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MASTER'S THESIS

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DEDICATION

This work is dedicated to my parents and my elder brother to whom I owe so much for my achievements.

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I would like to thanks Associate professor Mesfin Belayneh for his guidance, support and encouragement for this project. I fell so lucky to have him as my supervisor for this thesis, at times it look to me that he is more involve than myself. I always find him humble and cooperative. I am here not hesitating to mention that without him this work will be much more difficult to complete.

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$P_{formation}$= formation pressure
$P_{bottomhole}$= bottom hole pressure
$P_{hydrostatic}$= mud weight
$P_{friction}$= friction pressure
g = gravity
h= length
f= friction factor
P_{choke}= choke pressure
P_{wf}=fracture pressure
P_o= pore pressure
d_{mud}= mud density
D= total depth
D_a= depth of cased hole
D_s= water depth
D_b= open hole depth
d_{sw}= seawater density
d_o= pore pressure interm of desity gradient
d_{res}= reservoir fluid density
SF= safety factor
P_{burst}= burst pressure
P_c= collapse pressure
ρ_{km} = Kill Weight Mud (ppg)
ΔP_{over} = Formation over pressure (psi)
D = Total depth
D_w = water depth
D-Dw = True Vertical depth (ft)
ρ_m = Original weight mud (ppg)
ΔP_S = change in casing pressure at casing side in psi
ΔV_P = change in pit volume (volume gained) in bbl
γ_m = mud specific weight in bbl/ft
AV= Annular volume capacity in bbl/ft

List of abbreviations

HC = hydrocarbons
MPD = managed pressure drilling
BHP = bottom hole pressure
RMR = riserless mud recovery
HPHT = high pressure and high temperature
NPT = non-productive time
IADC = International Association of Drilling Contractors
SPE = Society of Petroleum Engineers
ECD = equivalent circulating density
RCD = rotating control device
TD = target depth/ total depth
HSE =health, safety and environment
CBHP = constant bottom hole pressure
BP = back pressure
AFP = annular friction pressure
CCS = continuous circulation system
DG D= dual gradient drilling
PMCD = pressurized mud cap drilling
FMCD = floating mud cap drilling
NRV = non return valve
BOP = blow out preventer
RBOP = rotating blow out preventer
DKD = drill kill density
SMIS = seawater mud isolation system
MODU = mobile offshore drilling unit
EdR = E duct return
JIP = joint industry project
DSV = drill string valve
SRD = subsea rotating diverter
SMD = subsea mud lift drilling
LOT = leak off test
SMO = suction module
SPM = subsea mud pump module
MRL = mud return line
HoJ = hang off joint
RPCD = riser pressure control device
MWD = measurement while drilling
SPP = stand pipe pressure
SICP = shut in casing pressure
SIDPP = shut in drill pipe pressure

Abstract

There are several problems which an oil and gas industry is facing. These problems can be solved by riserless drilling method which comes under managed pressure drilling umbrella. The most important problem is increasing number of casing strings to complete a well and to control a well in limited pressure profile.

A well model was developed and both conventional and riserless drilling approaches were applied to see how many casings will be needed to complete a same well with these approaches. All in all four different cases were established namely: conventional single mud drilling, dual gradient drilling, riserless zero well head pressure (back pressure application) and riserless zero well head pressure (U-tube effect application).

Casing design criteria were established to select best possible and available casing with API standards. Criteria were not only from drilling point of view but also production and cementing scenarios. Successfully P110 casing showed to fulfill all pressure requirements.

A well control comparison was made and find out that with riserless drilling approach a lot of time can be save in order to circulate the kick out of the well.

1 Introduction

1.1 Background of the thesis

There are several problems which an oil and gas industry is facing, such as increasing marine riser length and size, increasing well head size and narrowing formation pressure profile resulted by deep water drilling, depleted reservoirs, water injection (Gullfaks) and HPHT wells. But we cannot change the pressure profile rather we have to develop or improve a current technology to mitigate this limited down hole environment. We know that declining hydrocarbon reserves and increasing demand pushes oil and gas companies to explore areas which presents high economical risk and technical problems. Among those areas are deep water exploration which look quite promising but at same time present new challenges.

Targeting deep for hydro carbon (HC) exploration results in narrower window between formation pore pressure and fracture pressure. This is quite challenging when drilling deep because then well control is quite a concern in narrow working window, to avoid this we need to installed extra casing strings which itself is expensive, also with narrower window reservoir damage is multiplied and results in more economical loss. Problems associated with narrow pressure windows are;

- Well bore stability
- Kick
- Lost circulation
- Differential sticking
- Well control

One of the biggest challenges in deep water drilling is “marine riser”. With increasing depth, the size of well head and marine riser also increase and so as the wall thickness of marine riser to control increased pressure, weight and vessel size to hold this increased weight riser, all these things will results in tremendous increase in unit cost of riser.The problems related to marine riser are;

- Weight Handling Limitations
- Space Limitations
- Additional Mud and its Cost
- Additional Stresses
- Time

So we have to control these two types of problems. The limited down hole related issues become very difficult to handle in open pressure system (mud return exposed to open atmosphere), so if a closed loop system is utilized, we can solve this problem quite successfully. Managed pressure drilling (MPD) is solution for this, which is a closed loop system in which we can control our bottom hole pressure (BHP) quite precisely.

MPD is an adaptive method, which utilize tools and technique to mitigate the limited down hole environment. MPD also include control over;

- Back pressure

- Fluid density
- Fluid level in the annulus
- Circulatingfriction
- Hole geometryetc

The problems related to marine riser can be solved by riserless drilling, as a benefit we know that riserless drilling comes under MPD's umbrella. So by applying riserless drilling we can solve both problems. In Riserless drilling, the hydrostatic head is composed of two parts;

- Upper part is low density sea water, above sea bed
- Lower part is high density drilling mud, below sea bed

Current practice to drill top hole section in riserless drilling environment with pump and dump technique is overwhelming by new technology like Riserless mud recovery (RMR) by AGR technology etc, which employed mud pump at sea bed to transport returning drilling mud from well head to the vessel, this technology is quite successful in gaining results like:

- Reduce drilling mudcost
- Better well control in case of shallow water and gas

1.2 Scope and objective

The main objective of this thesis is to investigate the current drilling problems which an oil and gas industry is facing. Literature study will be done to have a broad understanding of causes of these problems. Then as a solution for these problem managed pressure drilling will be discussed as a potential solution. The different types of MPD and its advantages and disadvantages will also be discussed. Apart from this, riserless drilling methods, its types and advantages will also be discussed. Some focus will also be put on casing design criteria and different well control approaches.

The purpose of calculations is to investigate the outcomes, if the same riserless technology is employed to drill a complete well, to study different aspects which will be encountered during drilling and compare them with conventional conditions and as it is claimed that with exclusion of marine riser one would broadened the pressure window to play with, which can be beneficial in terms of:

- Less casing strings to complete a well
- Possible to reach deep targets
- Riser margin will not be consideration (already included)
- Reduced amount of drilling mud
- Better well control
- Time saving (in terms of circulating the kick out of the well)
- Early kick detection and control

So calculation parts will be consist of

- Conventional method of drilling a well and to see how many casing will be needed to complete a well
- Dual gradient method to see how many casing will be needed to complete a same well. In this part I assumed that
    - there is two gradient system,
        - low density (sea water) above sea bed
        - high density drilling mud below sea bed
    - this technology will be able to with stand deep water pressure
    - we can use this technology to complete well
- A new procedure "Riserless zero well head pressure approach" to drill a well and to see the number of casing it requires. The assumptions taken in this part is
    - Well head will be completely isolated from above, so we have zero pressure acting on well head annulus
    - Annulus will only be consist of single mud system
    - MPD choke will able to with stand the high operating pressures
    - Siem WIS riser pressure control devise will be able to isolate the well head
    - Riserless equipments will perform under deep water
    - Down hole safety valve will able to control the U-tube effect
- Casing design criteria will be reviewed to calculate the best available casing
- Well control comparison will be done to investigate the time saving to circulate out the kick

1.3 Readers guide

This thesis work consists of 4 chapters.

Chapter 1: Presents introduction and objective of the thesis work.
Chapter 2: Presents a broad literature study on the technology of MPD and theories to be used for design calculation. This section consists of four sub topics along with their references.

- Section § 2.1 Managed Pressure Drilling (References in page 22)
- Section § 2.2 Riserless Drilling(References on page 47)
- Section § 2.3 Casing design(References on page 61)
- Section § 2.4 Well control(References on page 74)

Chapter 3: Presents Design Calculations on casing seats determination, Casing design and well control (Reference on page 99)
Chapter 4: Summary and Recommendation

2 Literature study

In this chapter the main target is to study the main problems of conventional drilling and the solution of these problems by new technologies. Managed pressure drilling and as a type of it a riserless drilling will be especially focused, their history and advancements, equipments and advantages will be discussed. Different literature will be studied and back ground of calculation will be established especially for casing design and well control calculations.

2.1 Managed Pressure Drilling

2.1.1 Introduction

Drilling a well is becoming more and more challenging day by day because of depleted reservoir, water injections, high pressure high temperature (HPHT) wells and deep water wells. The operating window between formation pore pressure and fracture pressure is becoming narrow to work with and this leads to kick, loss circulation or stuck pipe cases.

Managed Pressure drilling has especial feature to counter the effect of narrow pressure window which in result turns out to be a High cost non-production time (NPT). In conventional drilling, mud return are exposed to an open environment and such open vessel method present great problems to drilling engineer such as to monitor the annular pressure. Annular pressure is contributed by mud weight in static condition and in dynamic condition annular pressure is contributed by mud weight and annular frictional pressure as shown in the figure1

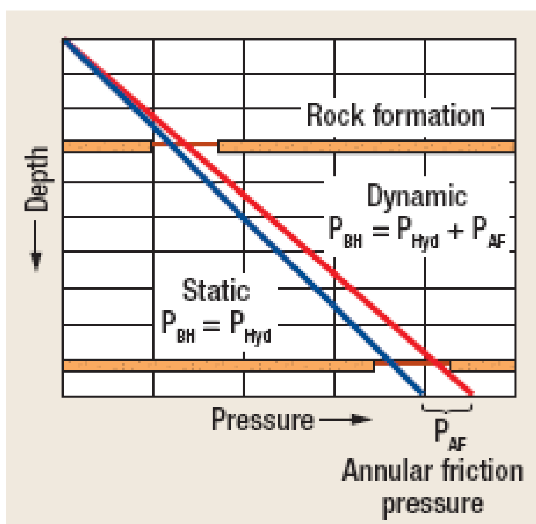

Figure 1: Static and dynamic pressure within the formation pressure[1]

Apart from this, targeting deep for hydro carbons (H.C) exploration results in narrower window between formation pore pressure and fracture pressure, This is quite challenging when drilling deep because then well control is quite a concern in narrow working window, to avoid this we need to installed extra casing strings which itself is expensive, also with narrower window reservoir damage is multiplied and results in more economical loss. The problem of Non Productive Time (NPT) is more severe in deep water drilling where the pressure window is very narrow to work with as shown in the figure 2. It is clear that moving towards deeper water exploration present us narrower formation pressure window, thus making it hard to drill the well with normal conventional drilling method and becoming more challenging regarding economics because more casing will be required to complete the well.

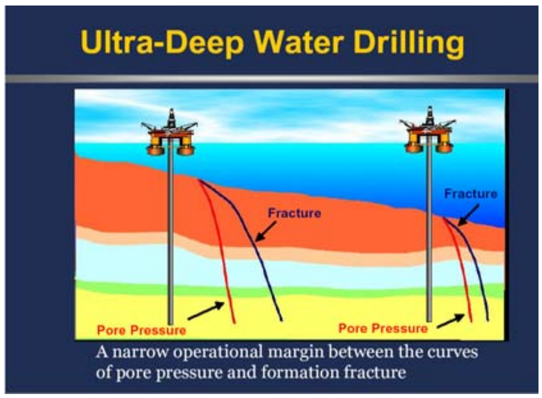

Figure 2: Formation pressure profile in deep water[2]

2.1.2 Definition of MPD

Managed Pressure Drilling is defined by the Underbalanced operation and managed pressure drilling committee of the international Association of Drilling Contractors as

> *"An adaptive drilling process used to more precisely control the annular pressure profile throughout the well bore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulics pressure profile accordingly. This may include the control of back pressure by using a closed and pressurized mud return system, downhole annular pump or other such mechanical devices. Managed pressure drilling generally will avoid flow into the well bore"*[3]

MPD process in employed to especially control the annular pressure profile for better well control, the main target is to avoid any NPT incident caused by narrow pressure profile. MPD is an improved and modified form of underbalanced drilling. The underbalanced drilling is defined by IADC as

> *"a drilling activity employing appropriate tools and controls where the pressure exerted in the well bore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluid to the surface"*[3]

The figure 3 describes the main difference between conventional drilling, underbalanced drilling and managed pressure drilling.

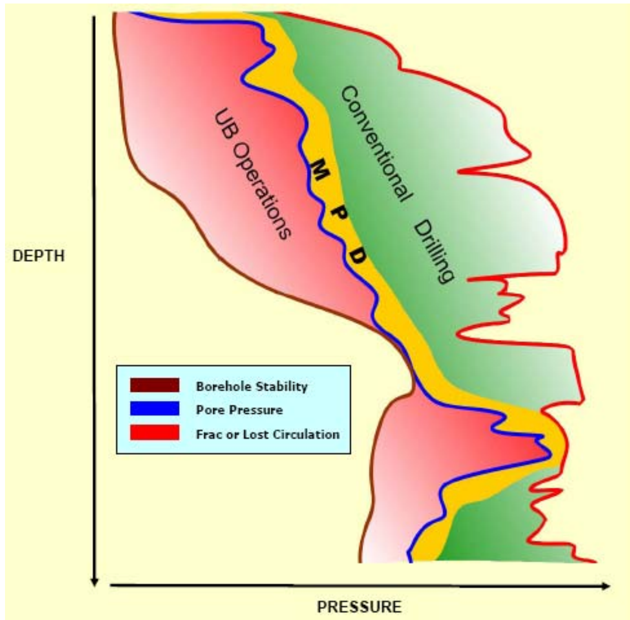

Figure 3: Drilling windows[4]

- To overcome the risk and cost regarding drilling wells that have narrow pressure window and narrow down hole environmental limits, MPD process uses a collection of tools and techniques, by proactively managing the annular hydraulic profile[3]

- Backpressure control, fluid density, fluid rheology, fluid level in the annulus, circulating friction and hole geometry, or combinations thereof may also be included in MPD[3]

- 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[3]

In conventional drilling operation, the bottom hole pressure (BHP) is controlled by static mud weight and annulus friction pressure (AFP):

$$P_{formation} = P_{bottom\ hole} = P_{hydrostatic} + P_{friction} \qquad 2.1$$

$$P_{hydrostatic} = \rho g h$$

$$P_{friction} = \frac{2 f \rho v^2}{d} h$$

Where

$\rho = density$

$g = gravity$

$h = length$

$f = frictionfactor$

$d = diameter$

$v = velocity$

In MPD application, the BHP is balanced by:

$$P_{formation} = P_{bottom\ hole} = P_{hydrostatic} + P_{friction} + P_{choke} \qquad 2.2$$

As discussed by Steve Nas (2011), managed pressure drilling is a primary well control as the well pressure is precisely control to prevent any formation flux to enter in the well bore. But still as setting the managed pressure drilling setup the secondary pressure control devices must be ready such as BOP and rig choke manifold, but the secondary control system should not be used during normal operation of managed pressure drilling[5]. MPD is a closed loop pressurized system, a typical MPD system can be shown by figure4

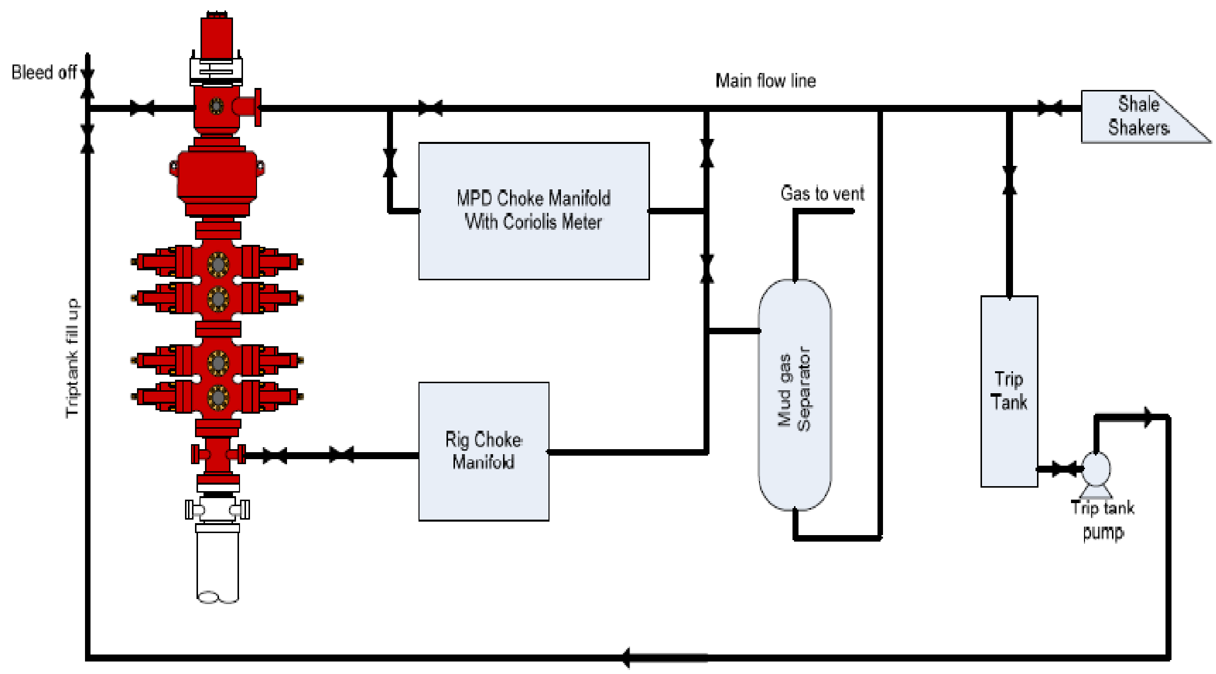

Figure 4: MPD process flow diagram[5]

Huge amount of hydrocarbons are still remained in offshore and majority of them are considered as risky, uneconomical and undrillable. With MPD all these prospects will be readily available, economical and in drillable in safe manner[6].

2.1.3 History and Advancements

Managed pressure drilling idea can be traced back the time where tools were developed for under balanced drilling. Rotating heads were mentioned in 1937 Shaffer tool company catalog[7].

In 1970s the concept of equivalent circulation density (ECD) was well defined and successfully used. In 1960s the rotating control devices made it possible for drilling with compressible fluids such as air, mist, gas and foam which is now known as Performance drilling, which has successfully proved itself in high penetration rate, longer bit life and more economical control over overall well cost [8].

Many of the ideas on which MPD is predicated 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 pressure and how to predict pressures and fracture gradient from available data[7].

Mud cap drilling (MCD) for years also known as dry drilling or drilling with no returns. More formalized version of MCD was used in Venezuela in the 1980s, in the Hibernia field off Nova Scotia in the 1990s and also in Kazakhstan[8].

With the passage of time the uses of rotating control device (RCD) evolved and industry learned how to manipulate the precise control over annular pressure by use of RCD. RCD also helped to drill the well near the formation pore pressure, although it is not intended to take formation influxes but one should be prepare for the worst case scenario. In 2003, the collection of techniques was recognized as a technology within itself and label as Managed Pressure Drilling[8].

Since 2005, more than hundred wells were drilled with MPD technology. After through studies it is noted that all the wells drilled with MPD technology results in better economics and time saving by eliminating NPT due to losses and other well control problems. Controlling the well bore pressure with closed loop system and introducing some simple techniques has made it possible to drill with was previously considered as undrillable. Approximately 20% time was saved which normally used in losses and kick related problems. MPD was deployed in all wells in fractured carbonate reservoirs, but only used in some of the wells which faced loss/kick scenario; MPD enabled all of these wells to be drilled to target depth (TD) without having significant delays[9].

John Kozicz (2006) presented different experiences from other people describing the prosper achievements by MPD technology and suggested that prospects to use these methods with the primary motive to improve competence will broaden as the capabilities of various MPD methods become better understood[10].

2.1.4 Categories of MPD

There are basically two approaches of MPD

Reactive: The well is planned to drill in conventional method but as a contingency plan, one needs to installed rotating control device, choke and drill string floats in order to efficiently and safely encounter any unexpected and abnormal down hole pressure environment limits e.g. the present mud system in the hole is not suitable to handle the current situation and replacing the original mud system need so much precious time, so a rapid and safer mode of controlling the situation is possible MPD installed[8].

Using RCD alone not necessarily means as MPD operation. RCD itself is very good and reliable tool of well control. Most of the RCDs are high pressure rated under static conditions and provide best means of directing any hydrocarbon escaping from well bore and diverting them away from rig floor[4].

Proactive: In this category of MPD, well is planned from the beginning with casing, fluid and open hole or any other alternate drilling program that utilizes full advantage of ability to control/manage the well bore pressure profile more precisely. This category of MPD is also known as "walk the line category" and present great benefits to drilling program[8].

This approach uses wide range of tools to control the placement of casing seats, utilizing less number of casings and most importantly better control over mud density requirements and mud cost. Proactive MPD provide us more drilling time with less NPT, thus it said that proactive MPD is used for the drilling of wells which are challenging in[4].

- Operations
- Economics
- Undrillabilty

2.1.5 Types of MPD

2.1.5.1 Return Flow Control

This is simplest type of MPD which is a closed annulus return system for health safety and environment (HSE) only. This system consists of diverting annulus flow away from rig floor especially in case of H_2S[9]. In this system we do not control any annular pressure, only RCD is added to the drilling operation to accomplish this type of MPD. It is used as a safety measure to tackle any abnormal condition such as during tripping if a gas spills onto rig floor, the flow line will be closed and flow will be routed to rig choke manifold where this flow is safely controlled.

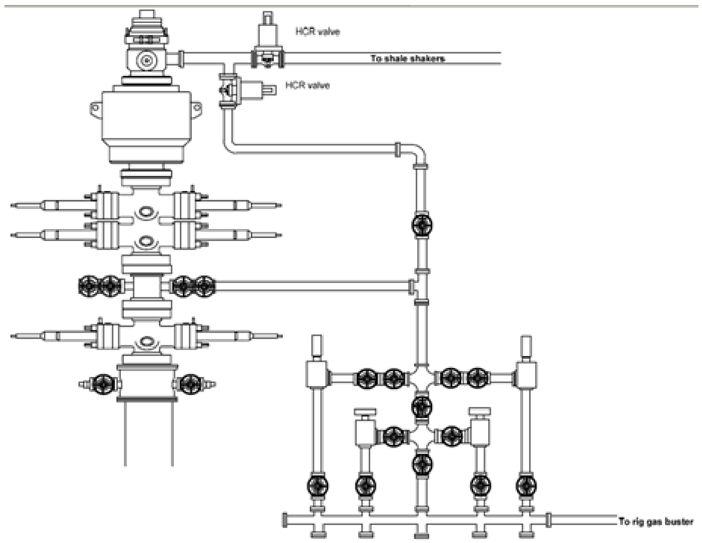

Figure 5: MPD rig-up for return flow control[9]

2.1.5.2 Constant Bottom Hole Pressure (CBHP)

Especially applied to case of drilling where there is very narrow or unknown pressure window exist between formations pore and fracture pressure and where the BHP needs to be control very precisely. The BHP is contributed by mud weight during static condition and by mud weight and annular friction pressure during flowing condition. As circulation stops during connection the BHP drops, annular back pressure system is used to apply back pressure (BP) to maintain the BHP thus preventing any formation fluid to enters into the well bore.

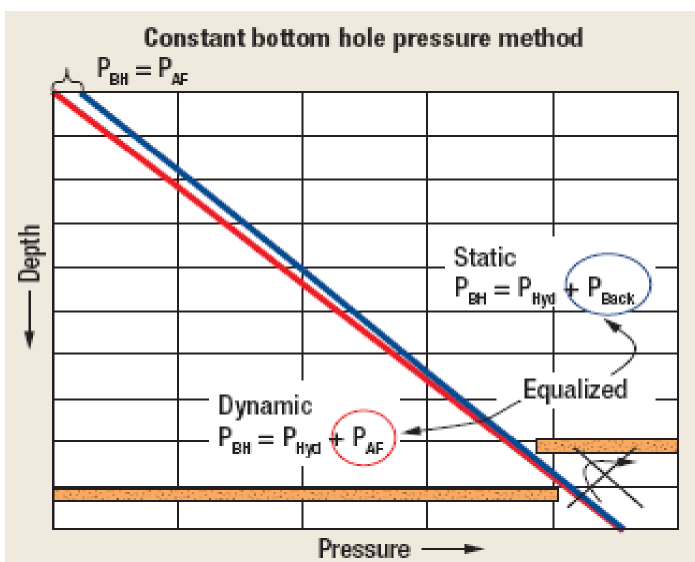

Figure 6: Constant bottom hole pressure method[1]

Pressure variation during different drilling operations may leads to severe case of kick or lost circulation, Constant bottom hole pressure method prevent these pressure variations and helps to drill deeper and longer sections.

