from an active sealing element ideally suited for stripping drill pipe. The remainder of the MPD stack was configured to provide component redundancy, flexibility and to facilitate efficient PCWD element change-out[63]. However, Hannegan mentioned about active seals that the inflated element does not handle stripping out under pressure very well[3]. Therefore, using a high pressure RCD is another option to consider.

The HPHT environment requires accurate automated choke control to compensate for BHP variations that arise from downhole temperature changes, drill pipe rotation, swab/surge and several other phenomena that are known to create significant BHP variations in HPHT wells[63].

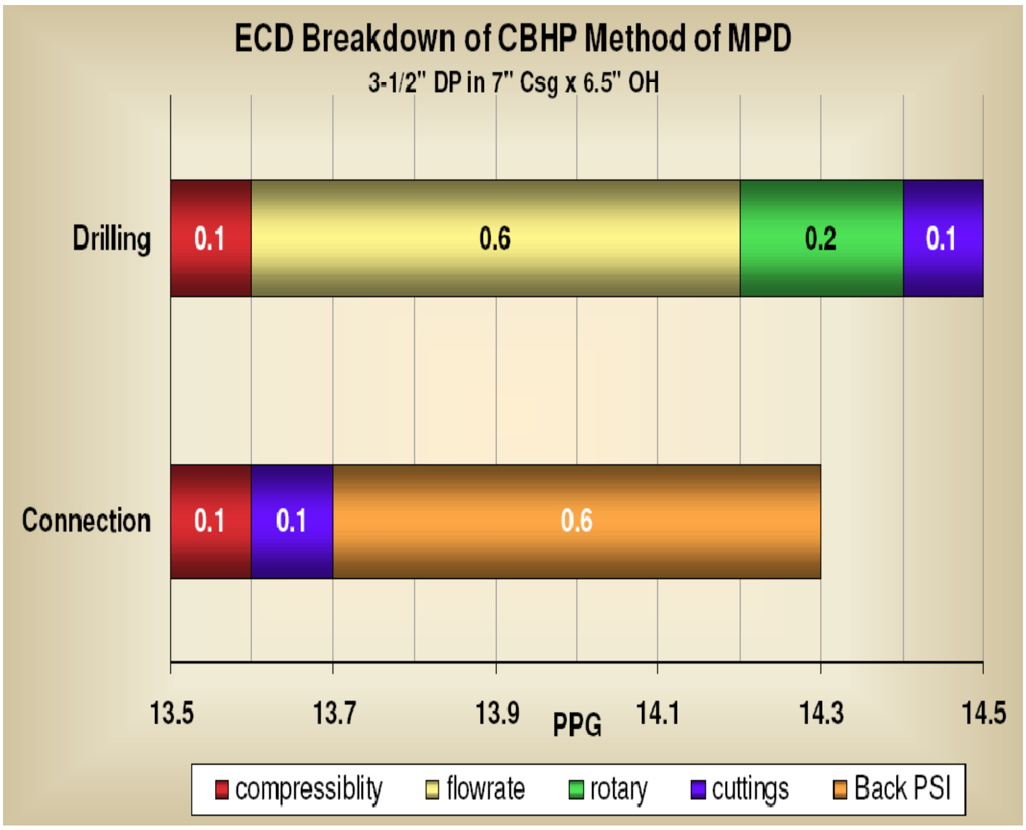


Figure 81 Bottom Hole Pressure Components[36]

Figure 81 is an illustration of the components of the BHP. It is important to note that the effect of rotation is considerably high, since it should be compensated in order to keep BHP constant.
Further consideration was required to avoid choke plugging or erosion, so the dual redundant automatic chokes were specifically selected to avoid choke erosion. This is a common concern on well clean-up operations, but less so during MPD operations. The problem has more or less been eliminated through choke design. Some testing was needed to optimize the size of the choke trim. A junk catcher immediately upstream of the choke manifold was considered but discounted as being of little practical benefit[63].

Automatic choke control is an essential requirement. Accurate input to the choke controller from the flow model is one aspect; the accurate and timely control of choke movements is another. Both are required for the system to react fast enough and work well[63].

Compensation is performed by manipulating the choke and adjusting the annulus back-pressure. To do this in the HPHT environment, an advanced dynamic flow model running in real time is required. Computing power can become a limitation, as can the accuracy and speed of input data from rig sensors. Calibration of the model with measured downhole pressure data is important to ensure accuracy[63].

The hydraulic flow model is vital to the adaptation of MPD technology for HPHT applications. HPHT wells have characteristically high BHP variations, not just from the high equivalent circulating densities (ECD). Downhole temperature changes affect mud weight and viscosity, pipe movements, rotation, torque, cuttings load, etc., all of which produce continuous and significant variations in downhole pressure. Only by compensating for these constant BHP can be achieved[63].

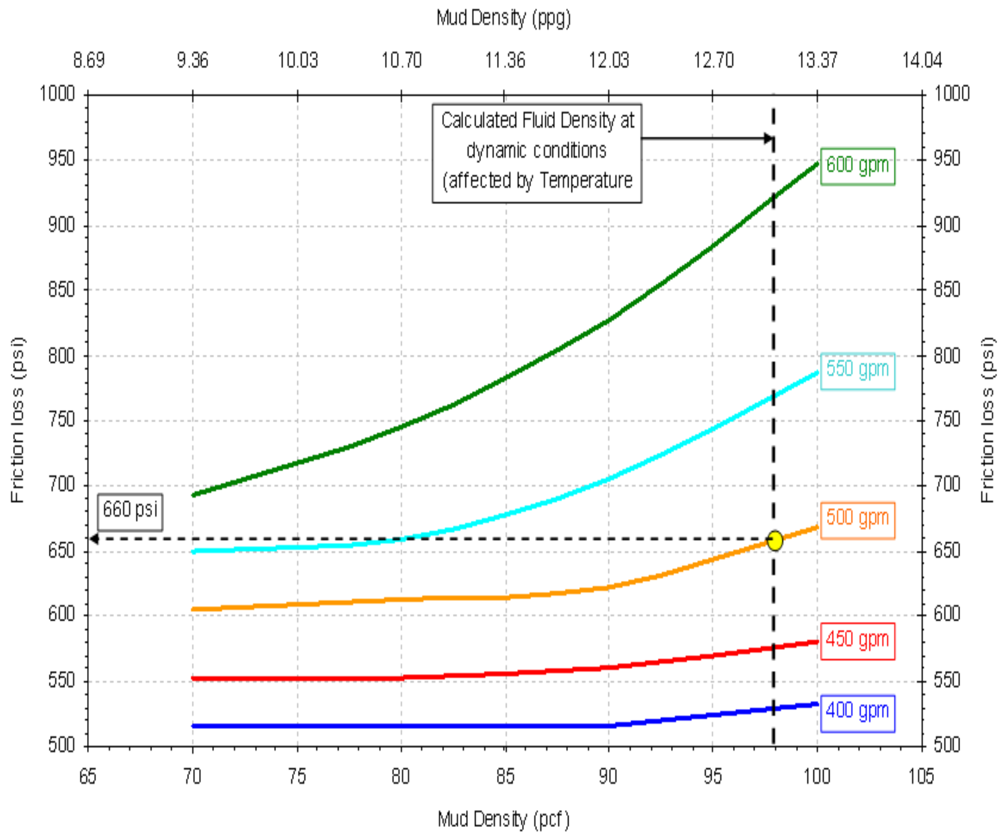


Figure 82 Effect of Flow rates on Frictional Pressures[41]

Figure 82 is an illustration of Frictional pressure losses changing with dynamic mud densities affected by temperature. As the flow rates are increased, the pressure variations get higher.

The mass flow-meter was configured with a bypass to allow for cleaning or unplugging if required. Once configured and calibrated, the meter provided exceptionally high-quality data. Potential exists for this data to be used for online analysis, event determination and automatic system response to unwanted events. On this operation, the mass flow-meter was used only for monitoring, with no direct control of the system. Further automation and the reduction of manual intervention is an achievable future goal for

MPD control systems[63]. On the other hand, PLC Choke Systems can be used in advance for operational control which has integrated flow meter on the choke manifold.

Another key tool, a NRV should be used in the drillstring to prevent flow into the string. In HPHT wells, dynamics of the system should be carefully controlled and managed, because any unexpected or non-controlled change could occur in dynamic conditions.

Pressure relief valves were included in the return flow line to protect equipment and the well. The primary relief valve immediately upstream of the choke manifold was automatically controlled by the choke control software. This valve was set to activate 5-10 bar above the choke set-point pressure, depending on the operation being performed. When the choke set-point pressure was adjusted by the flow model, the relief valve's set-point would also automatically change. Once triggered, this automatic relief valve would re-set itself when the pressure drops below the set-point. This provided exceptional protection of the well from over-pressure, and the re-set feature helped prevent underbalanced conditions. This device proved its worth on several occasions and performed exactly as intended[63].

Continuous circulation system (CCS) permits full circulation during drill pipe connections. In HPHT wells, it is only by maintaining full circulation at all times that we can control the impact of downhole temperature changes. By maintaining the downhole temperature profile with minimum variations, we can achieve something close to hydraulic stability in the well. This is a great benefit to choke control and improves the sensitivity for detecting trends in other parameters. Once installed and commissioned, the CCS requires aligning and tuning to the rig systems. However, once this has been completed, the system can perform reliably for extended periods of operation[63].

Another alternative to prevent continuous flow interruption is Continuous Circulation Valve (CCV). Although its design features enable the valve work under high pressure, working under high temperature should be tested before making up the string since it is a downhole tool and it may fail to resist high temperature.

Another alternative of using a mud heater can be considered as its eliminating temperature induced pressure variations in the bottomhole. However, as it is cited in study of Das[12], Iverson discussed the results of a simulation study of a MPD operation in a high pressure high temperature (HPHT) well to investigate the effect of (1) automatic choke regulation, (2) a continuous circulation device and (3) a mud heater. Application of a continuous circulation device or a mud heater has primarily a stabilization effect on the wellbore pressure profile, while automatic choke regulation is considered as a direct and fast response technique for back pressure application. The simulation results indicate that in case of drilling in the marginal high temperature reservoir, application of a mud heater does not contribute significantly to stabilization of downhole pressure, regardless of the type of mud is used.

5.3 Methane Hydrates Drilling

Methane Hydrates are a unique and challenging energy resource. Unlike conventional oil and gas deposits, Methane Hydrates will require an innovative technology package that can manage the dynamics of this resource safely and efficiently. The technology employed must control the methane hydrate resource throughout the exploration and production process[66]. Most mentioned technologies which are capable of drilling methane hydrates are Managed Pressure Drilling (MPD) and Drilling with Casing (DwC).

Hydrates are natural gases, typically methane, that are trapped within ice crystals. Since most of the hydrates that are found are methane gas, this shallow hazard is commonly referred to as methane hydrates. Methane hydrates form in low temperature, high pressure zones where water and methane are present together. Above 68 °F methane hydrates cannot exist, however below 68 °F methane hydrates can exist depending on the pressure within the zone[34].

Over the past three decades, expeditions into Polar Regions and deep-water continental shelves all over the globe have consistently reported the presence of methane hydrates. The magnitude of this previously unknown global storehouse of methane is truly staggering and has raised serious inquiries into the possibility of using methane hydrates as a source of energy. In the U.S., for example, about 900 trillion cubic feet (Tcf) of natural gas has been produced to date. An estimated “remaining recoverable with conventional technology” is 1,400 Tcf. The estimated amount of “in place” methane hydrates is 2,000 Tcf[18]. That is the reason why methane hydrate drilling is invaluable to challenge.

Methane Hydrates are a unique product because they expand hundreds of times from their solid to gas form. This sublimation process can happen in the reservoir, the well bore, or on the surface. Figure 83 provides a basic schematic illustration of hydrate phase relationships and implications for alternative drilling scenarios. Hydrate curves are represented by solid black lines. These can represent a family of hydrate quality curves for (e.g.) methane hydrates, or a series of hydrate curves for natural gas hydrates in which each curve applies for a different gas gravity. In this simplified graphical form, hydrates can exist if pressure & temperature conditions are to the left of the solid lines, and dissociation will occur to the right. The dashed lines with colored symbols represent indigenous and dynamic pressure vs. temperature relationships at depth. The black line indicates an example P & T relation for the formation strata. The colored dashed lines represent example P & T relationships within a wellbore under dynamic conditions – i.e. while drilling[66].

The different colors are labeled as indicating different drilling techniques. This is, of course, a schematic example. Nevertheless it serves to illustrate that applying conventional or underbalanced drilling to hydrate zones will at some point lead to dissociation of hydrates at a location within the wellbore while the cuttings are being transported to surface. Drilling extensive wellbores for production purposes, therefore, exposes the operator to this phenomenon or prolonged periods, and the need for immediate and rapid remedial well control must be continually anticipated. However, with Managed Pressure Drilling (MPD), it is proposed that wellbore conditions can be managed such that dissociation of hydrates within the wellbore can be prevented. Wellbore control is continually applied as per standard MPD operations[66].

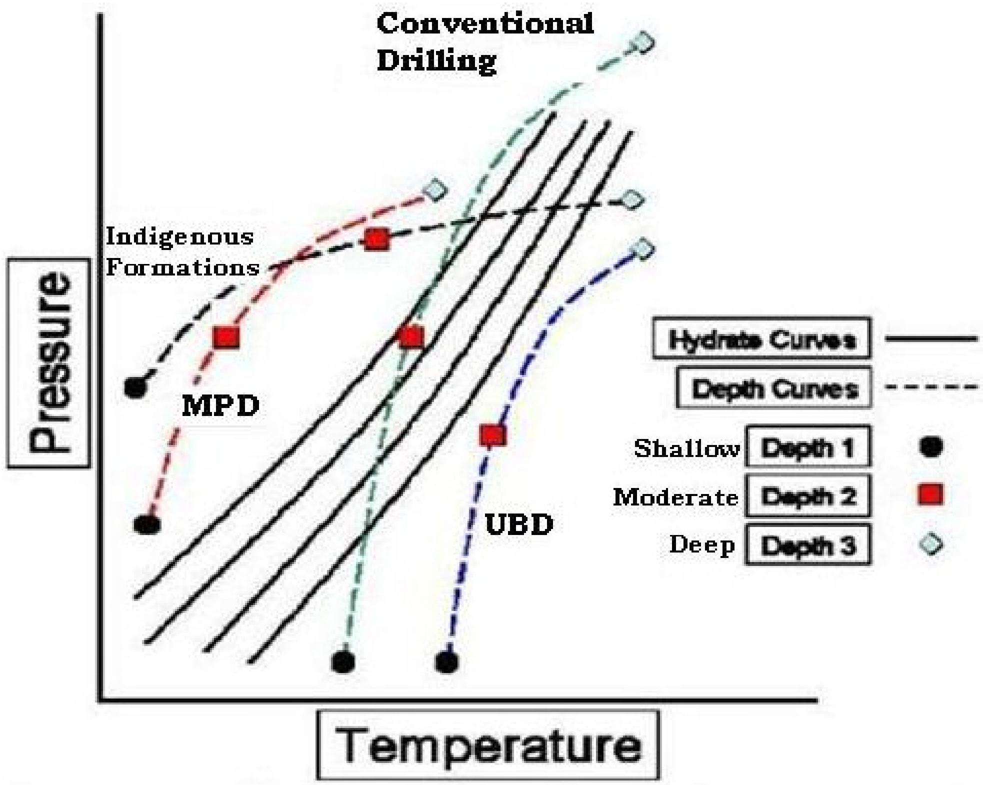


Figure 83 Depth Related Hydrate Curves & Drilling Methods[66]

Todd et al.[66] emphasized the narrow window in different point of view changing the lower boundary variable from pore pressure to dissociation pressure. In a Methane Hydrates deposit, the actual data on reservoir pore pressures and fracture gradients is not as well understood, but it is assumed that they are quite close. Now, rather than managing the pressure between the pore pressure and the fracture gradient of the reservoir, we need to manage between the dissociation pressure and fracture gradient, as well as manage the dissociation temperature.

