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Master thesis

High pressure high temperature (HPHT) well technologies while drilling

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ABBREVIATIONS

HPHT	high pressure high temperature
OECD	Organization for Economic Cooperation and Development
MWD	Measuring while drilling
LWD	Logging while drilling
BHA	Bottom hole pressure
PDC	Polycrystalline diamond
RPM	Rotation per minute
ROP	Rate of penetration
UHPHT	Ultra-high pressure high temperature
XHPHT	Extreme high-pressure high temperature
HP	High pressure high temperature
HT	High temperature
NPT	Nonproductive time
ECD	Equivalent circulation density
WBM	Water base mud
SOBM	Synthetic oil base mud
OBM	Oil base mud
WI	Wellbore instability
SEM	Scanning electron microscopy
LCM	Lost circulation material
BOP	Blowout preventer
API	American petroleum institute
TSP	Thermally stable polycrystalline
ASME	American society of mechanical engineering
SBM	Synthetic base mud
PVT	Pressure/volume/temperature
YP	Yield point
AV	Apparent viscosity
PV	Plastic viscosity
τ	Shear stress
NPs	Nanoparticles
AFE	authority for expenditure
UBD	Underbalance drilling
MPD	Managed pressure drilling
CBHP	Constant bottom hole pressure
RCD	Rotating control device
Pp	Pore pressure

Pwbs	Wellbore instability pressure
Plc	Lost circulation pressure
Pds	Pressure differential sticking
Pf	Fracture pressure
P_{ABL}	Annular pressure losses
Pbp	Surface back pressure
SBP	Surface back pressure
FITs	Formation integrity test
PRV	Pressure relief valve
NRV	Non return valve
HP	Hydrostatic pressure
g	Gravitational acceleration
ρf	Average fluid density
D	Real vertical depth
ppg	Pounds per gallon
ppf	Pounds per cubic foot
SG	Specific gravity
EMW	Equivalent mud weight
KRP	Killing rate pressure
SICP	Static initial circulation pressure
SIDPP	Static initial drill pipe pressure
ICP	Initial circulation pressure
W&W	Wait and weight
P_B	Bottom hole pressure
Pa	Annulus pressure losses
Pd	Drill pipe pressure losses
P_{CL}	Chock line pressure losses
t	Circulation time

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ABSTRACT

The goal of this research is to discuss the various objective of using Innovative drilling technologies in high pressure and high Temperature wells. The gas and oil Industry is growing rapidly and becoming more demanding because of the new reserves are being found in difficult atmospheres. Wells are being drilled at higher depth under High Pressure and Temperature situations (HPHT) which requires reliability of system to resolve the complexity because of High pressure and Temperature.

Now a day HPHT is very famous word in petroleum industry. With higher pressures and temperatures, moving into deeper wells shows up the operating working window limited and therefore much problematic than conventional wells. Few of the problems are found in this work when coping with a well setting in HPHT. Well control knowledge is required to maintain a secure and safe well during drilling operations. Selection of BOP's is much important during the well control of HPHT wells.

During operations of conventional well, it is important to maintain the well pressures in the formation just above the pore pressure and below the fracture pressure. This is to prevent the formation fluids inflow within the wellbore or into the formation of drilling mud. Therefore, the diagnosis of pore pressure is quite essential in the design of the casing and drilling mud. By using MPD & UBD technologies we came across to mitigate the many problems during the drilling operations.

This thesis is divided into five chapters and mainly concentrated on the well control and drilling operations under high pressure and temperature scenarios. The effort is made to complete this study to discuss the main considerations of HPHT wells.

The first chapter gives a brief summary of High pressure and High Temperature wells. It also provides the information about classification of HPHT wells, their challenges and Technological gaps in the industry related to HPHT wells.

The second chapter explains the drilling fluids and their selection criteria in HPHT wells. This chapter discusses the various types of drilling fluids used while drilling in HPHT zones and

also concentrated on selection of drilling fluids and their related problems. It also explains the behavior of drilling fluids and their rheological parameters and their effect on high temperature and pressure.

The third chapter is mainly focused on the wellbore instability and related issues. It explains the problem related to the wellbore instability and prevention techniques in order to avoid the wellbore instability under high temperature and pressure condition.

The fourth chapter highlights the drilling operations and their working in HPHT conditions and zones. This chapter is mainly about the use of drilling techniques under high pressure and temperature condition and the tools used. It discusses the use of MPD and UBD and their comparison in HPHT wells.

Lastly, the Fifth chapter represents the most important aspect of petroleum industry i.e. well Control. this chapter includes the aspects of well control aspects are explained, mainly with focus on kick detection, kick causes and the well kill methods and procedures and the prevention techniques to avoid major accidents.

1.1 CHAPTER ONE: INTRODUCTION AND HISTORICAL BACKGROUND OF HPHT WELLS

1.2 What is HPHT?

The HPHT well is defined as; it is a type of well in which the uninterrupted bottom hole temperature at depth of reservoir is higher than 300 °F which drills the porous formation with maximal pore pressure and exceeds the hydrostatic gradient of 0.8 psi/ft (Shows an EMW of 1.85 SG) or BOP with working pressure rate above 10M. (Shadravan & Amani, 2012).

Oil and gas industry has gained a significant attention worldwide due to the recent improvement in the drilling field where, most of the wells are being drilled with different methods and techniques and drilling under HPHT condition is one of the interesting and demanding challenge for both researchers and drillers. In addition, oil sector studies shows that approximately around 100,000 wells drilled globally in year 2012, and recent studies have made the estimates more accurate, about 1.5 percent should be categorized as HPHT. Even though these wells are comparatively small, they often represent considerable resources and mostly exist in regions in which exploration is ongoing in new horizons (Smithson, 2016).

1.3 Background of HPHT Wells

In a broad range of important services, including power generation, transport fuels, and consumer products, oil and gas continues to be used (Bland et al., 2006). Driven by increase in the population and consumer purchasing power in developing economies, overall global energy consumption of oil and gas (Douglas Westwood, 2014) is expected to rise by 34%, from today to 2030. The Organization for Economic Cooperation and Development (OECD) estimates that demand has been growing speedily since 1990 with higher oil and gas prices in recent years. This is because of a gradual slow down trend in the search for new oil and gas reservoirs, and the market is heading towards high risks and more challenging conditions that meet demand of global energy (Bland et al., 2006). This demand is mainly recognized for the development of oil and gas fields particularly focusing on Complex subsea /deep-water and ultra-deep-water (Douglas Westwood, 2014).

The extreme situations may be categorized as (i) Deepwater wells and (ii) wells of high - Pressure and temperature because these types of wells need a combination of various well planning and special tool specifications for exploration (Alemi et al., 2018).