Continuous circulation system (CCS) is also a variation of CBHP system. It is used to keep ECD constant by not interrupting the circulation during non-drilling operations (e.g. pipe connection). Especially used where AFP needs to constant to prevent cutting settling in extended reach wells. The figure 7 is a demonstration of how this system works. RCD seals the annulus and lead the flow through choke a closed loop system, the flow is pumped by back pressure pump and by selected opening of choke we applied a required back pressure.

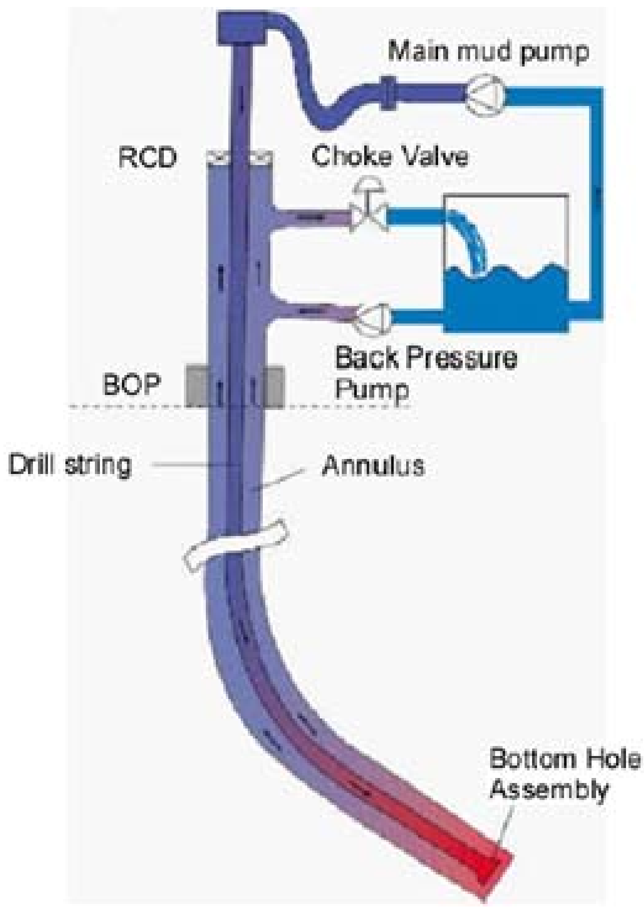

Figure 7: Continuous circulation system[2]

2.1.5.3 Dual Gradient Drilling

When a well bore is exposed to more than one drilling fluids in its annular path it is called a dual gradient drilling. This type of MPD is best known for deep water drilling, where large mud weight is only resulted because of large marine riser depth thus making it hard to drill in deep wells where pressure window is very small.

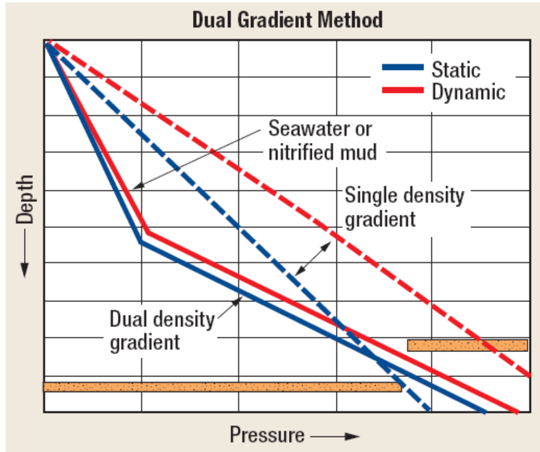

Figure 8: Dual gradient method[1]

There are several ways to accomplish dual gradient scenarios[8]

Injecting less density fluid in the annulus at predetermined depth; in offshore wells this is done at sea bed. Injecting air/gas etc at seabed reduces the mud density in marine riser thus creating two different mud weight system exposed to well bore annulus path.

In Artificial mud lift system, the pumps are installed at sea bed where flow is directed to these pump and they pump it back to the rig floor through separate line, the marine riser is filled with sea water in order to prevent from collapse. So two mud systems are develop, one being the sea water system in the marine riser and second the normal drilling mud bellow sea bed.

The figure 9 below is a systematic diagram of artificial mud lift system, the return flow through annulus is directed to subsea pump rather than in the marine riser. A separate line is used for mud return. The system is known as riserless drilling when there is no riser installed.

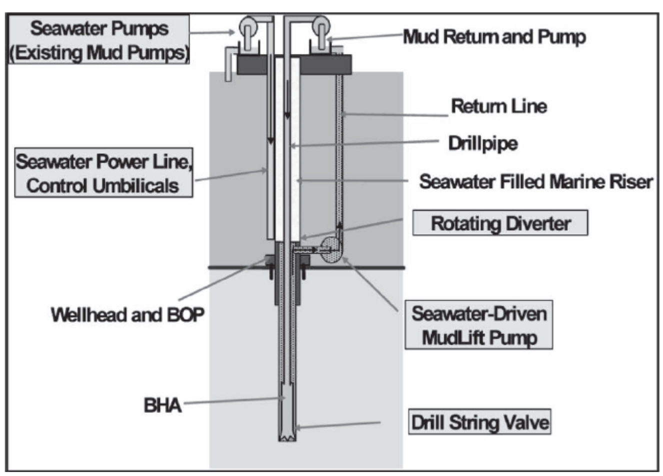

Figure 9: Artificial mud lift system[11]

2.1.5.4 Pressurized Mud Cap Drilling (PMCD)

It is a variation of MPD, drilling with no returns to surface where an annulus fluid column, assisted by surface pressure is maintained above formation that is capable of accepting fluid and cutting[3].

In order to address severe lost circulation issues, PMCD is used but with two drilling fluid. A heavy, viscous mud is pumped down the back side in the annulus space to some height[1]. This heavy and dense mud cap is serving as annular barrier while driller uses less density, cheap drilling mud to drill into the weak zones. PMCD method can be illustrated by figure 10

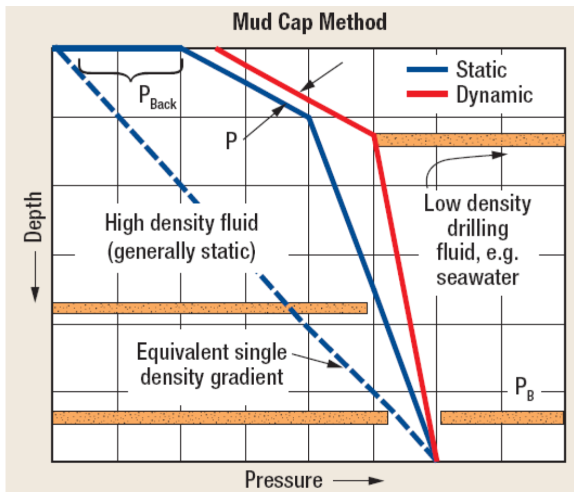

Figure 10: Mud cap method[1]

PMDC is widely used in highly fractured and vugular carbonate reservoirs[9]. It is used where total losses situation is experienced; this type of MPD is especially used in deep water drilling where depleted zones have to be drilled to reach the deeper targets.

Floating Mud Cap Drilling (FMCD) is considered as variation of PMCD. If annular fluid is not able to designed to provide surface pressure in the annulus, than we use FMCD and in this case the mud cap is called as floating. As in PMDC, the sacrificial fluid is pumped down the drill pipe.

2.1.6 Advantages of MPD

The main target of MPD is:

- Limiting Loss circulation
- Limiting NPT due to Kick and well control problems
- Limiting Well bore instability

- Limiting NPT due to Stuck pipe
- Extending the casing setting points
- Drilling with total lost returns
- Increasing the penetration rate

As the time passes people becoming more focus on economical aspects of drilling, previous records shows us that majority of drilling related cost are consuming just to mitigate well control problems. Non productive time (NPT) should be reduced to go further in the exploration because now we are moving towards unconventional resources and among those ultra-deep water exploration has bright future but for that we have to reduce NPT to make it feasible and economical. Statistical causes of NPT in the Gulf of Mexico, between year 1993 and 2003 for gas wells are true picture of current scenarios, about 40% of NPT, are resulted because of pressure related problems such as kick, lost circulation etc[7]. Figure 11 is the study by Dodson(2004) which reveals that about 40% of non productive drilling time was consumed by well instability and pore pressure issues.

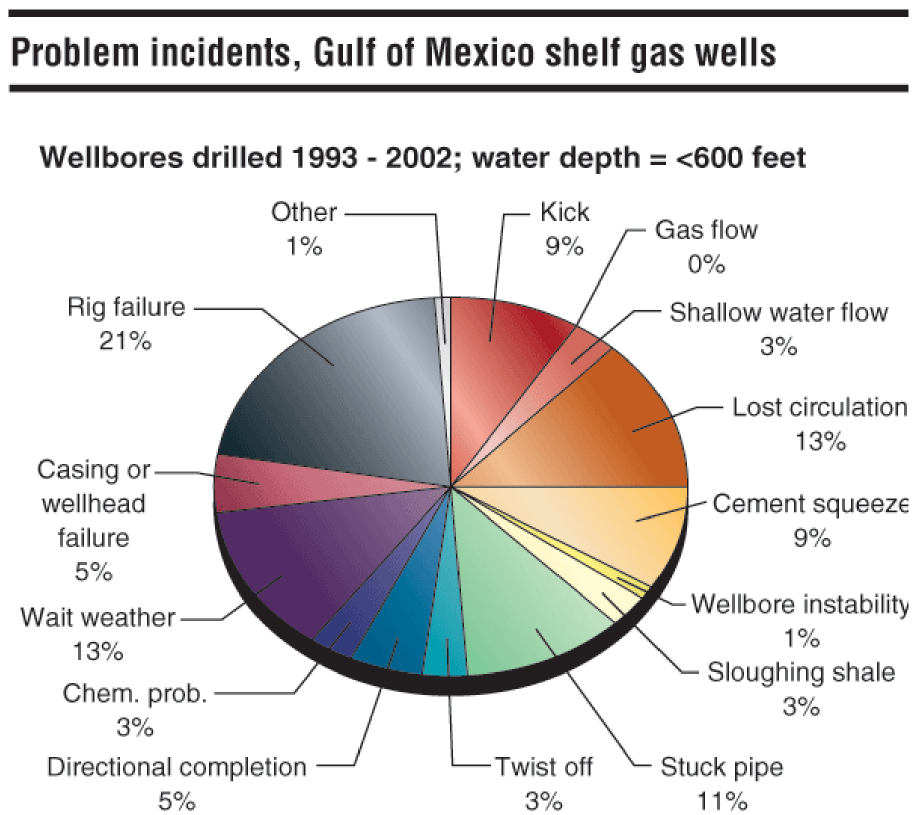

Figure 11: Contribution of different drilling problems[12]

2.1.6.1 An Adaptive Process

For a new technology to be successful it is very important that it must be adaptive, as mentioned in the definition MPD is an "adaptive drilling process". The most interesting aspect of MPD is that it prepares the drilling operation to adjust itself to meet the pressure profile objectives during drilling.

Steve Nas et al (2010), concluded in his paper that, rig modification for most MPD operations are minimal. MPD operations have been conducted on all types of rigs with minimal down time caused by MPD equipments[13].

2.1.6.2 Extending the Casing points

Most of the well bores problems are solved by casing, which not stabilizes the well bore but also, provide isolation between well bore and adjacent formation thus allowing further drilling. But as the exploration for hydrocarbons go deep the need for more casing strings increases. Today a deep well with conventional drilling methods normally required six or seven casing strings to be completed, drilling engineer have to plan the well to start with 30-in conductor to 6-in production liner.

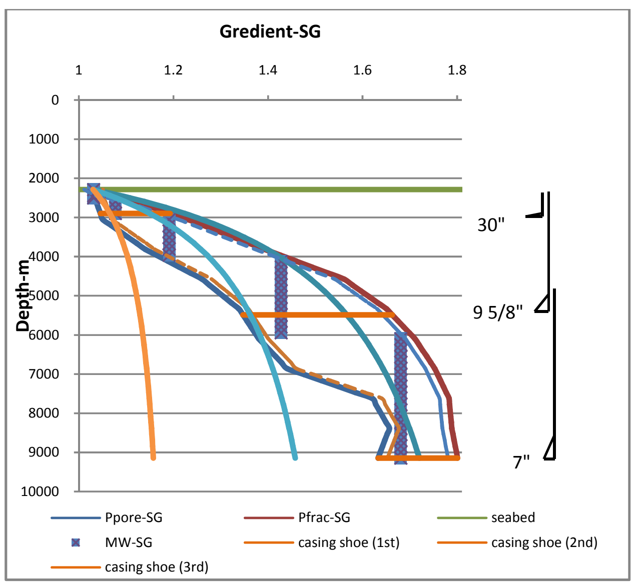

Figure 12: Comparison of No. of casing with and without riser

Figure 12 is an illustration of how MPD (riserless drilling) manages to reduce the number of casing to drill the same well which was to be completed by five casing, with MPD the same well can be successfully completed three casing strings. In this case MPD allow driller to eliminate or reduce the extra hydrostatic pressure by drilling mud in the riser, which result in wide drilling window. MPD technique deals with extending the casing seat beyond the normal pore pressure or fracture pressure limits to reduce the number of casings[7]. This as a result reduces the cost of casing.

MPD controls the mud pressure profile in the annulus, thus providing wide drilling window for casing seat extension. Drilling into deep with minimal number of casing allow to reach deep with large hole for further operations plus adding advantages of economical reduction in operations.

2.1.6.3 Lost Circulation

Lost circulation occur when mud hydrostatic pressure becomes greater then formation fracture pressure. This is very critical situation because it can lead to some other problematic events such as kick. As we further move in deep water drilling and deep targets the pressure widow becomes narrower and large marine riser contributed a lot in creating high mud weight at the bottom.

In MPD, maintaining the drilling mud density below formation fracture pressure and at the surface utilizing variable annular back pressure, unable drillers to maintain the well bore pressure between formation pore and fracture pressure[7].

Steve Nas at el (2010), describe the success story of MPD in CaNguVang Field, Vietnam. The plan was to drill the fractured granite basement reservoir. First three wells encountered high loss rate and resulted in very high brine and salt cost, suspension of drilling due to interruption in salt supply and inability to drill up to target depth. The use of MPD equipments allowed the brine weight to be reduced and therefore reduce the fluid loss rate. Fluid loss rate was reduce to 6% which in previous well was 15 to 20%[13].

2.1.6.4 Well Kick

The most common well pressure problem is kick which is define as flow of formation fluid in to the well when well hydrostatic pressure falls below formation pore pressure. The best practice to control in this situation is to detect kick as early as possible, stop the kick and circulate it out of the well in safe and controlled manner. But still there is additional cost required for time and mud materials and in addition a kick is a potential cause of lost circulation, differential sticking of drill pipe etc.

MPD operation always looks to avoid kick scenario by careful monitoring of equivalent circulation density (ECD), inflow and outflow or changes in the well bore pressure with impressed pressure at surface[7] .Even if kick occurs, the best part of MPD is the early detection of kick makes it very reliable source of well control.

Paco Vieira et al (2009), described in their paper that coriolis type flow meter are field proven tool for flow measurement[14]. It is installed downstream of choke manifold. Kicks can be detected very quickly by continuous monitoring of flow In and out and comparing when flow out deviate from flow in, trends are monitored, alarm can be set and if possible kick can be detected and control automatically.

2.1.6.5 Hole cleaning

Hole cleaning is very critical factor especially in deep water drilling. Several problems may arise due to improper cleaning of hole or riser such as: cutting beds, hole pack off and stuck pipe[17]. MPD controls the fluid loss and attributed to high flow rates which resulted in better hole cleaning. Steve Nas at el (2010), describe the success story of MPD in CaNguVang Field, Vietnam and described that other benefits of MPD were realized as better hole cleaning and reduction in torque and drag[13].

2.1.7 Disadvantages of MPD

- It is a application specific method[1]
- Equipment foot print is typically not as extensive[1]
- Extensive training of personnel is required[18]
- Still no suitable reference documents available[6]
- Complex in operation[18]
- High CAPEX (high initial cost of project)

2.1.8 Equipments for MPD Operations

2.1.8.1 Rotating Control Devices (RCD)

This is the most common and most important MPD tool, which is the main element of pressure controlling in MPD operations. RCD has many important functions which are the back bone of MPD concept which state that annulus must be packed off during drilling, connection and tripping etc. Among those functions are it maintains pressure tight barrier in the annulus section, allow flow diversion through choke to separation equipments and most importantly it allow rotation of drill pipe while performing the other functions[14]. Figure 13 is the schematic of typical RCD, which allow flow diversion to separation equipments and also isolating it from upper part or riser.

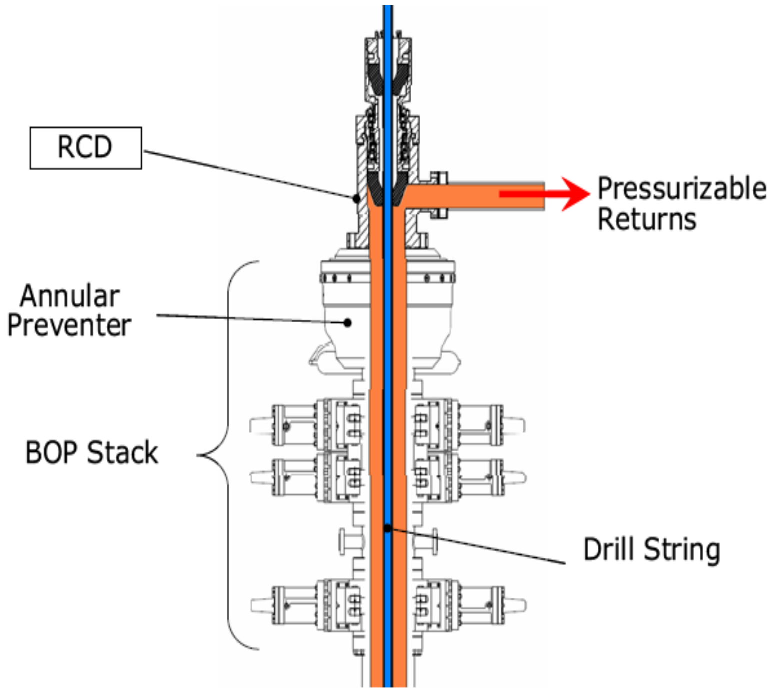

Figure 13: Rotating control device[14]

The usage of RCD can traced back to 1930's where it was primarily used for flow diversion of air and gaseated mud operations. Modern RCDs are available with pressure rating of 5000 psi static and 2500 psi rotating[7].

Modern technology consist of advance sealing rubber element which seals around drill string or Kelly, along with sealing it also provide vertical movement of pipe. The sealing sleeve is located in the secondary housing that allows unrestricted rotation of drill pipe while still maintaining the seals[14].

There are basically two RCDs system current in use, namely Passive system and Active system. The passive system utilizes well pressure for sealing element actuation, the system comprises of rotating packer that has under size annular seals to drill pipe and is forced to fit onto the pipe. The sealing element exposes directly to well pressure, the increasing well pressure is being exerted on sealing rubbers. The Active system does not rely on well pressure for sealing. Its sealing mechanism is actuated by hydraulic pressure. This type of RCDs uses a pressurized diaphragm which squeezes a packer element against the pipe.

Rotating Control Devices have hydraulic system for cooling and for active system they have separate system for closure. All the hydraulic systems operate from rig floor. All RCDs have snubbing force which is known as "hold up weight", which reduces the measured weight of bit but it is not a big problem and is normally resolved[7].

2.1.8.2 MPD choke manifold

Chokes are type of valves which are used to precisely control the flow. In MPD operations chokes are used primarily to control flowing pressure by applying back pressure. Depending upon their closure system they are classified as: choke gates, sliding plates and shuttles[7].

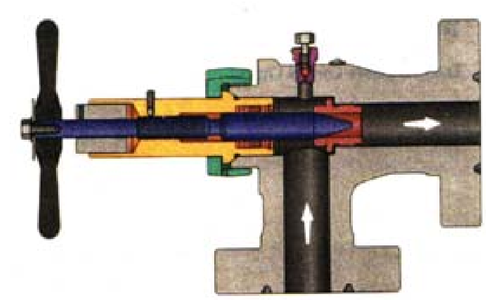

Figure 14: Choke illustration[2]

MPD Chokes are not used as secondary well control equipments as they used in conventional method. The point to be remembered is the intentions of MPD is not to allow any continuous influx for formation to the surface thus chokes in MPD operations are more used for pressure control rather than flow control. Because of its continuous work throughout drilling operation, MPD choke system is a part of drilling system and should not be considered as a part of well control system[14].

Depending upon its operation it is classified as: manual choke, semi automatic and automatic. Manual chokes are manually operated by operator communicating with driller. Automatic chokes are operated based on measurements and hydraulic model prediction to maintain constant set point pressure[2].

Some common used MPD chokes: Power Choke, which use a cylinder type choke gate that moves forward to choke against a seat and trim is pressure balance to allow smooth operation. Swaco Super Choke has two thick lapped tungsten carbide plates with half moon openings, the front plate is fixed and rare plate rotates against it for opening and closing. Swaco Auto Super Choke is most suited to MPD operation because it constantly holds the annular pressure. The shuttle closes bubble tight on a metal to Teflon seal[7].

2.1.8.3 Drill-Pipe Non Return Valves (NRV)

Drill-pipe non return valves are an essential part of drilling operations. Any communication from annulus to drill pipe due to U-tube effect needs to be stopped which can leads to down hole equipment damage or even blow out through drill pipe. U tube effect has to be address in MPD operation and because we have to apply annulus back pressure so the importance of drill pipe NRV increases.

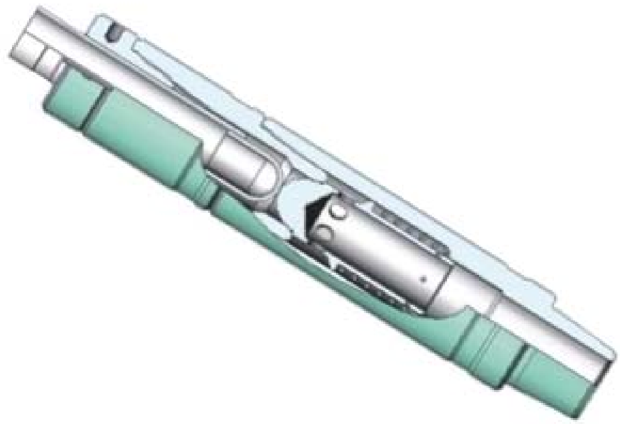

Figure 15: Inside BOP (NRV)[15]

NRV is also called as float or one way valve. Its basic function is to allow flow only in the desired direction and control the U-tube effect during connection. There are many types of drill pipe NRVs currently in the market such as: Basic Piston-Type Float, Hydrostatic Control Valve, Inside BOP (Pump-Down Check Valve) and Retrievable NRV or Check valve[7].

2.1.8.4 ECD reduction Tool

These tools (figure 17) especially used in the wells where friction (ECD) is a problem such as extended reach wells or deep water wells. This system is based on placing motor in the well that pumps fluids upwards. During its operation it creates dual gradient in the annulus[7].

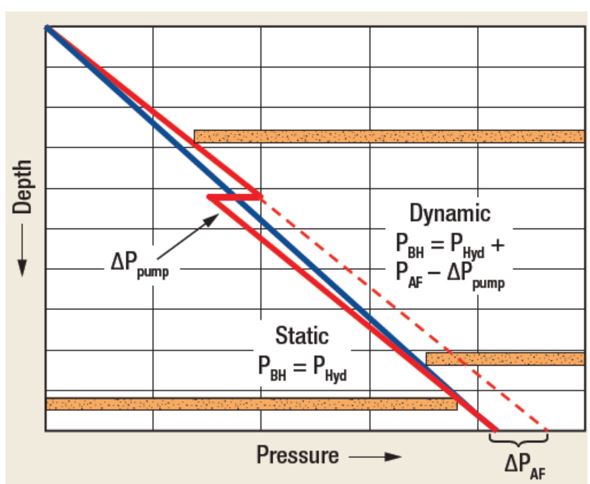

Figure 16: ECD reduction method[1]

ECD works against "impressed annulus pressure" system, and reduces the pressure in the annulus instead of impressing a pressure. Among its advantages are: Drilling rig modification is not required, site operator is not required, spikes in equivalent mud weight values can be reduced, in extended reach well it reduce the ECD between toe and heel by pumping the fluid in the long sections, MWD pluses are not affected, differential sticking and lost circulation can be reduced, extend the casing setting depth, increase the well bore stability, and tool is open to wire line operations[7].

ECD RT (Weatherford) is a newly developed tool (figure 17) used for ECD reduction. It is consisting of three components: Hydraulic Turbine Drive, Annular Pump and Sealing Element.