As described earlier and seen on Figure 83 (Hydrate Diagram) increasing the pressure can mitigate an increase in temperature only until the pressure then pushes into the fracture gradient of the Methane Hydrates. In addition, the fracture gradient is not only pressure dependent, but temperature dependent. Therefore, a specific and precise pressure/temperature gradient will need to be followed. Methane Hydrates, like other cryogenic materials could technically be kept solid in higher temperatures if the pressure was also increased, as long as we stay within the phase parameters of Methane, and water, simultaneously. However, assuming this is a fragile formation structure, and a tight gradient for both pressure and temperature, we will need to control both. Also, it needs to be understood that the fracture gradient if exceeded, could change the dynamic of the reservoir[66]. Therefore, one of the ways of enabling methane hydrate drilling is seen as MPD techniques with the adaptation of pressure/temperature gradient to the concept.

According to Elieff's study[34], the most common way methane hydrates impact on drilling operations is when hydrates form within the drilling system. Particularly critical is if they form in the Blowout Preventer (BOP) stack or in the choke and kill lines. These hydrates can block the lines and BOP and prevent the BOP from functioning properly (closing in the case of an emergency). It is necessary, for the safety of the drilling and completions crew, that a system be in place that can prevent the formation of hydrates within equipment. Chemicals known as hydrate inhibitors can be added to the drilling fluid to prevent the formation of hydrates within the equipment, but in a conventional top hole drilling system, these chemicals are not an option, because of environmental restrictions. However, if a closed system is used and the drilling fluid is returned to the rig floor, hydrate inhibitors can be added to the drilling fluid[34].

In addition to the primary problem caused by methane hydrates, Elieff also mentioned the other problem. Hydrates can compromise the safety of operations is less common, but equally dangerous. When hydrates are lying on the sea floor or within the formation, the gas is trapped within the ice. Drilling through these hydrates breaks the ice crystals imprisoning the gas and allows the gas to dissociate from the ice and into the wellbore. This dissociating gas acts like a shallow gas kick and the driller is immediately faced with the complication of handling gas within the annulus. If the gas is not controlled and the pressures within the wellbore annulus are not stabilized more reservoir fluid (gas/oil/water) may enter the wellbore and further complicate well control procedures[34].

In order to solve the problems caused by methane hydrates, Elieff suggested using DG drilling which is one of the MPD variations. In the case of drilling through dissociating hydrates, a significant well control problem, dual gradient technology offers the advantage of fast kick detection. When methane hydrates dissociate into the wellbore, the dual gradient drilling systems reacts the same was as if a gas influx has entered the wellbore. The subsea pump inlet pressure will increase and the subsea pump rate will automatically increase to compensate. Then the pit gain warning and increased subsea pump outlet and decreased surface pump outlet pressures will alert the driller to employ well control methods. The subsea mud return system supplies the driller with back pressure control over the formation that prevents the dissociating methane hydrates from causing other influxes. The dissociating methane hydrates can be proactively and safely circulated from the wellbore and drilling can resume quickly[34].

Todd et al.[66] further extended the challenges list related with methane hydrates drilling. The primary challenges in drilling for production of Methane Hydrates include:

- Narrow margins between pore pressure and fracture gradient in ocean surface sediments and within the hydrate reservoir.

- Surface hole instability.
- Subsidence caused by hydrate production.
- Manage temperatures and pressures within the well bore during drilling to limit hydrate dissociation in the reservoir beyond the well bore.
- Avoid pressure fluctuations (e.g., swabbing, surging, and ballooning) on the hydrate reservoir common to conventional drilling methods.
- At-balance installation of liners, screens, and completions.
- Drilling extensive wellbores within Methane Hydrate zones magnifies the necessity for total well control over a longer time interval than previously required.
- Facilitating a rapid response to combat pressure/ temperature anomalies occurring at any location with a wellbore during the drilling & completion process.

Depending on distribution of reserves that methane hydrates occur, other drilling technologies should be considered to deal with the challenges. A large portion of the Methane Hydrates deposits, other than subsea, may be in very narrow deposits, or vanes. Drilling into these deposits vertically would not be practical or efficient. The most efficient approach to a thin, but large deposit is horizontal drilling. Horizontal drilling will need to be employed both to find the deposits in some regions, and to exploit the vanes of Methane Hydrates product[66].

In addition, depending on the volume of the reserves, a more complex drilling technique can be exploited considering the advantages. When the vane of Methane Hydrates is large and expansive, multilateral technology will need to be used to reach into different depths and range enough horizontally to reach more of the reservoir. Depending on the dissociation of the Methane

Hydrates reservoir, multilateral technologies may be crucial in exploitation of the resource. A multilateral fishbone style well system will be a practical method for reaching through the varying vanes of a Methane Hydrates reservoir particularly in an offshore environment where the rig installation in deep water will be eased with fewer vertical drill strings or risers[66].

Regardless of which technology or method will be used, throughout the well bore, pressure and temperature will need to be monitored and controlled. Sensing these parameters at the bottomhole assembly and at the surface will not be enough to thoroughly control the dissociation process of the Methane Hydrates. Throughout the well bore, instrumentation subs will need to be utilized to produce as much data as needed to control the pressure and temperature in the well bore, so that the well bore environment can be controlled and manage the dissociation of the Methane Hydrates[66].

Another challenge mentioned by Todd et al. is the pressure fluctuations (e.g., swabbing, surging, and ballooning) which should be mitigated or eliminated. A downhole safety valve installed in the casing will be important in controlling the well bore into the reservoir by preventing fluctuations in pressure and temperature caused by tripping and other drilling and completions operations. The downhole valve will help keep the reservoir at a consistent pressure. This valve will also act as a safety measure to prevent massive Methane Hydrates flows to the surface in the case of a dissociation loss of control. Several downhole valves could be deployed in the casing string to control varying well bore environments depending on the geology of the Methane Hydrates reservoir. A downhole valve equipped with instrumentation to indicate the pressure and temperature above and below the valve would add another important safety factor for well bore control while also aiding in safety and prevention of uncontrolled dissociation[66]. However, downhole safety valves should be developed since expanding contingencies of methane hydrates should be kept in mind.

Medley and Reynolds[19] mentioned about one of the unexploited strengths of MDP, Reactive RFC, while dealing with methane hydrates. The HSE MPD variation recently proved beneficial for a major operator while drilling an offset from a production platform offshore Vietnam. Industry sources reported that cuttings coming to the surface released methane gas, and the combustible mixture was observed by the readout. Subsequently, production lines were shut down and a substantial loss in production was looming. The operator applied the HSE variation, using a closed circulating system to send the methane to a flare line, which allowed the production lines to be reopened. Drilling ahead with a Marine Diverter Converter RCD, typical drilling-related problems were avoided by being able to quickly react to unexpected, downhole pressure environmental limits. In this case, reactive MPD served as a type of insurance policy with cost-effective premiums[19].

Another variation which is applicable to methane hydrates is Dual Gradient technology. DG offers a closed system, which improves drilling simply because the mud within the system is recycled. The amount of required mud is reduced, the variety of acceptable mud types is increased and chemical additives to the mud become an option. This closed system has the potential to prevent the formation of hydrates by adding hydrate inhibitors to the drilling mud. And more significantly, this system successfully controls dissociating methane hydrates, over pressured shallow gas zones and shallow water flows[34].

5.4 Extended Reach Drilling (ERD)

Extended reach drilling is a derivative of directional drilling, where the well is most often kicked off at a shallow depth, and then a lateral section with great horizontal departure (HD) is held. The well is then commonly kicked off again, to build to horizontal near the reservoir target. One definition of extended reach wells is that the horizontal departure is at least twice the TVD of the well[31]. In addition, Extended Reach Drilling can be defined as drilling where the real challenges initiate just after the kick off point (KOP).

The most common challenges are cited in the study of Grottheim[31]. There are many operational challenges in drilling ERD wells, like torque and drag, drillstring and casing design, and hole cleaning. Well control of ERD wells becomes increasingly complex as these types of wells have a greater chance of taking a kick. ERD wells do have some advantages after a kick is taken, however, as gas migration rates are lower in high-angle wells. Deviated wells, including ERD wells, have added complications with trapped gas in rugose and/or highly deviated wellbores. The same considerations of tripping and circulation rates, with regard to the trapped gas, need to be evaluated for ERD wells[31]. Therefore, designing an ERD well becomes complicated due to the operational limitations caused by challenges.

The need for ERD and the advantages of ERD in deep water offshore projects is cited in Grottheim's study. Most ERD wells have been drilled from onshore locations, and the ones that exist offshore have been in fairly shallow waters. There is potential for ERD technology to move into deep waters, however, but careful simulation and planning of problem areas such as well planning, wellbore stability, sand control, and hole cleaning must be performed in order to be successful. Certain deepwater fields might benefit from ERD technology in that larger offshore fields might be produced with “fewer wells and less production units.” With the combination of technologies, ERD and deepwater challenges will be combined, and well control operations will become increasingly complex[31]. However, with a proactive planning of the deep water ERD project might probably deal with arising challenges.

Vuelta[67] also mentioned about how to apply ERD in offshore projects. It has been estimated that the costs of field development with subsea wells is nearly double that of a development with ERD wells at today’s semi-submersible rig rates. Consequently, a high number of ERD wells are being drilled from platforms in the North Sea. Combining the risks and challenges of successfully exploiting mature assets with the inherent risks and challenges of executing ERD wells, demands a high degree of detailed well planning, innovation and effort in order to succeed. In most cases, the use of correct differentiating technologies is the key to achieving increased operational performance. Nevertheless, it is quite challenging for an oil operator to identify and select the right technology out of the many options available in the market. As a result, it is not unusual that good technology is rapidly discarded because of its weaknesses when deployed in isolation, or simply because its benefits are not properly identified[67]. It is an undeniable fact that the unexploited strengths of MPD should be understood in order to deal with extreme challenges.

In ERD projects, one of the important goals is controlling of the annular frictional pressures. Need for accurate control of bottomhole pressures is the reason why Frictional Management Method is becoming a current issue. Annular pressure measurements can be used to detect poor hole cleaning and help the operator modify fluid properties and drilling practices to optimize hole cleaning. In conjunction with other drilling parameters, real-time annular pressure measurements improve rig safety by helping avoid potentially dangerous well control problems—detecting gas and water influxes. These measurements are often used for early detection of sticking, hanging or balling stabilizers, bit problem detection, detection of cuttings build up and improved steering performance[7].

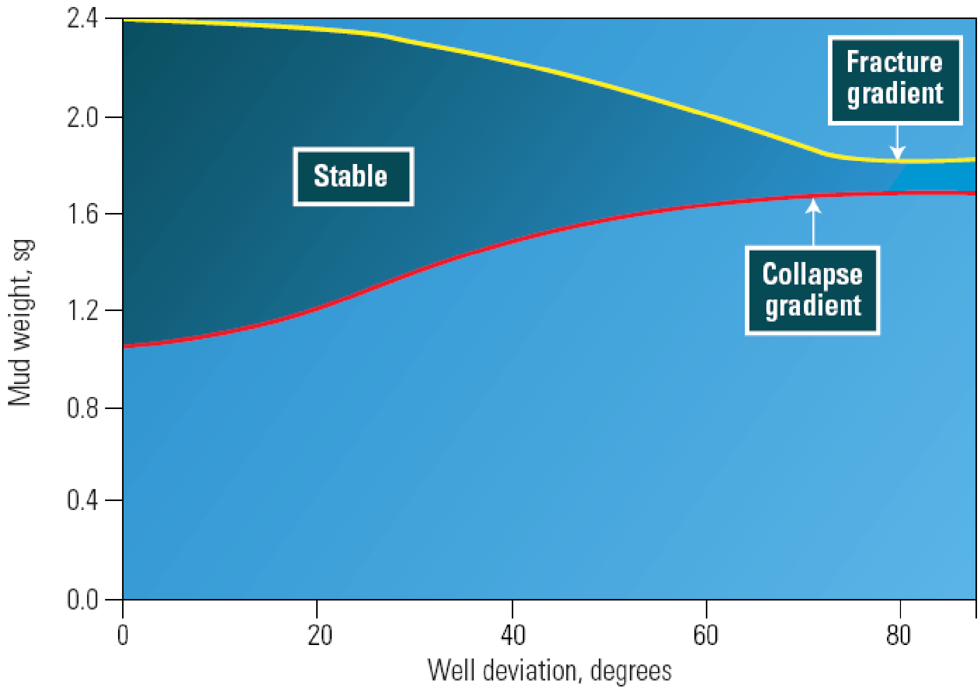


Figure 84 The effect of well deviation on the drilling window[7]

Figure 84 is an illustration of drilling window depending on mud weight and well deviation. In ERD wells, collapse gradient becomes more important than the pore pressure gradient. As it is mentioned in the introduction part, for some cases collapse pressures are bigger than the pore pressures. That is the reason why collapse pressures are defining the lower boundary of the drilling window. As it is seen on the figure, collapse gradient are increasing, since the effect of gravitational forces on the upper side of the wellbore is increasing with the increasing well deviation.

Friction management techniques are part of the constant bottom hole pressure systems and these are used in Extended Reach wells, where the annular pressure is maintained to keep the bottomhole pressure as constant as possible. In ERD wells the annular pressure loss often needs to be reduced to achieve the required length and reach of the well. This can now be achieved through the use of an annular pump. The pump is placed in the cased section of the well and pumps annular fluid back to surface thus reducing the annular friction pressures[50,15].