Several governments even in the past given an incentive scheme for oil and gas contractors, as in the United Kingdom and Norway.(Douglas Westwood, 2014)

The places with a large number of such field types are the continental shelf of the deep-water Gulf of Mexico(Ruiz, 2016) , northern India (Shadravan & Amani, 2012), Saudi Arabia (Wagle et al., 2018) and Brunei (Bland et al., 2006). Thailand, Indonesia and northern Malaysia have also exceeded the number of high pressure and high temperature fields under development (Shadravan & Amani, 2012).

At present, the biggest challenges for oil and gas exploration is to operate under conditions of HPHT , that can also be characterized as temperatures higher than 150 ° C (300 ° F) and bottom hole pressure greater than 69 MPa (10,000 psi) (Joshi & Lee, 2013). These extreme conditions, when experienced at the time of drilling operations, cause massive fluid system problems and annular pressure limits while drilling (PWD), and also measure while drilling/logging while drilling (MWD/LWD) tools (Bland et al., 2006).

The growth of the petroleum industry emerges from the continuous discovery of hydrocarbons in new and unexplored areas. In terms of temperatures, pressure and depths, the search for hydrocarbons has become more challenging in extreme environments, contractors and service companies are pushing forward with new HPHT drilling technologies and innovations. (Shadravan & Amani, 2012).

A variety of innovations and developments are ongoing in pipeline to give relief to the industries in order to access hydrocarbons that once were considered too complicated to access in the search of natural gas and oil, oil industry has spent a great deal and recently reached to an agreement: there is no production of undiscovered fields in offshore environments. Thus, according to Simmons, the new solutions and developments to deep HPHT well drilling is important to achieve the engineering requirements while keeping the projects economically feasible. Key aspects well drilling above 20,000 ft, sub-salt drilling, very short drilling windows, operational difficulties such as circulation loss, stuck pipe and well-control problems are much more likely while drilling in HPHT environments. (Joshi & Lee, 2013).

The most specific HPHT definition is that when the pressure is greater than 10 000 psi (690 bars) and the temperature is higher than 300 ° F (149 ° C). As per research, HPHT will be defined in the near future when the pressure exceeds 15 000 psi and the temperature exceeds

300 ° F. New categories were therefore developed to help define operating conditions of HPHT, stable operating systems and technological gaps. Such HPHT classifications are divided into three main tiers. The Tier I applies till present to water wells with initial reservoir pressure between 10,000 -20,000 psi and/or reservoir temperatures between 300 - 400 ° F, some HPHT operations in shale plays and most of future HPHT deep-water gas / oil related to Tier I generally in the Gulf of Mexico. (Joshi & Lee, 2013).
Kristin fields, with a reservoir pressure of 13200 psi and a temperature of approximately 350 ° F, are considered to be HPHT fields in Norway. Tier II is known as "Ultra" HPHT and involves a reservoir with pressure higher than 20,000 less than 30,000 psi and /or the range of temperature between 400 -500 ° F. various deep gas reservoirs on U.S. land and on the continental Gulf of Mexico fall in this category. Tier III include "extreme" HPHT wells having reservoir pressures ranging from 30 000 - 40 000 psi and/or temperatures ranging between 500 - 600 ° F (Payne et al., 2007).

1.4 Well planning in HPHT condition

Whereas High Pressure High Temperature (HPHT) wells compensate just 1-3 % of the total wells being drilled, this practice is worldwide and has received significant attention. The development of some of these reservoirs primarily depends on the capacity of service companies to drill, analyze and complete wells under HPHT conditions. Recently, demands for the provision of HPHT-enabled and effective equipment from directional drilling service companies have appeared in a number of drilling and assessment tenders in different regions of the world.

Operating companies are familiar of the challenges involved with durability of downhole equipment under HPHT scenarios. Fig.1.1 shows the drilling activities of HPHT locations. Reliability of downhole equipment in HPHT wells remains a significant challenge for the oil and gas sector. The upstream service companies of gas and oil are involved in the production of wells are impacted by reliability problems. The petroleum industry has already been in process of developing Bottom Hole Assembly (BHA) of HPHT components for generations (Ahmad, Akimov et al., 2014).

The below graph shows all the drilling operations worldwide

Figure 1.1 : Location of HPHT market around the globe (Ahmad, Akimov et al., 2014)

1.4.1 Evaluation Capabilities Limitation

- Some tools operate on wireline at 425 ° F; quite small tool accessibility on wireline at 425 - 450 °
- For MWD applications, battery technology operates at 400 ° F (mercury).
- For increased temperature the accuracy of sensors decreases.
- LWD / MWD tools are accurate to 275 ° F with a significant fall in durability to 350°F

1.4.2 Producing Zone Low ROP

- In this environment bits basically remove 10 percent of the rock per bit rotation compared with normal drilling conditions for wells in the Gulf of Mexico.
- At these conditions, crystalline structure starts to break-down in PDC-bits. (Issue of boron expansion).
- Bits of the roller-cone are inadequate for this situation.
- Impregnated cutters are quite often slow to drill.
- By increasing rpm, the ROP increased by enhancements in motor and turbine design.
- Torque seems to be the primary issue, though seal work less Moy no pumps provides the highest torque solutions.
- Optimizing the dynamics of the bit, motor and mud and drill string like a system offers opportunities for improving reliability and penetration rate. (Proehl & Sabins, 2006)

1.4.3 Well Control

- The drilling window is indeed very limited, and it can create potential problems with well-control.
- Drilling fluid loss is a lithological and geo-pressure problem.
- Storage of mud due to ballooning hole.
- Methane and H2S (hydrogen sulfide) solubility in oil-based mud;
- Design of Well head is currently 15,000 psi and 350 ° F. A work is in progress for equipment of 20,000 psi, 350 ° F.
- Design of Wellhead needed at 25,000 psi, 450 ° F (Proehl & Sabins, 2006).

1.5 High-Pressure High Temperature Operations Classification

The Classification system depend upon temperature and pressure boundaries representing the stability limits of Schlumberger's common components, including seal elements and electronics hardware . The HPHT-hc classification explains improbable conditions for oil and gas wells, while geothermal wells that surpass 500 ° F and even some deep-water wells having Downhole pressure at depths of more than 35,000 psi (Smithson, 2016).

Description of the classification of the field may rely on the area, operator and service provider (Payne 2007). Many service companies and operators are defining the range of temperatures and pressures for their tools, fluids, equipment and cement in compliance with operating limitations (Shadravan & Amani, 2012).

For Instance, (Payne et al., 2007) Payne et al. stated that offshore magazine performed a study of 239 MWD / LWD tools from 12 multiple contractors with the goal of obtaining a rating for the best MWD / LWD technologies for high temperature operation.

For most MWD tools the average operating temperature is 150 ° C (302 ° F), with only 23 tools approved with 175 ° C (347 ° F) operations. Because of that, companies have several operational work boundaries, so HPHT classification could be different for them as well.