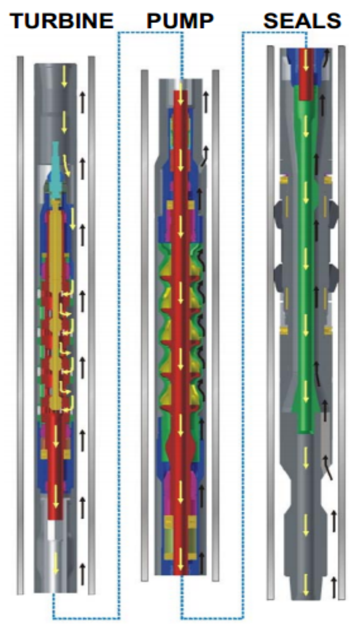

Figure 17: 8.2" ECD RT[16]

2.1.8.5 Coriolis Flowmeter

One of the most important aspects of some MPD operation is to measure the flow in and out especially in case of kick detection. Coriolis flowmeter is newly developed flow measurement tool for drilling operations, which depends upon flowing mass deflecting a tube, a U-tube based phenomena[7]. It is a high accuracy mass flow meter which measures: mass flow, volumetric flow, density and temperature.

Bill Rehm et al (2008) described an operational procedure of coriolis flow meter as[7]:

U-tubes are vibrated in opposite direction by magnet and coil with magnet mounted on one tube and the coil on the other tube. The vibration cause sine waves output from coil that is a representation of one tube relative to other. Sine wave from the input and out coils coincides when there is no flow. The Coriolis Effect from mass flow through the inlet of tubes resists the vibration while Coriolis Effect from outside mass flow adds to the vibration. The mass flow is calculated by phase difference between signal from input and output sides while density changes is an indication of natural frequency changes from the natural frequency. By dividing mass flow with density we get volume flow and temperature is directly measures to correct the temperature changes. Figure 18 of coriolis flow meter manufactured by Weatherford.

Figure 18: Coriolis flow meter[2]

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2.2 Riserless Drilling

2.2.1 Introduction

Declining hydrocarbon reserves and increasing demand pushes oil and gas companies to explore areas which presents high economical risk and technical problems. Among those areas are deep water exploration which look quite promising but at same time present new challenges. Riserless drilling is a new innovative solution for this which is consists of mud circulation system without riser. Subsea mud pumps are used to pump drilling mud from sea bed up to the rig floor. In this chapter we will look deep in to riserless drilling phenomenon and the technology available to accomplish this, moreover we will also put some light on the main disadvantages of having riser installed in deep water drilling which pushes engineers to look towards new innovative technology and the advantages of riserless drilling. Also the history of riserless drilling and the advancement the field will also be discussed.

The main idea of riserless drilling is to have dual gradient in the annulus which will be discussed in more detail latter on in this chapter. Figure 19 illustrate the difference between single and dual gradient approach regarding hydrostatic head and bottom hole pressure. Note that for both the cases we have the same bottom hole pressure but in conventional method, we have light weight drilling mud and in riserless drilling, we have heavy drilling mud which adds up in bore hole stability.

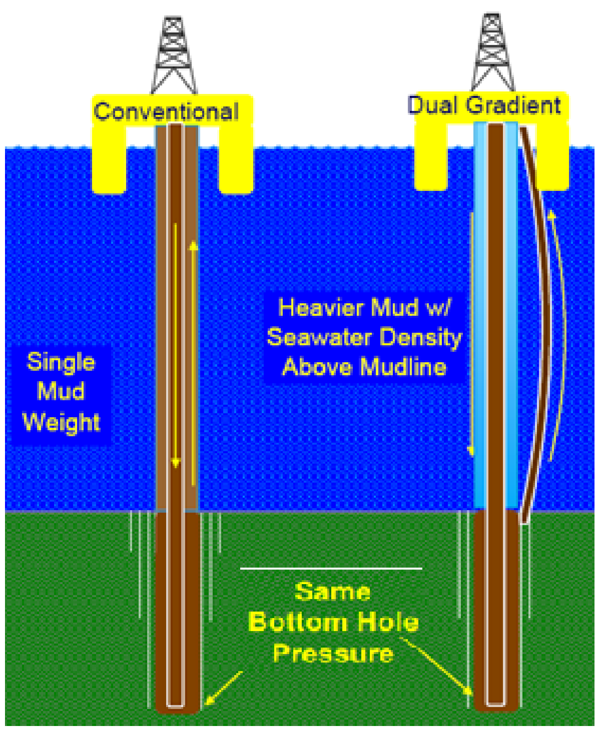

Figure 19: Single vs. dual gradient drilling[15]

2.2.2 Problems with Conventional Riser Drilling

One of the biggest challenges in deep water drilling is "marine riser". With increasing depth, the size of well head and marine riser also increase and so as the wall thickness of marine riser to control increased pressure, weight and vessel size to hold this increased weight riser, all these things will results in tremendous increase in unit cost of riser.

Weight Handling Limitations: For normal 21 in. marine riser with 19.5 in. inner diameter, the net steel weight is 160,000 lbs per 1000 ft. the buoyed weight of riser in sea water with 15.5 ppg mud in it will be 250,000 lbs per 1000 ft. this extremely high weight equipment becomes very difficult to be handled in deep water conditions, as a matter of fact only fourth or fifth generation semisubmersible may have adequate space and weight capacities to handle these requirements[2].

Space Limitations: Deep the water is more joints of marine riser it will need to reach the seabed. Especially for smaller or older vessels this will results in deck space and loading capacity limitations. This case becomes very difficult to handle during periodic retrieval of the riser due to emergency disconnect, storm or pulling out the BOP stack for any repair[3].

Additional Mud and its Cost: A 21 in. marine riser with 19.5 in. inner diameter and 10,000 ft in length needs around 3,700 bbl of mud to be filled. The amount needed for this for a synthetic based drilling fluid is normally around $400,000[3]. The 19.5 in. ID marine riser needs additional 3340 bbl of mud to circulate through the riser, in comparison with 6 in. ID returns line. The cost to prepare and maintain such large volume of drilling fluid is also very high[2], because we then have to arrange extra space for this large volume drilling mud and in addition to that, during transportation we will require vessels which can accommodates such large volume of mud. All these things require especial transportation arrangements and cost lot of money. Another concern regarding drilling mud is loss of mud during drilling upper hole section where pump and dump approach is used.

Additional Stresses: Marine riser during drilling exposes to severe stresses. Weight of the riser with mud inside, the movement of a floating vessel, surface and subsea water currents are the main contributors of these stresses. As the water depth increases so as these stresses increases and we need to increase the wall thickness. This increased wall thickness is to resist the burst pressure from mud inside, handle severe stresses and to attach buoyancy units. All these things will add into the high cost of riser as well[2].

Time: Large diameter and long marine riser are very difficult or impossible to run, where high currents are present. It may require a larger and expensive vessel in order to maintain the station keeping within the operational ranges. It will increase waiting-on-weather time and required long tripping time.

Limitation in Formation Pressure Window: Targeting deep for H.C exploration results in narrower window between formation pore pressure and fracture pressure thus resulting in severe well control problems like kick, lost circulation and differential sticking of drill pipe. This is quite challenging when drilling deep because then well control is quite a concern in narrow working window, to avoid this we need to installed extra casing strings which itself is expensive, also with narrower window reservoir damage is multiplied and results in more economical loss. The number of casing normally used in conventional drilling method can be shown in figure 20

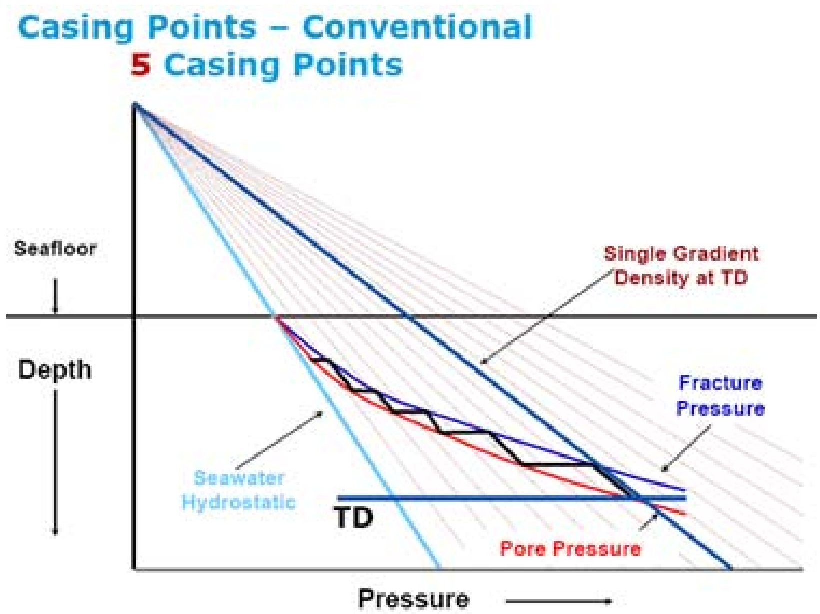

Figure 20: Casing program in conventional drilling method[1]

The long marine riser adds up the difficulties regarding these well control issues. The problem of Non Productive Time (NPT) is more severe in deep water drilling where the pressure window is very narrow to work with as shown in the figure 21.

It is clear that moving towards deeper water exploration will result in longer marine riser. This will results in high hydrostatic gradient and having narrow formation pressure window, making it hard to drill the well with normal conventional drilling method and becoming more challenging regarding well control and economics because more casing will be required to complete the well.

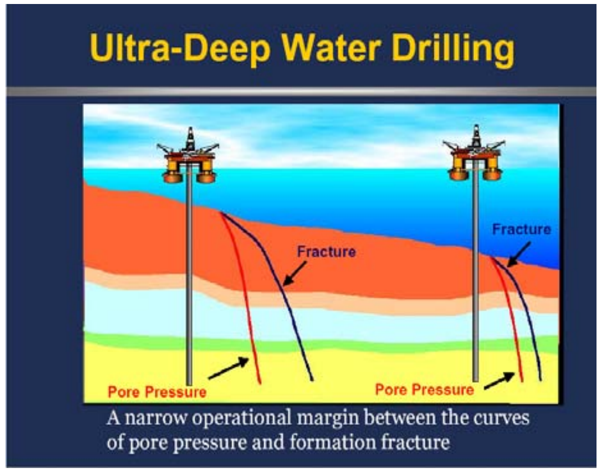

Figure 21: Formation pressure profile in deep water drilling[4]

2.2.3 The Concept of Riserless Drilling

Riserless drilling is a dual gradient drilling approach which is classified as systems belonging to the "Managed Pressure Drilling". In dual gradient system, the hydrostatic head in the well is composed of two parts. In the upper part above the seabed a seawater gradient is often used and below seabed a heavier mud is used[4]. This gives an effective mud weight downhole that often fits much better in between the pore and fracture gradients, thus making it possible to drill much deeper before setting casing[4]. The figure 22 is conceptual scheme of riserless drilling.

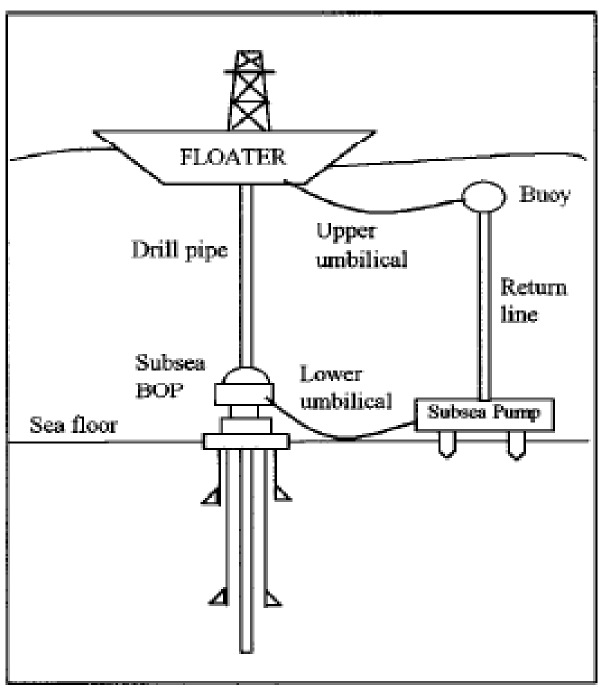

Figure 22: Simplified scheme of riserless drilling[2]

The riserless drilling system is simple in operations. As it can be seen from the figure 22, it is consist of bare drill string and a separated non concentric mud return line. The rotating blow out preventer (RBOP) direct the return mud towards subsea mud pump which transfer flow through mud return line up to the rig vessel[2]. Depending upon system configuration and flow rate, more than one return line can be used for the return. Choke and kill lines can be run separately or tied to gather with return line.

2.2.4 History and Advancements

The concept of riserless drilling in offshore drilling was previously used to bring drill cutting back to the rig floor through a rubber hose during very early times of offshore development. But it was not implemented further because of shallow water depths and the problem related with water depth was possible to solve by simply increasing the size of marine riser and well head[2].

Drilling without a marine riser schemes were developed in 1960s and the concept of riserless drilling was first patented by Watkins in 1969, to reduce rotating blowout preventer (RBOP) wear and by balancing subsea internal and external well pressure drill pipe re-entry made easier[5].

Around 1996, for water depth greater than 5000 ft, four projects were commenced to build up dual water gradient drilling technology. These projects were namely, Shell Oil Co.'s Project, the Subsea Mud Lift Drilling Joint Industry Project, Deep Vision Project and Maurer Technology's Hollow Glass Sphere Project. To discuss the advantages of dual gradient drilling, several publications were published around 1996 to 1999[6].

In 1996, J.J. Schubert at el, published a paper in which they described a comparison of well control procedures between dual gradient drilling and conventional riser drilling[6].

Michael Johnson at el (2001), in their paper, described another alternative to extend the casing seats while drilling upper hole section (riserless section). The methodology deploys the use of Dynamic Kill Drilling (DKD™) fluids and related equipments to mix weight, pre formulated fluids with sea water[7].

Neil Forrest et al (2001), describe the Deep Vision project which has been working on dual gradient solutions since 1998, and among those solutions is sea water/mud isolation system (SMIS).

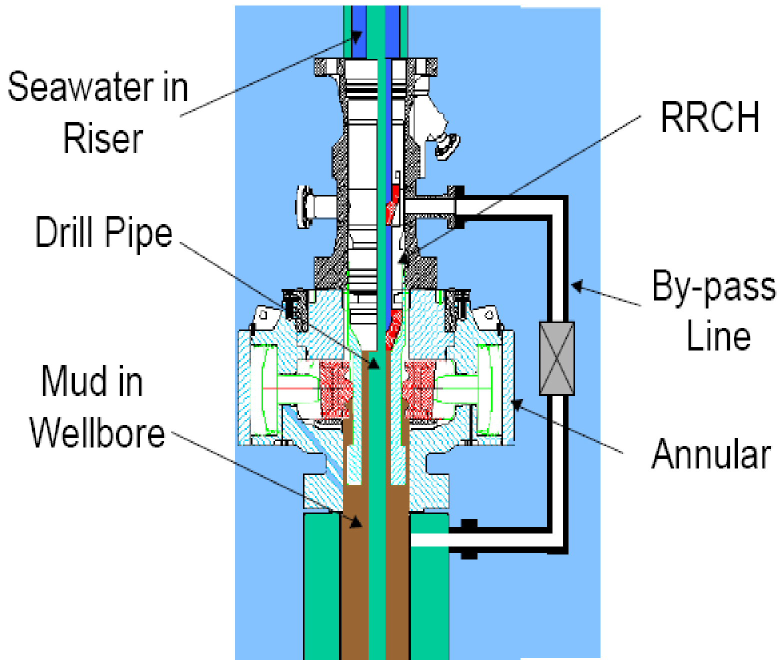

Figure 23: Seawater mud isolation system[8]

This system is one of several key components of dual gradient solution that were identified early in the project. This paper concentrated on development of mechanical seawater-mud isolation system (SMIS) located above the subsea BOPs[8].

Rotating control head (RCH), has several applications in onshore drilling. Until the early 1990's primarily the tool was used as a rotating flow diverter for air, natural gas and geothermal drilling application[8].

G. Carter et al(2005), In their paper described a new technological advancement in riserless drilling which will extend the Mobile Offshore Drilling Unit (MODU) load capacity and deck space requirement. The primary tool consist of an E duct Return(EdR) subsea unit, flexible composite pipe providing the drilling conduit and to permit bidirectional flow a cutting return design, a closed circuit BOP and control housing, subsea bop with integrated guiding choke and kill lines, and intelligent drill pipe, BHA and bit with down hole motor[9].

The figure 24 is schematic diagram of the entire system. It can be seen that the return drilling mud is diverted through rotating control housing installed in the transition housing. The mud through E-duct return line pumped to EdR deployment system.

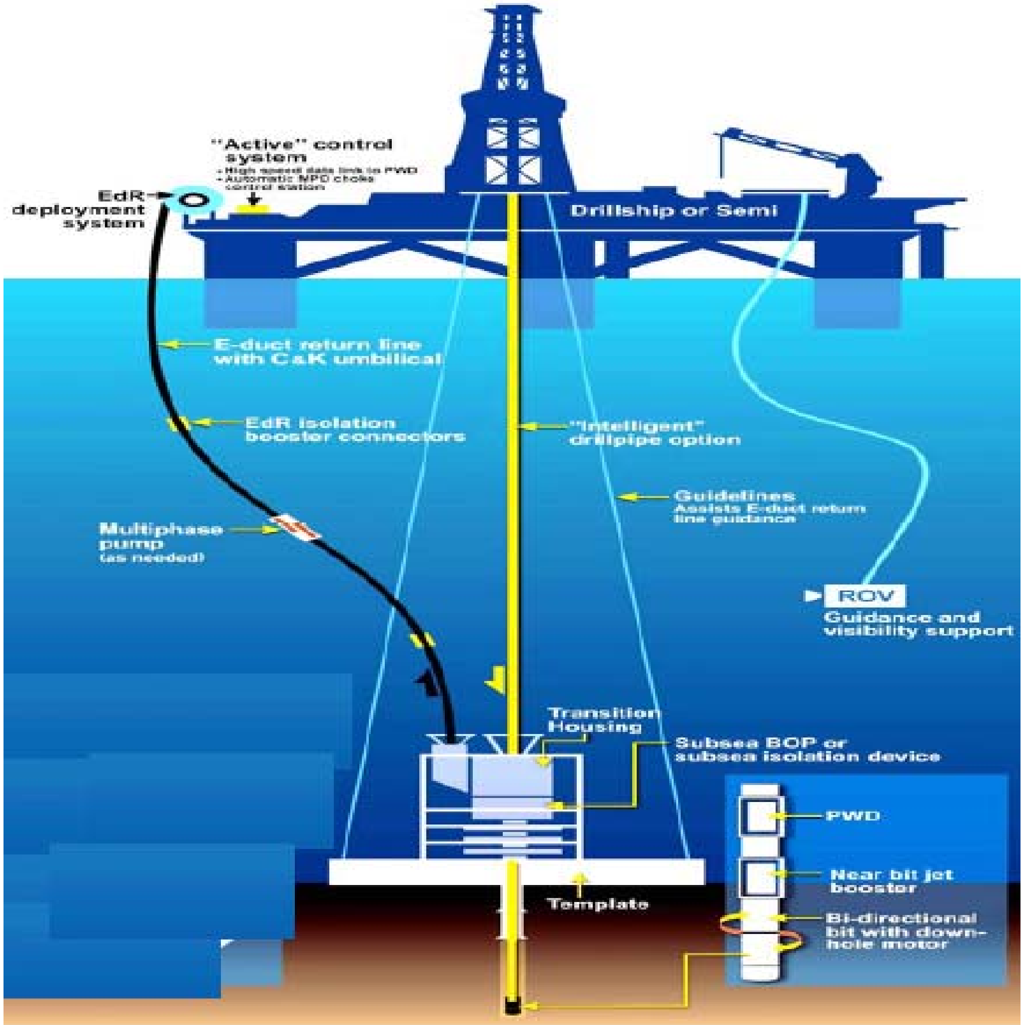

Figure 24: Schematic flow diagram of EdR system[9]

In 2006, AGR Subsea AS developed a remarkable riserless technology a "Riserless Mud Recovery (RMR)" system-which is used for open hole/top hole drilling[11]. RMR is an innovative way of transporting drilling mud and cuttings to the rig before the marine riser is run, without discharge to the seabed.

To date, RMR has been used all over the world on more than 160 wells. By utilizing the application or RMR, an operator has eliminated a 20" casing and set 13 5/8" surface casing successfully down to more than 2350 meter[10]. Figure 25 is a sketch of the RMR system.

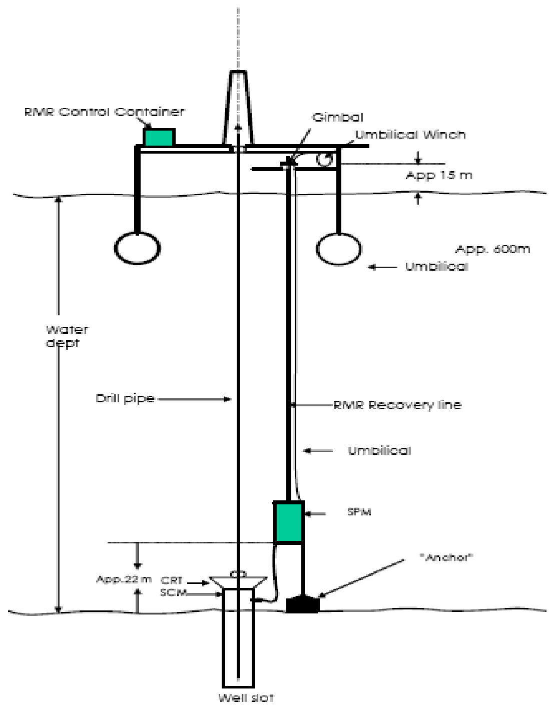

Figure 25: RMR system schematic[11]

In the early 1996, a joint industry project (JIP) was launched and come up with an innovative technology named as Subsea Mud Lift Drilling System (SMD JIP). The main components are Drill String Valve (DSV), The Subsea Rotating Diverter (SRD) and Subsea Mud Lift Pump[12]. Figure 26 shows a schematic of SMD system.

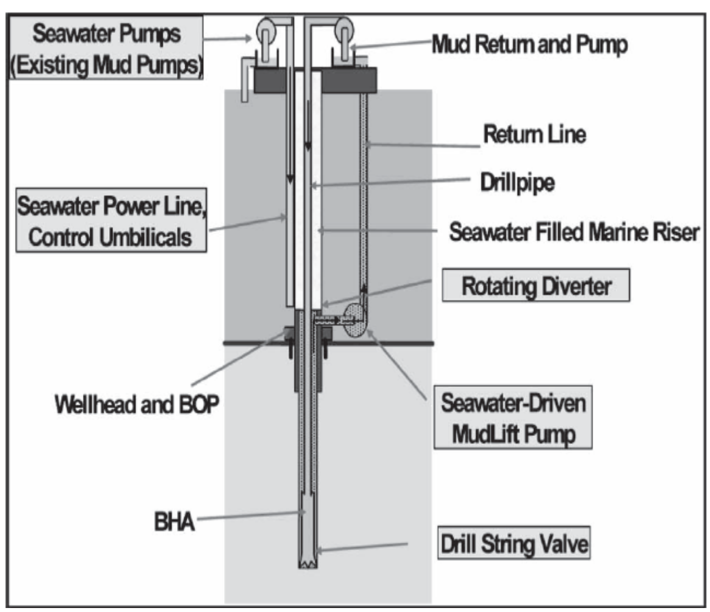

Figure 26: Subsea mud lift drilling system[6]

2.2.5 Advantages of Riserless Drilling System

The most important thing to be looked about a new technology to be implemented is, will this technology provide answers about problems the previous methodology presents. From recent developments we will try to put some light on advantages of riserless drilling.

2.2.5.1 Well Control

Better well control resulted in enhanced safety and environmental performance. With better well control we have better detection, reaction and control over kick, which resulted in less risk to well as a whole and also provide low risk of environmental hazards. It is proven from recent example of riserless drilling, that kick is quickly detected thus providing better chance of handling it. Riserless drilling well control is quite simple and does not present any serious difficulty, and most importantly it is quite similar to well control in conventional method with riser, Differential flow rates at well head and lower stand pipe pressure will make easier and faster kick detection[5].

2.2.5.2 Fewer Casing strings

One of the most important aspects of riserless drilling is the economical benefit in term of reduction in the number of casing required. The figure 27 is an illustration of how one can complete a well with only three casing string which with conventional method requires nine casing strings, also we can see the trend of hydrostatic pressure gradient along the well bore. In conventional method the gradient follow a straight line but in riserless drilling due to dual gradients system the gradient line follow nearly the same path as pore pressure curve.

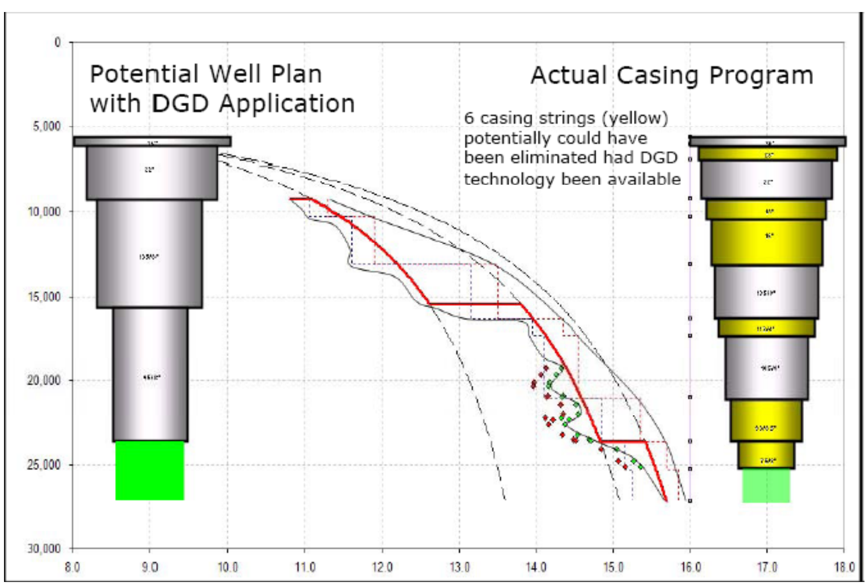

Figure 27: Casing program with conventional and DGD method[1]

In this case riserless drilling allow driller to eliminate or reduce the extra hydrostatic pressure by drilling mud in the riser, which result in wide drilling window. By providing wide pore and fracture pressure window, the casing setting depth can be extended and results in less string to complete the well. For top hole section of the well, use of recirculated drilling mud enabled surface casing to be set deeper then was possible using traditional non circulating seabed spreading of drilling fluid and cuttings[13].