In addition, annular pressure losses can be minimized by using another method considered under CBHP variation of MPD. Continuous Circulation Method (CCM) can be applicable in ERD projects, since the method is supported with continuous circulation systems which enable using a less dense mud in the applications resulting in low ECD rates. Without interrupting circulation, drilling fluid can be designed according to the dynamic condition which will reduce the annular frictional losses in an excepted range. Additionally, CCM has another advantage on hole cleaning which is one of the primary concepts in ERD projects. Especially in the highly deviated sections of the well, it is probable that cutting tend to settle down to the low side of the wellbore when the circulation is stopped for some reason. Then, the settlement of the cutting causes high torque, stuck pipe, twists-offs etc. To conclude, in order to reach the target, MPD methods can be applied since the primary aim of MPD is mitigating drilling hazards.

5.5 Lessons Learned about MPD

Based on the numerous applications of Managed Pressure Drilling methods both on fixed rigs and floating rigs, it is obvious that MPD has both positive influence for the ones who are satisfied with the application and negative influence for the ones who confronted with disturbances or considered the contingency of disturbances of application.

- The MPD testing and training in cased hole provided a complete understanding of the MPD system for both planned and unplanned events[35].
- HAZID/HAZOP workshops and personnel training are vital steps to contingency planning. Contingency plans are critical to prevent the undesirable results of overpressure or under-pressure events[35].
- MPD operations can be performed on critical applications and made safer than conventional drilling practices with the proper personnel for planning and execution[35].
- One of the main issues encountered on land rigs is the obvious issue of space under the rig floor. The best solution is to use pony subs under the rig and raise the rig to ensure that the equipment fits. Removing a ram or the annular BOP to make space for the RCD is not recommended as this can seriously impact well control and well kill operations. It must be remembered that the BOP stack must still function as the secondary well control system[15].
- Flowlines routings to the BOP stack must be reviewed to ensure that operations can be conducted from the rig floor standpipe or from the choke manifold. The installation of lines, valves and additional pumps located in the

substructure adds complications and potential errors when switching circulation systems during connections or trips[15].

- Pressure testing of the MPD equipment must be agreed with the operator and the drilling contractor. It must be remembered that RCD elements cannot be tested against a closed annular BOP or ram as neither the annular preventer nor ram preventers hold pressure from above. The RCD is not a BOP so if the RCD leaks, the well must be closed at the BOP and the bearing or rubbers replaced until it holds pressure[15].
- Logging requirements using lubricators must be prepared in advance. Logging adaptors are available, but testing procedures for logging adaptors need to be in place and agreed with all parties before rig up commences[15].
- Casing running and cementing operations can all be conducted with the RCD in place. It should be ensured that ID and OD measurements are known when using unitized wellheads and hangers[15].
- Rigging up for CBHP using an RCD and a choke manifold and then finding out that with total losses, PMCD operations are required causes significant delays, as now a flow spool and the associated hoses will be required to pump fluid into the annulus. The opposite applies to PMCD operations where losses are only marginal. Now the mud cap cannot be maintained and it may be that a CBHP system with a choke manifold is required[15].
- Gate valves cannot be opened with pressure, so rigging up for flow control and finding that when the flow line gate valves are closed for a connection, surface pressure builds up, causes issues with opening the system without going through the rig choke manifold[15].

- Rig alignment and drillpipe condition are all important for RCD rubber life. Stripping 20,000 ft of drillpipe through a set of dual rubbers is possible if the rig is aligned and the drillpipe is in good condition and surface pressures are kept low[15].
- Plugging of the 6 in return line and valves is often raised as a concern, yet this has not occurred in any of the operations conducted. Even when drilling larger hole sizes, these return lines can be used[15].
- MPD operations have been conducted on all types of rigs with minimal down time caused by MPD equipment. MPD operations have resulted in considerable savings by enabling drilling to continue in a kick loss scenario or in wells where well control issues occur at almost every connection. Drilling with a closed wellbore and simply allowing pipe to be rotated when killing a well and avoiding stuck pipe can already result in large savings[15].
- As the larger diameter tool joint passes through the stripping element, the upward force exerted on the drill string increases due to the simple fact that the force equals back pressure at the wellhead multiplied by the cross section area of the element being stripped. As the tool joint "jumps" through the element, wellhead pressure may be lost in small increments. In more than one case this has resulted in automatic choke oscillation as the software tries to make allowance for the pressure change. This choke oscillation then requires manual control of the choke to be implemented to stop the cycle[16].
- Auxiliary pump problems often result in failure to maintain constant backpressure. Again, as the automatically controlled choke valve attempts to compensate for the variation in pressure manual control may be required.

- Pressure surges and vibrations resulting from inconsistent pump action require pulsation dampeners in the system at the very least[16].
- Equipment failure in any part of the system can force the operation to revert to manual control at any time. This occurrence must be planned for and mitigated by training the operations personnel to handle the situation[16].
- Contingency events of operational or procedural nature may occur without warning that result in a change of annular pressure or of one or more components of annular pressure. While some of these can be handled quite easily with software adjustments, many cannot, resulting in reversion to manual control[16].
- Failure to calibrate software modeled ECD to PWD tool readings or unavailability of PWD brings into question the advisability of utilizing software controlled back pressure systems[16].
- Software failure or Computer "Lock-up" is a common contingency that must be addressed through manual application of annular backpressure. This may be as perplexing as "the blue screen of death" or as simple as power failure to the computer[16].

CHAPTER 6

STATEMENT OF THE PROBLEM

Recently, the usage of MPD variations in offshore applications is increasing rapidly in order to increase drilling performance, mitigating drilling hazards, and enhancing the production rates since the budget spent is considerably higher than onshore applications. In order to achieve a precise control of bottom hole pressure, the usage of back pressure is a vital deal. In this study the primary aim is to estimate the minimum required back pressures to mitigate drilling hazards for in operational and situational conditions according to the pore pressures which determine lower boundary of the drilling window at the depth of interest.

Two cases will be simulated by using *MPD Back Pressure Calculator,* a computer program built in Microsoft Office Excel 2007. Back pressure calculations will be made according to API Recommended Practice 13D which advises the use of Herschel-Bulkley rheological model for calculations of annular frictional losses (AFL). The effect of rotation is neglected in AFL calculations since the common usage of downhole motors in offshore applications eliminates the pressure loading due to the rotation of the drillstring. Simulation of different drilling parameters and conditions will be used for preparing figures. The graphics will be analyzed and discussed, in order to reach general conclusions for back pressure requirements.

CHAPTER 7

MATHEMATICAL MODELLING

Back pressure calculations will be made according to API Recommended Practice 13D which advises the use of Herschel-Bulkley rheological model for calculations of annular frictional losses (AFL). Therefore, the equations of Herschel-Bulkley fluid will be used to determine the flow behavior and annular frictional losses accordingly.

Annular Frictional Losses (AFL) can be modeled according to the following assumptions;

- The effect of rotation is neglected in AFL calculations since the common usage of downhole motors in offshore applications eliminates the pressure loading due to the rotation of the drillstring.
- The effect of temperature is ignored in the AFL calculations
- The wellbore walls are rigid and bore is in gauge
- All the BHA components is supposed to be in the open hole section.
- Change in the drilling fluid densities and rheology due to downhole pressure and temperature is ignored since calculations are made according to the water base mud.

7.1 Back Pressure (BP) Modeling

In MPD applications different from conventional drilling, Bottomhole Pressure (BHP) is a function of Annular Frictional Losses (AFL), Hydrostatic Head (HH), pressure losses in Choke Line (CL) and Back Pressure (BP).

$$BHP\ (psi) = AFL\ (psi) + HH\ (psi) + BP\ (psi) + CL\ (psi)$$

Hydrostatic Head (HH) depends on Mud Weight (MW) which is average density in the drilling fluid column approximated using surface measurements and True Vertical Depth (TVD).

$$HH\ (psi) = 0.0052\ xMW\ (ppg)\ xTVD\ (ft)$$

Hydrostatic Head (HH) also depends on the formation and rate of penetration (ROP) since formation type determines the Cutting Density (CD) and ROP determines the Cutting Concentration (CC) in the column of drilling fluid. Therefore, HH is a function of not only MW and TVD but also CC and CD.

$$HH(psi) = 0.0052x\left[(1-CC)xMW(ppg) + 8.345xCCxCD(g/cm^3)\right]xTVD(ft)$$

Under dynamic conditions, Annular Frictional Loss (AFL) is a function of flow rate, flow regime, section length, rheological properties and hydraulic diameter.

Flow rate (Q) determines the average annular fluid velocity (v_a) depending on the cross sectional area of the respective fluid conduit.

$$v_a = \frac{24.51Q}{d_h^2 - d_i^2}$$

Hydraulic diameter (d_{hyd}) which is mostly defined based on the ratio of cross sectional area to the wetted perimeter of the annular section, determines fluid behavior in the annular section. It can be calculated by using the outer diameter of the drillstring which is the inner radius of flow conduit (d_i) and inner diameter of the casing, riser or hole diameter (d_h) depending on the section of interest.

$$d_{hyd} = d_h - d_i$$

Rheological parameters for Herschel-Bulkley fluids;

$$n = 3{,}32 \log_{10}\left(\frac{2PV + YP - \tau_y}{PV + YP - \tau_y}\right)$$

$$k = \frac{PV + YP - \tau_y}{511^n}$$

Rheological parameters for Power-Law fluids;

$$n = 3{,}32 \log_{10}\left(\frac{2PV + YP}{PV + YP}\right)$$

$$k = \frac{PV + YP}{511^n}$$

R is an additional parameter useful for defining rheological behavior. R = 0 for Power-Law, R = 1 for Bingham-Plastic, and 0 < R < 1 for Herschel-Bulkley fluids.

$$R = \frac{\tau_y}{YP} \qquad \text{(for YP > 0)}$$

In order to calculate pressure losses, the Newtonian shear rate have to be converted to shear rate at the wall since the well geometry factor depends on the rheology. For Power-Law fluids, field viscometer shear rate correction factor varies from 1 to 1.1569 or alternatively for Herschel-Bulkley fluids, field viscometer shear rate correction factor can be assumed "1". Then combined geometry shear rate correction factor can be calculated.

$$B_a = \left[\frac{2n+1}{3n}\right]\left[\frac{3}{2}\right]$$

$$B_x \approx 1$$

$$G = \frac{B_a}{B_x} \approx B_a$$

In order to calculate shear stress at the wall (τ_w), shear rate at the wall (γ_w) and shear stress in viscometer units (τ_f) should be determined.

$$\gamma_w = \frac{1.6Gv_a}{d_{hyd}}$$

$$\tau_f = \left(\frac{3}{2}\right)^n \tau_y + k\gamma_w^n$$

$$\tau_w = 1.066\tau_f$$

Flow regime can be determined by using the relationship between Critical Reynolds number ($N_{\mathrm{Re}c}$) and Generalized Reynolds number ($N_{\mathrm{Re}g}$).

$$N_{\mathrm{Re}c} = 3470 - 1370n$$

$$N_{\mathrm{Re}g} = \frac{MWv_a^2}{19.36\tau_w}$$

HH, which is hydrostatic head equivalent of MW in terms of ppg due to the cuttings load in the annulus, should be preferred to be used in the calculation of generalized Reynolds number instead of MW since pressure loads are not the same while drilling is in progress.

$$N_{\mathrm{Re}g} = \frac{HHv_a^2}{19.36\tau_w}$$

In order to determine AFL, Fanning friction factor (f), which is a function of generalized Reynolds number, flow regime and fluid rheological properties, have to be calculated.

Laminar flow friction factor can be calculated as;

$$f_{lam} = \frac{16}{N_{\mathrm{Re}g}}$$

Transitional flow friction factor can be calculated as;

$$f_{trans} = \frac{16N_{\mathrm{Re}g}}{N_{\mathrm{Re}c}^2}$$

Turbulent flow friction factor can be calculated according to pipe roughness (a) and drag reduction (b) which are functions of rheological parameter for Power-Law fluids (PLn or n_p);

$$f_{turb} = \frac{a}{N_{\mathrm{Re}g}^{b}}$$

$$a = \frac{\log_{10}(n_p) + 3.93}{50} \qquad b = \frac{1.75 - \log_{10}(n_p)}{7}$$

Friction factor can be determined for any Reynolds number and flow regime by using laminar friction factor and intermediate friction factor which is based on transitional and turbulent friction factors.

$$f_{\mathrm{int}} = \left(f_{trans}^{-8} + f_{turb}^{-8}\right)^{-1/8} \qquad f_{all} = \left(f_{\mathrm{int}}^{12} + f_{lam}^{12}\right)^{1/12}$$

Finally, Annular Frictional Losses (AFL), which is one of the key variables affecting the amount of back pressure, can be calculated for each section accordingly by using the formula below;

$$P_a = \sum \frac{1.076 HHv_a^2 f_{aa} L_{\mathrm{sec}\,tion}}{10^5 d_{hyd}}$$

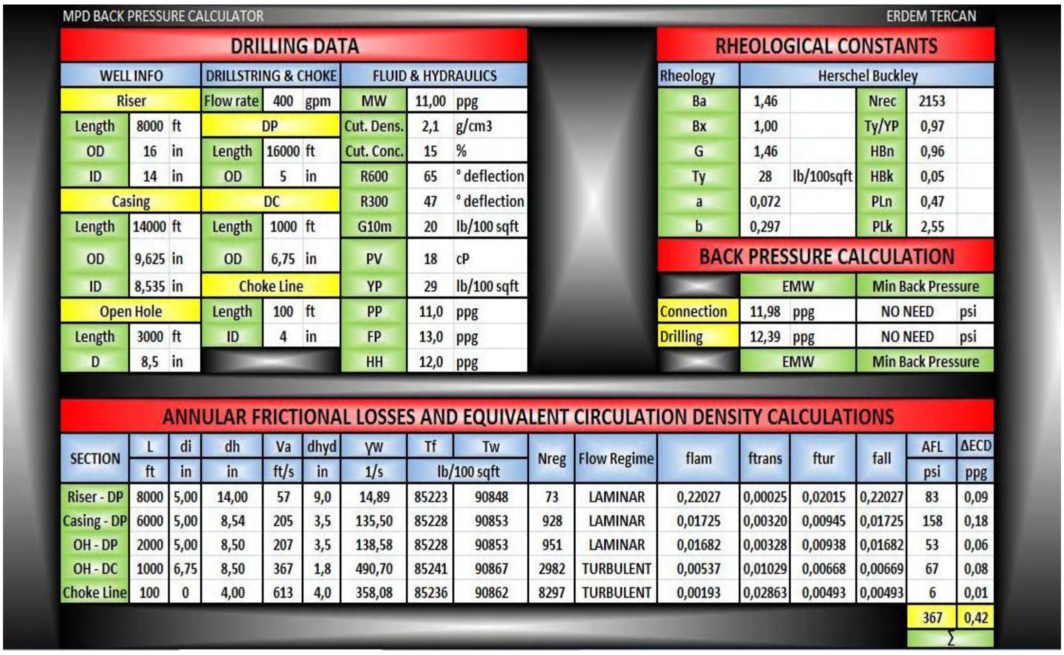
Pressure losses in the choke line can be calculated in the same manner so the only unknown variable remaining in the BHP equation is the amount of back pressure which is dependent on minimum pore pressure at the section of interest. In order to prevent wellbore instability, the amount of back pressure applied from surface should be at the least to maintain a BHP equal or higher than the pore pressure.

$$BHP\ (psi) = AFL\ (psi) + HH\ (psi) + BP\ (psi) + CL\ (psi) \geq PP\ (psi)$$

$$BP(psi) \geq PP(psi) - \left[AFL(psi) + HH(psi) + CL(psi)\right]$$

7.2 MPD Back Pressure Calculator

According to the variables which are given in the back pressure modeling section, *MPD Back Pressure Calculator was* built in Microsoft Office Excel 2007. Back pressure calculations were made according to API Recommended Practice 13D which advises the use of Herschel-Bulkley rheological model for calculations of Annular Frictional Losses (AFL). A schematic illustration of the program is shown in Figure 85. The input data can be selected in the drilling data part in order to simulate minimum back pressure required to obtain wellbore stability. R600 and R300 viscometer readings are used to determine the rheological parameters which are the key parameters in the calculation process of frictional pressure losses. The upper boundary (FP) and the lower boundary (PP) of the drilling window can be set depending on the formation limitations.