Thus according to Greenaway (Greenaway 2008) from Schlumberger industry, as shown in Figure 1.2, HPHT conditions can be defined as fields with bottom hole temperatures higher than 300 ° F (149 ° C) and borehole pressure more than 10,000 psi (69 MPA) (DeBruijn et al., 2008). In order to be considered ultra HPHT situations, wells will need to establish temperatures between 204.44 ° C and 260 ° C (400 -500)°F and a pressure vary significantly from 20,000 psi to 35,000 psi (Stamatakis et al., 2012). Lastly, for extreme HPHT, which include borehole temperature ranges from 260 ° C to 315,55 ° C (500 ° F to 600 ° F), and borehole pressure higher 35,000 psi.

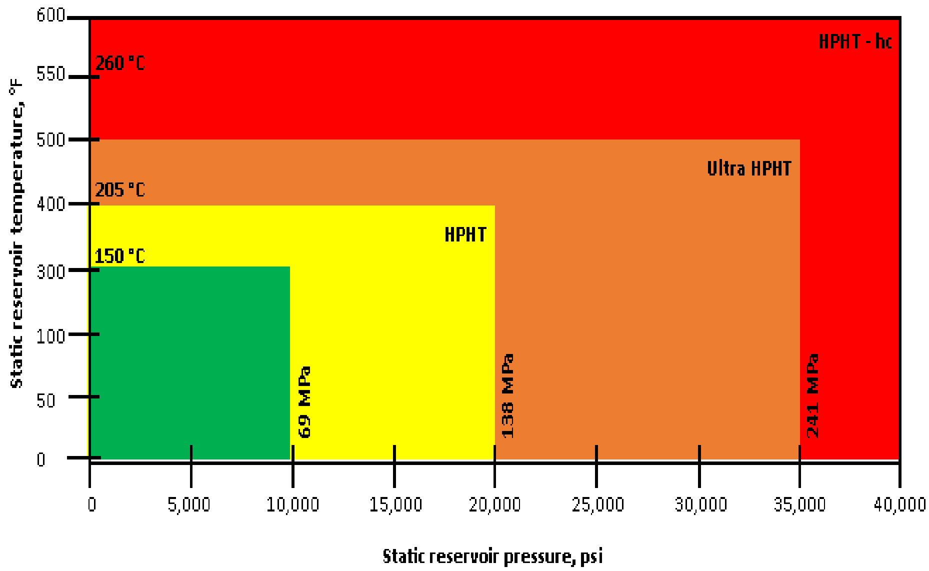


Figure 1.2 Modified form of HPHT Tiers (DeBruijn et al., 2008)

Table 1.1 and 1.2 demonstrate the different operating range of temperature and pressure measurement recognized by services companies of various oilfield. There are similarities among the various companies, as shown in the tables below.

Table 1.1 Modified HPHT Borehole Temperature (Shadravan & Amani, 2012)

Borehole Temperature						
Temperature						
HPHT operations	**Halliburton**		**Baker**		**Schlumberger**	
	°F	°C	°F	°C	°F	°C
	300-350	150-175	300-350	150-175	300-401	150-205
Extreme HP/HT	350-400	175-200	350-400	175-200	401-500	205-260
Ultra HP/HT	> 400	> 200	> 400	> 200	> 500	> 260

Table 2.2 Modified HPHT Borehole Pressure (Shadravan & Amani, 2012)

Borehole Pressure						
Pressure						
HPHT operations	**Halliburton**		**Baker**		**Schlumberger**	
	Psi	Mpa	Psi	Mpa	Psi	Mpa
	10,000-15,000	69-103	10,000-15,000	69-103	10,000-20,000	69-138
Extreme HP/HT	15,000-20,000	103-138	15,000-20,000	103-138	20,000-35,000	138-241
Ultra HP/HT	> 20,000	> 138	> 30,000	> 207	> 35,000	> 241

The presence of a high temperatures is obvious, but a normal pressure well is probable and vice versa. Additionally, as exploratory drilling advanced, wells with progressively higher pressures and temperatures were found, resulting in a demand for new classifications as illustrated in Figure 1.3 below:

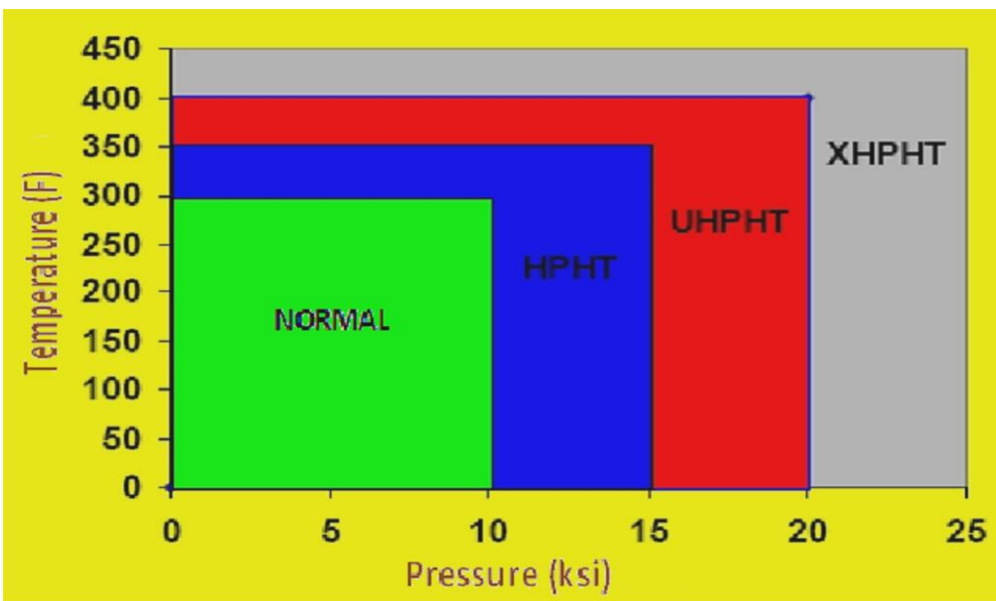


Figure 1.3 HPHT Classification (Shadravan & Amani, 2012)

• High Pressure High Temperature (HPHT)

• Ultra HPHT (UHPHT)

• Extreme HPHT (XHPHT)

Seek for hydrocarbons has led the oil and gas industry to drill for oil in even more severe environments at extreme high pressures and high temperatures (HPHT). These conditions are commonly referred to as HPHT environments and are typically defined on the pressure and temperature scales as seen in the table 1.3 below.

Table 1.3 the pressure and temperature scales of HPHT

	PRESSURE			TEMPERATURE	
	Kpsi	**Bar**	**Kg/mm2**	**°C**	**°F**
HP/HT	10-15	689-1034	7-10.5	150-180	300-350
UHP/HT	15-20	1034-1379	10.5-14	180-204	350-400
XHP/HT	20-30	1379-2068	14-21	204-260	400-500

This is known that the biggest problems usually occur where there is a mix of HP and HT. The relationship among the two is not a linear one. The industry helps to develop reservoirs by ever-increasing pressures and temperatures, and that it is recognized that 350 degrees F and 25.000 psi are a modified step - by - step in the specification of the equipment and the implications of these changes. Additionally, to high pressure and temperature, these reservoirs may also have characteristics of complexity and connectivity (Shadravan & Amani, 2012).