2.2.5.3 More Completion Opportunities

Simple well design provides opportunities for better completion. The figure 28 shows how effectively the well is completed with large diameter production tubing. This makes it really easy for completion engineers to fulfill all their requirements to turn this well bore into stable and productive well.

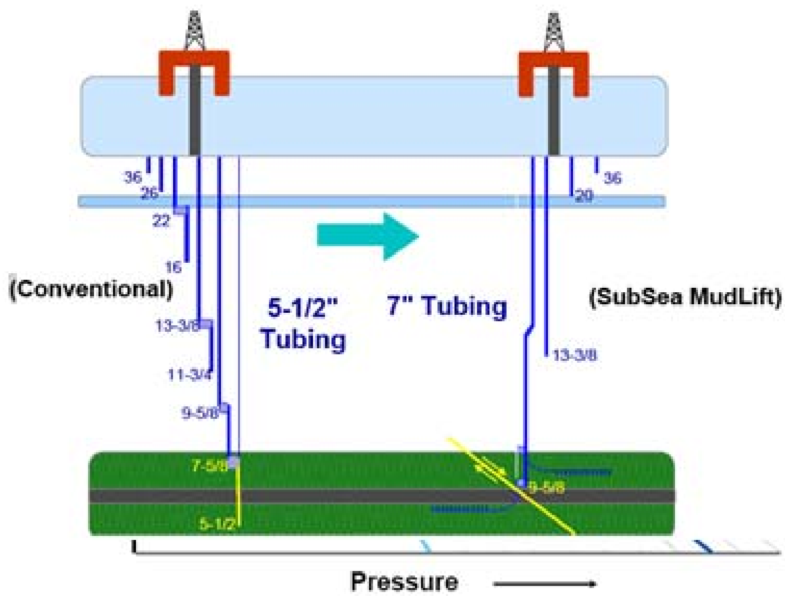

Figure 28: Completion with and without riser[1]

Large diameter production tubing can accommodate more completion tools and is more easily accessible through wireline or any other mean in the future for any well intervention job. All these things will result in an improved productivity.

2.2.5.4 Reduced Drilling Cost

With fewer casing string and better well control to reduce a chances of lost circulation, riserless drilling is a answer to economical control over drilling cost. Eliminating two or three casing strings will reduce size of well head, size of well bore and number of days required to drill the well. An estimated saving of an average $1.0 million overall per casing point reduction will be provided by riserless drilling approach[7].

2.2.5.5 Improve well integrity

The overall well integrity will improve as a result of better cement job, fewer squeezes, reduction in casing loads and greater completion integrity. The use of riserless drilling approach with Dynamic Kill Drilling (DKD™) to simply push the 20 in. casing farther than conventional seawater and to overcome wellbore stability issues, the push ended up totaling 1334 ft, plus no indication of hole closure, no cement squeezes required and higher than expected LOT[7].

R. Stave et al(2005), in his paper described the benefits of dual gradient RMR system as improved bore hole stability and reduced washouts due to possibility to use weighted and inhibited mud and well control both with regards to shallow gas and water improved due to weighted mud[14].

2.2.5.6 Station Keeping

Because of less weight attached to the vessel, station keeping will be easier for riserless drilling. Along with this less environmental forces on drill pipe and return line and less strict station keeping requirements. All these things provide less expensive station keeping and reduce waiting-on-weather time[2].

2.2.5.7 Weight and Space

By reducing weight and space requirements for drilling in deep water depths, semisubmersibles or medium to large drill ships can be utilized for deep water drilling. The importance of this increases because of the fact that majority of fourth generation semisubmersibles are in great demand and already in under long term contracts, so with reduced weight and space demand and little up gradation of third and second generation semisubmersibles can be used for deep water drilling[2].

Reduction of riser, mud volume and related equipment of riserless drilling will enhanced the mobile offshore drilling units (MODU) load capacities and deck space requirements. With impact or riserless drilling with potential upgrades with increase the existing floating rig fleet generation's operation depth[9].

2.2.6 New riserless technology in the Market:

In this section, we will see some of the major advancements in the field of riserless drilling, which helped this innovative technology to move forward.

2.2.6.1 Riserless Mud Recovery (RMR™)

Until now much of the research and publication on dual gradient drilling concern the utilization of this technology only after surface casing. But in early 2000, AGR come up with a unique development which opens up the use of DGD in the top hole section prior to the installation of surface casing and has until now many success stories under its belt.

Riserless mud recovery system uses subsea pump to return the drilling mud and cutting from the sea floor to the drilling vessel and it is the first dual gradient drilling system which is available commercially[3].

Some of the unique possibilities with RMR system is the treatment and re-usage of drilling fluid which allow economical use of costlier more inhibitive fluid system, collection of cutting for geological evaluation, gas detection and volumetric monitoring of well for gain and loss[13]. Figure 29 is simple illustration of RMR system

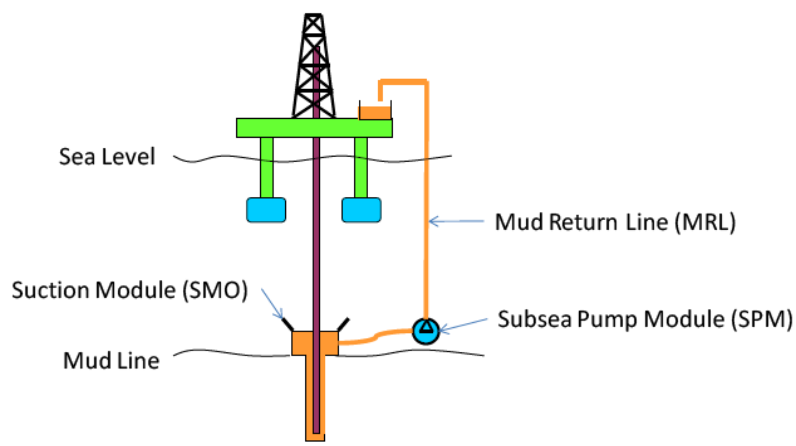

Figure 29: Shallow water RMR system[13]

The system consist of subsea mud pump transmitting mud from suction module which is mounted on the well head, via a hose line and transporting the fluid and cuttings back up to the rig[11].

The main control system of RMR is its computer control system, which control subsea pump based on pressure set point measured at well head. The pump act automatically and pump all returns to the surface with keeping bottom hole pressure constant. This is very critical point that since pump is controlled automatically. It responds to any drilling situation down hole is at once and without any operator intervention. This makes the system simple while maintaining improved well bore stability[3].

Primary uses of RMR [3 & 13]:

- To be able to use an engineered mud system with higher density then seawater and avoid the cost of pumping and dumping
- Maintain the stability or well bore by use of inhibited WBM which is returns to the surface
- To be able to control volume and kick detection in the top hole sections
- By avoiding pumping and dumping, prevent pollution in environmentally sensitive areas
- With the use of weighted mud and thorough volumetric monitoring, control the shallow gas and water
- Surface casing setting depth to be extended by improving bore hole quality through economical use of more effective drilling mud
- By reusing drilling mud, reducing the logistical support to transport large volume of drilling mud

The reason people are looking toward this new technology is the success it has with in short period of time. Shallower version of RMR is commercially being used since 2003 on over 100 wells around the world. Table 1 presents the previous RMR operations and the reasons for using this.

Geo-region	No. of Wells	Water Depths (meters)	Year	Reasons for using RMR
North sea	35	85-430	2004-2009	New equipment field trail Shallow geo hazards Shallow water flow Avoid pilot hole Build angle in shallow section
Caspian	33	118-525	2003-2008	Shallow geo hazards Extend surface casing depth
Australia	24	47-306	2006-2009	Shallow geo hazards Extend surface casing depth Slumping sand Zero discharge regulations
Russia and	7	76-350	2006-2009	Zero discharge regulations

Barents sea				Avoid pilot hole, riser and pin connector
Egypt	7	85-108	2007-2008	Shallow geo hazards Eliminate drilling liner
Malaysia	1	1419	2008	Deep water RMR field trail Extend surface casing depth
US Gulf of Mexico	1	620	2009	Mud logistics and cost Extend surface casing depth

Table 1: Previous record of RMR operations[13]

2.2.6.2 New development in RMR Technology

Joint Industry Project (JIP) was formed by BP America, Shell, DEMO2000 and AGR. The aim was to develop deep water version of RMR. This followed an earlier DEMO2000 JIP, which in 2004 conduct a field trail of jointed steel tubular as mud return line. By using the same jointed steel return line philosophy deep water RMR improved in pumping power, environmental resistance and deployment system to lift the return drilling mud and cuttings from greater depths. This system utilizes two subsea mud pump each with three stages pump, one installed near the bottom and other near mid water depth[13]. Figure 30 is schematic of deep water RMR system

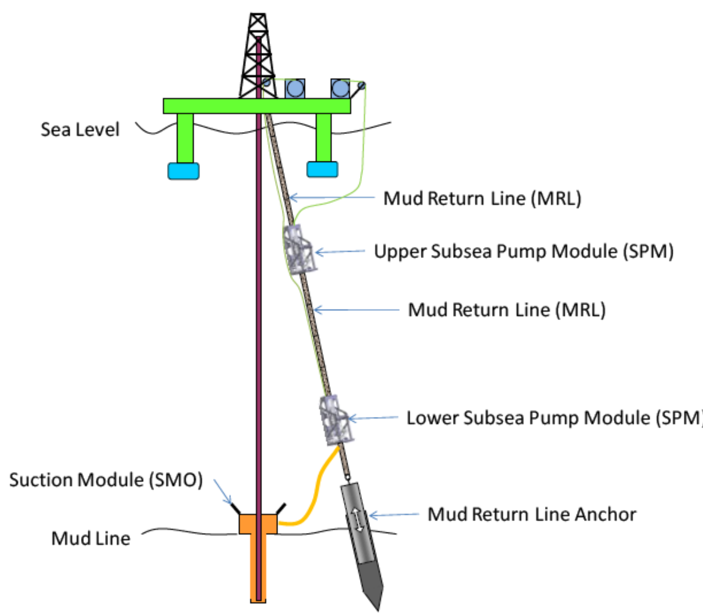

Figure 30: Deep water RMR system[13]

In 2008, field trail of deep water RMR was conducted on a well in South China Sea along with PETRONAS as partner in the well[13]. Deep water RMR resulted in several advantages such as:

- Mud logistical limitations were overcome
- Potential shallow hazards were safely drilled
- Detailed mud logging were provided through shallow hazards

2.2.7 Equipments

The RMR system comprises of following main parts

2.2.7.1 Suction Module (SMO)

Suction Module is normally attached on the low pressure well head on surface and run with the jet and drill string[13]. Different models are available for different well heads. The main tasks of SMO are to provide connection point for subsea pump, to provide access to the well for the drill pipe and mud/sea water interface, provide mean of adjusting the height of drill cutting to a constant level so that cutting and drilling mud should return to the surface at the same rate they exist the well bore, provide provision for cameras to be mounted and also pressure sensors are mounted to monitor the hydrostatic pressure of mud in the SMO. SMO can be run to the well head on drill pipe or cable[3]. Figure 31 is the schematic diagram of SMO.

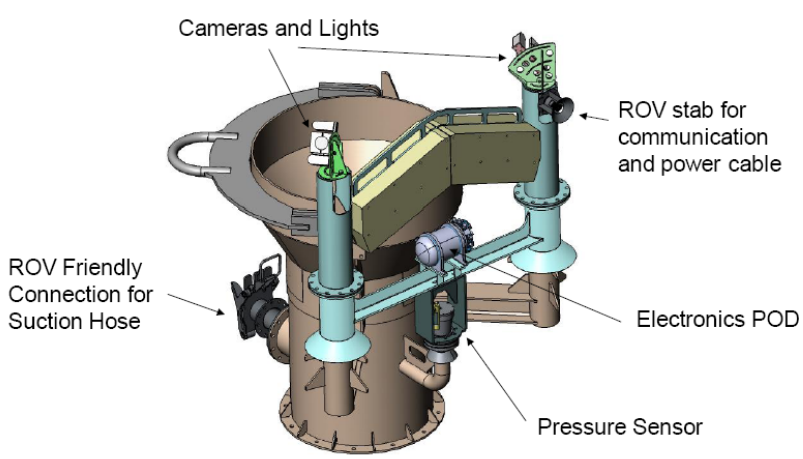

Figure 31: Suction module[13]

2.2.7.2 Subsea Mud Pump Module (SPM)

These are the friction pumps and used to lift the drill mud and cutting up to the vessel. These pumps are available in different configurations and can be set either on sea bed or can be suspended from the deployment umbilical. The pump uses special impellers which are composed of discs with minimal profile. As high speed spinning discs rotates, friction is generated between discs and fluid. Pumping is achieved by this generated friction. These pumps have high resistance against wear when pumping abrasive media and cuttings. One of the very critical point is that these pumps are quite capable of holding a column of mud at a fixed level in the return line in a quasi static condition[3].

Subsea mud pumps are connected with SMO through suction hoses. The weight of suction hoses is reduced by buoyancy for easy installation.

Figure 32: Upper and lower subsea pumps[13]

2.2.7.3 Mud Return Line (MRL)

For the return fluid MRL provide conduit from seabed to surface, for two subsea pump modules and anchor mass provide sufficient strength to support and resist forces caused by currents and vessel movement. By MRL anchoring system, MRL is anchored to the sea bed and is hang off at surface on the Hang off Joint (HOJ) landed in the Hang of Module. The bottom end of the MRL is fixed by MRL anchoring system to the seabed and holding it away from well head and drill string to avoid clash. It should be noted that the MRL anchoring system is only design to restrain the MRL from horizontal movement and not from vertical movement[13]. The figure 33 is schematic of MRL anchoring system

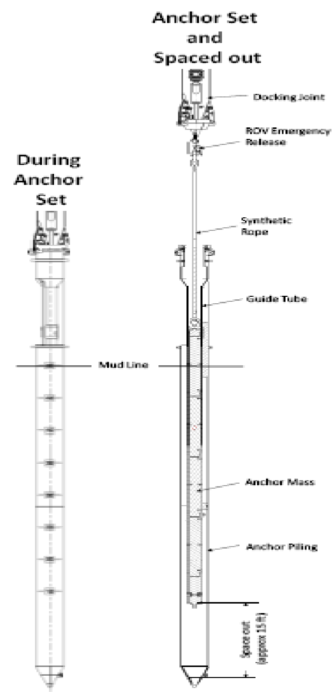

Figure 33: Mud return line anchoring system[13]

2.2.7.4 Deployment

To allow direct access to the sea, the deployment unit is designed to mount on the edge of the drilling vessel. Deployment is a separate unit to which pump is attached through the umbilical. Deployment line also contains power lines and fiber optic lines[3].

2.2.7.5 Winch and Umbilical

Winches are used to store and handle the umbilical, also it is used to store and handle the keel hauled umbilical. Umbilical is used to provide power and communication to the subsea pump modules and other equipments[13].

Figure 34: Winch for umbilical[13]

2.2.7.6 Power Supply

The most important thing for any operation to be run successfully is the proper distribution of power supplies. Power supply unit conditions and distribute power to RMR system. It contains variable frequency drive which powers the subsea pump and allows precise control over speed. This unit also provides power to the deployment and control module[3].

2.2.7.7 The Control System

The control system/module controls the RMR system and contains all necessary hardware and software for that. All the accurate information is recorded and passed on to panel. The control system panel is mounted on the driller's cabin to facilitate good communication between driller and RMR operator. It also includes diagnostic information about the pump, so any unwanted incident can be detected and action taken to resolve this[3, 13].

Figure 35: RMR control panel in driller's cabin[13]

2.2.8 The U-tube Effect in Riserless Drilling

The success of riserless drilling depends upon how better one can understand the U-tube effect, its impact on drilling and how it can be managed. Conventional deep water well depicted as U-tube or manometer. The hydrostatic head in the drill string and the annulus are equal for conventional drilling well under static condition with uniform mud weight throughout the well bore. Therefore U-tube is balanced[3].

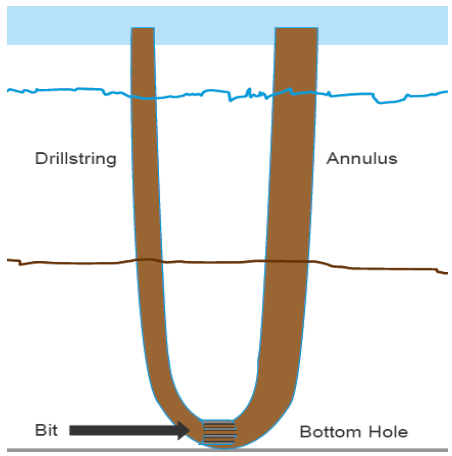

Figure 36: Balance condition of U-tube[15]

In case of riserless drilling, with annulus consists of mud and sea water have lower overall mud weight as compared to drill string thus disturbing the U-tube balance. In static condition the U-tube in the well bore will balanced itself by pushing the fluid in the annulus and thus fluid level in the drill string drops and we have flow return from the well. This can be very tricky and can easily be confused with kick. Even during kick, U-tube effect will make the problem more difficult to better understand and handle.

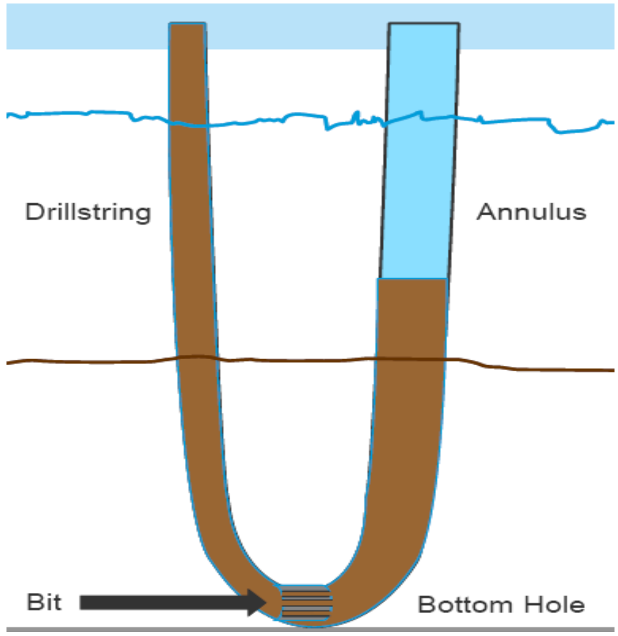

Figure 37: U-tube is disturbed during Riserless Drilling[15]

During U-tube balancing the fluid will free fall. This free fall (U-tube) is depends upon six factors[3]:

1. Water depth
2. Mud density
3. Mud viscosity
4. Inside diameter of drill string
5. Bit nozzle size
6. Other restrictions in the drill string

Among these factors; water depth and mud density are most important. As both increase, the U-tube rate increase and final fluid level in the drill pipe decrease. So the time to reach equilibrium in the well bore will increase. J.J. Schubert et al(2006), showed through studies that freefall rates for ultra-deep water (up to 10,000 ft) with drill pipe inside diameter in excess of 5 in. and mud weight of 15.5 ppg can result in free fall rate up to 500 gpm and could take over 20 minutes for equilibrium to occur[6]. Figure 38shows flow rate vs. time with respect to different drill pipe sizes.

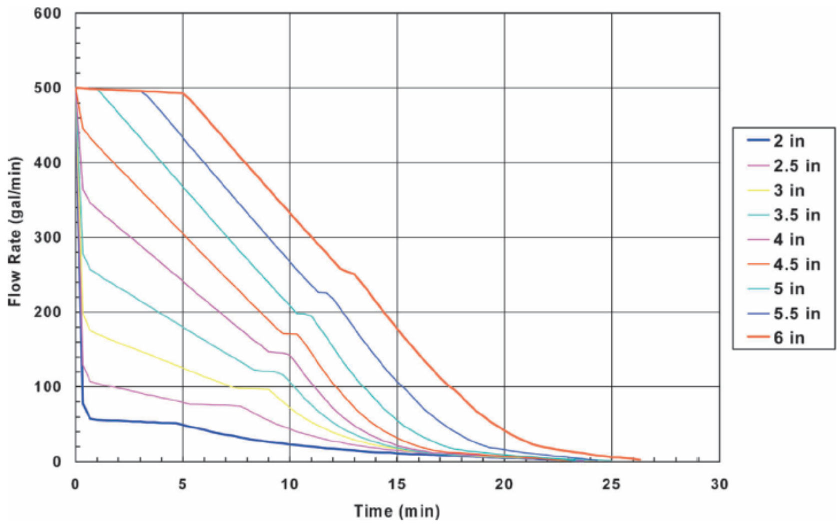

Figure 38: U-tube (flow) rate as function of time[6]

The problem U-tube present is well flow when pumps off. This can be confused with kick, but pit gain as result of U-tube is difficult to distinguish from kick. There are several ways to determine the difference such as; modeling the U-tube behavior and recording the U-tube trend during connection. But as long as U-tube effect presents it always create problems especially in well control.

2.2.8.1 Down Hole Safety Valve

In dual gradient JIP, the valve of such operation mechanism was designed which can be operate by positive pump pressure above a present amount. Figure 39 is the schematic diagram of valve in open and closed position. When circulation is stopped, the spring loaded valve is closed, thus stopping the U-tube effect. With this development the DGD operation looks like conventional. The valve is designed so that the spring closing force can be adjusted on surface according to the need. Based on water hydrostatic pressure and the anticipated mud density, the spring force is set for each hole interval. By this way the opening pressure of the valve is higher than differential pressure between mud and sea water hydrostatic. The most important point is the with arrestor valve in place, all circulating conditions recorded with positive rig pump pressure while with no arrestor valve and circulation below natural U-tube rate, the drill pipe will not full and no rig pump pressure is recorded[3].

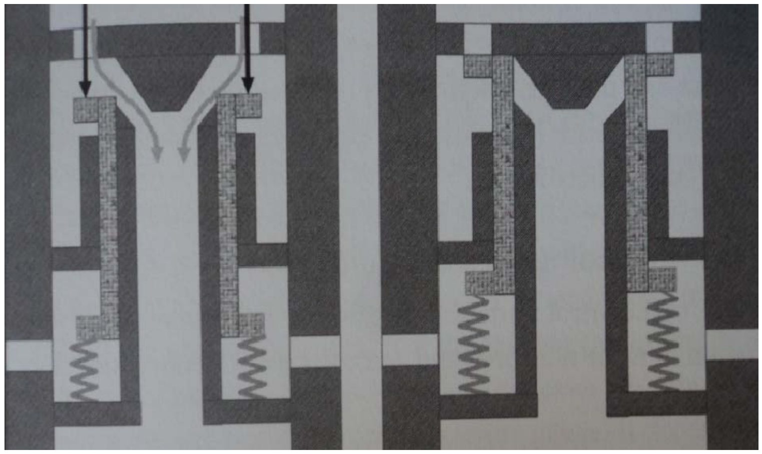

Figure 39: The U-tube arrestor valve in open position-left and closed position-right[3]

2.2.9 The Siem WIS RPCD (Riser pressure control device)

Managed pressure drilling allow much safer use of mud weights by controlling the bottom hole pressure by applying back pressure. To apply back pressure some sealing element is required to isolate the marine riser. The Siem WIS RPCD is a new seal technology which installed below slip joint and allowing the seals to rotate with the pipe[16].

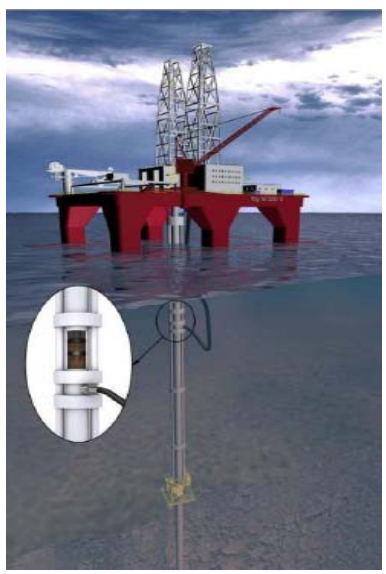

Figure 40: Siem WIS RPCD[17]

The seal package consists of four or more stationary seals depending upon the pressure requirements. The pressure sealing is obtained in stages through the gradient system between the seals. The gradient and pressure is continually monitored to check any warnings. During the operation the sealing elements represent the primary well barrier. We in our thesis assumed that this equipment is installed at well head thus creating a zero well head condition[16].