MPD BACK PRESSURE CALCULATOR

ERDEM TERCAN

DRILLING DATA

WELL INFO			DRILLSTRING & CHOKE			FLUID & HYDRAULICS		
Riser			Flow rate	400	gpm	MW	11,00	ppg
Length	8000	ft	DP			Cut. Dens.	2,1	g/cm3
OD	16	in	Length	16000	ft	Cut. Conc.	15	%
ID	14	in	OD	5	in	R600	65	° deflection
Casing			DC			R300	47	° deflection
Length	14000	ft	Length	1000	ft	G10m	20	lb/100 sqft
OD	9,625	in	OD	6,75	in	PV	18	cP
ID	8,535	in	Choke Line			YP	29	lb/100 sqft
Open Hole			Length	100	ft	PP	11,0	ppg
Length	3000	ft	ID	4	in	FP	13,0	ppg
D	8,5	in				HH	12,0	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley				
Ba	1,46		Nrec	2153	
Bx	1,00		Ty/YP	0,97	
G	1,46		HBn	0,96	
Ty	28	lb/100sqft	HBk	0,05	
a	0,072		PLn	0,47	
b	0,297		PLk	2,55	

BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	11,98	ppg	NO NEED	psi
Drilling	12,39	ppg	NO NEED	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	8000	5,00	14,00	57	9,0	14,89	85223	90848	73	LAMINAR	0,22027	0,00025	0,02015	0,22027	83	0,09
Casing - DP	6000	5,00	8,54	205	3,5	135,50	85228	90853	928	LAMINAR	0,01725	0,00320	0,00945	0,01725	158	0,18
OH - DP	2000	5,00	8,50	207	3,5	138,58	85228	90853	951	LAMINAR	0,01682	0,00328	0,00938	0,01682	53	0,06
OH - DC	1000	6,75	8,50	367	1,8	490,70	85241	90867	2982	TURBULENT	0,00537	0,01029	0,00668	0,00669	67	0,08
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	8297	TURBULENT	0,00193	0,02863	0,00493	0,00493	6	0,01
															367	0,42
															Σ	

Figure 85 MPD Back Pressure Calculator

According to the drilling data, the calculation of annular pressure losses for each section is made to determine the amount of required back pressures for maintaining the wellbore stability for different hole conditions. Although the calculator was built for offshore applications with marine riser, the model is capable to simulate onshore conditions by just changing the length of the riser to zero. Another feature of the model is to simulate casing drilling applications by entering the outer diameters of both drill pipes and drill collars with the same amount of the outer diameter of the casing which is used as a drill string. In addition, the effect of cuttings loading should not be ignored while calculating the required back pressures in connection since the amount of cuttings is directly proportional to the circulation time while not drilling. The amount of cuttings has a stepwise decrease from the beginning of circulation period to the bottoms up time and there will be no cuttings in the wellbore. Therefore, the cuttings concentration has to be adjusted according to the period of circulation while not drilling. Figure 86 is an example of flexibility of the model which simulates 7” DwC situation on a land rig after the bottoms up time.

MPD BACK PRESSURE CALCULATOR — ERDEM TERCAN

DRILLING DATA

WELL INFO			DRILLSTRING & CHOKE			FLUID & HYDRAULICS		
Riser			Flow rate	400	gpm	MW	8,70	ppg
Length	0	ft	DP			Cut. Dens.	2,1	g/cm3
OD	16	in	Length	16000	ft	Cut. Conc.	0	%
ID	14	in	OD	7	in	R600	65	° deflection
Casing			DC			R300	47	° deflection
Length	14000	ft	Length	1000	ft	G10m	20	lb/100 sqft
OD	9,625	in	OD	7	in	PV	18	cP
ID	8,535	in	Choke Line			YP	29	lb/100 sqft
Open Hole			Length	100	ft	PP	11,0	ppg
Length	3000	ft	ID	4	in	FP	13,0	ppg
D	8,5	in				HH	8,7	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley			
Ba	1,46		Nrec	2153
Bx	1,00		Ty/YP	0,97
G	1,46		HBn	0,96
Ty	28	lb/100sqft	HBk	0,05
a	0,072		PLn	0,47
b	0,297		PLk	2,55

BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	8,70	ppg	2034	psi
Drilling	10,09	ppg	807	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	0	7,00	14,00	67	7,0	22,27	85224	90848	71	LAMINAR	0,22413	0,00025	0,02025	0,22413	0	0,00
Casing - DP	14000	7,00	8,54	411	1,5	626,09	85246	90872	2713	TURBULENT	0,00590	0,00936	0,00687	0,00690	995	1,13
OH - DP	2000	7,00	8,50	422	1,5	657,13	85247	90873	2854	TURBULENT	0,00561	0,00985	0,00677	0,00679	151	0,17
OH - DC	1000	7,00	8,50	422	1,5	657,13	85247	90873	2854	TURBULENT	0,00561	0,00985	0,00677	0,00679	75	0,09
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	6026	TURBULENT	0,00266	0,02079	0,00542	0,00542	5	0,01
															1226	1,39
															Σ	

Figure 86 Simulation of CwD on a Land Rig after bottoms-up

7.3 Analysis of MPD Back Pressure Variations

In order to clarify the back pressure concept, the effect of drilling parameters has to be understood under both dynamic and static conditions. The main goal of applying back pressure is to maintain a constant BHP for different parameters such as mud weight, flow rate, cutting density, cutting concentration and length of the components of BHA. The following graphs which is drawn by using the MPD Back Pressure Calculator data, illustrates the required back pressure amounts for the varying drilling parameters.

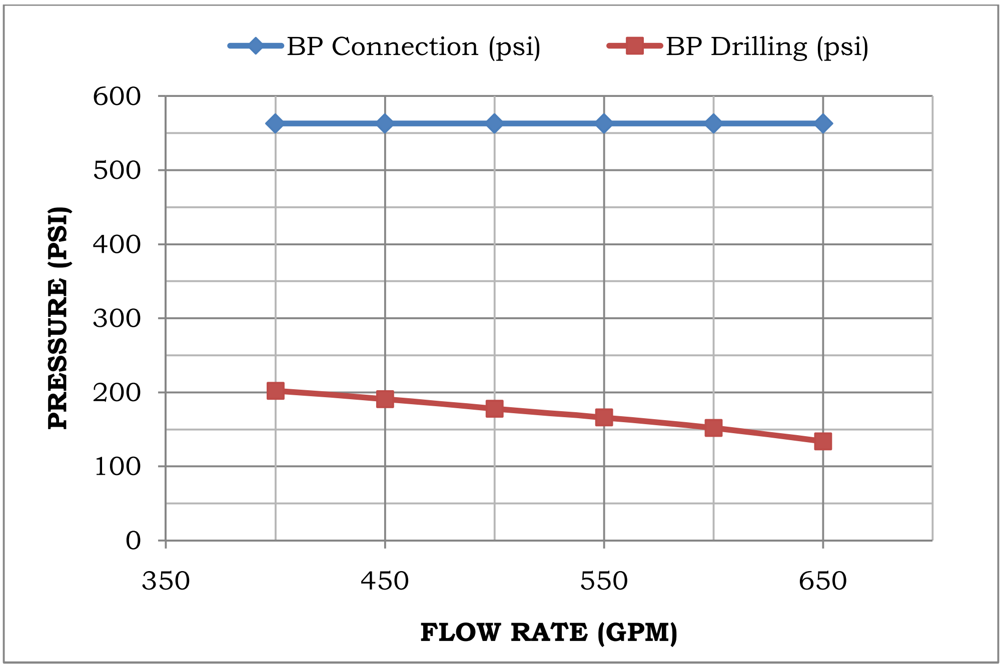


Figure 87 Back Pressure Variations with Flow Rate

Figure 87 is an illustration of variations of back pressure depending on the flow rate. Blue lines simulate the static condition and the red lines simulate the dynamic condition. As it is seen in the figure the amount of back pressure remains constant under static conditions since the BHP is a function of hydrostatic head of the mud column with cuttings regardless of flow rate if the cuttings concentration is assumed to be constant in the circulation period.

However, the flow rate has a direct effect on back pressure since the annular frictional losses depend on the flow rate under dynamic condition. As the flow rate increases the need for back pressure decreases depending on the amount of increase in annular frictional losses. As a result, the static condition determines the maximum need for back pressure and the dynamic condition determines the minimum required back pressure depending on the flow rate.

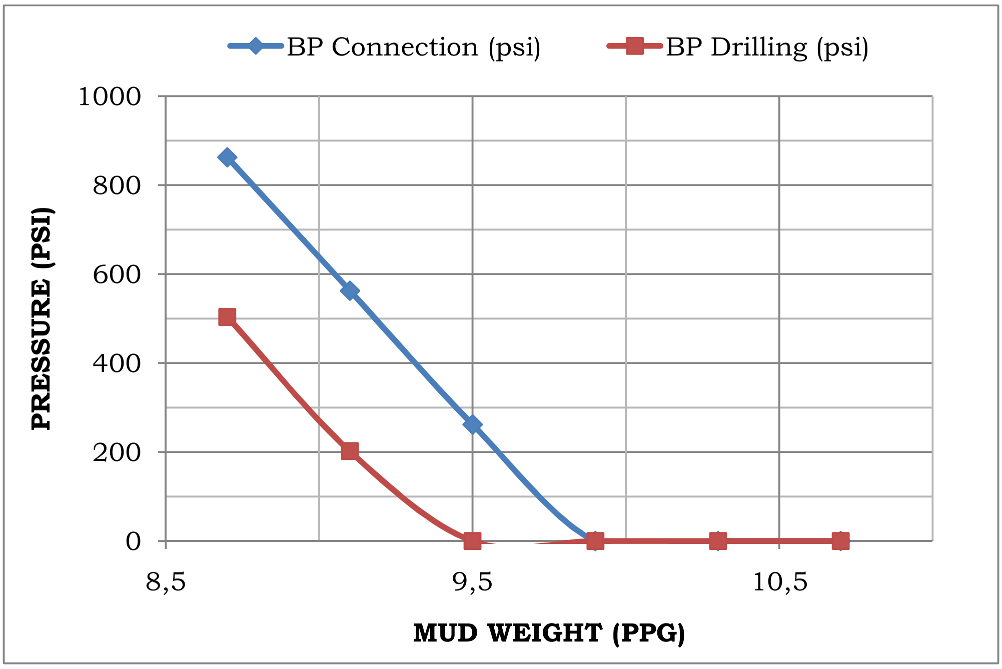


Figure 88 Back Pressure Variations with Mud Weight

Figure 88 is an illustration of back pressure variations depending on the mud weight. The difference in required back pressure between static and dynamic conditions is because of annular frictional losses as it is discussed earlier. The increase in the mud weight decreases the need for back pressure since the system becomes overbalance. 9,9 ppg simulates the conventional drilling condition which requires no back pressure, on the other hand mud weight between 9,5 ppg to 9,9 ppg simulates the application of CBHP MPD which requires back backpressure under static condition and less than 9,5 ppg simulates further applications of CBHP MPD / DTTL MPD in which the application of back pressure under dynamic condition is necessary.

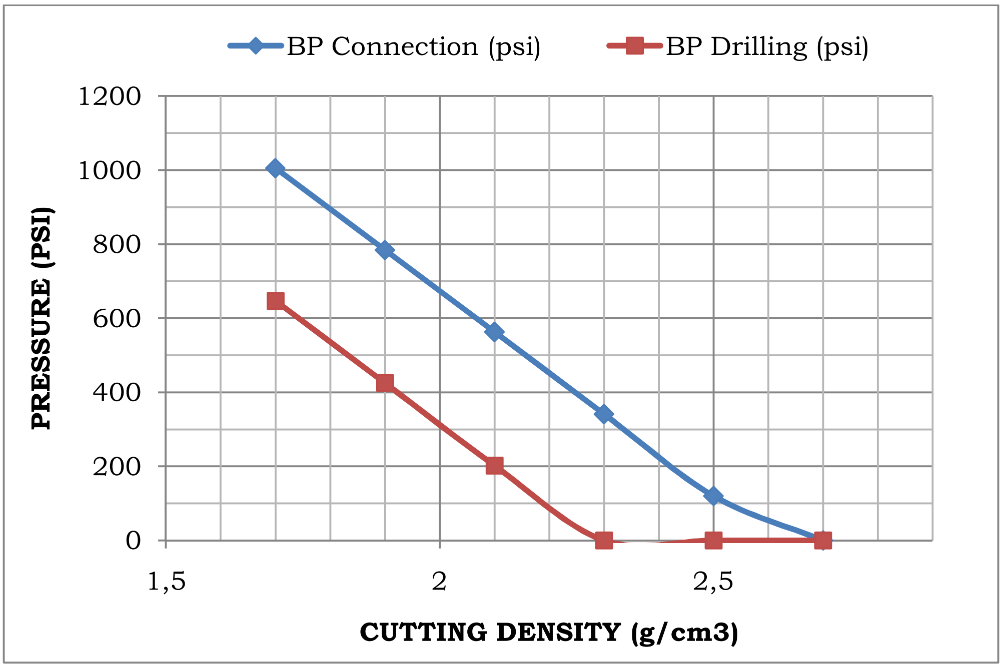


Figure 89 Back Pressure Variations with Cutting Density

Figure 89 is an illustration of back pressure variations depending on cutting density. As it is explained in the mathematical modeling section, BHP is a function of hydrostatic head of mud column and the frictional pressure losses. It is obvious that the effect of mud column on BHP changes with the density of the formation drilled. The required back pressure to maintain wellbore stability is bigger while drilling through low density sediments than the one while drilling through high density metamorphic rocks since the increase in the density of the formation increases the head of mud column. Therefore, pressure loadings due to cuttings should not be ignored since cutting density determines the actual mud gradient which is bigger than the original mud gradient. In brief, the maximum amount of back pressure has to be correlated in order not to fracture the formation drilled in case the drilling window is narrow.