1.6 HPHT Drilling Challenges

While dealing with an HPHT well, we have several challenges; one is because of the narrow margin between the pressure of the fracture and the pressure of the pore which requires extensive control of the BHP. The effects of temperature, pressure and ballooning in a HPHT condition can often be very much challenging.

HPHT drilling technological principles are effective tools for designing, preparing and construction of HPHT wells. Formation pressure forecast, fracture pressure measurement, depth of casing setting, rheological performances of drilling fluid, hydraulics, selection of bit and cementing programs all must be thoroughly adjusted for HPHT drilling conditions. In addition, unconventional drilling methods like casing-drilling and managed pressure drilling could be used to reduce non - productive time (NPT) and result in safer drilling. Daunting difficulties such as; limited assessment capability, low ROP in production areas, well control and non -productive time have been of main consideration for drillers in the design and construction of HPHT wells.

In general, the sensitive nature of HPHT wells is important for drilling crew to really be highly alert so that things are done as safely and effectively as necessary. For accurate result, proper communication in between driller, the team of mud logging and the well pressure measurement equipment operator is very essential. Furthermore, even after the pumps have shut down, pressure, temperature and tank volunteers eventually change. The drilling team probably uses a "decision tree “which relies on the series of events that have taken place during the well-shut-in and the reports of annular and surface pressures, it is possible to detect whether the incident is a kick or some other phenomenon likewise a ballooning or breathing formation (Auwalu et al., 2015).

1.6.1 Temperature effect

In high temperature wells, we have effect of temperature. Probably as a result of temperature, the density of the drilling fluid changes in the depth of a well. This effect of High temperatures will reduce the mud density, however if the well has been influenced by high temperatures, the effective mud weight of the downhole will be smaller than what you see on the surface. In certain situations, the temperature effect can be easily mixed with a kick event and as a result increase in the amount of mud on the surface.

This could be hazardous during drilling operations as we will get an appropriate mud weight down into the well which is smaller than what we see on the ground, which indicates that the risk of an underbalance condition is greater (Rommetveit et al., 2003).

If we have an underbalanced at drilling time, in the wellbore the formation fluids will begin flowing, in order to prevent kicks, the mud weight of efficient surface can be adjusted to obtain the required effective weight of mud down the hole.

While we have static conditions into a well the temperature of mud reaches the geothermal temperature of the well, the drilling mud temperature of the will change quickly depends on the operation. As we begin to flow into the well, cold mud come out of the drill string reaches the annulus where warm mud flows into the top of the annulus. This results in a rapid change in density and rheology of mud at various locations in the well, resulting the change in ECDs and changes in mud volumes in the surface (Aadnoy, 2006).

1.6.2 Pressure effects

For HPHT wells, hydrostatic pressure differences are greater than in normal wells for drilling. It is because of variations in density of mud caused by pressures and temperatures. High pressure raises the mud density and the downhole mud weight is greater than that measured on the surface, if the well is dominated by higher pressure. We often encounter pressure effects as a result of rheology change, first we experience frictional variations due to temperature effects causing rheology variations and even changes in rheology can lead to transitions within flow schemes that lead to increased frictional pressure losses (Rommetveit et al., 2003).

1.6.3 Ballooning

HPHT wells are typically deeper as compared to the conventional wells; hence we can observe ballooning effect. Ballooning effects may occur when the return volume of mud rapidly changes, with an excessively low or high rate of return. Such unusual kicks will force the driller to shut-down the well if it is not necessary. Furthermore, the ballooning effect needs to be separated from scenarios where we can have a mud loss or a kick into the formation. When we look at the well in both the dynamic and static conditions, we can encounter the ballooning effect (Aadnoy, 2006).

Shale ballooning is also one of the effects. Whenever the pumps into a well are enabled, we lose pressure in the annulus and the hydrostatic drilling pressures generate excess pressure in the well on the formation of shale. If the pumps are switched off, the pressure on the shale decreases, which may result a slight decrease in the well's diameter leading to a rise in the volume of mud from the well. It can be described as a kick, which leads to a successful shutdown of well. The ballooning effect appears often in conventional wells but is far more prevalent in HPHT wells since they mostly have a greater depth (Karstad, 1998) & (Paula et al., 2009).

1.6.4 Undetected kicks

There is a risk for HPHT wells, that the oil-based mud will cause small undetected kick, because of totally dissolves gas influx and is hidden with in mud. In the present scenario, we won't observe a change in the volume of pit as the influx rises to the surface till free gas begins to boil out. Then the pit volume will increase sharply, and we will shut down as quickly as possible. It is indeed very essential that the kick does not really hit the riser, which leads to an extremely risky situation, as we can no further are unable to lead the kick away from the initial platform. Once free gas begins to bubble-out of the solution, the BHP can decrease, which will lead to new kick situation into a well.(Ng, 2009)

1.6.5 Safety

Control of Pressure and temperature is the most difficult safety issue in HPHT reservoirs. All operations, including drilling, completion and well of well, exposes the equipment to a difficult operating condition. Operating conditions often exceed the upper limit of hardware requirements thus improving the risk of failure of tool or metal fatigue resulting in a loss of rig time, cost overruns and increased cost of replacement. Standard operating procedures (SOPs) must be defined and properly enforced to guarantee safe and effective operations. Quality control measures should be developed for all products and equipment so as not to exceed operating pressure and temperature limits.

1.6.6 Drilling Fluid

In the exploration phase important interpretation of lithology, formation tops, and the associated drilling challenges and operational dangers should be obtained during the well drilling. High temperatures therefore have significant effect the rheology of mud which is directly related to drilling efficiency by influencing cuttings suspension and hydraulics of well. It is important to have a well-designed mud programme. A successful mud system retains favorable rheological properties at higher temperatures and balances the weight of mud to maintain minimal invasive formation pressure and achieve a sufficient penetration rate (ROP) into the wells. During production, water-based mud (WBM) was drilled at all intervals above the portions of the reservoir-The mud system was turned over to a synthetic oil-based mud (SOBM) before reaching the reservoir portion.

Oil-mud is quite appropriate for water-sensitive shale. In addition, oil is the constant phase, in which water is distributed: the whole mud results in a non-reactive shale. However, if water is distributed, however, it is important to provide adequate salinity to stop migration of water into the shale before dehydrating it. Through field experience the suitable salinity was measured. Usually, oil-mud results in quick drilling than water-based mud yet giving excellent stability of shale. Oil-mud is suitable for drilling formations whereby BHT crosses tolerances of WBMs, particularly in contaminants presence, such as water, gases, cement, salts, at above 550 ° F.