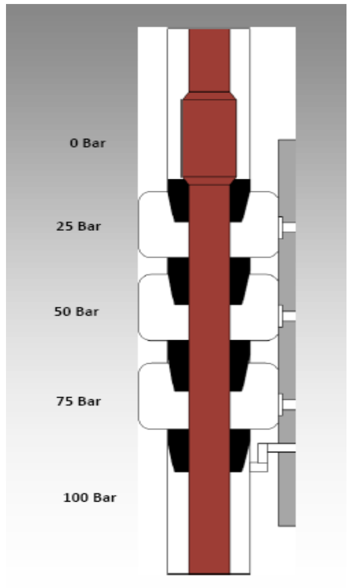

Figure 41: The seal package[17]

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2.3 Casing Design

2.3.1 Introduction

Casing design is most important event of the entire well design. During drilling the well must withstand the abnormal events and provide mean of further activities which transform a costly well bore into productive well. Casings and tubing are the main part of the well construction. All the wells either for production of oil/gas or for injection must be strong enough to make sure the full functionality throughout its life.

The casing design is basically stress assessment of casing to provide cased envelop around the well. This assessment involves burst, collapse and tensional loading of casing[1].

Casing: One of the major components of well is casing which is used to maintain the borehole stability, prevent communication from water sands, isolate water from producing formation and most importantly control well and formation pressures during drilling and afterwards. Casing also provide means of installing blowout preventer, well head equipments, production packers and production tubing. The major part of the overall well cost is comprises of casing cost, so its selection regarding size, connector and most importantly setting depth is a primary engineering and economic concern[2]. Figure 42 is a typical casing program.

2.3.2 Types of casings

Basically there are seven types of casings.

Stove Pipe

The first steel pipe which is basically a drive pipe driven usually to sufficient depth (15-60 ft) to protect loose surface formations and also it enables the circulation of drilling fluids[3]. It is also called as structural casing.

Conductor Casing

Conductor casing is the first set of casing set below the stove pipe. This is the casing onto which casing head is installed. This casing is cemented to the surface or in case of offshore well up to the mudline[2]. The main functional requirements of conductor casing are[1]:

- Isolation of unconsolidated layers
- Support template and marine riser on floating rigs
- Support surface casing and well head
- Enough internal diameter to accommodate surface casing and also provide efficient cement displacement
- It should be deep enough and strong enough to handle kicks

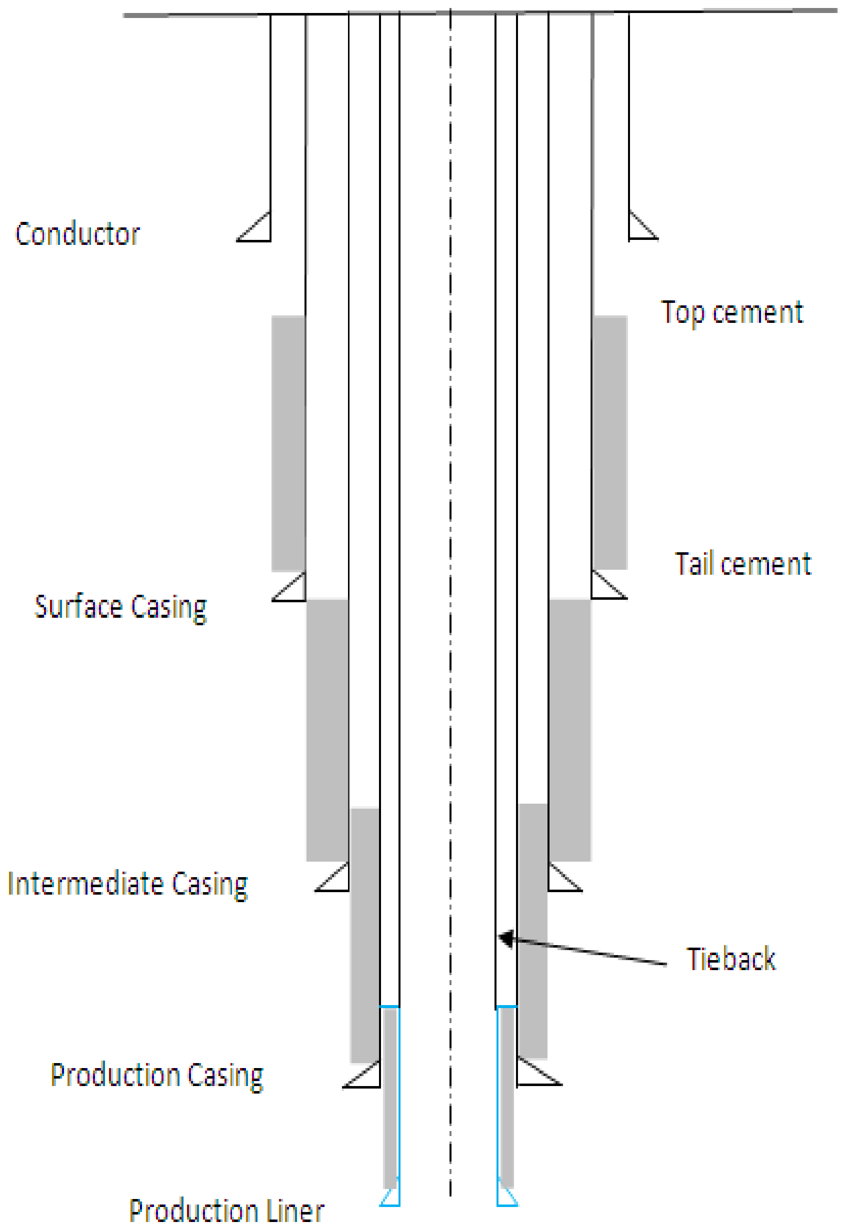

Figure 42: Typical casing program

Surface Casing

Surface casing is the third casing string which also cemented to the surface or to the mudline, and also it is casing after which full well control is established. The main functionalities are[1]:

- Zonal isolation of weak formations
- Well head and blowout preventer support
- Isolation of formation down to any potential gas zones.

Intermediate Casing

This casing is set often in the transition zone from normal to abnormal pressure. The cement top is decided to isolate any hydrocarbon zones. Depending upon situation, some wells require multiple intermediate casing[2]. The main functional requirements of the intermediate casing are[1]:

- Up to surface casing shoe, zonal isolation of all formations especially the unstable hole sections, lost circulation zones, low pressure zones, and productive zones
- Provide sufficient well integrity for further drilling especially in the pay zones
- Fulfill production casing requirements if production liner is planned to complete the well

Production Casing

The main casing, which placed directly against the pay zone, for this casing especially a good primary cement job, is very crucial. The main duties of production casing are[1]:

- Proper isolation of productive zone
- Should withstand the mechanical and chemical wear from formation and completion fluid
- It should be designed to maintain well integrity during all production and work over periods
- It should allow further drilling if it is planned

Production Liner

Liner is especial type of casing, which does not extend up to the surface but it is hanged off from another casing string through liner hanger. The main reason for its use is economical benefits. Main functions are[1]:

- It should isolate the productive zones if production casing is not installed.
- All casing and liner should fulfill all production casing qualities if they exposed to the production activities

Tieback String

These are also casing strings which provide extra pressure integrity from the liner top to the surface. Tieback can be uncemented or partially cemented. Functional requirements[1]:

- Same as production liner except that the axial load from testing is not present
- In case of corrosive agents it should also increase corrosion resistance.

2.3.3 Casing Setting Depth

Most of the text in this section is taken from Bret S. Aadnoy (2010). The main points which direct the whole casing setting depth design are pore pressure and fracture pressure. The main elements to be evaluated for casing setting depth design are as follows. The list can be changed or modified according to each individual well conditions[1].

Hole stability:

- Unconsolidated formation
- Swelling clays
- Fractured formations
- Collapse/washout
- Fluid loss zones
- Plastic formations
- Subsidence
- Zone isolation

Formation pressure and integrity:

- High integrity formations
- Low integrity formations
- High pressure formations
- Charged formations
- Highly permeable formations
- Well control integrity and margins

Drilling fluids, hole cleaning and cementing precautions:

- Pressure losses, circulation density and pump performance
- Hole cleaning capabilities
- Cementing of permeable intervals
- H_2S and CO_2 bearing intervals
- Formation temperature
- Mud system chemical/physical tolerances
- Differential sticking
- Reservoir invasion and damage

Hole curvature:

- Kick-off points
- Drop-off points
- Hole angle

- Dog leg severity
- Build-up/drop-off rates
- Potential side tracks

Mechanical equipment:

- Drilling rig hoisting/rotating capabilities
- Drill string and bottom hole assembly capabilities
- Tensile strength, burst and collapse capabilities of casing
- Mechanical wear on previous casing
- Equipment availability

Economy:

- Equipment cost
- Penetration rate
- Pilot hole
- Time versus depth profile
- Probability and consequences of hole problems
- Primary and secondary objectives
- Formation evaluation and geological markers

Casing setting depth evaluation is very critical, where we have to determine the primary and secondary well objectives, factors have to be identified for especial emphasis, determining the cement requirements and for each hole its objectives has to be determined. If the standard practice cannot satisfies the well completion, an extra intermediate casing or production liner can be installed or a non standard casing program can also be considered[1].

2.3.4 Casing setting depth criteria

Keeping in mind the riserless drilling condition we describe the following criterions for casing design:

- Limitation by mud weight to setting depth
- Oil filled scenario for burst loading calculation (intermediate/production casing)
- Reduce well integrity
- Kick margin
- Collapse loading calculation for losses occurs to thief zone (intermediate/production casing)
- Collapse during cementing

- Collapse during plugged perforations during production (production casing/liner)
- Tubing leaking scenario for burst loading calculations (production casing/liner)

Criterion 1: Limitation by mud weight to setting depth

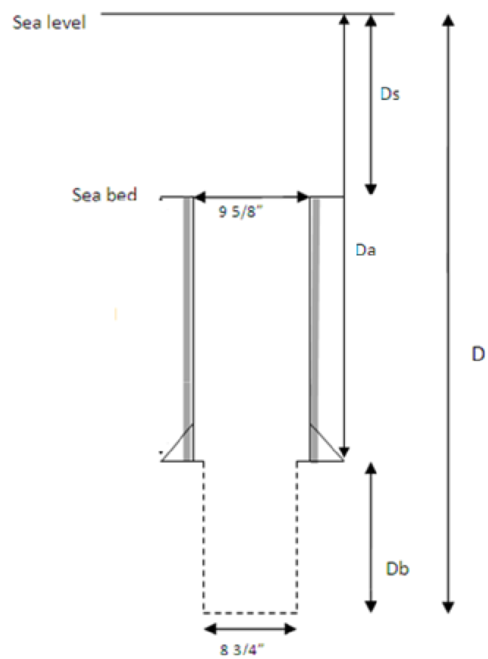

Figure 43: Well for casing design

According to the available pressure profiles the casing depth is determined from the bottom and keep working upward, this is known as down-up principle, by this minimum numbers of casing will be selected[4]. The basic approach is to select optimum mud weight which exceeds the pore pressure at the bottom but should not fracture the formation at casing shoe.

In term of equation it is expressed as

$$P_{wf} \geq P_o - 0.0981 d_{mud} (D - D_a) \qquad 2.3$$

Where

P_{wf} = Fracture pressure

P_o = Pore pressure at bottom

d_{mud} = Density of mud

Figure 44 shows the formation pressure profile and casing setting depth design.

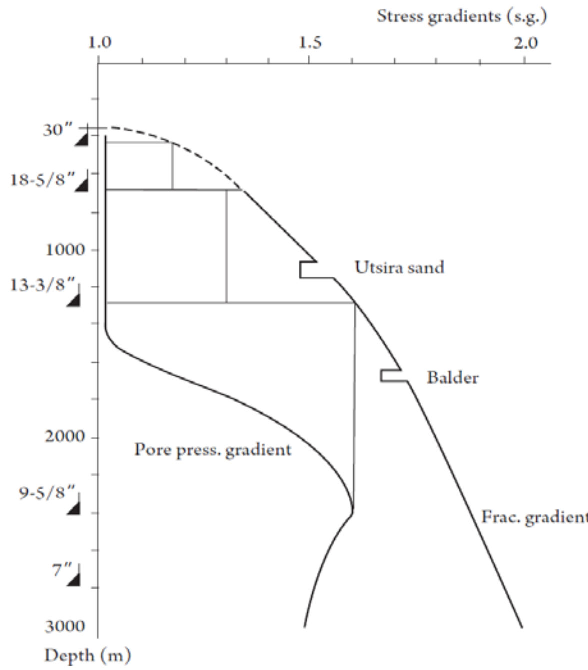

Figure 44: Casing depth limited by mud weight[4&1]

Criterion 2: Oil filled scenario for burst loading calculation (intermediate/production casing)

In this criterion, we assume the worst case scenario that all well control fails and well is completely filled with oil/gas from formation. The internal well head pressure will be formation pressure minus weight of the column of formation fluid. The external pressure is assumed to be sea water. The casing should withstand the burst pressure at well head. The external pressure is given by:

$$P_{wh}^{ext} = 0.0981 d_{sw} D_s \tag{2.4}$$

Internal pressure at well head is given by:

$$P_{wh}^{\text{int}} = 0.0981\, d_o D - 0.0981\, d_{res} (D - D_s) \tag{2.5}$$

Burst pressure is equal to:

$$P_{burst} \geq SF\, (P_{wh}^{\text{int}} - P_{wh}^{ext}) \tag{2.6}$$

Where

d_{sw} = Density of sea water

D_S = Depth of sea floor

d_{res} = Density of reservoir fluid

d_o = Pore pressure density gradient at bottom

Criterion 3: Reduce well integrity:

In this criterion which we have to design our production casing which is the last casing as full well integrity. With full well integrity both casing and open hole can withstand formation fluid filled casing exposed to full formation pressure. For this the design criteria is "the minimum fracture gradient needed to ensure full well integrity and to reach the end of the next open hole section"[1]

All the other casings except production casing are designed with reduced well integrity. Reduce well integrity applies that well is not capable of handling formation fluid filled scenario. We have to save our casing bellow well head so we have to design in such a way that weak point lies just below casing shoe i.e. before the pressure reaches at level to burst casing below well head the formation below casing shoe fracture and our casing below well head will be saved. For reduced well integrity following design conditions must be established:

- Minimum fracture gradient to reach next casing setting depth
- Maximum fracture gradient to ensure that weak point stays below casing shoe
- Maximum kick size that can be handled without fracturing formation below casing.

Criterion 4: Kick margin

In this criterion we will define the amount of kick which can be taken without fracturing our formation below casing shoe. Reason for this that although we have reduced well integrity, but still we want to establish a limit for kick so that we can save our well with any disaster.

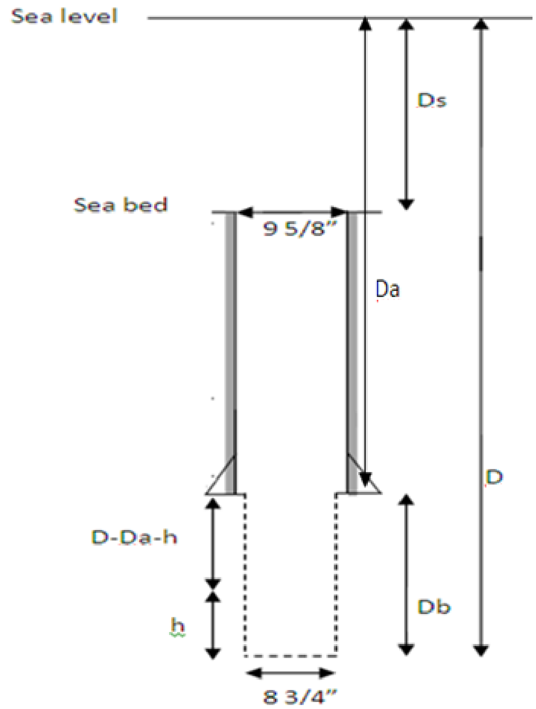

Figure 45: Kick margin

Fracture pressure at given depth is given by:

$$P_{wf} = 0.0981 d_{frac} D_a \qquad 2.7$$

Pore pressure formation at bottom of the well:

$$P_o = 0.0981 d_o D$$

Pressure balance is given by:

$$P_{wf} \geq P_o - (0.0981 d_{res} h) - (0.0981 d_{mud} (D - D_a - h)) \qquad 2.8$$

Where

d_{frac} = Fracture pressure density gradient

h = height of kick influx

From the above equation we can find out the height of kick, and from this height we can find out the volume of kick we can take without fracturing our formation below casing shoe.

Criterion 5: Collapse loading calculation for losses occurs to thief zone (intermediate/production casing)

During drilling we may have mud loss to thief zone. In this criterion we assume that mud loss occurs during casing running. As mud loss occurs the fluid level start decreasing. The pressure outside casing will remain constant but pressure inside casing will reduced and can cause severe collapse. Sea water will be used as lower limit for the mud loss pressure, in other words, if loss occurs the annulus level will stabilize when the bottom hole pressure is equal to weight of sea water column to that depth[1].

Pressure of sea water column is:

$$P_{sw} = 0.0981 d_{sw} D \qquad 2.9$$

Pressure at the bottom is:

$$P = 0.0981 d_{mud} (D - l) \qquad 2.10$$

Where

l = height of mud column decrease

By equating both equations we will get the height of mud column decrease and at this point we can find out the collapse loading.

Criterion 6: Collapse during cementing

After cementing the external pressure is very high. It is composed of seawater gradient up to sea bed and cement below it. For this criterion we assume that outside of the annulus is completely filled with cement plus sea water and inside is filled with displacing fluid which is sea water. Refer to the figure 46

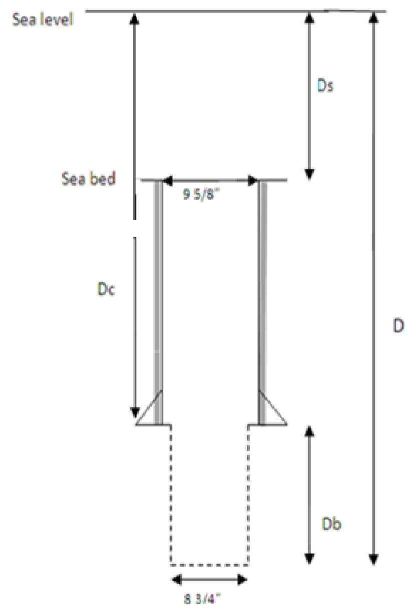

Figure 46: Collapse during cementing

So the external pressure at bottom is given by:

$$P_{bot}^{ext} = (0.0981 d_{sw} D_s) + (0.0981 d_{cem} (D_c - D_s)) \quad 2.11$$

Internal pressure is given by:

$$P_{bot}^{\text{int}} = 0.0981 d_{sw} D_c \quad 2.12$$

Collapse loading is given by:

$$P_c = SF(P_{bot}^{ext} - P_{bot}^{\text{int}}) \quad 2.13$$

Criterion 7: Collapse during plugged perforations during production

In this case we assume that our well is in production and perforations get plugged, so we will take formation pressure as an external pressure and formation fluid as an inside the casing. External pressure at casing shoe:

$$P_{bot}^{ext} = 0.0981 d_o D \quad 2.14$$

Internal pressure at casing shoe

$$P_{bot}^{\text{int}} = 0.0981 d_{res} D \quad 2.15$$

Collapse loading is given by

$$P_c = SF(P_{bot}^{ext} - P_{bot}^{\text{int}}) \quad 2.16$$

Criterion 8: Tubing leaking scenario for burst loading calculations

In tubing leaking scenario we assume that production tubing is completely filled with formation fluid and well is shut in. tubing leaking occur below well head and all pressure transmitted to annulus which is filled with completion fluid. So point of concern is the casing above production packer must be able to withstand the high internal pressure.

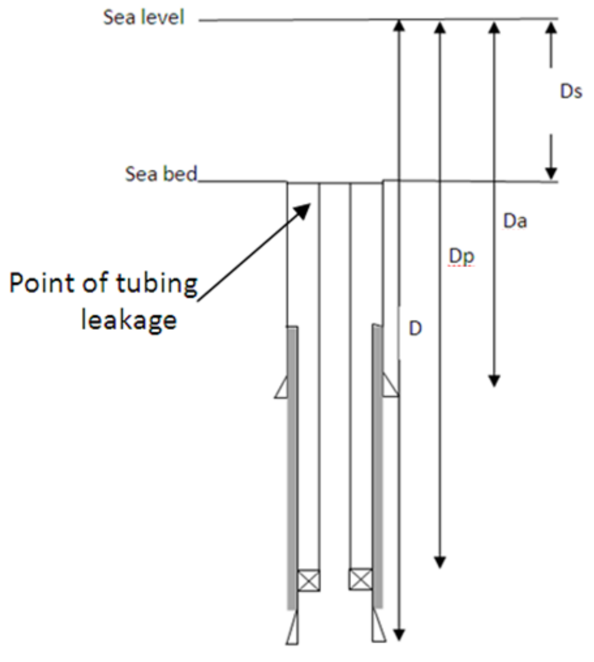

Figure 47: leaking tubing scenario

Formation pressure is:

$$P_o = 0.0981\, d_o D$$

Pressure at the well head is:

$$P_{wh} = P_o - 0.0981 d_o (D - D_s) \quad 2.17$$

Pressure above packer is:

$$P_{packer}^{int} = P_{wh} + 0.0981\, d_{comp}\,(D_p - D_s) \quad 2.18$$

External pressure at packer:

$$P_{packer}^{ext} = 0.0981\, d_{sw} D_p \quad 2.19$$

Burst loading is given by:

$$P_b = SF\,(P_{packer}^{int} - P_{packer}^{ext}) \quad 2.20$$

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2.4 Well Control

2.4.1 Kick

Kick is defined as unscheduled flow of formation fluid in to the well bore[10]. The conditions for kick occurrence are[12]:

- Pressure in the formation exposed must be higher than the well bore pressure
- Formation must have sufficient permeability to let flow into the well bore
- The pore fluid must have sufficiently low viscosity so that it can flow

If kick is handled well it can be safely killed if not then initially a small looking kick can be turned out as large, uncontrollable blowout can cause severe damage to the well and personal at the rig as well.

Recent well control incident pushed the oil and gas industry to see the kick scenarios in more attentive way in order to prevent it to become deadly and uncontrolled blow out which recently occurs at Deepwater Horizon oil rig working on the Macondo exploration well for BP in the Gulf of Mexico[7]. The figure 48 is of the same well after blowout of gas kicks which turns out in to a deadly fire after explosion, resulting in for rig damage and personal life loss as well.

Figure 48: Deepwater Horizon oil rig[7]

2.4.2 Causes of kick

Kick can be result either directly because of drilling crew mistakes or indirectly by any change occurs in the well, namely these causes are;

Inadequate mud weight: Mud weight we use to drill should be greater than formation pore pressure to control the formation, if somehow we let drilling mud weight smaller then formation pore pressure the fluid will start entering in the well and cause kick[3].

Improper hole fill-up during trips: Proper calculation needs to be done before tripping-in, because improper fill-up oh hole may leads to fluid level drop in the well which results in reduced hydrostatic heat and can cause kick[3].

Swabbing: This phenomenon normally occurs as a result of rapid pulling of pipe out of the hole which causes swabbing. Due to this vacuum can be created and can cause formation fluid to enter in the well bore[3].

Cut mud: Drilling through gas bearing zone may sometime cause reduce hydrostatic head because of gas contaminated cutting which reduces the density of drilling fluid[3].

Lost Circulation: Higher mud weight then formation pressure may cause lost circulation which leads to fluid level drop and through upper formation we may have kick[3].

2.4.3 Well control

The term well control regarding kick covers different activities such as:

- Kick detection
- Kick captivity(determining formation over pressure)
- Circulating kick out of the well in safe and economical way

2.4.4 Kick detection

A successful drilling operation requires very active and quick observation on any kick occurring at the bottom of the well. Especially in deep water drilling, kick detection play vital role in completing your well without any major time loss. As an ideal condition we should never have a kick but it is not possible, so in real case scenario the best approach is to detect a kick as early as possible and control it in a safer manner.

Normally there are two types of kick indicators namely: primary indicators and secondary indicators as described below[4]

2.4.4.1 Primary indicators

Pit gain: It is defined as difference between volume of drilling mud pumped in and volume of mud out of the well, for kick, the volume coming out of the well is greater than volume pumped in. In stabilize conditions both in and out volume will be same[3].

Increase in return flow rate: As the formation start entering the well it will displace drilling mud and we have increase mud flow at return lines.

Well flow with pump off: A very important yet quite tricky indicator of kick, during kick as we shut down the mud pump and the well is keep flowing is clear indication of invasion from formation fluid into the well but this need to be very vivid because in HTHP well the high temperature expands the mud and we have same situation also in riserless drilling we can have same phenomena due to U-tube effect[2].

Improper hole fill up during trips: During trip-out, the fluid level in the well should drop by equal amount of pipe body volume. If well is not taking the calculated volume then there is clear indication that some foreign fluid is displacing the drilling mud[3].

2.4.4.2 Secondary indicators

Drop in BHP with MWD: As the light weight formation fluid enters in the well bore it reduces the overall hydrostatic head and can be good indication together with some primary indications.

Drop in stand pipe pressure (SPP): With more and more formation fluid entering in the hydrostatic head will reduce and as a result stand pipe pressure (SPP).