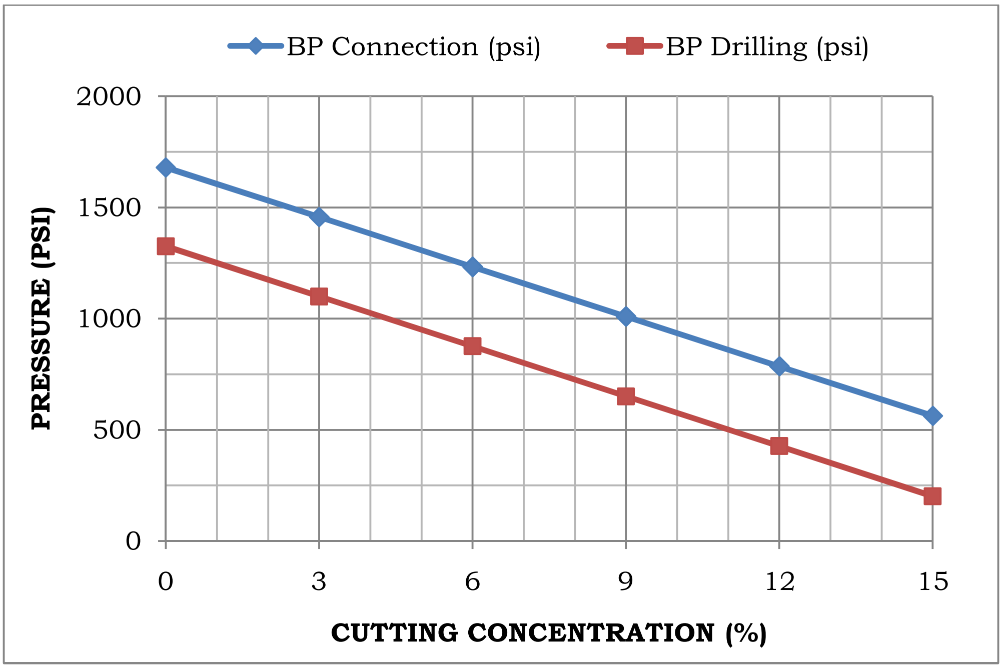


Figure 90 Back Pressure Variations with Cutting Percentage

Figure 90 is an illustration of back pressure variations depending on cutting concentration. As it is seen in the figure any increase in the amount of cuttings decrease the need for back pressure due to the cuttings load on BHP. In addition, the concentration of cuttings in the mud in the annulus is a function of penetration rate which restricts the maximum required back pressure. In order to prevent the loss of drilling fluid, penetration rate should be optimized while drilling in a narrow window. For example; while drilling such an increase in the cutting concentration from 3 % to 4 % decreases the need for back pressure from 1100 psi to 1000 psi which means keeping constant back pressure could cause fluid loss in case of any increase in the penetration rate. On the other hand, cutting concentration is a function of time while only circulating since the cutting concentration decreases gradually depending on the bottoms-up time. For example; while circulating such a decrease in the cutting concentration from 3 % to 0 % increases the need for back pressure from 1450 psi to 1700 psi which means keeping constant back pressure could cause an influx to the wellbore.

CHAPTER 8

CASE STUDY

8.1 Defining Challenges

In order to understand the need for combining technologies, the challenges should be properly identified and solution of the challenges should be clarified before adapting MPD techniques in the project. The main challenges that cause the need for combining technologies are defined as;

- Enhanced Drilling Performance
- Mitigated Drilling Hazards
- Deep water
- Harsh Environment
- Sub-Salt Drilling

8.2 Defining MPD System with Respect to Challenges

At first glance, it is a significant consideration to use the proven strengths of CBHP MPD.

At first it is widely known that, in order to enhance the drilling performance, using less dense mud which is hydrostatically slightly overbalanced is the best choice. In addition, with a surface back pressure it is possible to prepare a lesser dense mud which is hydrostatically underbalanced.

Secondly, in order to mitigate drilling hazards, in other words reducing the risk of taking a kick, losing mud, differential sticking and well instability, an accurate BHP management is required. BHP adjustment is maintained accurately with the help of computerized flow control and pressure control equipments.

Thirdly, drilling in deep water is another challenge to deal with. In order to apply CBHP method, it is known that the risers are one of the restrictions. It is not possible to drill with conventional marine riser because of the pressure limitations of the riser. Then a more pressure resistant slim marine riser should be used. The primary aim of using the slim riser instead of conventional marine riser is to increase the pressure rating of the riser for MPD purposes.

The floating drilling rig should have a storm disconnect system (SDS) or an emergency disconnect system (EDS) available on the wellhead at the mud line, in case of uncontrollable situations /events such as storms and hurricanes.

8.3 Definition of the Problems

8.3.1 First Problem

A Company is drilling in deep water from a floating rig with a slim riser which is 16" marine riser capable of 10000 psi and high pressure surface BOP stack. In case of emergency, the only available solution is a SDS (storm disconnect system) on the well head at the mud line. The Company is practicing CBHP MPD to drill through salt section; however, the PP and FP of the environment immediately below the salt is unknown with any degree of certainty. It's very important that while poking the bit below the salt, the well is so overbalanced comparing with the subsalt section where losses are immediate and where the drilling string may get differentially stuck, maybe at risk of twisting off the drill string, and encountering the resulting well control problems.

The statement of first problem is the mitigation of drilling hazards due to the sudden changes of pressure profiles just below the base of the salt section in deep water well while practicing the CBHP MPD variation.

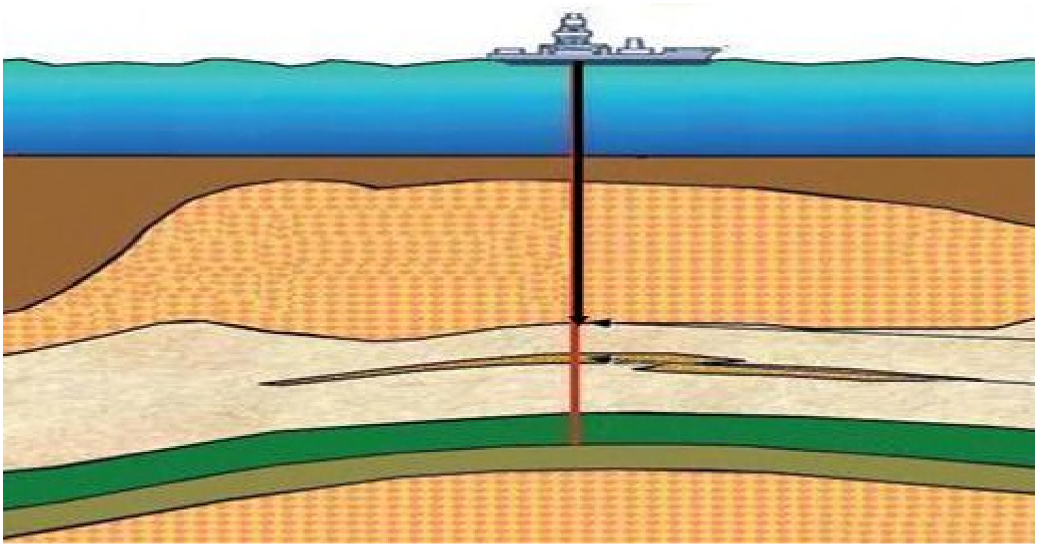
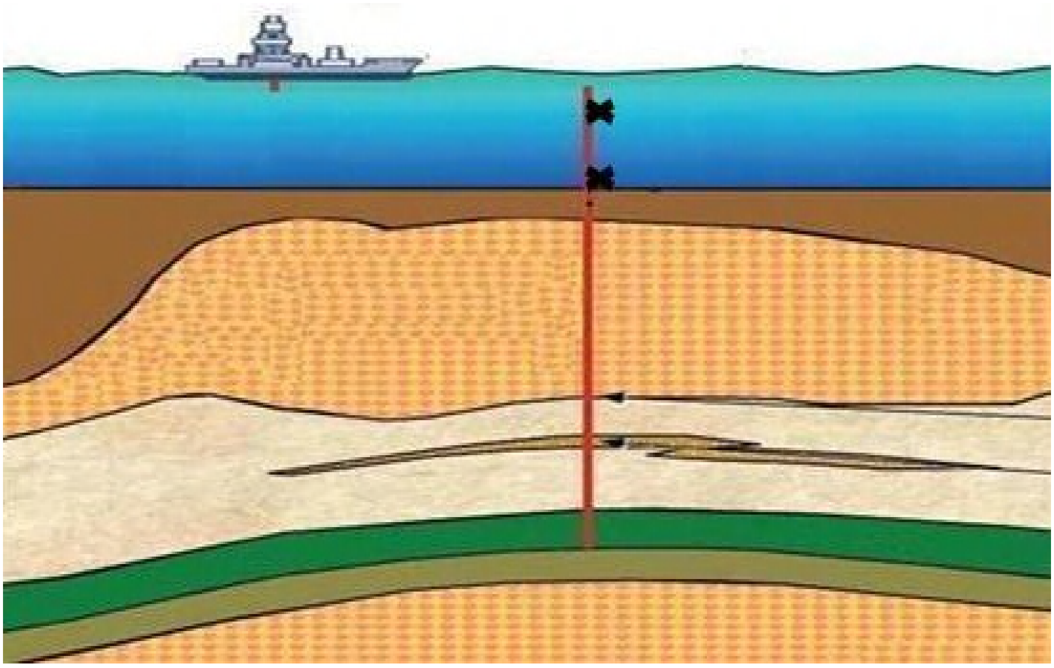


Figure 91 Basic Illustration of the First Problem (Case I)

8.3.2 Second Problem

A Company is drilling in deep water from a floating rig with a slim riser which is 16" marine riser capable of 10000 psi and high pressure surface BOP stack. In case of emergency, the only available solution is a SDS (storm disconnect system) on the well head at the mud line. The Company is practicing CBHP MPD to drill through salt section with statically underbalanced and dynamically slightly overbalanced mud to improve the drilling performance. In case of SDS is needed or its activation is a must due to the unexpected hurricane or storm, most of the engineers think there will be enough time to add kill fluid. If such an unexpected situation occurs, it is preferable to lift the BHA above the shear-ram which is a part of SDS system placed on the subsea. While tripping, kill mud could be used to fill the displaced volumes of the string being tripped to above mud line. Shortly afterwards, though, the bottled up pressure would have some sort of impact on the un-cased hole, cave-in, rupture, or stabilize with its surroundings. If there is not enough time to circulate a kill mud before activating the SDS and driving or drifting off location, the SDS acts as a subsea sheer-ram BOP which would isolate the wellbore from subsea pressure gradient and hopefully maintain some amount of backpressure.

The statement of second problem is the complete compensation of the surface back pressure loss due to the activation of SDS in an emergency situation if there is not enough time to add kill mud while practicing the CBHP MPD variation through the salt section in deep water well.



Şekil 92 Basic Illustration of the Second Problem (Case II)

8.4 Solutions to the Problems

The solutions of the two cases are simulated by using *MPD Back Pressure Calculator* and the reliability of the recommendations for the situational problems is proven according to the simulation results which are placed in Appendix D.

8.4.1 Solution to the First Problem

The solution of the first problem is not possible by choosing a specific variation or technology that addresses the mitigation of drilling hazards. The only way of reducing the risks is possible not only using both strengths of Proactive MPD and unexploited strengths of Reactive MPD, but also combining MPD methods and DHM technologies, all together.

While drilling and nearing the base of the salt section with CBHP MDP variation with a less dense mud (see App. D - Fig. 95), it is a good decision to switch over to practice DTTL MPD (see App. D – Fig. 96) with a high pressure RCD atop the surface BOP. In order to modify the drilling mud to the DTTL MPD, system mud should be changed to adaptive seawater of which rheology is enhanced with the additives to have compatibility with salt, for the drilling fluid to improve the chance of not exceeding the FP. Then, a plan on drilling with consistent (mud pumps on & off) surface backpressure should be estimated in case the zone immediately below the salt happens to have a PP that requires it (see App. D – Fig. 97). With the usage of hydraulic flow modeling and process control computers, real-time evaluation of the actual drilling window when the bit has just drilled into is possible to make a decision for the best mud weight for the following downward section of the well. At last, the light fluid prepared for DTTL is circulated out and the mud most suited for sub-salt is circulated in (see App. D – Fig. 98). That leads to reverting back to CBHP MPD; choke open when circulating, choke closed when not.

While poking the bit just below the salt section, although CHBP MPD has just switched over to apply DTTL MPD with a high pressure RCD atop the surface BOP, it is probable that the point which is just below the salt layer has more tendencies to cause loss circulation. If any fracture occurs at that point, complete mud loss might be faced in such situations. So there should be proactively considered a "plan B" such as PMCD for contingency. If such a hazard occurs the only way to continue to drill and mitigate the hazard is pumping highly viscous mud down the annulus at the same time the mud weight is reduced or changing to enhanced seawater. While drilling with PMCD, it is important to understand that the losses might stop after the fracture or vugs is filled with PMCD sacrificial mud. At the time there is no occurrence of losses, and then the system will shift back to CBHP MPD with a proper mud design while circulating out the highly viscous mud to go on the process at the beginning.

The most important restriction to the solution is the wellbore stability especially at the salt section. The enhanced seawater usage of the DTTL MPD should be improved considering the salt section limitations. In order to apply DTTL MPD while drilling in salt, it is absolute that management of both less dense mud and stability of the salt section of the wellbore should be considered. The common way of stabilization of the salt is designing a salt saturated mud to prevent initial reaction between salt and wellbore. However, saturation of the water based mud cause an increase of the mud density. Therefore the only solution for applying DTTL MPD is the design of an oil based mud in order to prevent the reaction between wellbore and salt section that allows both maintaining of wellbore stability and keeping a less dense mud for DTTL MPD.