The oil mud has a thinner filter cake which reduces the friction among wellbore and pipe, therefore reducing the risk of sticking and is particularly suitable for horizontal and highly diverged wells. The oil present is the outer phase which reduces the corrosion of the pipe and behaves as a pipe coating. The most important corrosion properties are the fact that oils are non - conductive, that additives are stable thermally and don't really create corrosive products, and that bacteria do not grow in oil mud. SOBM was selected over OBM, however, as SOBM is more easily bio-degradable than OBM & viscosity at normal conditions is significantly greater than OBM, least toxic than OBM & gives better hole gauge and good logging atmosphere (Shah et al., 2012).

1.7 Future need of HPHT

Many of Important innovations implemented over the past few years allow operators to address many of the challenges presented by HPHT projects and conditions with confidence. As HPHT activity keeps rising and conditions of well become quite serious, it will need other advanced devices and materials.

Engineer's teams are working on translating significant advancement with wireline logging from HPHT into the MWD / LWD atmosphere. Should not only the measuring systems bear higher pressure and temperature, but they must also perform constantly when subjected to shocks and vibrations affiliated with operations of drilling. The aim is to minimize the risk of drilling by allowing better positioning, improved borehole stability and a reduced number of necessary trips.

Recent chemical work includes the extension into the HPH-hc domain of the useful spectrum of primary and corrective cementing additives and fluids stimulation. This study involves creating novel sealants to plug and abandon HPHT wells at both the end of their helpful lies and maintaining long-term isolation to avoid flow of fluid among subterranean areas or towards surface. Furthermore, research is ongoing to establish equipment for completion manufactured from materials with improved resistance to corrosive gases and fluids.

Participation of extensive operator in the design and construction of equipment and in the development of the chemical product is not common for standard wells but operator involvement is essential for success of potential Ultra-HPHT and HPHT activities. For the necessary certification tests, production, assembly, Installation and testing, collaboration amongst operators and service providers would be crucial. Engineers and Scientists of Schlumberger's are engaged in this collective process, which allows the industry to make substantial progress in technology required to meet increasing energy demand worldwide (DeBruijn et al., 2008).

2. CHAPTER TWO: DRILLING FLUIDS FOR HPHT

2.1 Introduction

Technology of Drilling fluid has become highly developed and involves good chemical and physical knowledge to better understand the materials' molecular nature when dealing with geological formations and the reactions occurring during drilling a well. The drilling processes may become complicated, as various phenomena happen in the blower part of hole (Agboola, 2015). It is therefore essential to know the primary role played by drilling mud within the drills hole, as well as the technological gap that may have been established by the reservoir characteristics. In this chapter explaining that why functionality of drilling fluid is useful for drilling activities, the drilling fluid types for various well needs, and the rheological model widely used to match drilling fluid behavior.

2.2 Drilling fluids functions

The principal functions of drilling fluid are:

1. To suspend drilling cuttings and weighted material while decreasing or stop mud circulation (Dn et al., 2005).
2. Control corrosion for Drill string, casing and tubular (Annis & Smith, 1996).
3. Drill bit cooling and cleaning (Darley & Gray, 1988) & (Dn et al., 2005).
4. Prevents the inflow of gas, water and oil from penetrated rocks (Darley & Gray, 1988).
5. To control the pore pressure of formation and to support well-bore stability (Dn et al., 2005).
6. Construction of a thin filter-cake of low-permeability to reduce filtrate loss to the penetrated formation (Darley & Gray, 1988).
7. Help to collect and interpret the drill cutting (Darley & Gray, 1988).
8. Minimize damage of formation in reservoir.

2.3 Drilling Fluid Objectives in HPHT wells

Drilling fluids can basically be classified into gases, liquids and mixtures of gas and liquids. Liquids are most frequently used and can be classified into oil based (OBM) and water based (WBM). Because of its lubricants and thermal stability properties, the OBM is more effective in directional wells under HPHT than WBM. The OBM's developed from conventional oils, like synthetic oils or diesel because of the environmental awareness. Barite sag (static and dynamic) is a major issue in wells under HPHT. This phenomenon created from circulation loss, drag and torque, fluctuations of ECD and other processes that involve the drilling fluid to stay long time in static. To date, the solutions applied for eliminating this issue involve the addition of unconventional mud additives rather than barite, like Manganese Tetraoxide fumes (Mn3O4) and/or Ilmenite (FeTiO3) (Elkatatny et al., 2012).

Mud circulation acts like a heat exchanger. The heat exchange rate among the formation, casing and mud at certain depth based on thermal conductivity, velocity of mud and temperature. Temperature distribution is further complicated by vertical heat conduction in the presence of casing.

In case of insufficient circulation, the gravity can allow weighting material such as barite to drop, causing segregation of density or sagging (a). Barite layer on hole lower side in a deviated well may result in the sagging (b). The barite may slump down like an avalanche to the wellbores low side (c), depending on the wellbore angle and the bed's strength. During sagging, the movement of the solids in the mud might result in a reducing viscosity by reducing the shear and accelerating the process. In the end, slumping can result in accumulation of barite and a marked change of drilling fluid density (d) (Adamson et al., 1998), Figures 2.1, 2.2 and 2.3.

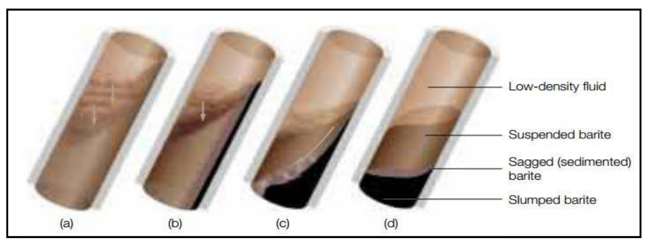


Figure 2.1 Barite sag affected by fluid properties, (Adamson et al., 1998)

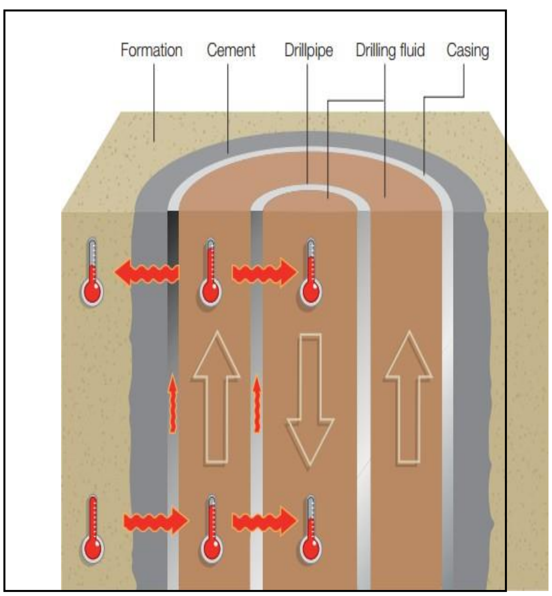


Figure 2.2 schematic of Heat transfer into the wellbore, (Adamson et al., 1998).