Drilling break: A sudden increase in penetration rate is called "drilling break", normally occurs when entering in the soft formation such as sand. It is not oblivious that a drilling break will be followed by kick but flow check is a good measure after getting drilling break[3].

Increased Hook load: Any intrusion from lighter fluid will decrease the drilling mud density thus reducing its buoyant force, this result in increase pipe weight and can be observed by increase hook load[3].

Although the primary indicator such as pit gain and return rate increase are good indicators together with hook load changes and drilling breaks but in riserless condition due to U-tube effect it is very tricky to detect the real cause of the well flow. Also during tripping the well flowing condition will always be hindered by U-tube effect, so tripping should be done after U-tube effect with great difficulties of determining the exact fluid level, fluid level can be determined with the help of sonic devices[5].

Pit gain, subsea power and RPM of subsea pump are the main parameters of kick indication[5]. But for riserless drilling we have to evaluate their significance. By care full monitoring of flow rate difference or pump stroke increase of subsea pump inlet, we may have a fair chance of early kick detection in riserless drilling. Also decrease in stand pipe pressure in a good indicator because surface pressure is lower. Measurement while drilling (MWD) in combination with other kick indicators may be used to confirm the kick occurrence[5].

2.4.5 New emerging technology for kick detection RMR simulator

Shallow Gas Scenario

Johnny Froyen et al (2006) developed a Riserless Mud Recovery (RMR) simulator in order to evaluate the significance of three kick detection indicators namely pit gain, subsea mud pump rpm and power. In their modeling they developed two models one for 26” open hole and second for 9 7/8” pilot hole in which they evaluate the case of drilling when gas influx is introduced. The simulation starts as bit reaches above the gas zone and the gas influx increases[5].

As gas started flowing into the well it displaces the mud and as a result increase in mud flow out and the increase flow rate will results in increase in frictional pressure loss and resulted in increased subsea outlet pressure figure 49. The criterion for pit gain is set as 3 cubic meter and kick is detected after 2.1 minutes and during this time subsea pump rpm increased by 25% and power consumption increased by 200%[5].

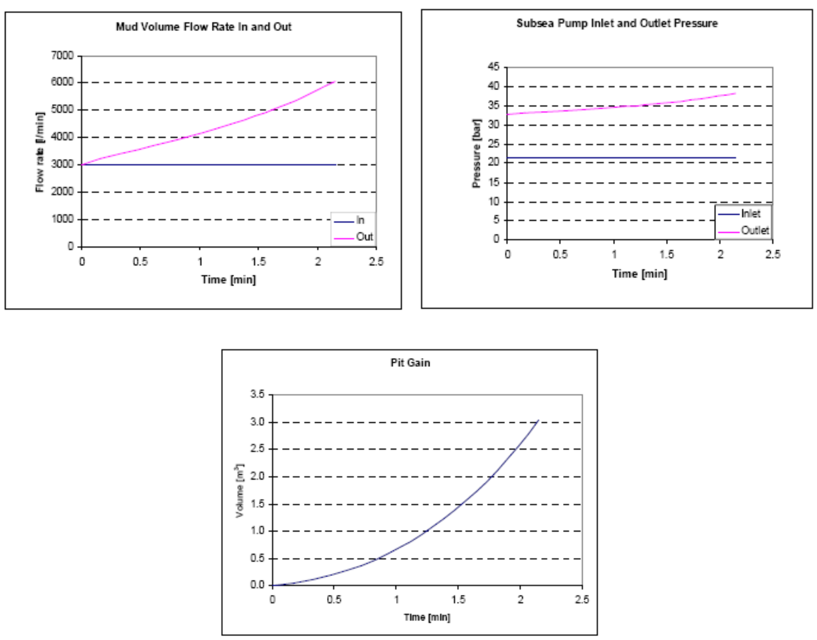

Figure 49: Kick indications[5]

It is of great importance to identify the height or distance travel by gas influx before it is detected, during this experiment the height of gas flux is 130m when it was detected after 2.1 minutes and it is 370m below the subsea pump[5].

For 9 7/8” pilot hole all graphs were produced and major difference was observed in pit gain, because of slim hole the friction pressure was high thus compressing the gas in the well and not letting it expend much, that leads to slow pit level gain initially but as more gas enters in the well and as gas travel upwards it expands quickly, as a result the pit level increases very rapidly in later stages. The time it took to detect gas kick was 5 minutes[5].

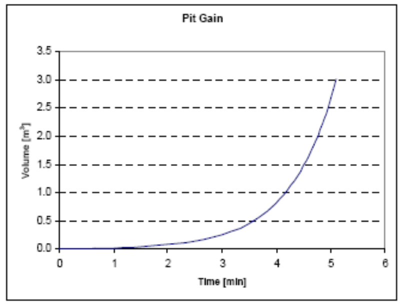

Figure 50: Kick indication for 9 7/8" pilot hole[5]

The same trend can be observed in all other parameters i.e. slow increase at initial stages and rapid increase at later stages. As a conclusion of this simulation it can be stated that subsea pump rpm and power are more superior indicators then pit gain in case of riserless drilling conditions.

2.4.6 Kick captivity (determining formation over pressure)

In this topic we will be focus on kick scenarios in riserless drilling. Assuming that the kick is detected by above mentioned indicators, the next very important question to be answer is how to stop kick. Jonggeun Choe (1999) in his paper discussed three methods to stop kick namely[4]:

- Constant pressure mode
- Constant flow rate mode
- Surface pump shut down mode

2.4.6.1 Constant pressure mode

Following example is given to show how to stop kick and determine formation over pressure. Figure 51 shows circulation rate of pumps at surface and subsea, Surface pump rate is maintained at 420gpm and subsea pump operate at predetermined rate. Subsea pump rate start increase due to change in flowing bottom hole pressure(FBHP) at this point we stop drilling and subsea pump rate is decreased as kick is detected by above mentioned indicators. The pressure in the well increase and FBHP become equal to formation over pressure and kick is stopped[4].

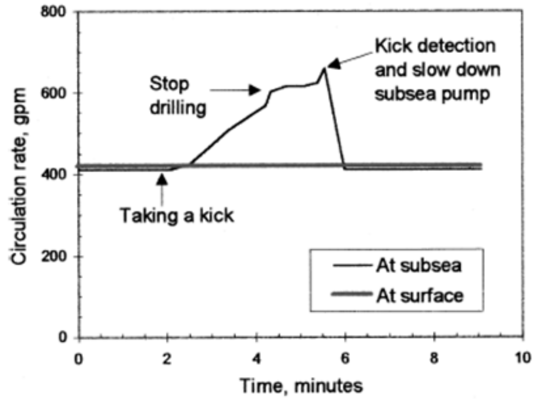

Figure 51: Circulation rate at the surface and subsea pump during the early stages of well control[4]

Next step is to determine formation over pressure, though this is a dynamic kill method but still there is a way to determine SDIPP which is very important to estimate formation over pressure and kill mud weight. Figure 52 show SPP and subsea pump inlet pressure at early stages of well control. SPP is constant at 500 psig until kick begin, initially it increases because of friction loss due to increase in flow rate then it start decreasing due to reduction in hydrostatic pressure reduction and it is a good indicator of kick. After the kick is detected we slow down the pump rate of subsea pump and as a result SPP start increases and stabilize at 800 psig. SPP stabilize as FBHP rise to formation over pressure[4].

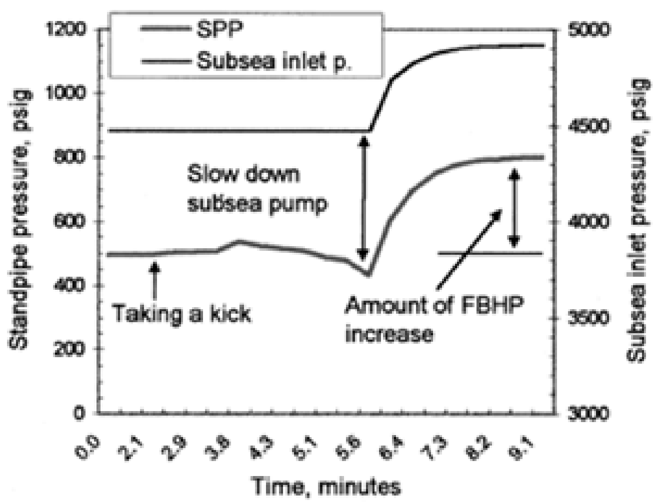

Figure 52: SPP and subsea pump inlet pressure for constant pressure mode[4]

The formation over pressure is same as net increase in SPP and is enough to kill well dynamically but for static conditions we also consider friction losses. For the fig-b, the net-increase in SPP is 300 psig and let us assumes that the friction losses are 220 psig, so[4]

$$\Delta P_{over} = \Delta P_{sp} + \Delta P_{f,ann} \qquad 2.21$$

Where

ΔP_{over}= formation over pressure

ΔP_{sp} = increase in SPP

$\Delta P_{f,ann}$ = friction pressure loss in annulus

ΔP_{over}= 300 + 220=520 psig

Kill mud weight can be calculated by the formula[4]

$$\rho_{km} = \rho_m + \frac{\Delta P_{over}}{0.052(D - D_w)} \qquad 2.22$$

Where

ρ_{km} = Kill Weight Mud (ppg)

ΔP_{over} = Formation over pressure (psi)

D = Total depth

D_w = water depth

D-Dw = True Vertical depth (ft)

ρ_m = Original weight mud (ppg)

2.4.6.2 Constant flow rate mode

Another way to stop kick is to set both surface and subsea pump at constant rate. As kick influx start entering the well the pressure in the well increase because of constant subsea rate and eventually stops. Figure 53 shows stand pipe pressure and subsea pump pressure. Note that both SPP and subsea pump pressure start increasing after taking a kick without any time consuming[4].

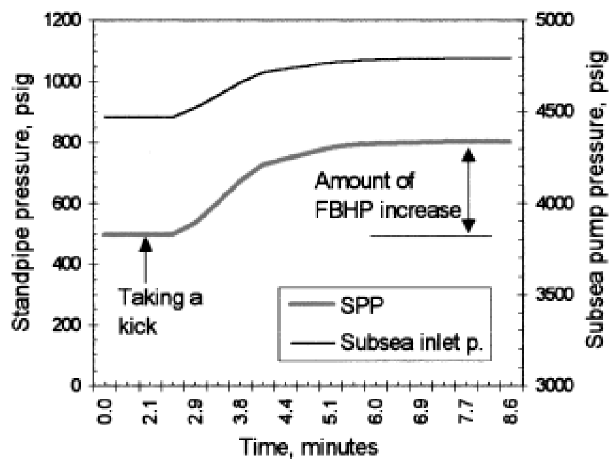

Figure 53: SPP and Subsea Pump Pressure for constant circulation rate[4]

2.4.6.3 Surface pump shut down mode

With some modification we may use conventional well shut-in approach to stop the kick influx. If the fracture pressure of the formation is known, we may set maximum subsea inlet pressure with a safety margin to stop kick influx fast[4].

2.4.7 Kick control methods

Over the years many well control procedures have been developed, some based on systematic approach while some on logical approach[4]. the main approach is to control the well with constant bottom hole pressure during the entire well control procedure, one more thing to mention here is that because we intended to keep bottom hole pressure just above the formation pressure so it also save us from any formation damage and underground blowout.

- Driller's method
- Wait and weight method
- Volumetric method
- Bull heading

2.4.7.1 Driller's method

It is also known as two circulation method[1]. In first step the kick fluid is circulated out of the well and then the mud is weighted up to desired density (kill mud) and replaces the old mud. The principle of this method is to keep the bottom hole pressure (BHP) constant.

BHP= hydrostatic pressure + well friction + choke pressure

Driller normally follow the kill sheet to be clear that the BHP is kept constant, Below is the typical kill sheet for driller's method.

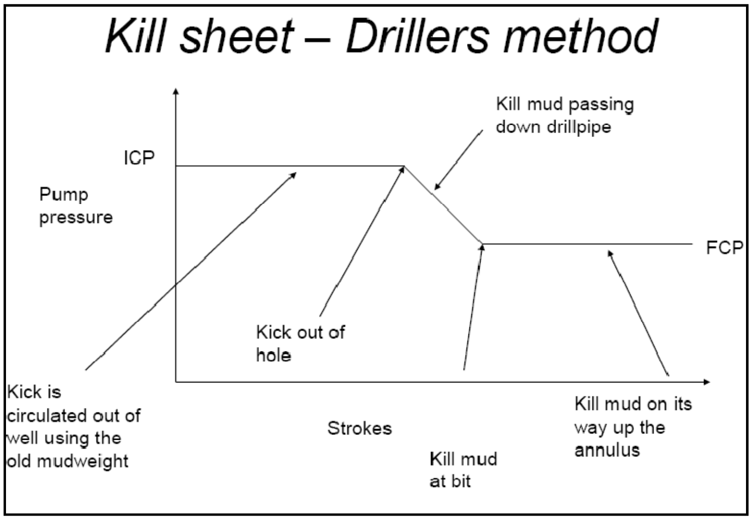

Figure 54: Kill sheet Driller's method[9]

Normally the driller's method is accomplished in two main steps

- In the first step the well is circulated at half pump rate while keeping the drill pipe pressure constant (figure 54). This step is completed when the formation fluid is out of the well[1].
- As the formation fluid is out of the hole the kill mud is circulated through drill pipe, the pressure reduces, after the kill mud reaches drill bit and start moving up through the annulus the surface pressure is kept constant through choke adjustment[1].

2.4.7.2 Wait and Weight method

Also known as one circulation method, in this method the fluid is weighted up to kill density and then introduced in the well and at the same time the kick is circulated out of the well through annulus. This method is applied in four steps[1];

- In first step the kill mud is weighted up to desired weight and circulated down the drill pipe and stand pipe pressure gradually reduced.
- In second step the kill mud move up through the annulus, the stand pipe pressure is kept constant by proper choke adjustment
- The formation fluid is circulated out of the well through annulus

- During this step the original mud followed by kick influxes is circulated out through annulus and heavy weight kill mud fills the annulus, during this the choke is open more and more to keep stand pipe pressure stable and constant

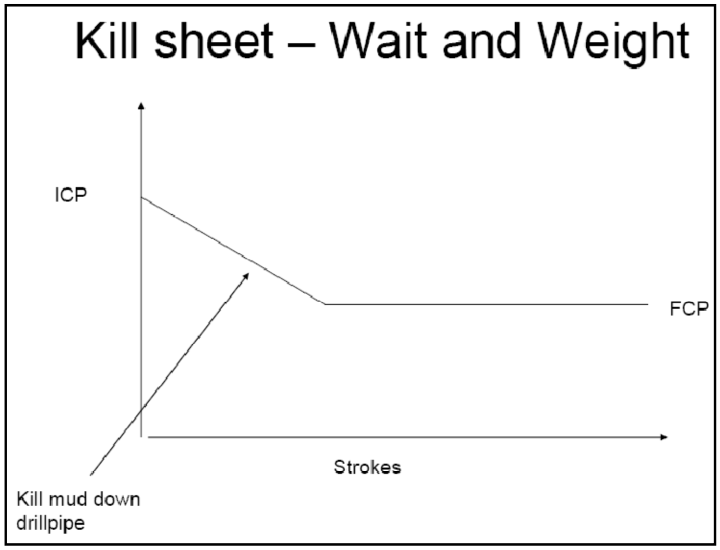

Figure 55: Kill sheet Wait and Weight method[9]

2.4.7.3 Volumetric method

We use this method when the drill string is off the bottom or even not in the hole. This method consists of bleeding of gas in steps. The constant bottom hole pressure concept is utilizes to control the well in this condition. It is a time consuming operation to control well.

The well control is achieved by equating the pit volume change with the corresponding change in annulus pressure[1],

$$\Delta P_S = \frac{\Delta V_P}{AV} 0.052 \overline{\gamma_m} \qquad 2.23$$

where

ΔP_S = change in casing pressure at casing side in psi

ΔV_P = change in pit volume (volume gained) in bbl

γ_m = mud specific weight in bbl/ft

AV= Annular volume capacity in bbl/ft

It should be noted that the term 0.052 γ_m /AV expresses the expected increase in casing pressure when 1 bbl of pit gain is recorded

During the kick control the magnitude of casing pressure is[1]

$$\Delta P_S = SICP + \frac{\Delta V_P}{AV} 0.052\overline{\gamma_m} \qquad 2.24$$

Where SICP= Shut-In Casing Pressure in psi

When the pit volume will be stabilizes, there will be an equilibrium in the annulus and the kick fluid is out of the well.

The volumetric well control method is performed in two steps

- The formation gas in the well is allowed to migrated up the well and during this the bottom hole pressure increases
- The mud is bleed with keeping the casing pressure constant by choke adjustment and the bottom hole pressure is decreased.

The figure 56 illustrate the bleeding off the gas volume by volumetric method while bottom hole pressure changes during each step as stated above.

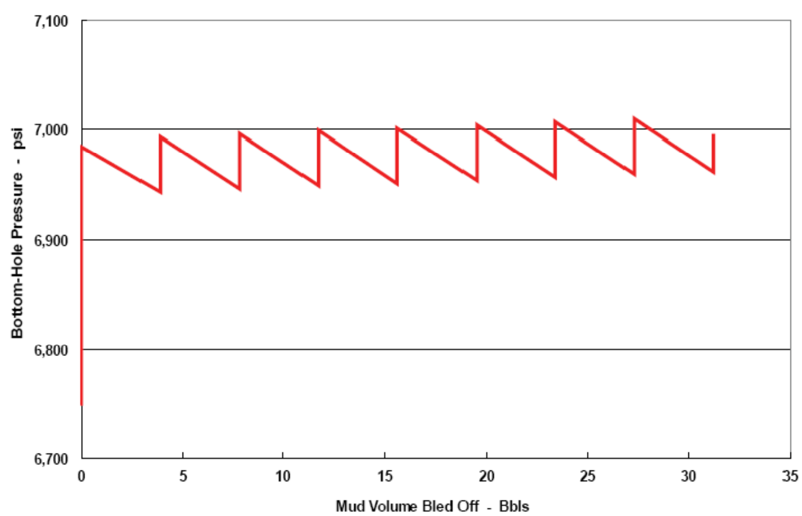

Figure 56: Volumetric well control[8]

The figure 57 is showing the total time to bleed of formation fluid out of the well. It should be noted that the first bleeding took almost 23 hours to complete but step after step the time taken to bleed becomes shorter and shorter.

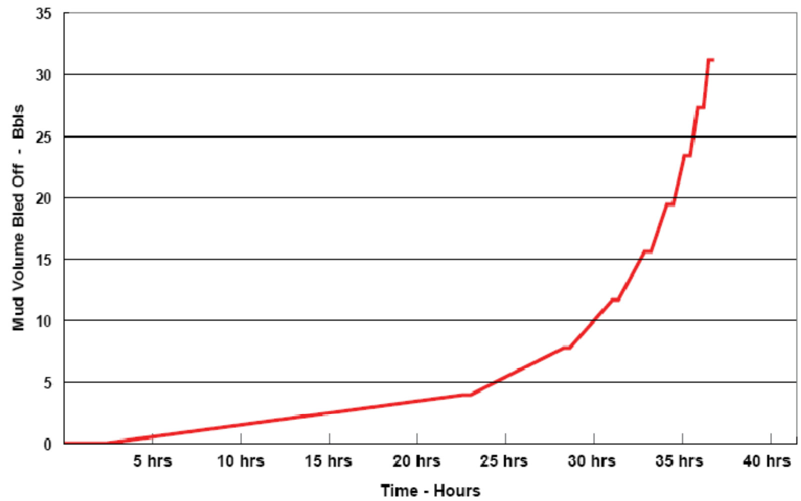

Figure 57: Mud volume bleed off vs. time[8]

2.4.7.4 Bull heading

In this method we pump the fluid through annulus or through drill pipe to forces back the formation fluid in to the formation. The intensions are to remove the formation fluid from the well and push them back in the formation as soon as possible, the formation will be fractured and this will happen at the weakest formation. After the removal of formation fluid the balanced fluid column will be established through normal circulation. The flow rate during bull heading is kept very high in order to save time by quick removal of influxes and to avoid any gas migration[6]. This method is especially used in;

- Completion and work over job
- Danger of H_2S

The figure 58 illustrates the well bore process during bull heading.

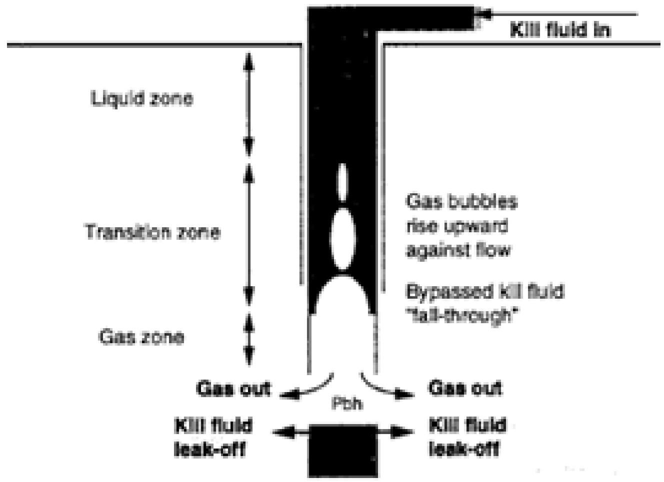

Figure 58: Well bore processes during bull heading[6]

2.4.8 A New Approach for well Control

John-Morten Godhvan et al (2010) developed and tested successfully a new approach to control a well in Managed Pressure Drilling method. They successfully able to circulate out small volume of kick i.e. 1m^3 through back pressure choke[11].

The procedure they described is[11]:

- Kick is detected automatically
- Stop the drilling string rotation
- Pick up off bottom
- Increase bottom hole pressure by adding back pressure
- Circulate out the influx through MPD choke and poor boy degasser
- Large kicks should be handled with standard well control procedures with shutting down the BOP and not through MPD choke

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3 Design Calculations

3.1 Well design

Based on literature studies, we have to design a well with different approaches to see what will be the impact of different methods on our well design. In first case we will apply conventional drilling method which utilizes single mud system, after wards we will use dual gradient drilling method, riserless drilling with zero well head pressure and use back pressure to control the whole drilling program and at last we will use riserless drilling with zero well head pressure under U-tube effect.

Conventional single mud system

With the given data about a well the first task was to develop a formation pressure profile. The Down-up principle[1] was used to calculate the appropriate number of casing strings to complete a well. The available data is given below:

All calculations from sea level

- Depth to seabed: Ds: 2286m
- Total depth of the well: D: 9144m
- Pore pressure @ 9144m: 1.63 sg
- Fracture pressure @ 9144m: 1.8 sg
- Formation fluid density: ρ0 0.76 sg

Formation pore and fracture pressures at 9144m is given by

$$P_o = 0.0981\, d_o D \qquad 3.1$$

$$P_{wf} = 0.0981 d_{wf} D \qquad 3.2$$

In term of equation it is expressed as

$$P_{wf} \geq P_o - 0.0981 d_{mud} (D - D_a) \qquad 3.3$$

Where

- P_{wf} = Fracture pressure
- P_o = Pore pressure at bottom
- d_{mud} = Density of mud
- d_o= pore pressure gradient
- d_{wf}= Fracture pressure gradient

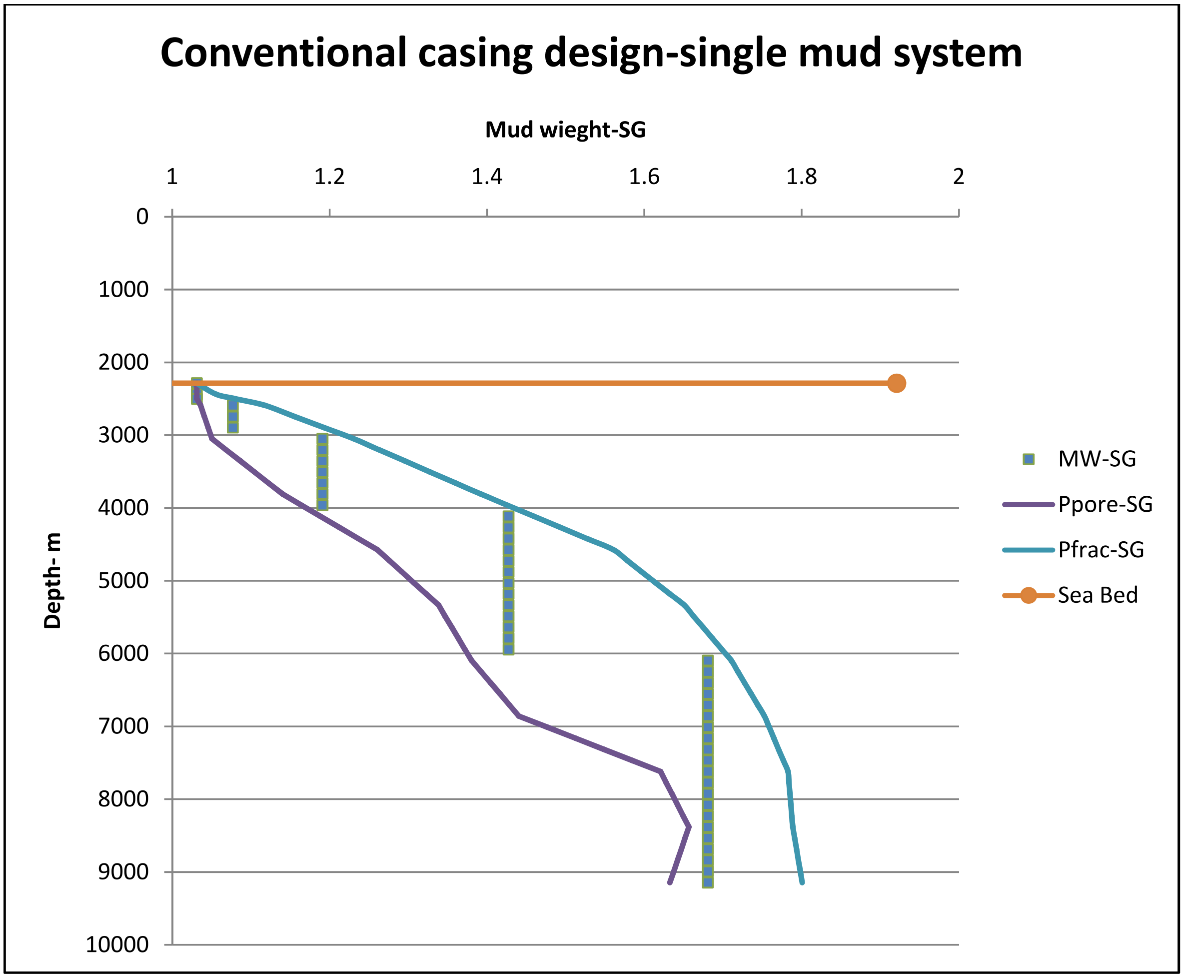

Figure 59: Conventional single mud system

The figure 59 is showing the number of casings we use to complete the well.