Combination of the MPD variations is a primary solution to the problem; however, it will be possible to adapt DHM technologies in MPD variations by understanding the concept, using existing strengths of MPD and making further designs of tools in order to improve the solution. Drilling with Casing (DwC) is a powerful technology to mitigate drilling hazards and reducing NPT, indeed combination of CCS/CCV with the strengths of CBHP MPD and DwC gives us the opportunity of managing BHP and improving drilling performance. The result is more accurate control of BHP because of not having jointed pipe connections which leads the transitional frictional pressures losses. However DwC has high frictional losses on the system due to the reduced annular space. In order to reduce AFL, the best combination could be maintained with combining CBHP MPD and DwC together.

Further design and analysis should be done to combine DTTL and DwC (see App. D – Fig. 99-100). The strength of DTTL, which is using less dense mud and back pressure while drilling or connection, have to be adapted to DwC. A new method "Casing Drilling to the Limit (CDTTL) or Drill thru the Limits with Casing (DTTLwC)" should be introduced to the industry. This new method needs the re-designing of the rotating control devices which will enable to drill with casing while keeping backpressure both in drilling and connection process. The new equipment, "Rotating Casing Control Device (RCCD) or Casing Drilling Control Head (CDCH) or Casing Drilling Back Pressure Head (CDBPH)" has to be designed and adapted for future use and purposes of CDTTL or DTTLwC.

8.4.2 Solution to the Second Problem

The solution of the second problem is not possible with the conventional technologies and equipments. In order to solve the problem it is necessary to understand BHP changes at the time when SDS is activated. The technology gap in deep water drilling leads to such an unexpected occurrence of problem, and finding the missing part reveals the solution to the problem.

A Company is drilling in deep water from a floating rig with a slim riser which is 16" marine riser capable of 10000 psi and high pressure surface BOP stack. In case of emergency, the only available solution is a SDS (storm disconnect system) on the well head at the mud line. The Company is practicing CBHP MPD to drill through salt section with statically underbalanced and dynamically slightly overbalanced mud to improve the drilling performance. The bottomhole pressure is a function of hydrostatic head pressure of the drilling mud and annulus friction pressure losses due to circulation.

$$BHP\ (psi) = HH\ (psi) + AFL\ (psi)$$

Where

BHP : Bottom Hole Pressure

HH : Mud Hydrostatic Head Pressure

AFL : Annular Frictional Losses

In case of SDS is needed or its activation is a must due to the unexpected hurricane or storm and there is not enough time to circulate a kill mud before activating the SDS and driving or drifting off location, the first thing should be done is to stop drilling. Because of having statically underbalanced mud, the back pressure should be applied from the surface to compensate the same amount of annulus frictional pressure losses in order to prevent well collapse or taking a kick.

$$BHP\ (psi) = HH\ (psi) + SBP\ (psi)$$

Where

SBP : Surface Back Pressure

Once the SDS is activated, it acts as a subsea sheer-ram BOP which would isolate the wellbore from subsea pressure gradient and hopefully maintain some amount of backpressure. Consequently, hydrostatic head of mud column is divided into two separate sections.

$$HH\ (psi) = HH1(psi) + HH2(psi)$$

Where

HH : Hydrostatic Head of Mud from BH to surface

HH1 : Hydrostatic Head of Mud from SDS shear ram to surface

HH2 : Hydrostatic Head of Mud from BH to SDS shear ram

Bottomhole pressure calculation should be updated because of reduced hydrostatic head pressure and induced back pressure due to SDS activation.

$$BHP'(psi) = HH2(psi) + SDSBP\ (psi)$$

Where

BHP' : Reduced Bottomhole Pressure

SDSBP : Induced Back Pressure due to SDS

In order to find the pressure that is needed to be compensated, the change in the bottomhole pressure should be calculated as below

$$\Delta P(psi) = BHP'(psi) - BHP\ (psi)$$

$$\Delta P(psi) = [HH2(psi) + SDSBP(psi)] - [HH(psi) + SBP(psi)]$$

$$\Delta P(psi) = HH2(psi) + SDSBP(psi) - HH(psi) - SBP(psi)$$

$$\Delta P(psi) = [HH2(psi) - HH(psi)] + [SDSBP(psi) - SBP(psi)]$$

$$\Delta P(psi) = [-HH1(psi)] + [SDSBP(psi) - SBP(psi)]$$

$$\Delta P(psi) = [-HH1(psi)] + [-\Delta BP(psi)]$$

$$\Delta P(psi) = -\left([HH1(psi)] + [\Delta BP(psi)]\right)$$

Where

$\Delta P(psi)$: Pressure need to be compensated

$HH1(psi)$: Hydrostatic Head of Mud from SDS shear ram to surface

$\Delta BP(psi)$: Pressure difference between SBP and SDSBP

The SDS induced backpressure is relatively small comparing with the sum of reduced amount of pressure due to the hydrostatic head of mud and complete loss of SBP. That is to say, not only the length of column of the mud in the riser due to deep water environment but also the SBP requirements due to the use of less dense mud means higher pressures compared to SDS induced pressures.

“The technology gap in the deep water drilling leads to such an unexpected occurrence of problem which means finding the missing part reveals the solution to the problem” was mentioned before above. The missing part of this concept is the absence of pressure compensation equipment. That means the solution of the second problem is designing a back pressure system in case of emergency due to storms and hurricanes.

There have to be designed a 1) "Emergency Activated Subsea Back Pressure Pump (EASSBP)" or 2) "Riser Attached Emergency Activated Hydrodynamic Pump (RAEAHP)" for future purposes of adapting MPD to the deep water wells.

The primary design of EASSBP should have the capability of measuring subsea SDS shear ram to wellhead hydrostatic mud pressure + back pressure applied from surface. After the primary design is completed, SDS induced back pressure should be measured to reduce the same amount of pressure from the first measurement which is gathered from first design (see App. D – Fig. 101). Moreover, a connection joint should be adapted to place under the SDS shear ram. The control of the system could be managed from the surface by using the developing PLC systems or operated by using a ROV.

The need for RAEAHP is necessary if SDS shear ram is placed somewhere on the high pressure riser between the surface and seabed for ultra deep marine wells (see App. D – Fig.101). Preferably, SDS shear ram might be placed the shallower sections of the deep water rather than the deeper sections on account of mainly two reasons. The first reason is to prevent higher pressure differences due to the isolation of long riser sections considering the back pressure limitations of the pump. Second reason is back pressure system control limitations in the deeper sections of seawater from the surface due to the water distance between pump and surface PLC system considering the communication problems and response time of the system. The primary and secondary designs of RAEAHP are nearly the same with EASSBPP according to the depth of the SDS shear ram.

CHAPTER 9

CONCLUSION

9.1 Discussion on the Study

Managed Pressure Drilling is an evolving concept which is supported with unique techniques and specialized devices. The combination of these techniques and devices lead MPD to be an invaluable technology which has capability of mitigating drilling hazards, improving drilling performance and increasing production rates in the same project and simultaneously. In addition, MPD is an advance form of drilling supported with other technologies and proactive planning which leads MPD not only to drill challenging but also undrillable wells.

Although most of the decision makers are focused on the Proactive category of the MPD to obtain more satisfactory results both economically and operationally, the real but unexploited strength of MPD is the Reactive usage of the technology since it has the ability to give fast responses to unexpected occurrence of events. Proactive planning is only a way up to an extent while challenging the “Mother Nature”, because the word unexpected suggests the unpredicted which cannot be planned. Therefore, without being supported by Reactive MPD, Proactive MPD can only makes use of a restricted strength of MPD.

There are four main variations of MPD, addressing different challenges and a variety of methods covered under these variations which improve the adaptability of MPD. The flexibility of MPD allows combinations of different technology applications together with the variations of MPD, which are resulting in ultimate management of drilling operations. One of the examples is Controlled Mud Cap (CMC) -Mud Cap without loss circulation- which combines the strength of Pressurized Mud Cap (PMC) and Constant Bottom Hole Pressure (CBHP). Another example is Riserless Dual Gradient which combines the advantages of Riserless Drilling and Dual Gradient (DG). Another alternative is Continuous Circulation Concentric Casing Drilling which combines the capabilities of two Drilling Hazard Mitigation (DHM) technologies. To conclude, all these combinations are discovered to be ready for dealing with more challenging applications such as in HPHT, depleted reservoirs, extended reach and unconventional resources such as methane hydrates.

On the other hand, while focusing in advance control of pressure profiles, one of the variations of MPD, Return Flow Control (RFC) or HSE method, is becoming a less pronounced concept in spite of the fact that the primary aim is “Safety First”. Moreover, in order to make use of RFC unlike the other variations; there is no need for advanced or highly technical equipments, PLC automated systems, various analyses and designs, confusing conceptual thinking, HSE restrictions –since it is already a HSE method- etc. As a result, RFC is unfortunately one of the unexploited strengths of MPD which has capability to be applied in a wide range of operations to minimize blow-outs, and mitigate the operational risks on the rig floor.

In conclusion, MPD is not only a tooled up technology but also ultimate way of getting ready to challenge "Mother Nature" in all aspects. As she reveals the problems, the solutions should be found out to reach the target. Recently, pressure management -MPD- can be defined as one of the ultimate problem solvers until a better way is discovered.

9.2 Future Work

Since Managed Pressure Drilling (MPD) is still evolving to adapt its strengths to deal with challenges, the process requires an extra effort to find out the missing parts of the concept. Once, the missing parts of different variations in a range of applications are revealed, the next step is to minimize the effect of gaps with the adaptation of available technology to MPD and/or discovering a new technology to lead to the usage of MPD. One of the major technology gaps on the way of adapting MPD should be clarified in order to speed the adaption process of MPD up to deep water applications.

One of them is the need for back pressure compensation in case of emergency disconnect due to unexpected events which was discussed in the case study section of the thesis. In conventional drilling applications it was not a problem because of the statically over-balanced mud; however, in MPD applications the back pressure attributable to statically underbalanced mud should be compensated in order to eliminate wellbore stability problems. The concept of emergency activated back pressure pumps should be introduced to the industry. As a result, additional study about the concept should be made to adapt MPD to floating drilling applications.

In conclusion, there have to be designed a 1) "Emergency Activated Subsea Back Pressure Pump (EASSBPP)" or 2) "Riser Attached Emergency Activated Hydrodynamic Pump (RAEAHP)" for future purposes of adapting MPD to the deep water wells.

9.3 Recommendations

In order to expedite the adaptation period of MPD to the industry, the recommendations according to the study are listed below;

- MPD should be practiced stepwise rather than jumping to the more challenging well with more sophisticated methods.
- The strengths of each method should be understood clearly since MPD is application specific.
- At first, Reactive MPD should be practiced with conventional programs to be more familiar with the concept. Reactive usage of CBHP and RFC can be a good the starting point.
- After practicing enough to understand the fundamentals of Reactive MPD, the usage of Proactive MPD should be practiced with enhanced casing programs and mud designs.
- Proactive MPD should not be practiced without a contingency plan in order to be ready for probable or less expected incidents.
- Different combinations of the available or upcoming technologies with MPD should be examined to maintain ultimate control.
- "What if" scenarios should be clarified since it is one of the best ways to visualize the missing parts of the concept, which lead the industry to improve the existing system and eliminate the technology gaps.

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APPENDIX A

MPD OPERATION MATRICES

Table 1 MPD Operation Matrix 1[22]

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 Modeling	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 Modeling	ECD Reduction Tool	Down hole Pressure Monitoring	Foam Drilling	Drilling With Casing

Table 2 MPD Operation Matrix 2[22]

Shallow Water - Jack Up / Platform / Barge Mounted (Surface BOP)																		
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
Conventional Drilling Obstacles																		
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

Table 3 MPD Operation Matrix 3[22]

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

Table 4 MPD Operation Matrix 4[22]

	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

APPENDIX B

CBHP EXAMPLE

Figure 93 CBHP Pump Shut-down for Connection Example[68]