Figure 2.3 Drilling Fluid Should Withstand the HPHT Condition.

Shadravan, Beck, Amani, Schubert, Ravi and Zigmond performed HPHT test series on water and oil-based mud by the Rheometer of extreme HPHT, concentrating on HPHT fields in the Qatar and United states. Lee, Young and Shadravan assessed different HPHT Rheometers performance, modeling the rheological characteristics of a HPHT oil based mud and submitting some recommendations to the API Committee (Amani & Al-Jubouri, 2012) (Amani, 2012) Table 2.1 summarizes the reguired properties of drilling fluid at HPHT conditions.

Most HPHT Rheometers depend on an ideal "frictionless" design to give the readings, the ideal condition might not have been met particularly when the test influenced by some factors like pressure, temperature, solid content, solids type and using time. That can certainly have an effect on the data quality that generated under the instrument's maximum capacity (Figure 2.4) That difference may be due to various mechanical designs.

Drilling Fluid Properties	Required Performance in HPHT Wells
Plastic Viscosity	As low as reasonably possible to minimize ECD
Yield Stress and Gel	Sufficient to prevent sag, but so high as cause gelation, or high surge and swab pressures
HPHT Fluid Loss	As low as reasonably possible to prevent formation damage and risk of differential sticking
HPHT Rheology	Stable and predictable to control sag , gelation and ECD
Compressibility	Must be known to estimate downhole pressures and ECD
Stability to Contaminants	Stable in presence of gas, brine and cement
Gas Solubility	Needed for accurate kick detection and modeling
Stability to Aging	Properties do not change over time under either static and dynamic conditions but in reality properties slightly, drop after dynamic aging and increase after static aging.
Solid Tolerance	Properties insensitive to drilling solids
Weighting	Must be able to weighted up rapidly if a kick is taken

Table 2.1 The drilling fluid`s desired properties for optimum performance at HPHT condition (Shadravan 2012).

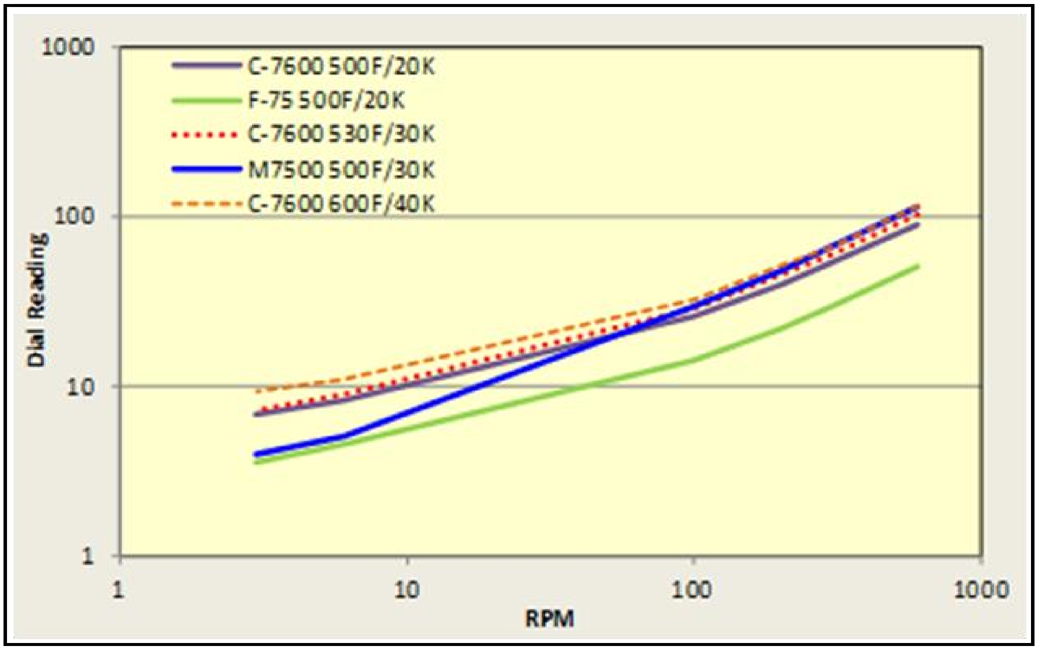


Figure 2.4 A Comparison of the Extreme HPHT Rheological measured by HPHT Viscometers at their max capability, (M-I SWACO and Texas A&M, 2012- Courtesy).

Stamatakis et al. explained the challenges of drilling mud under HPHT and discovered a new fluid system used in HPHT conditions. Wang and Zhao described the drilling fluids for deep wells, high density water based, and oil based. It was argumentative problem for some time to mix confining fluid and test sample, although designs of various cells were used to reduce the mixing of the two fluids. Additionally, composition of fluid and chemistry of product are needed under extreme-HPHT conditions to ensure enough thermal stability of the test fluid. Developing the right products for formulating extreme-HPHT might involve more effort than only doing the extreme-HPHT test. Absence of thermal stability it will not reliable to simulate the properties obtained at lower pressure and temperature (Lee et al., 2012).

The process of planning hydraulics and designing fluids depends on determining how wellbore temperature and pressure conditions affect the rheology of fluid. Ignoring these effects in calculation is bound to obtain error results, and its correction with related costs might be needed in later drilling stages. Every drilling mud should be designed to maintain the designed properties in the wellbore. The rheological properties of drilling mud not just determine the fluid ability to bring cuttings but also the value of the drop in frictional pressure that happens when the mud is circulated. This drop in frictional pressure, also determines pressure increasing during circulation at bottom of hole (ECD).

ECD control is required for narrow operating windows in drilling operations (pore pressures is close to fracture pressures that noticed in deep HPHT wells) to prevent fracture formation and loss of circulation, which can lead to problems of well control and wellbore stability. Temperature and pressure are also influenced by fluid rheology. Rheological properties changing affect the ECD during circulation and also the capacity to clean the hole. For instance, a fluid may have enough viscosity and cuttings be removed to surface under normal conditions, but it changes as too thin under the conditions of the downhole, thus causing severe problems in the cleaning of the hole due to the dropping of the drilled solids and the packing off at bit.

These issues are magnified in deviated wells where problems associated with hole-cleaning may cause in cost and consuming time in side-tracking, or even abandon the well. Zamora (2012) checked the volumetric behavior under HPHT of a wide oils range, brines, synthetic, and water based (Zamora et al., 2012).