Casing Program

- 30" casing
  - Mud weight: 1.03 sg-Setting depth: 2499 m
- 20" casing
  - Mud weight: 1.08 sg-Setting depth: 2895 m
- 13 3/8" casing
  - Mud weight: 1.19 sg-Setting depth: 3962 m
- 9 5/8" casing
  - Mud weight: 1.43 sg-Setting depth: 5943 m

– 7” casing

  – Mud weight: 1.68 sg-Setting depth: 9144 m

The figure 60 is well design but in terms of pressure which also illustrate the casing program.

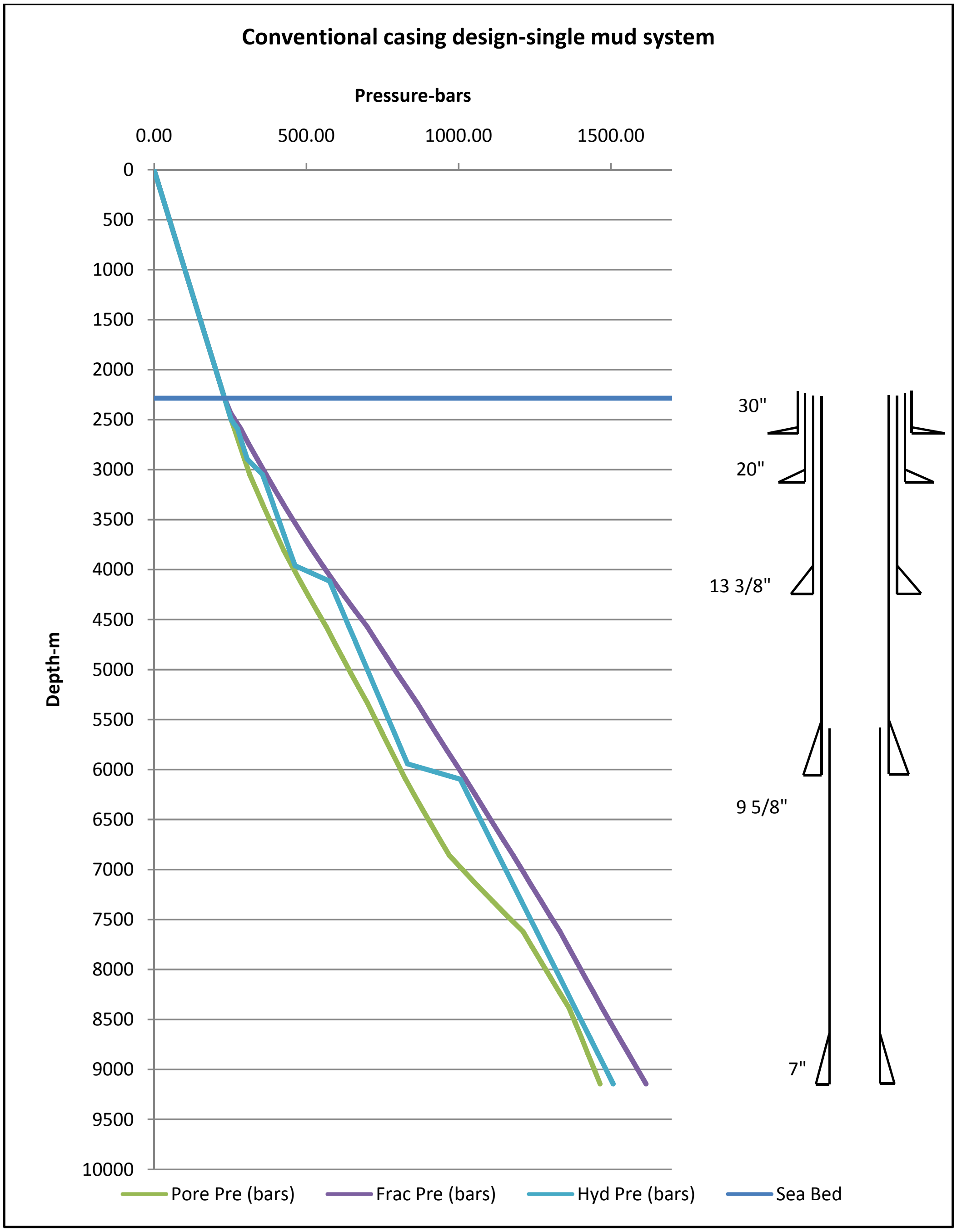

Figure 60: Conventional casing design-single mud system

Dual Gradient Drilling Method

In second step we used the dual gradient method to complete the well. The upper consist of light density sea water above sea bed and lower part is consisting of high density drilling mud below sea bed. The mud weight was calculated in segments. The resulted mud weight was calculated by following formulas:

$$P_{mud} = P_{pre} + (0.0981 d_{mud} (D_2 - D_1)) \quad 3.4$$

$$d_{re-mud} = \frac{P_{mud}}{0.0981 D} \quad 3.5$$

Where

P_{mud}= drill mud hydrostatic pressure

P_{pre}= Hydrostatic mud weight of previous segment

d_{mud}= Mud density to be used

$d_{re\text{-}mud}$= Resulted mud weight

D_2-D_1= Length of current segment

D= Total depth up to that segment from sea level

Casing Program

- 30” casing
  - Mud weight: 1.2 sg-Setting depth: 2895 m
- 9 5/8” casing
  - Mud weight: 1.6 sg-Setting depth: 5486 m
- 7” casing
  - Mud weight: 1.95 sg-Setting depth: 9144 m

The results were quite satisfied. The well which needed five casing to be complete is only requiring now three casings to complete. This will result in

- Huge amount of savings in terms of casing
- Drilling time reduction
- Mud cost reduction
- Better well control
- Reduced non-productive time

Also in this calculation we introduced the safety factor due to following reasons

- Kick
- Trip out-swab effect

- Trip in- surge effect
- To counter the uncertainties regarding pore and fracture pressure.

The figure 61 illustrate the outcome of the calculations

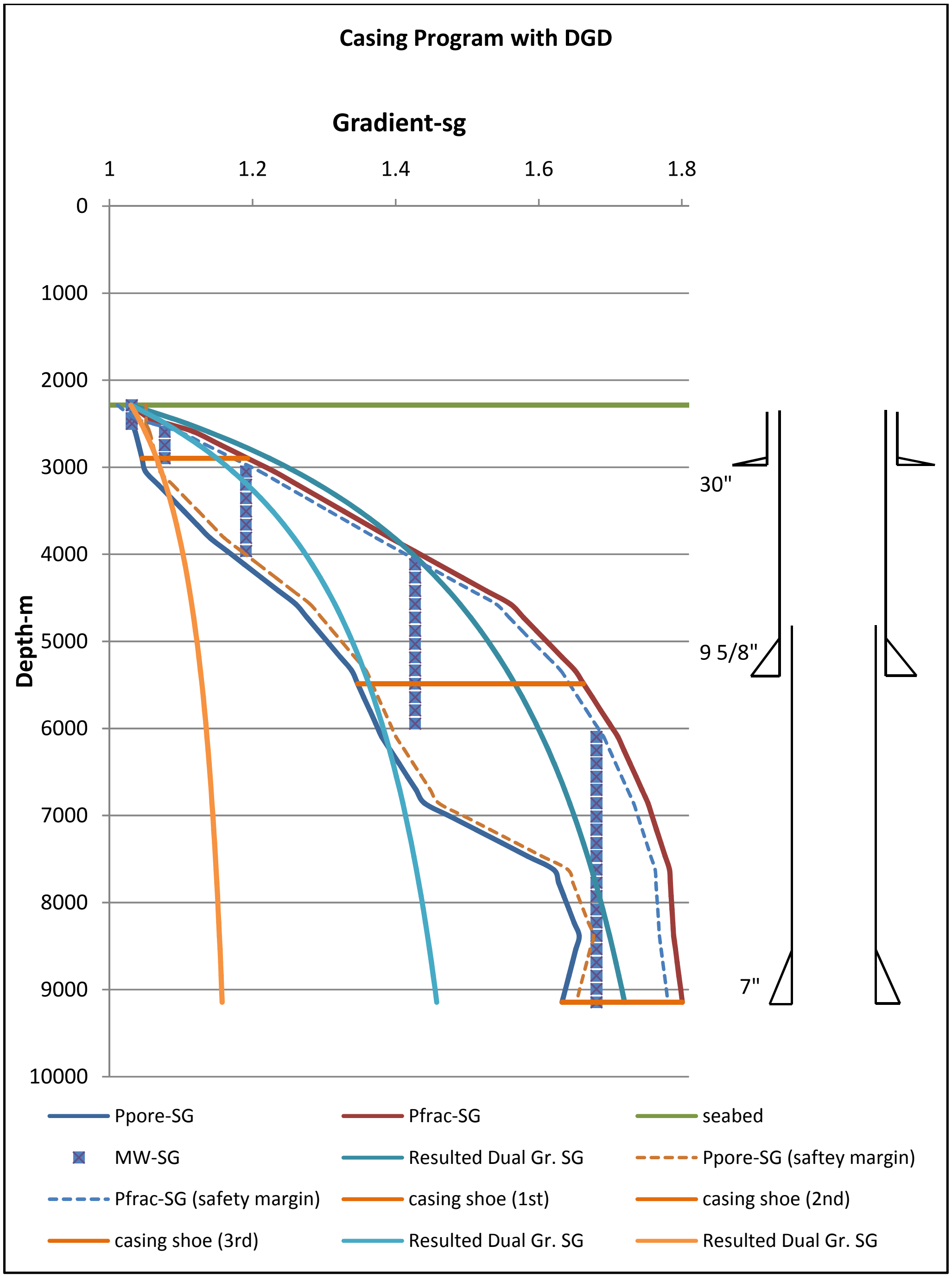

Figure 61: Casing Program with DGD

Casing program with Zero Well Head Pressure- Back Pressure

In this third step we took the zero well head condition and apply back pressure to control the whole drilling program. We assume that the annulus will be isolated from above water environment so that no water gradient is acting on annulus well head. The tool used for that purpose is Siem WIS riser pressure control device. The main idea was to apply sufficient back pressure to meet the formation pressure profile. It also ended up with three casing strings. Assumptions taken for this approach are:

- Annulus will only be consist of single mud system
- Well head will be completely isolated from above, so we have zero pressure acting on well head annulus
- Continuous circulating system will applied for complete drilling program
- MPD choke will able to with stand the high operating pressures
- Siem WIS riser pressure control devise will be able to isolate the well head
- Riserless equipments will perform under deep water

Casing Program

- 30” casing
    - Mud weight: 1.08 sg-Setting depth: 2590 m
- 9 5/8” casing
    - Mud weight: 1.6 sg-Setting depth: 4572 m
- 7” casing
    - Mud weight: 1.95 sg-Setting depth: 9144 m

The figure 62 illustrates the casing program.

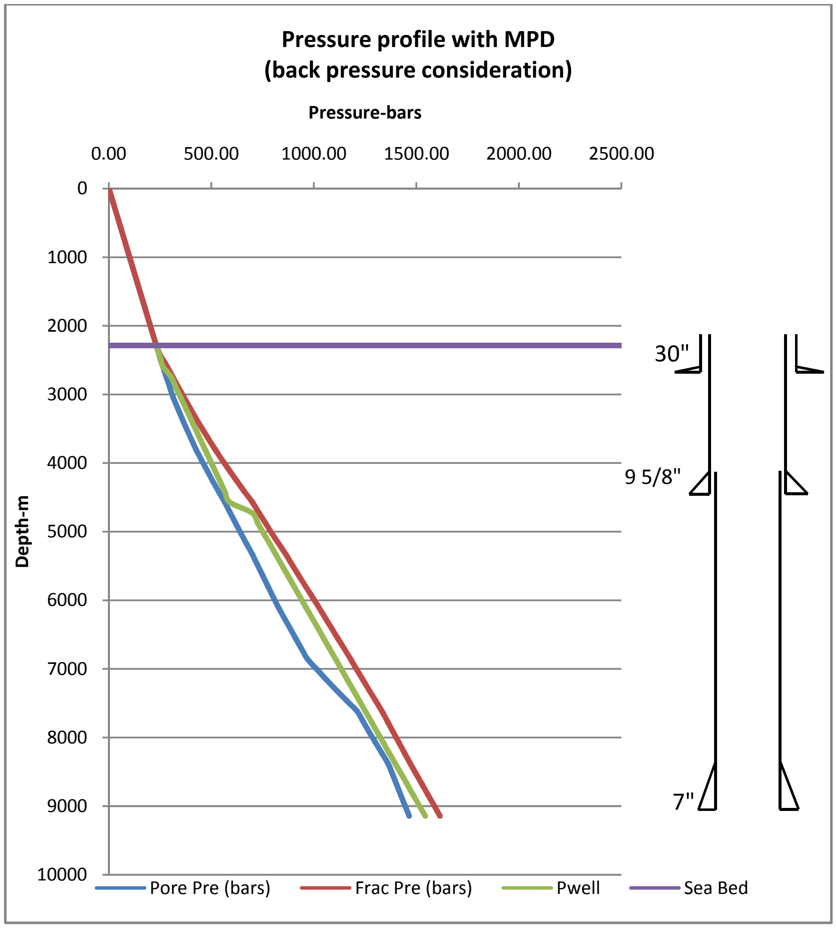

Figure 62: Pressure profile with MPD (back pressure application)

Casing program with Zero Well Head Pressure- U tube effect

With same method of zero well head pressure, we in this method tried to utilize the U-tube effect. Figure 63 illustrate the concept of U-tube. The pressure at point “b” is equal to pressure at point “a”. Using high density mud we have much higher pressure at well head annulus than formation pressure profile. To meet with this pressure profile we have to reduce the pressure. As soon as we open the MPD choke at well head the pressure will reduce. Now we will reduce this pressure up to nearly 180 bars to come inside the pressure envelop of formation. Assumption taken in this approach is:

- Well head will be completely isolated from above, so we have zero pressure acting on well head annulus
- Annulus will only be consist of single mud system
- MPD choke will able to with stand the high operating pressures
- Siem WIS riser pressure control devise will be able to isolate the well head
- Riserless equipments will perform under deep water
- Down hole safety valve will able to control the U-tube effect

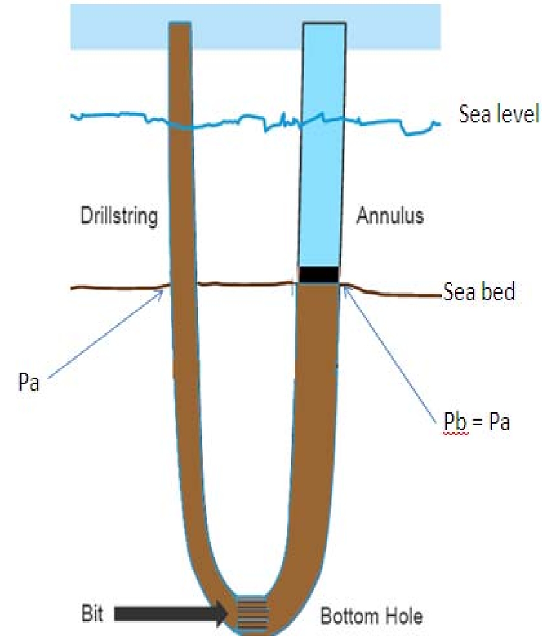

Figure 63: U-tube effect in zero well head pressure[2]

The layout of the system will look like as shown in figure 64.

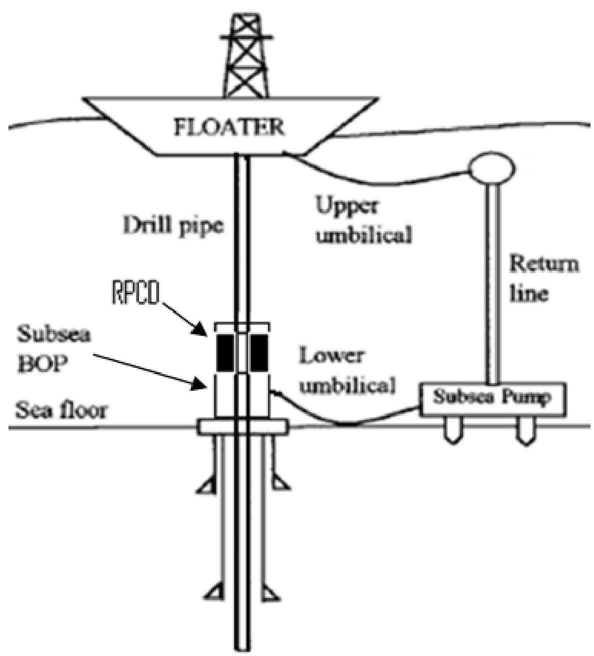

Figure 64: Riserless drilling with zero well head pressure (riser pressure control device installed at well head)

Keeping the same pressure drop we start drilling and surprisingly it ends up with first casing far beyond the previous cases before it go below formation pore pressure at depth of 5791 m. we decided to set our first casing here. For second casing we only reduce the mud weight up to 87 bars to keep our BHP inside the pressure envelope. With this we completed our well with only two casings. Below is the mud and casing program

Pressure reduction for each casing

- 9 5/8” casing: 180 bars-mud weight: 1.8 sg
- 7” casing: 87 bars-mud weight: 1.8 sg

Casing Program

- 20” foundation
    - Setting depth: 2686 m (400 meters below seabed)
- 9 5/8” casing
    - Mud weight: 1.8 sg-Setting depth: 5791 m
- 7” casing
    - Mud weight: 1.8 sg-Setting depth: 9144 m

The figure 65 illustrate the outcome of the calculations

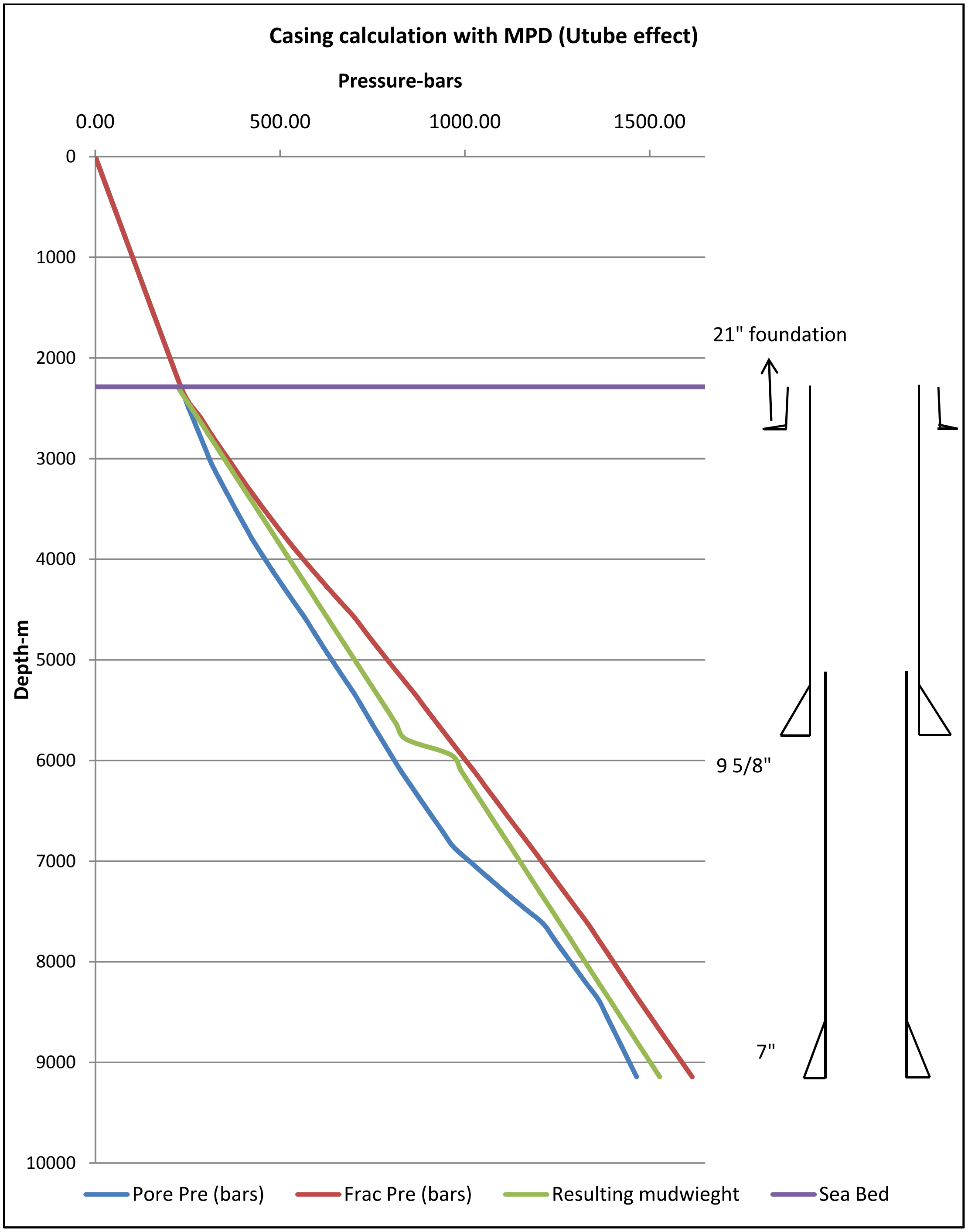

Figure 65: Casing calculation with MPD (Utube effect)

3.2 Casing setting depth selection

Over the years well integrity becomes more and more important. Well integrity means that one or two barriers must be present in the well at all time. We know that casing is very important element of well barrier thus its selection and defining its setting depth plays very critical part over the entire life of the well. Selection of casing setting depth normally depends upon pore pressure and fracture pressure profiles, operational and well bore stability controls.

As previously calculated through U-tube effect the dummy well was completed with two casing, now we will evaluate the setting depth of our casing and well integrity under the following criterions Brent S. Aadnoy (2010)

- Limitation by mud weight to setting depth
- Oil filled scenario for burst loading calculation (intermediate/production casing)
- Reduce well integrity
- Kick margin
- Collapse loading calculation for losses occurs to thief zone (intermediate/production casing)
- Collapse during cementing
- Collapse during plugged perforations during production (production casing/liner)
- Tubing leaking scenario for burst loading calculations (production casing/liner)

Limitation by mud weight to setting depth:

According to the available pressure profiles the casing depth is determined from the bottom and keep working upward, this is known as down-up principle, by this minimum numbers of casing will be selected. As in the previous calculation based on U-tube effect, the number of casing selected was two with first casing depth at 5791meters as shown in the figure above.