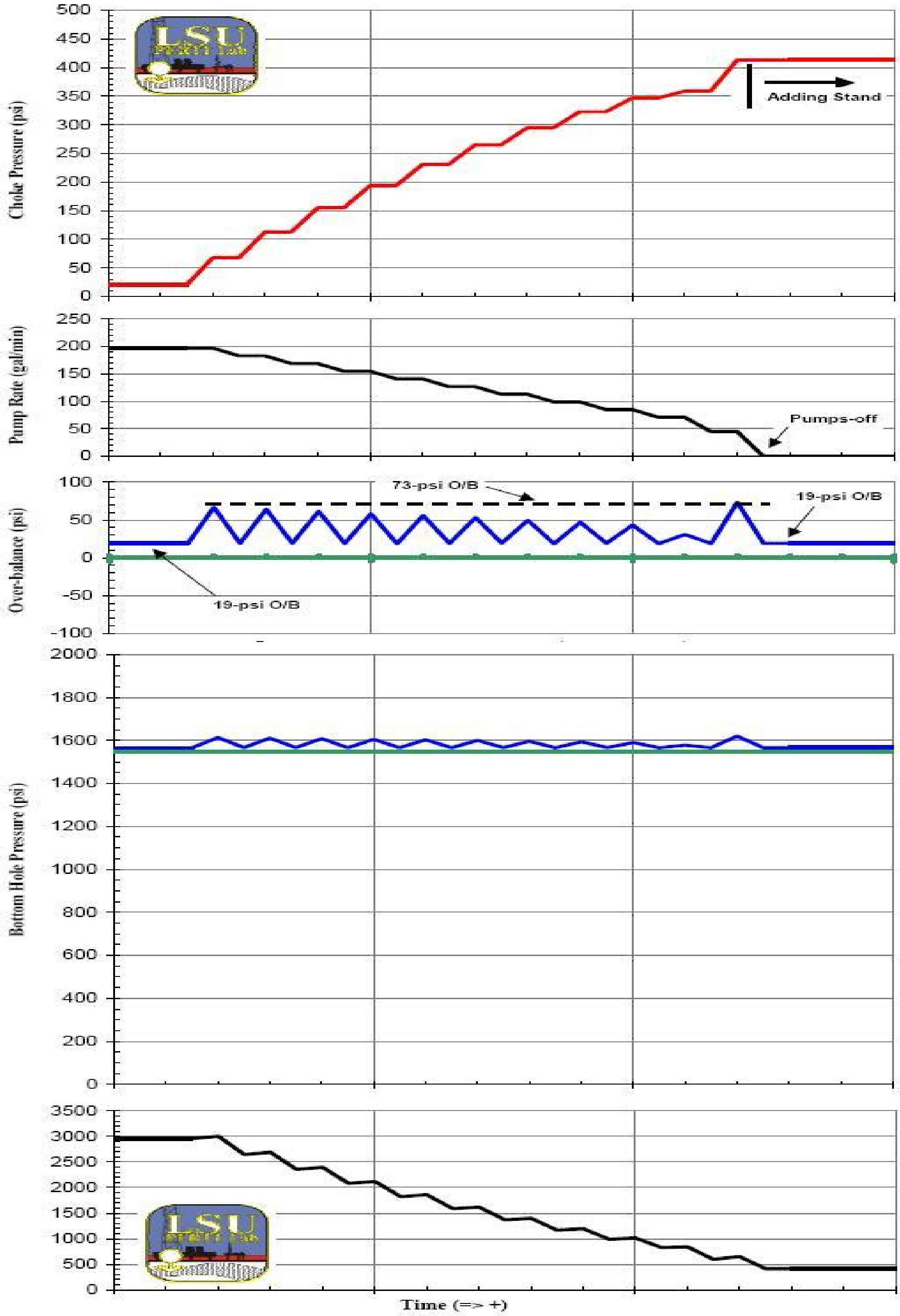
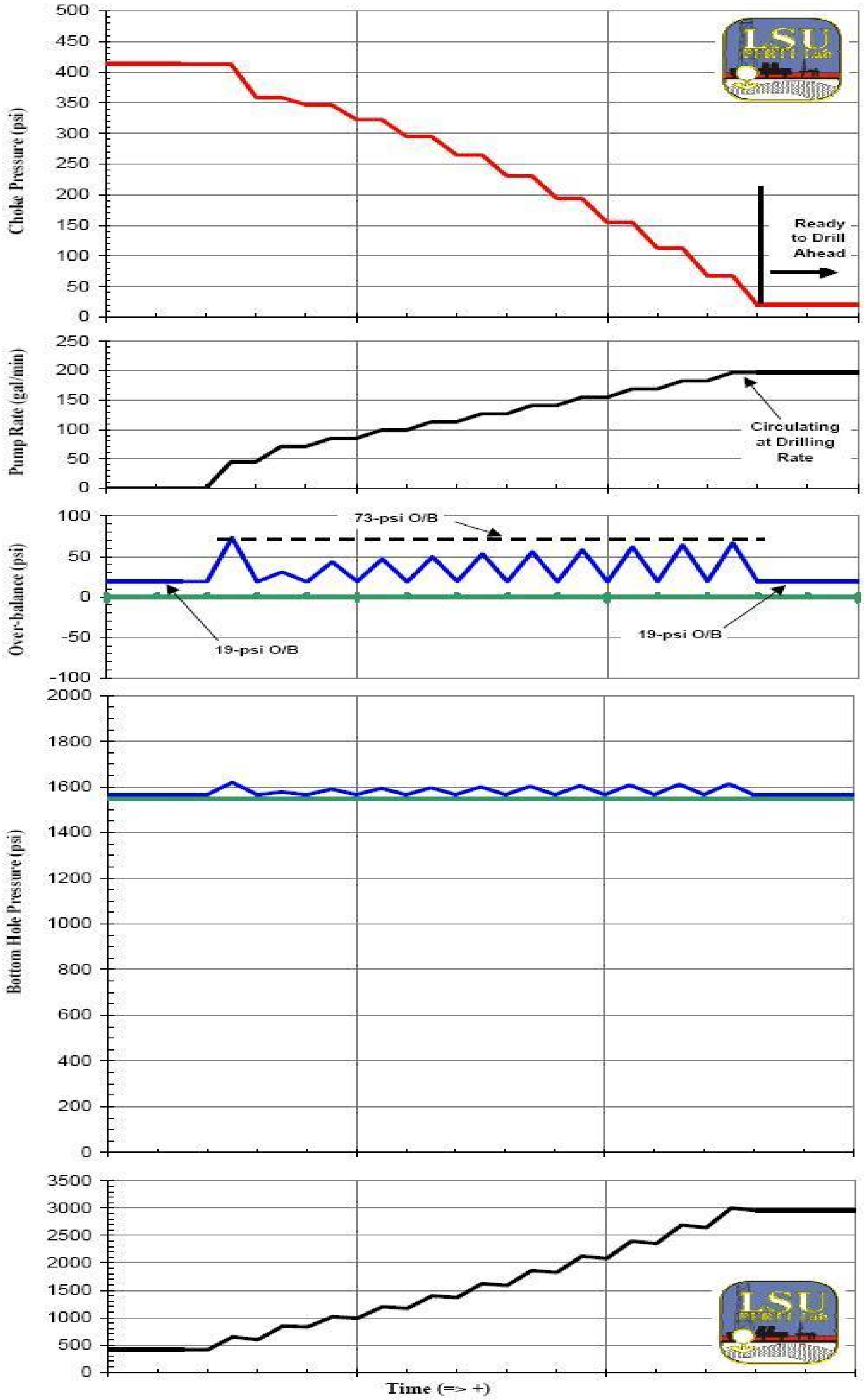


Figure 94 CBHP Pump Start-up after Connection Example[68]



APPENDIX C

BHP CONTROL EVALUATION

Table 5 Evaluation of Selected MPD Systems for BHP Control[42]

	Drilling	Tripping in	Tripping out	Drill pipe connection
Continuous circulation system (CCS) / Drill string Coupler			1)	3)
Secondary Annulus Circulation (SAC)			2)	3)
RCH and choke valve			4)	5)
RCH and choke valve + additional mud supply				
Subsea mud lift – Dual gradient		6)	6)	
Subsea mud lift w/ RCH – Dual gradient			7)	7)
Subsea mudlift – Single gradient		8)	8,9)	10)
Subsea mudlift w/ RCH – Single gradient				

	No compensation of dynamic pressure possible
	Limited control – full control may be achieved in some scenarios
	Full control/compensation of dynamic pressures

Notes:

1. Can be limited by pump pressure.
2. When there is circulation through drill string, the method will allow for faster tripping speed compared to CCS
3. Large heave will requires great variations in the pump rate in a short period of time. Compensation of swab pressure will also be limited by the available pump rate.
4. System will be able to compensate for lost volume by pumping mud through drill string.
5. Bleeding off a certain volume of mud is required to compensate for the surge pressures and pressure due to mud compression. Additional mud supply and back pressure are needed to compensate for swab pressure.
6. Ability to compensate depends on the selected mud weight and water depth.
7. Fluid supply needed for pressure and volume compensation.
8. This can be a time-consuming operation because the air / mud level in the riser has to be adjusted for each drill pipe stands.
9. With a RCH above the mud/air inter-phase, the air in the riser act as a "cushion" and the desired back pressure needed for tripping out will be achieved faster.
10. Compensation possible for moderate changes in downhole pressure[42].

APPENDIX D

MPD SIMULATION RESULTS

MPD BACK PRESSURE CALCULATOR — ERDEM TERCAN

DRILLING DATA

WELL INFO			DRILLSTRING & CHOKE			FLUID & HYDRAULICS		
Riser			Flow rate	400	gpm	MW	9,40	ppg
Length	8000	ft	DP			Cut. Dens.	2,17	g/cm3
OD	16	in	Length	16000	ft	Cut. Conc.	12	%
ID	14	in	OD	5	in	R600	65	° deflection
Casing			DC			R300	47	° deflection
Length	14000	ft	Length	1000	ft	G10m	20	lb/100 sqft
OD	9,625	in	OD	6,5	in	PV	18	cP
ID	8,535	in	Choke Line			YP	29	lb/100 sqft
Open Hole			Length	100	ft	PP	11,5	ppg
Length	3000	ft	ID	4	in	FP	13,0	ppg
D	8,5	in				HH	10,4	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley			
Ba	1,46		Nrec	2153
Bx	1,00		Ty/YP	0,97
G	1,46		HBn	0,96
Ty	28	lb/100sqft	HBk	0,05
a	0,072		PLn	0,47
b	0,297		PLk	2,55

BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	10,45	ppg	933	psi
Drilling	10,84	ppg	585	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	8000	5,00	14,00	57	9,0	14,89	85223	90848	63	LAMINAR	0,25261	0,00022	0,02098	0,25261	83	0,09
Casing - DP	6000	5,00	8,54	205	3,5	135,50	85228	90853	809	LAMINAR	0,01978	0,00279	0,00984	0,01978	158	0,18
OH - DP	2000	5,00	8,50	207	3,5	138,58	85228	90853	830	LAMINAR	0,01929	0,00286	0,00977	0,01929	53	0,06
OH - DC	1000	6,50	8,50	327	2,0	381,96	85237	90863	2058	LAMINAR	0,00778	0,00710	0,00746	0,00787	47	0,05
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	7235	TURBULENT	0,00221	0,02496	0,00513	0,00513	5	0,01
															347	0,39
															∑	

Figure 95 Simulation of CBHP Application (Salt Section)

MPD BACK PRESSURE CALCULATOR

ERDEM TERCAN

DRILLING DATA

WELL INFO

Riser		
Length	8000	ft
OD	16	in
ID	14	in
Casing		
Length	14000	ft
OD	9,625	in
ID	8,535	in
Open Hole		
Length	3000	ft
D	8,5	in

DRILLSTRING & CHOKE

Flow rate	400	gpm
DP		
Length	16000	ft
OD	5	in
DC		
Length	1000	ft
OD	6,5	in
Choke Line		
Length	100	ft
ID	4	in

FLUID & HYDRAULICS

MW	8,70	ppg
Cut. Dens.	2,17	g/cm3
Cut. Conc.	12	%
R600	65	° deflection
R300	47	° deflection
G10m	20	lb/100 sqft
PV	18	cP
YP	29	lb/100 sqft
PP	11,5	ppg
FP	13,0	ppg
HH	9,8	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley				
Ba	1,46		Nrec	2153	
Bx	1,00		Ty/YP	0,97	
G	1,46		HBn	0,96	
Ty	28	lb/100sqft	HBk	0,05	
a	0,072		PLn	0,47	
b	0,297		PLk	2,55	

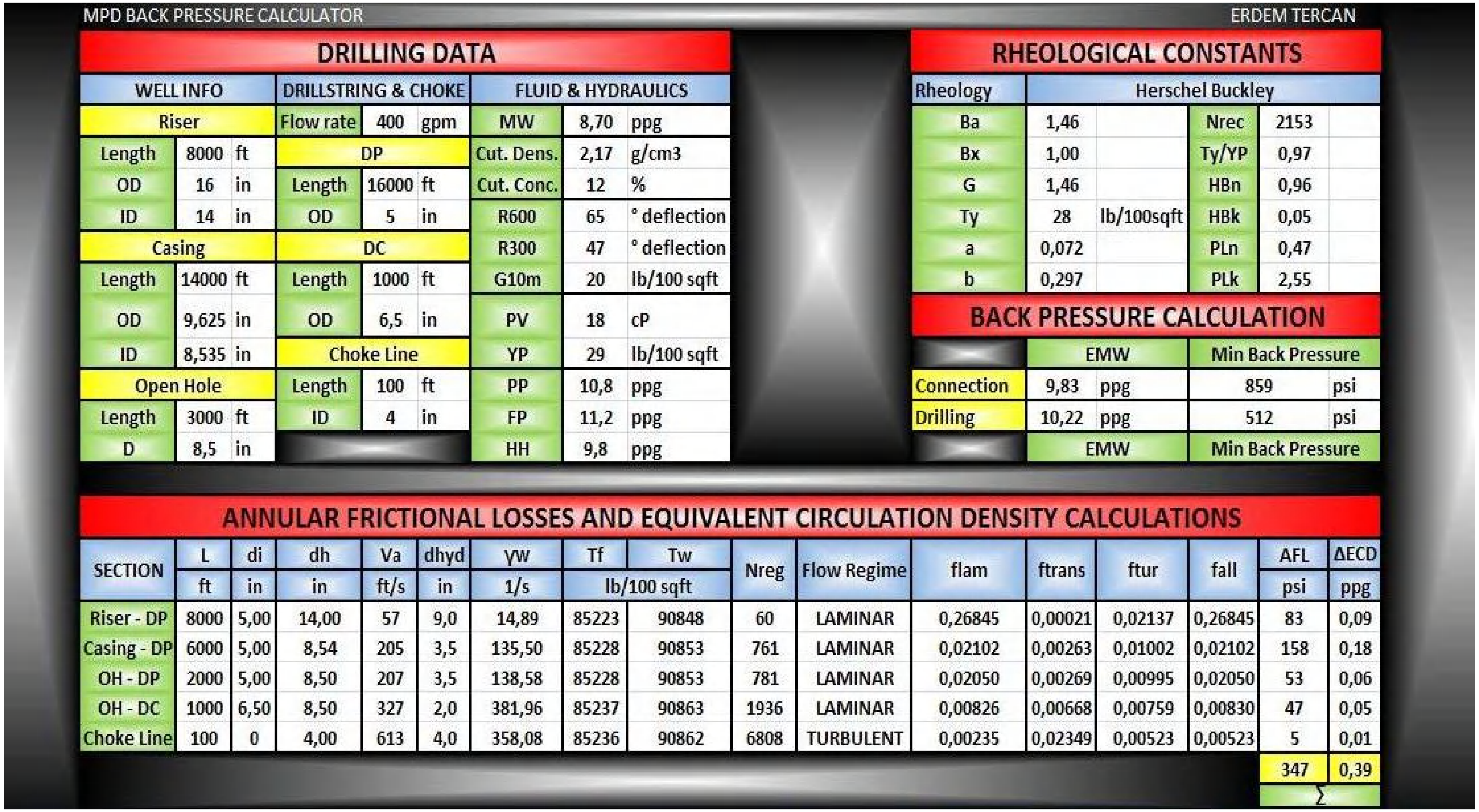
BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	9,83	ppg	1478	psi
Drilling	10,22	ppg	1131	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	8000	5,00	14,00	57	9,0	14,89	85223	90848	60	LAMINAR	0,26845	0,00021	0,02137	0,26845	83	0,09
Casing - DP	6000	5,00	8,54	205	3,5	135,50	85228	90853	761	LAMINAR	0,02102	0,00263	0,01002	0,02102	158	0,18
OH - DP	2000	5,00	8,50	207	3,5	138,58	85228	90853	781	LAMINAR	0,02050	0,00269	0,00995	0,02050	53	0,06
OH - DC	1000	6,50	8,50	327	2,0	381,96	85237	90863	1936	LAMINAR	0,00826	0,00668	0,00759	0,00830	47	0,05
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	6808	TURBULENT	0,00235	0,02349	0,00523	0,00523	5	0,01
															347	0,39
															∑	

Figure 96 Simulation of DTTL Application (Salt Section)