2.4 Selection of drilling fluids for HPHT wells

The Well known as HPHT well when the formation pressure approach an equivalent circulating density of 1800 kg / m3 and the temperature of the static bottom hole reaches above 350 ° C. To understand the of drilling fluids behavior under specific HPHT scenarios, the cost and risk of drilling mud should be minimized, and the operational efficiency should be maximized (Bland et al., 2006). HPHT wells need a high-density fluid typically requiring a heavy solid load. Because of the low rate of penetration, additional drilling costs (Bland et al., 2006), and improves location time, higher solid loads and excessive pressure values are mixed at rock depth.

Both deep and hot well drilling is highly dependent on the rheological characteristics of the drilling mud for various downhole situations. Within downhole situations, the water-based fluids rheological properties can vary greatly from the properties determined under the surface conditions. This is because the temperature and the shear affect drilling fluid properties.

Temperature increase will decrease the effectiveness of the majority of drilling fluid additives which might sustain the rheological, fluid loss and electrochemical properties. High-temperature problems are accelerated when high chemical contaminants such as calcium salt, sodium, and magnesium are encountered. The problem of high temperatures is considered as one of the drilling fluid contaminants that cannot be treated with any additives. The drilling fluids could become too thick in the lower parts of the hole when there is no mud circulation in the borehole. Excessive heating can cause drilling fluids to solidify.

If there is a case of a stuck pipe, circulation may continue for a long time and consideration is given to the aging of the drilling fluid. Aging effects of drilling fluids rheology together with temperature, and research shows that the effect of dynamic aging is greater than static aging (Galindo et al., 2015). For many reasons, when drilling a well, knowing the exact pressure drop is very important.

2.5 Types of drilling fluids

Drilling fluids, like oil-based muds, water-based muds and gas, are classified according to their base fluid. Figure 2.5 and 2.6 display the classification of drilling fluids for water based and oil based, respectively. The two figures illustrate various variations for both systems. Each system is designed to meet a specific need for the well. Each geological formation requires various specific fluid properties for drilling. Figure 2.5 and 2.6 attempt to express variations of drilling fluid system parameters.

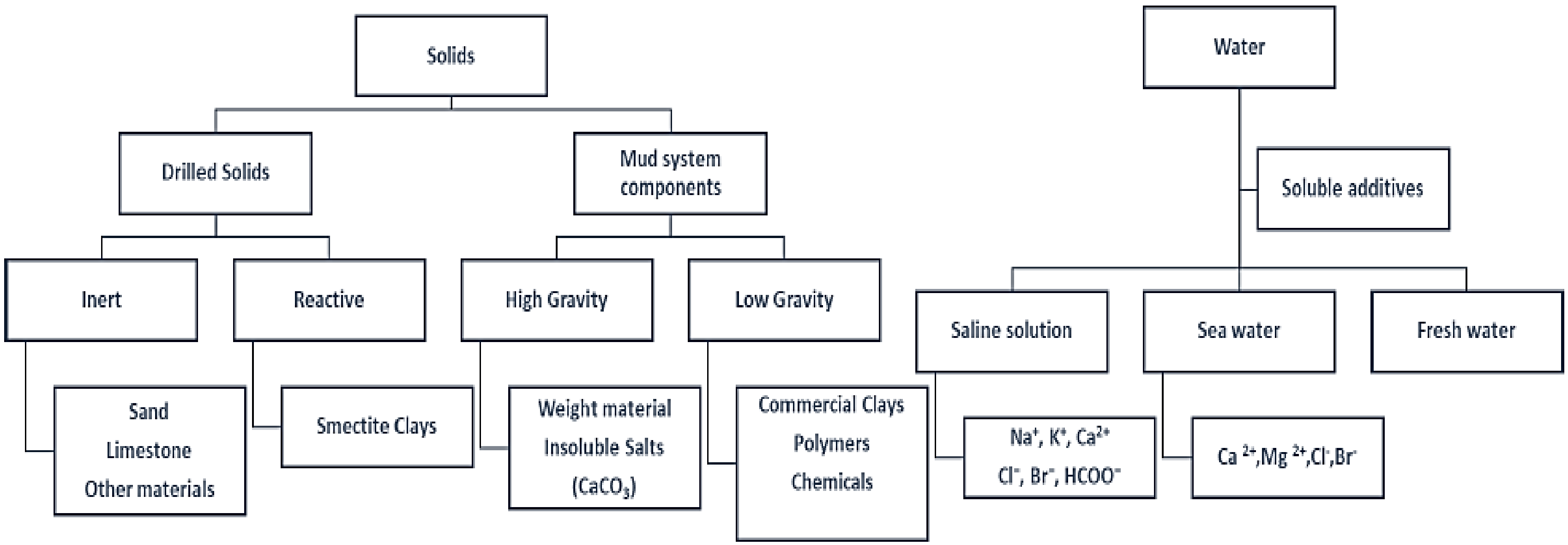


Figure 2.5 Type of water-based muds. (Dn et al., 2005)