Given data for following calculations

1^{st} casing: 9 5/8”

All calculations from sea level

Depth to seabed: Ds: 2286m

Depth of 1^{st} casing: Da: 5791m

Depth of next open hole section: Db: 3620m

Total depth of the well: D: 9144m

Pore pressure @ 9144m: P_o: 1.63 sg

Formation fluid density: d_o:0.76 sg

Mud density: d_{mud}: 1.8 sg

Lead Cement density: d_{cl}: 1.75 sg

Tail cement density: d_{ct}: 1.9 sg

Sea water density: d_{sw}: 1.03 sg

API design factors

Collapse design factor > 1.125

Burst design factor > 1.1

Tension design factor > 1.8

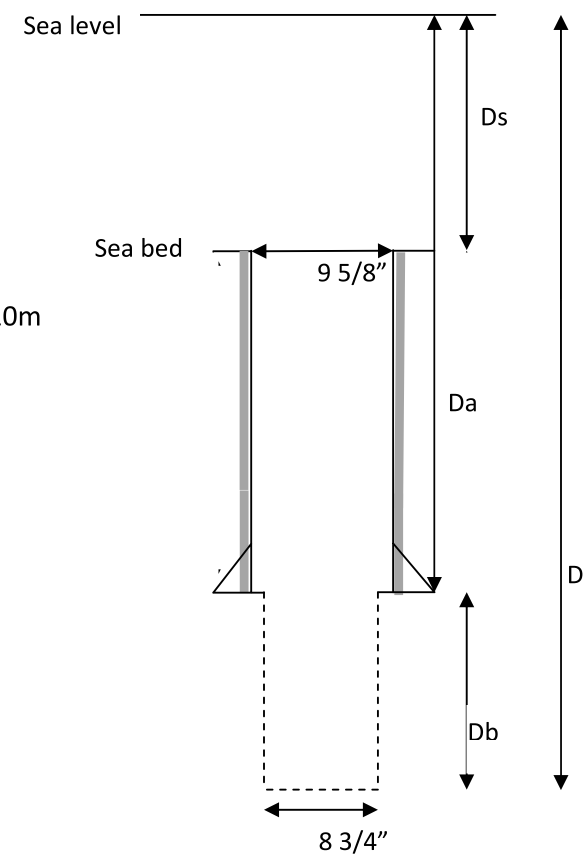

Figure 66: Typical well

Oil filled scenario for burst loading calculation:

We now in this case take the oil filled scenario and assume that there is sea water behind the casing,

External pressure at well head: 0.0981*1.03*2286=231 bars

Bottom pressure: 0.0981*1.63*9144=1462 bars

Internal pressure at well head: 1462-(0.0981*0.76*(9144-2286)) =950.8 bars

Highest burst load will be at well head i.e. 950.8-231= 720 bars

So strength required: strength/load = design factor

Strength = 1.18*720 = 850 bars

Reduce well integrity:

For this case we assume that the internal well head pressure is 950.1 bars, so at casing shoe the pressure will be:

950.8+ (0.0981*0.76*(5791-2286)) =1212 bars

In sg: 1212/ (0.0981*5791) =2.1 sg

Fracture pressure at 5791m is 1.69 sg, which means that before the pressure reaches at value of 950.8 bars, the formation below the casing shoe will fracture and casing below well head is not a weak point which is called reduced well integrity and it is acceptable for intermediate casing.

Kick margin:

In this criterion we will define the amount of kick which can be taken without fracturing our formation below casing shoe. Reason for this that although we have reduced well integrity, but still we want to establish a limit for kick so that we can save our well with any disaster.

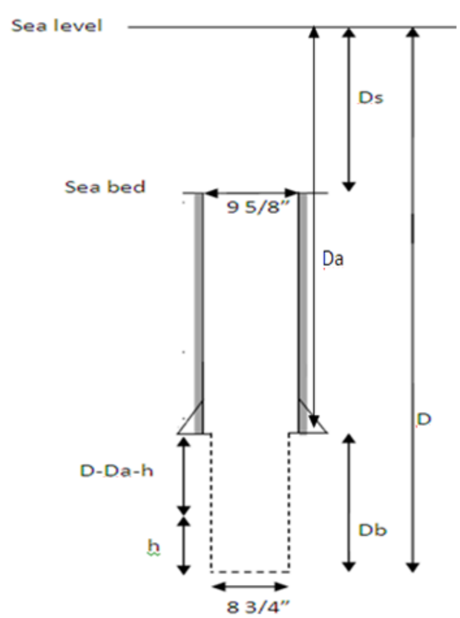

Figure 67: Kick Margin

At 5791 meter Fracture gradient: 1.69 sg

P_{frac}: 0.981*1.69*5791= 960 bars

At 9144m Pore gradient: 1.63 sg

P_o: 0.0981*1.63*9144= 1462 bars

From pressure balance we have following relation

960=1462-(0.981*.76*h)-(0.0981*1.8*(9144-5791-h))

960=1462-0.074h-592+0.176h

So, h= (960+592-1462)/0.103

Finally, h=874.5m

Hole dia: 8 ¾"=.22m

Drill pipe dia: 5"= 0.127m

Annuals area= $(\pi/4)*(0.22^2-0.127^2)$ =.025m^2

Volume= 0.025*874=21.8 cubic meter

So this is the value of maximum kick, which we can take into well without fracturing our formation below casing shoe.

Collapse loading calculation for losses occurs to thief zone:

If losses occur at thief zone, the mud level drops and become stabiles at depth equal to hydrostatic sea water pressure, or:

0.0981*1.03*5791= 0.0981*1.8*(5791-h)

585=1022.5-0.176h, So, h=2486 m

Internal pressure at 193m is zero

External pressure at 193m: 0.0981*1.03*2486= 251 bars

Collapse loading at 193m: 251-0=251 bars

Collapse during cementing:

In this case the external load is cement outside of casing all the way up to well head and we have sea water inside the casing as displacing fluid.

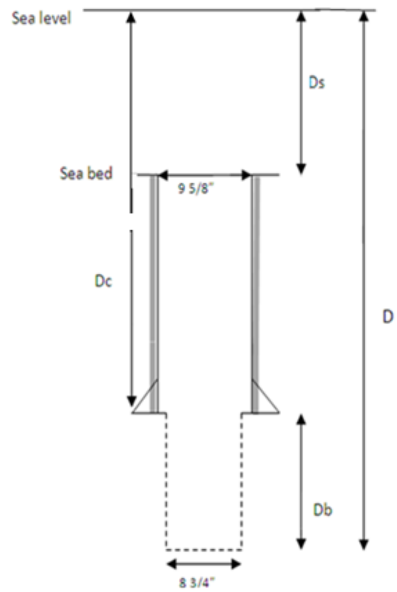

Figure 68: Collapse during cementing

The pressures are:

External pressure

At sea bed: 0.0981*1.03*2286) =231 bars

At top of tail cement: 231+ (0.0981*1.75*(4770-2286)) = 657 bars

At casing shoe: 657+ (0.0981*1.9*(5791-4770)) = 847 bars

Internal pressure

At casing shoe: 0.0981*1.03*5791= 585 bars

Collapse loading at casing shoe: 847-585= 262 bars

Duration due to biaxial forces; 10%

So, resulting collapse load: 262/0.9= 291 bars

So required strength: 1.125*291= 327.5 bars

The next two scenarios which we will discuss are related to production liner i.e.

- Collapse during plugged perforations during production (production casing/liner)

- Tubing leaking scenario for burst loading calculations (production casing/liner)

For Production liner

Given data for following calculations

Production liner: 9 5/8”

All calculations from sea level

Depth to seabed: Ds: 2286m

Depth to production packer: Dp: 8900m

Depth of 1st casing: Da: 5791m

Depth of production liner: 9144m

Length of production liner: 3620m

Pore pressure @ 9144m: P_o: 1.63 sg

Formation fluid density: d_{res}:0.76 sg

Mud density: d_{mud}: 1.8 sg

Cement density: d_{ct}: 1.9 sg

Sea water density: d_{sw}: 1.03 sg

Completion fluid density: 1.1 sg

API design factors

Collapse design factor > 1.125

Burst design factor > 1.1

Tension design factor > 1.8

Collapse during plugged perforations during production:

In this case we assume that our well is in production and perforations get plugged, so we will take formation pressure as an external pressure and formation fluid as an inside the casing.

External pressure at casing shoe: 0.0981*1.63*9144=1462 bars

Internal pressure at casing shoe: 0.0981*0.76*9144=681.7 bars

Collapse loading: 1462-681.7=780 bars

Design factor: 1.125

Strength=1.125*loading

Strength=1.125*780=878 bars

Tubing leaking scenario for burst loading calculations:

In tubing leaking scenario we assume that production tubing is completely filled with formation fluid and well is shut in. tubing leaking occur below well head and all pressure transmitted to annulus which is filled with completion fluid. So point of concern is the casing above production packer must be able to withstand the high internal pressure.

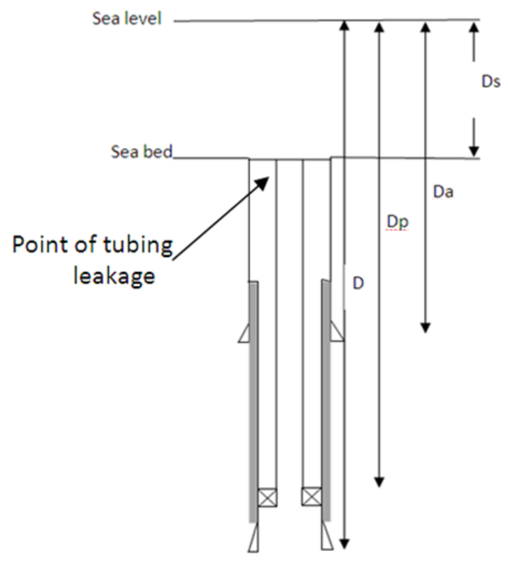

Figure 69: Tubing leaking scenario

Formation pressure at 9144m: 0.0981*1.63*9144=1462 bars

At well head: 1462-(0.0981*0.76*(9144-2286)) =951 bars

Pressure above packer: 951+ (0.0981*1.1*(8900-2286)) =1664.4 bars

External pressure at packer: 0.0981*1.03*8900=899.2 bars

Burst loading above production packer: 1664.4-899.2=765 bars

Design factor: 1.1

So, strength: 1.1*loading

Strength: 1.1*765=842 bars

3.3 Casing performance calculation

In this section we will check the performance of different casing to select the best available casing. The table 2 include all the calculated collapse and burst strength of three different casing grades for 9 5/8” casing. The casing grades evaluated is M65, L80, T95 and P110. Note here that wall thickness is also playing an important role, so we have to select the casing grade with optimum/minimum wall thickness to provide better access for the future intervention.

Casing Grade	Minimum yield strength-psi	Minimum ultimate tensile strength	OD inch	Wall thickness inch	D/t	Collapse bars	Burst bars
M65	65000	85000	9.625	0.352	27.34	315.591	428.4
M65	65000	85000	9.625	0.545	17.66	478.458	663.2
M65	65000	85000	9.625	0.609	15.8	530.875	741.1
L80	80000	95000	9.625	0.352	27.34	388.419	478.8
L80	80000	95000	9.625	0.545	17.66	588.871	741.3
L80	80000	95000	9.625	0.609	15.8	653.385	828.3
T95	95000	105000	9.625	0.352	27.34	461.248	529.2
T95	95000	105000	9.625	0.545	17.66	699.284	819.3
T95	95000	105000	9.625	0.609	15.8	775.894	915.5
T96	95000	105000	9.625	0.734	13.11	922.185	1103
P110	110000	125000	9.625	0.352	27.34	534.076	629.9
P110	110000	125000	9.625	0.545	17.66	809.697	975.3
P110	110000	125000	9.625	0.609	15.8	898.404	1090

Table 2: Casing performance calculation

Note that T96 with wall thickness 0.734” also satisfies the strength demand but here we will select P110 because the wall thickness is 0.609” which provide better space for future drilling and intervention.

3.3 Well Control

In this section we will evaluate the case in which a kick is taken and detected, we will use driller’s method to circulate kick out of the well for conventional riser drilling (CRD) and then for comparison we will try to establish a way to circulate kick out of the well for riserless drilling (RD). We will use the same dummy well for our evaluation and see the results for both CRD and RD. In his paper Jonggeun Choe (1999) compared CRD and RD[3], which is given below.

After our evaluation we will try to establish such comparison.

Sr. No.	Conventional Riser Drilling	Riserless Drilling
1	Drilling	Drilling
2	Taking kick	Taking kick
3	Stop drilling	Stop drilling
4	Kick detection	Kick detection
5	Stop surface pump and well shut in	Slow down subsea pump and keep pumping
6	Circulate kick out	Pump kick out

Table 3: Comparison of both methods during taking kick[3]

Let us assume that a kick is taken at 9144m depth, by primary and secondary indicators it is detected and we have stopped the kick with use of either of three methods mentioned by Jonggeun Choe (1999)[3]. The final stage of this well control scenario is to circulate the kick out of the well in safe and economical manner, so we use following data to calculate the time it would need to circulate the kick out of the well for both CRD and RD.

Given Data:

Depth: 9144m

Depth to seabed: 2286m

Last casing: 5944m

Drill collar section: 300m

Drill pipe dia: 5”= 0.127m

Open holedia: 8.75”= 0.22m

Casing inner dia: 9.625”= 0.24m

Drill pipe capacity: 9.15 lit/m

Drill collar capacity: 4.0 lit/m

Annular capacities

Drill Pipe/Riser:180 lit/m

Drill Pipe/Casing: 34.3 lit/m

Drill Pipe/Open Hole: 25 lit/m

Drill Collar/ Open Hole: 15.2 lit/m

Kill pump: 18.2 lit/stroke

Pump strokes; 30 spm (stroke per minute)

Kill rate: 18.2*30=546 lit/min

For Conventional Riser Drilling

Original mud in the well: 1.68sg

Well friction during pumping a kill mud (Sr): 10 bars

Safety factor (Sm):10 bars

SIDPP: 15 bars

SICP: 20 bars

Ppore = SIDPP+ hydrostatic mud in Drill pipe =15+1.68x0.0981x9144=1522 bar.

Kill mud density = (1522+10)/(9144x0.0981)= 1.7 sg.

Initial circulation pressure (ICP) = SIDPP+Sr+Sm=15+10+10= 35 bar,

Final circulation pressure (FCP) = 1.7xSr/old-density=1.7x10/1.68= 10.11 bar.

Sections	Calculations	Volume (liters)	Strokes	Time (min)
Drill-pipe section	(9144-300)x9.15	80922		
Drill Collar	300x4.0	1200		
Drillpipe+BHA		**82122**	**82122/18.2 =4512**	**4512/30= 150**
DC/OH	300x15.2	4560		
DP/OH	(3200-300)x25	72500		
DP/Csg	3658x34.3	125469		
DP/Riser	2286x180	411480		
Annulus		**614009**	**614009/18.2=33736**	**33736/30=1124**
Total		**696131**	**38248**	**1274 min**

Table 4: volume calculation for conventional method

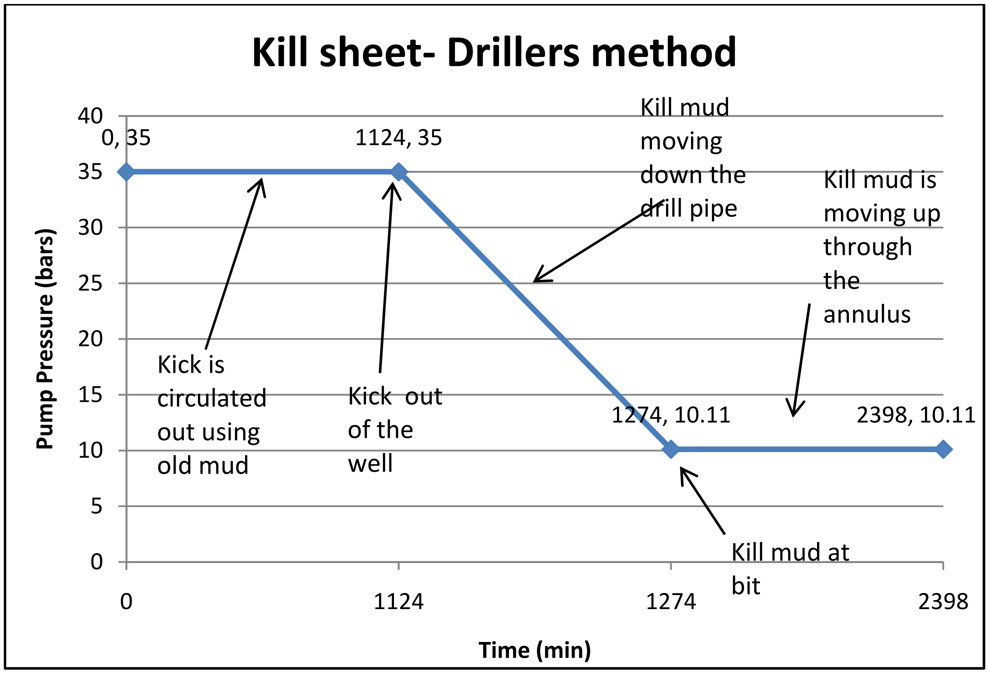

Figure 70: Kill sheet driller's method

So the total time it takes to circulate kick out of the well and kill it with heavy weight mud is 2398 min: 39 hrs and 58 minutes.

In next step we will evaluate the same case but with Riserless Drilling scenario.

For Riserless drilling:

Given data:

Everything will be same except the following data

Depth to last casing: 5791m

Mud weight: 1.8sg

Apparent mud weight: 1.7sg

Even for the dynamic kill method, SIDPP can be obtained as discussed by JonggeumChoe (1999)

Solution:

$\Delta P_{over} = \Delta P_{sp} + \Delta P_{f,ann}$

Where

ΔP_{over}= formation over pressure

ΔP_{sp} = increase in SPP= 15 bars

$\Delta P_{f,ann}$ = friction pressure loss in annulus= 10 bars

ΔP_{over}= 15+10=25 bars

Kill mud weight can be calculated by the formula (Jonggeum Choe)

$$\rho_{km} = \rho_m + \frac{\Delta P_{over}}{0.0981(D - D_w)}$$

Kill mud density: 1.7+ [25/ (0.0981*(9144-2286))]

=1.737 sg

Initial circulation pressure (ICP) = ΔP_{over} = 25 bar,

Final circulation pressure (FCP) = 1.737xSr/old-density=1.737x10/1.7= 10.21 bar.

Because we have closed loop system with adjustable choke at subsea mud pump by which we can change the apparent mud weight of the whole system, so here we only need to adjust the subsea choke to in increase our hydrostatic weight by 15 bars and start circulating the kick out of the well.

Sections	Calculations	Volume (liters)	Strokes	Time (min)
Drill-pipe section	(9144-300)x9.15	80922.6		
Drill Collar	300x4.0	1200		
Drillpipe+BHA		**82122.6**	**82122.6/18.2 =4512**	**4512/30= 150**
DC/OH	300x15.2	4560		
DP/OH	(3200-300)x25	72500		
DP/Csg	5944x34.3	203879		
Annulus		**280939**	**280939/18.2= 15436**	**15436/30=515**
Total		**363061.6**	**7057**	**665 min**

Table 5: Volume calculation for riserless drilling

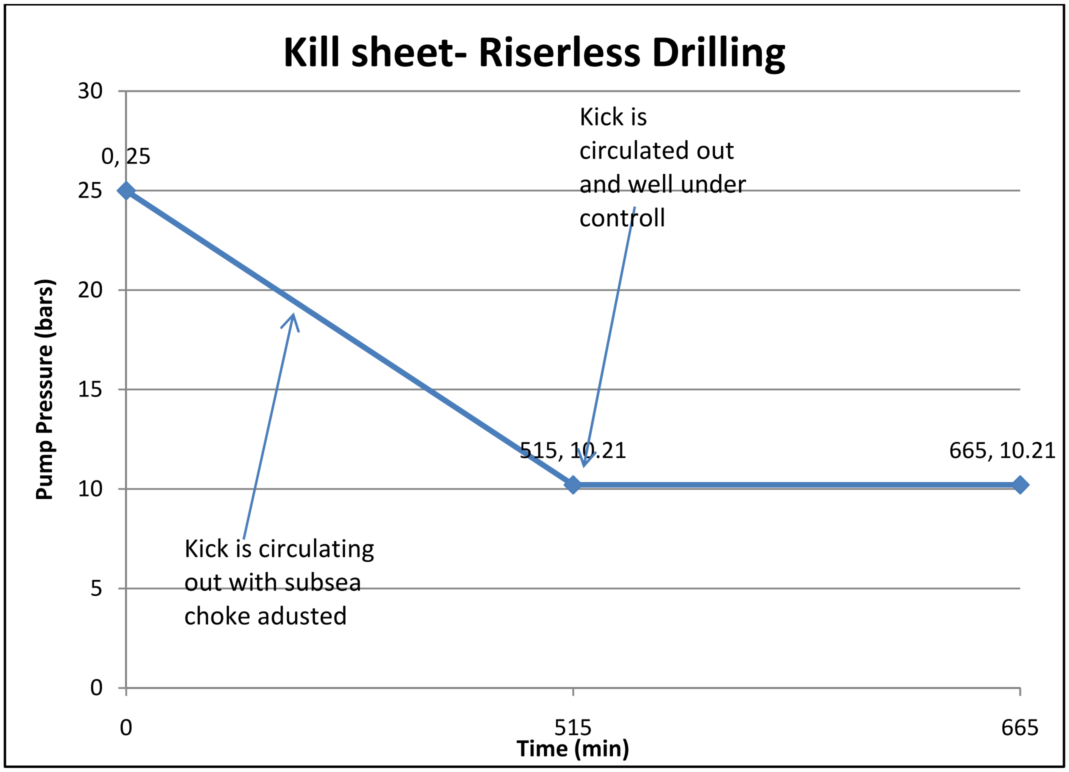

Figure 71: Kill sheet riserless drilling (MPD choke control)

So the total time it takes to circulate kick out and to control the well is 515 min: 8 hrs and 35 minutes.

Comparison between Riserless drilling and conventional riser drilling

At last we compare conventional riser drilling with riserless drilling.

Sr. No.	Conventional Riser Drilling	Riserless Drilling
1	Kick detection by conventional method requires more time	Quick kick detection by return rate difference, subsea pump rate, SPP increase
2	Large economics involve for kill mud (**696131 liters**)	No additional kill mud requires to kill the well.
3	Extra space requires to accommodate kill mud	No worries for kill mud space
4	Time need to control well: **39 hrs 58 minutes**	Time need to control well: **8 hrs 35 minutes**
5	Requires normal 400 ton 18 ¾" BOP	200 ton 13 5/8" BOP can be used, which increase our savings
6	Additional mud cost to fill riser	No additional mud required

	annulus	
7	Economical mud loss during Pumping and Dumping	No pumping and dumping

Table 6: Comparison between Riserless drilling and conventional riser drilling

References

1. Brent S. Aadnoy, SPE, Univ. Of Stavanger; Eirik Kaarstad,SPE, Univ. Of Stavanger; Mesfin Belayneh, SPE, Univ. Of Stavanger.: "Casing Depth Selection Using Multiple Criteria" IADC/SPE 150931, Presented at IADC/SPE Drilling Conference and Exhibition held in San Diago, California, USA, 6-8 March 2012.
2. David Dowell, Chevron North America Exploration and Production Company.: "Dual Gradient Drilling The System" DEA Presentation, June 23, 2011
3. JonggeumChoe, SPE, Seoul Natl. U.: "Analysis of Riserless Drilling and Well-Control Hydraulics" SPE 55056, Drill & Completion, Vol. 14, No. 1, 1999

4 Summary and recommendation

4.1 Summary

The summary and the conclusion in this section is based on our formation pressure profiles (pore pressure, fracture pressure), reservoir fluid and completion fluid properties. The first task was to develop a formation pressure profile. The Down-up principle was used to calculate the appropriate number of casing strings to complete a well. The well was successfully completed with five casing strings

In second step we used the dual gradient method to complete the well. The results were quite satisfied. The well which needed five casing to be complete is only requiring now three casings to complete. This will result in

- Huge amount of savings in terms of casing
- Drilling time reduction
- Mud cost reduction
- Better well control
- Reduced non-productive time

In the third step we took the zero well head condition and apply back pressure to control the whole drilling program. The main idea was to apply sufficient back pressure to meet the formation pressure profile. It also ended up with three casing strings

With same method of zero well head pressure, we tried to utilize the U-tube effect. With this we completed our well with only two casings.

With this result we decided to go further in this and the task was to investigate whether only two casing will hold up the immense pressures. The target was to see what collapse and burst pressure we will have in this case and is there API standard casing available for the task or we have to recommend a non standard casings. For different scenarios the required pressure ratings were

- For Oil filled scenario for burst loading calculation (intermediate/production casing), the required burst strength: 850 bars
- Reduce well integrity and Kick margin: the well was under satisfactory reduce well integrity condition and kick margin calculated was: 21.8 meter^3
- Collapse loading calculation for losses occurs to thief zone (intermediate/production casing), the required collapse strength: 251 bars
- Collapse during cementing, the required collapse strength: 327.5 bars
- Collapse during plugged perforations during production (production casing/liner), the required collapse strength: 878 bars

- Tubing leaking scenario for burst loading calculations (production casing/liner), the required burst strength: 842 bars

It is found that casing P110 can be successfully handle all these pressures, so we don't have to go for any non standard casing.

In the last task we compare a well control scenario for conventional drilling (driller's method) and riserless drilling with zero well head pressure in which kick is controlled by applying back pressure through MPD choke. The result was quite encouraging and showed that:

- For conventional method, total time it takes to circulate kick out of the well and kill it with heavy weight mud is 2398 min: 39 hrs and 58 minutes.

- For riserless drilling method, total time it takes to circulate kick out and to control the well is 515 min: 8 hrs and 35 minutes.

So we can save our time up to thirty one hours and twenty three minutes.

At last we can have great benefit if we able to install 200 ton 13 5/8" BOP instead of normal 400 ton 18 ¾" BOP.

4.2 Recommendations

- Although the results from calculation showed quite promising results but still this approach must be run on any simulator for more precise results

- Equipments need to be improved. In calculation and design we assumed equipment will be able to withstand the deep water environment and also they will cope with high working pressures.

- As we have no proven record of procedure, technology and tools. So we lot of experiment and research has to be done.

- During tripping, how to get out of hole with BHP under control. The system only deals with bottom hole assembly (BHA) inside the well, but have no sufficient clues that what will happen when hole is empty, one of the suggestion is to control the well by continuous circulating system.