MPD BACK PRESSURE CALCULATOR — ERDEM TERCAN

DRILLING DATA

WELL INFO			DRILLSTRING & CHOKE			FLUID & HYDRAULICS		
Riser			Flow rate	400	gpm	MW	8,70	ppg
Length	8000	ft	DP			Cut. Dens.	2,17	g/cm3
OD	16	in	Length	16000	ft	Cut. Conc.	12	%
ID	14	in	OD	5	in	R600	65	° deflection
Casing			DC			R300	47	° deflection
Length	14000	ft	Length	1000	ft	G10m	20	lb/100 sqft
OD	9,625	in	OD	6,5	in	PV	18	cP
ID	8,535	in	Choke Line			YP	29	lb/100 sqft
Open Hole			Length	100	ft	PP	10,8	ppg
Length	3000	ft	ID	4	in	FP	11,2	ppg
D	8,5	in				HH	9,8	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley				
Ba	1,46		Nrec	2153	
Bx	1,00		Ty/YP	0,97	
G	1,46		HBn	0,96	
Ty	28	lb/100sqft	HBk	0,05	
a	0,072		PLn	0,47	
b	0,297		PLk	2,55	

BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	9,83	ppg	859	psi
Drilling	10,22	ppg	512	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	8000	5,00	14,00	57	9,0	14,89	85223	90848	60	LAMINAR	0,26845	0,00021	0,02137	0,26845	83	0,09
Casing - DP	6000	5,00	8,54	205	3,5	135,50	85228	90853	761	LAMINAR	0,02102	0,00263	0,01002	0,02102	158	0,18
OH - DP	2000	5,00	8,50	207	3,5	138,58	85228	90853	781	LAMINAR	0,02050	0,00269	0,00995	0,02050	53	0,06
OH - DC	1000	6,50	8,50	327	2,0	381,96	85237	90863	1936	LAMINAR	0,00826	0,00668	0,00759	0,00830	47	0,05
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	6808	TURBULENT	0,00235	0,02349	0,00523	0,00523	5	0,01
														∑	347	0,39

Figure 97 Simulation of DTTL Application (Sub-Salt Section)

MPD BACK PRESSURE CALCULATOR — ERDEM TERCAN

DRILLING DATA

WELL INFO			DRILLSTRING & CHOKE			FLUID & HYDRAULICS		
Riser			Flow rate	400	gpm	MW	9,10	ppg
Length	8000	ft	DP			Cut. Dens.	2,17	g/cm3
OD	16	in	Length	16000	ft	Cut. Conc.	12	%
ID	14	in	OD	5	in	R600	65	° deflection
Casing			DC			R300	47	° deflection
Length	14000	ft	Length	1000	ft	G10m	20	lb/100 sqft
OD	9,625	in	OD	6,5	in	PV	18	cP
ID	8,535	in	Choke Line			YP	29	lb/100 sqft
Open Hole			Length	100	ft	PP	10,8	ppg
Length	3000	ft	ID	4	in	FP	11,2	ppg
D	8,5	in				HH	10,2	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley				
Ba	1,46		Nrec	2153	
Bx	1,00		Ty/YP	0,97	
G	1,46		HBn	0,96	
Ty	28	lb/100sqft	HBk	0,05	
a	0,072		PLn	0,47	
b	0,297		PLk	2,55	

BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	10,18	ppg	547	psi
Drilling	10,57	ppg	200	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	8000	5,00	14,00	57	9,0	14,89	85223	90848	62	LAMINAR	0,25917	0,00021	0,02114	0,25917	83	0,09
Casing - DP	6000	5,00	8,54	205	3,5	135,50	85228	90853	789	LAMINAR	0,02029	0,00272	0,00992	0,02029	158	0,18
OH - DP	2000	5,00	8,50	207	3,5	138,58	85228	90853	809	LAMINAR	0,01979	0,00279	0,00984	0,01979	53	0,06
OH - DC	1000	6,50	8,50	327	2,0	381,96	85237	90863	2006	LAMINAR	0,00798	0,00692	0,00752	0,00804	47	0,05
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	7052	TURBULENT	0,00227	0,02433	0,00517	0,00517	5	0,01
															347	0,39
															Σ	

Figure 98 Simulation of Modified CBHP Application (Sub-Salt Section)

MPD BACK PRESSURE CALCULATOR — ERDEM TERCAN

DRILLING DATA

WELL INFO			DRILLSTRING & CHOKE			FLUID & HYDRAULICS		
Riser			Flow rate	400	gpm	MW	8,70	ppg
Length	8000	ft	DP			Cut. Dens.	2,17	g/cm3
OD	16	in	Length	16000	ft	Cut. Conc.	12	%
ID	14	in	OD	7	in	R600	65	° deflection
Casing			DC			R300	47	° deflection
Length	14000	ft	Length	1000	ft	G10m	20	lb/100 sqft
OD	9,625	in	OD	7	in	PV	18	cP
ID	8,535	in	Choke Line			YP	29	lb/100 sqft
Open Hole			Length	100	ft	PP	11,5	ppg
Length	3000	ft	ID	4	in	FP	13,0	ppg
D	8,5	in				HH	9,8	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley				
Ba	1,46		Nrec	2153	
Bx	1,00		Ty/YP	0,97	
G	1,46		HBn	0,96	
Ty	28	lb/100sqft	HBk	0,05	
a	0,072		PLn	0,47	
b	0,297		PLk	2,55	

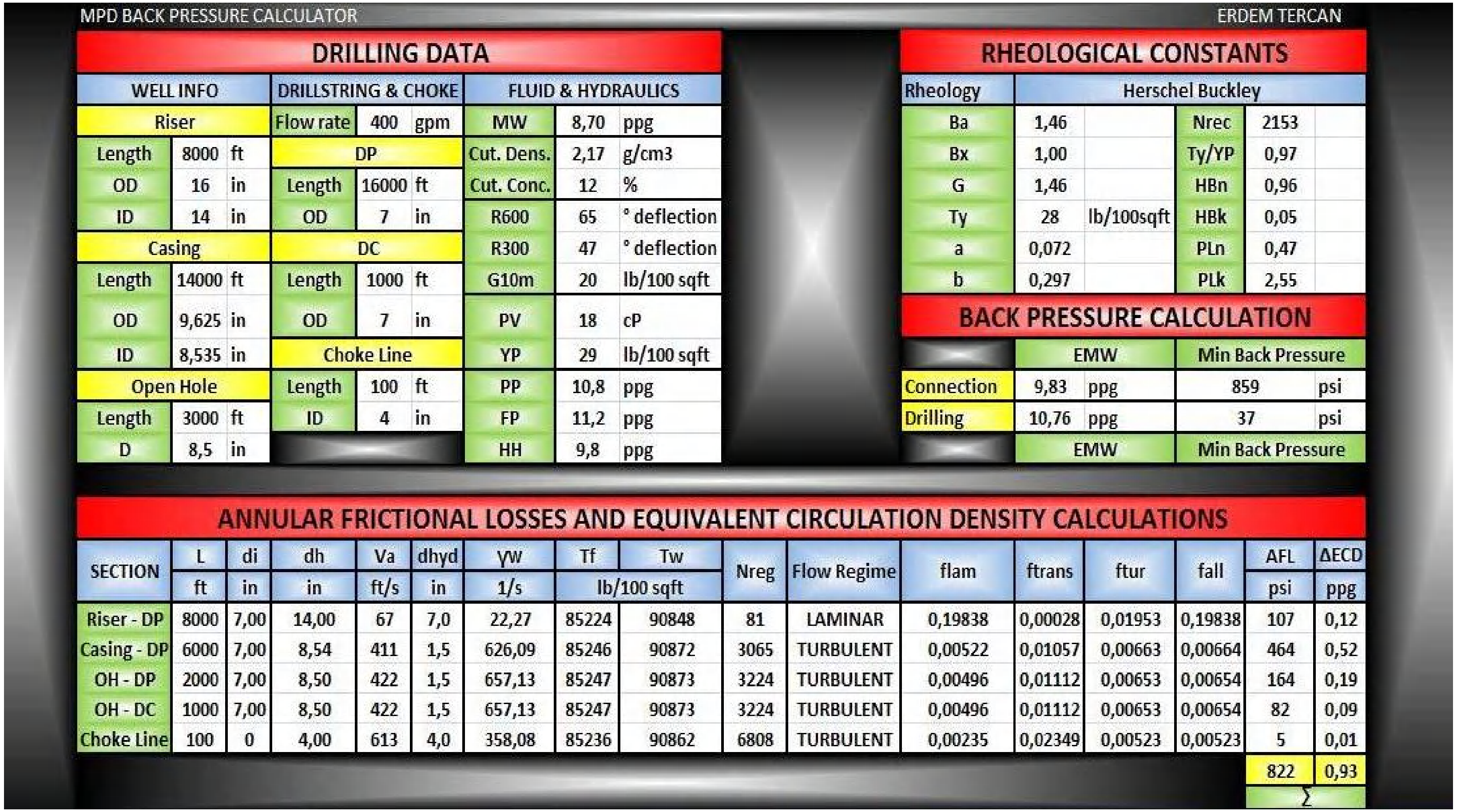
BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	9,83	ppg	1478	psi
Drilling	10,76	ppg	656	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	8000	7,00	14,00	67	7,0	22,27	85224	90848	81	LAMINAR	0,19838	0,00028	0,01953	0,19838	107	0,12
Casing - DP	6000	7,00	8,54	411	1,5	626,09	85246	90872	3065	TURBULENT	0,00522	0,01057	0,00663	0,00664	464	0,52
OH - DP	2000	7,00	8,50	422	1,5	657,13	85247	90873	3224	TURBULENT	0,00496	0,01112	0,00653	0,00654	164	0,19
OH - DC	1000	7,00	8,50	422	1,5	657,13	85247	90873	3224	TURBULENT	0,00496	0,01112	0,00653	0,00654	82	0,09
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	6808	TURBULENT	0,00235	0,02349	0,00523	0,00523	5	0,01
															822	0,93
															∑	

Figure 99 Simulation of CDTTL Application (Salt Section)



MPD BACK PRESSURE CALCULATOR — ERDEM TERCAN

DRILLING DATA

WELL INFO			DRILLSTRING & CHOKE			FLUID & HYDRAULICS		
Riser			Flow rate	400	gpm	MW	8,70	ppg
Length	8000	ft	DP			Cut. Dens.	2,17	g/cm3
OD	16	in	Length	16000	ft	Cut. Conc.	12	%
ID	14	in	OD	7	in	R600	65	° deflection
Casing			DC			R300	47	° deflection
Length	14000	ft	Length	1000	ft	G10m	20	lb/100 sqft
OD	9,625	in	OD	7	in	PV	18	cP
ID	8,535	in	Choke Line			YP	29	lb/100 sqft
Open Hole			Length	100	ft	PP	10,8	ppg
Length	3000	ft	ID	4	in	FP	11,2	ppg
D	8,5	in				HH	9,8	ppg

RHEOLOGICAL CONSTANTS

Rheology	Herschel Buckley			
Ba	1,46		Nrec	2153
Bx	1,00		Ty/YP	0,97
G	1,46		HBn	0,96
Ty	28	lb/100sqft	HBk	0,05
a	0,072		PLn	0,47
b	0,297		PLk	2,55

BACK PRESSURE CALCULATION

	EMW		Min Back Pressure	
Connection	9,83	ppg	859	psi
Drilling	10,76	ppg	37	psi
	EMW		Min Back Pressure	

ANNULAR FRICTIONAL LOSSES AND EQUIVALENT CIRCULATION DENSITY CALCULATIONS

SECTION	L	di	dh	Va	dhyd	γw	Tf	Tw	Nreg	Flow Regime	flam	ftrans	ftur	fall	AFL	ΔECD
	ft	in	in	ft/s	in	1/s	lb/100 sqft								psi	ppg
Riser - DP	8000	7,00	14,00	67	7,0	22,27	85224	90848	81	LAMINAR	0,19838	0,00028	0,01953	0,19838	107	0,12
Casing - DP	6000	7,00	8,54	411	1,5	626,09	85246	90872	3065	TURBULENT	0,00522	0,01057	0,00663	0,00664	464	0,52
OH - DP	2000	7,00	8,50	422	1,5	657,13	85247	90873	3224	TURBULENT	0,00496	0,01112	0,00653	0,00654	164	0,19
OH - DC	1000	7,00	8,50	422	1,5	657,13	85247	90873	3224	TURBULENT	0,00496	0,01112	0,00653	0,00654	82	0,09
Choke Line	100	0	4,00	613	4,0	358,08	85236	90862	6808	TURBULENT	0,00235	0,02349	0,00523	0,00523	5	0,01
															822	0,93
															∑	

Figure 100 Simulation of CDDTL Application (Sub-Salt Section)

MPD BACK PRESSURE CALCULATOR — ERDEM TERCAN

DRILLING METHOD	PP	FP	MW	STATIC	DYNAMIC	BP CONNECTION	BP DRILLING
	ppg	ppg	ppg	ppg	ppg	psi	psi
CONVENTIONAL DRILLING	11,00	13,00	11,70	12,49	12,92	NO	NO
	11,00	13,00	11,00	11,98	12,40	NO	NO
	11,00	13,00	9,90	11,04	11,46	NO	NO
CBHP MPD	11,00	13,00	9,40	10,62	11,04	337	NO
	11,00	13,00	9,20	10,45	10,86	488	120
DTTL MPD	11,00	13,00	8,70	10,02	10,44	863	497

ASSUMED SDS INDUCED BACK PRESSURE : 1000 PSI

MPD METHOD	PP	FP	MW	STATIC	BHP(w/o BP)	BP	EABP
	ppg	ppg	ppg	ppg	psi	psi	psi
CBHP MPD	11,00	13,00	9,40	10,62	9388	337	x
AFTER SDS (EASSBP)	11,00	13,00	9,40	10,62	4970	337	3755
AFTER SDS (EARAHP)	11,00	13,00	9,40	10,62	8284	337	441
DTTL MPD	11,00	13,00	8,70	10,02	8858	863	x
AFTER SDS (EASSBP)	11,00	13,00	8,70	10,02	4689	863	4031
AFTER SDS (EARAHP)	11,00	13,00	8,70	10,02	7816	863	905

EASSBP DEPTH	8000	ft	Riser Depth	8000	ft
EARAHP DEPTH	2000	ft	Total Depth	17000	ft

Figure 101 Simulation of Back Pressure Compensation with EASSBP / EARAHP

APPENDIX E

PERMISSION LETTER OF WEATHERFORD

Weatherford

December 16, 2009

To whom it may concern:

Re: Erdem Tercan – MPD Thesis

I am pleased to have the opportunity to serve as a technical resource for Mr. Erdem Tercan's work towards a thesis speaking to Managed Pressure Drilling (MPD) tools and methods.

Although MPD is poised to become one of the most influential drilling technologies over the next 2 decades, the predominance of the upstream industry's drilling decision-makers are only just beginning to understand many of its nuances and drilling hazard mitigation potential.

His thesis subject is very timely and will have strong potential to make a valuable contribution to the industry as a whole.

The purpose of this document is to confirm that he has my permission to use the various published and un-published technical materials, articles, drafts, photographs, graphs, charts, etc. that I may provide him for his reference and use in support of his thesis work.

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