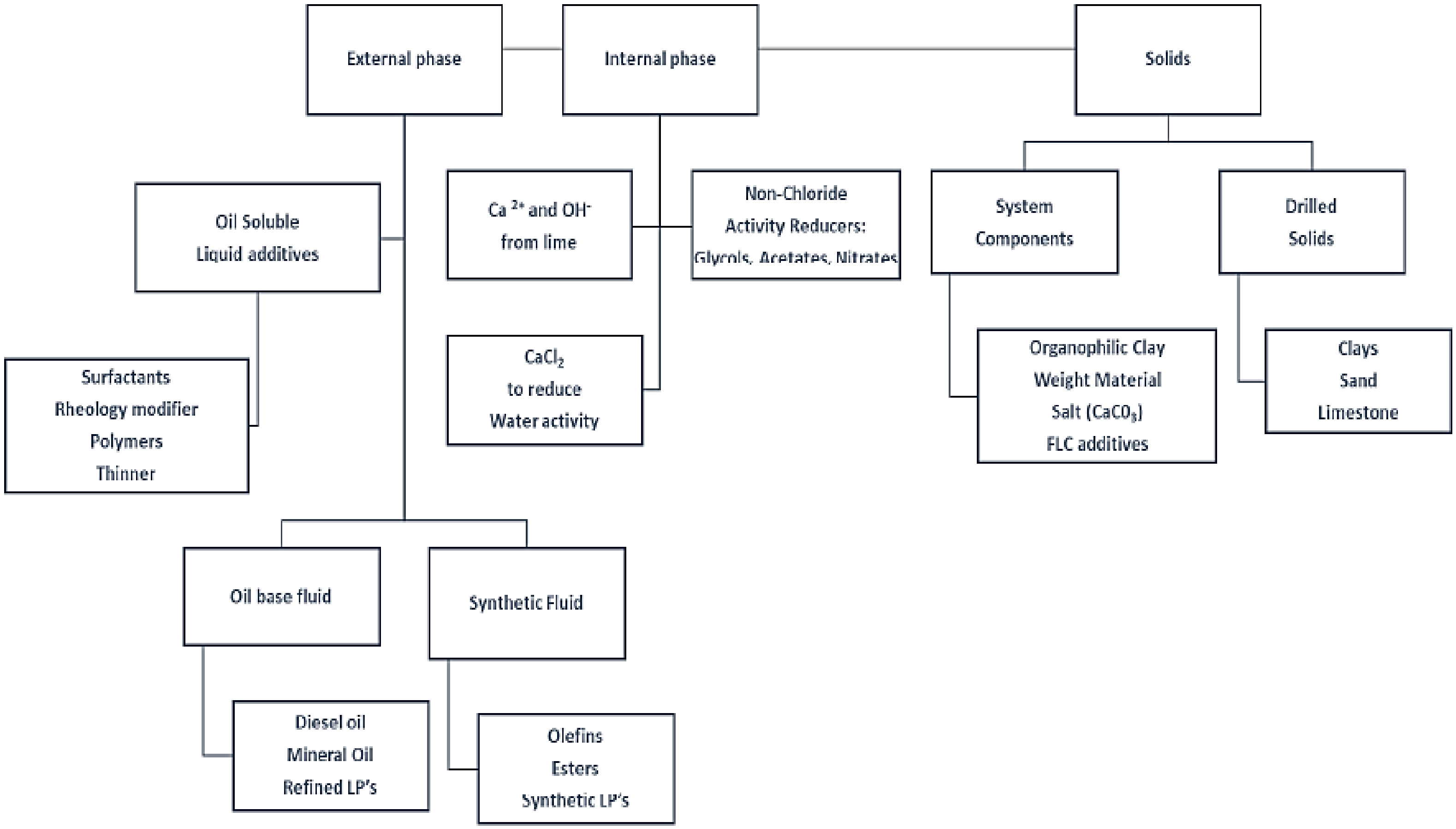


Figure 2.6 Types of Invert-Emulsion (Dn et al., 2005)

2.5.1 Water-based muds

Because of the low cost compared with other types, like oil-based muds (Van Oort, 2018), this type is most widely utilized in drilling operations. This system is integrated with water or brine suspended solid particles (Swaco, 1998). Oil in the water can be emulsified, and water represent the continuous phase (Darley & Gray, 1988).

2.5.2 Inhibitive Fluids

These types significantly delay shale swelling and accomplish cation inhibition (J. M. Shaughnessy et al., 1999) & (Shaker, 2011) typically, sodium (Na+), potassium (K+) and calcium (Ca2 +) are called inhibitive. Ca2 + or K+ generally, or both in combination, provide the best inhibition of clay. Generally, they used to drill hydratable, reactive clays and sands that contain hydratable clays (Annis & Smith, 1996)

2.5.3 Non-Inhibitive Fluids

They do not substantially cure the problem of clay swelling and usually they made up of bentonites with caustic soda or some lime (Swaco, 1998). They may compose of de-flocculants like lignosulfonates, lignite, or phosphates (Hughes, 2006).

2.5.4 Polymer Fluids

They depend on macromolecules either both , with or without interactions of clay-mineral to provide properties of mud, and that are extremely diverse in their application (Darley & Gray, 1988). They, depending on whether an inhibitive cation is used, can be inhibitive or non-inhibitive (Baroid, 1998) Polymers may be used to increase fluid viscosity, to control filtration, to defloculate solids or to encapsulate solids (Swaco, 1998). Polymer systems' thermal stability can range up to 400 ° F (Hughes, 2006).

2.5.5 Oil base muds

The fluid formulation consists of suspended solid particles in oil. Water may added to oil to make emulsion, the oil is considered as continuous phase and water represent the dispersed phase (Darley & Gray, 1988) & (Swaco, 1998).These systems are usually more expensive and require a higher level of environmental assessment (Bourgoyne Jr et al., 1986). However, the most oil-based muds (OBM) common uses is drilling reactive formations of shale and enhances wellbore stability(Ammoco, 1994).

These fluid types have various applications, such as wells under HPHT conditions. They reduce damage to the formation (INTEQ & Drilling, 1995) have good lubricity and help to inhibit clay hydration (Ammoco, 1994).

Such mud types also have the advantage of being reconditioned and reusable. The cost of a multi-well program can then be compared by the use of a water-based mud system (Ammoco, 1994).

2.5.6 Gas/liquids

They used in case of the geological formation can produce water at a considerable rate of flow (Dn et al., 2005). A high stream velocity of natural gas or air can remove cuttings, and minor water inflows are removed by adding foaming agents (Bourgoyne Jr et al., 1986).

2.6 Behavior of drilling Fluids on HPHT Well Conditions

2.6.1 Rheology of Drilling Fluids

Rheological properties show the deformation characteristics and the drilling mud flow. The drilling fluid behavior can be assessed to solve problems in calculating mud treatment, hole cleaning, and hydraulics. Yield Point (YP), Apparent Viscosity (AV), Plastic Viscosity (PV) and Viscosity is a property that demonstrates drilling fluid's resistance to flow, which is described as ration of shear stress to shear rate .

Apparent viscosity is the viscosity at a fixed temperature and measured at a given shear rate. Most of the drilling muds show plastic behavior that illustrated by means of τy. For initiating the flow, plastic fluids require a certain shear stress value that is represented by yield point. Plastic viscosity is shear stress per shear rate curve slope above the value of YP. YP / PV ratio is a flattening measure of the flow profile. Higher YP / PV ratios give more preferable cutting transportation in laminar flow. The drilling muds majority are non-Newtonian fluids, in which, viscosity decreases as shear rates rise (Thivolle, 2004) (Herzhaft et al., 2002) indicated that the plastic viscosity is greatly influenced by changes in temperature. In the Deepwater wells, the riser's cooling effect may result in increasing the drilling fluid PV.

In addition, the riser length increases the effect of cooling throughout mud circulation, generating major rheological changes if mud of synthetic or oil-based is used. Variation in the viscosity of mud can also create surge and swab problems, transmitting of MWD pulses, increased ECD and fluctuations in the efficiency of hole cleaning.

2.6.2 Temperature and pressure effects in the drilling fluid rheology

Physically: the fluid’s viscosity decreases with increasing temperature and pressure increasing increases the fluid's viscosity and density.

Chemically: Temperature affects the fluid's alkalinity which causes the fluid's thinner properties and affects the process of flocculation, deflocculation or aggregation in the fluid. (Politte, 1985); obtained from his own study of emulsion rheological data that yield point of drilling mud is not a strong pressure function and is gradually decreasing when increasing temperature. However, the temperature effect on yield point are hard to forecast since they associate the effects of chemical particles. (Davison et al., 1999) indicated by research on the rheological data collected from a viscosity meter that the low temperature effect is pronounced on viscosity of both synthetic mud and oil-based mud (OBM). By contrast, when pressure increasing at different temperatures, the oil-based viscosity increases, particularly at higher shear rates (Figure 2.7). The influences of the pressure do not exist to be temperature dependent as illustrated in Figure 2.7

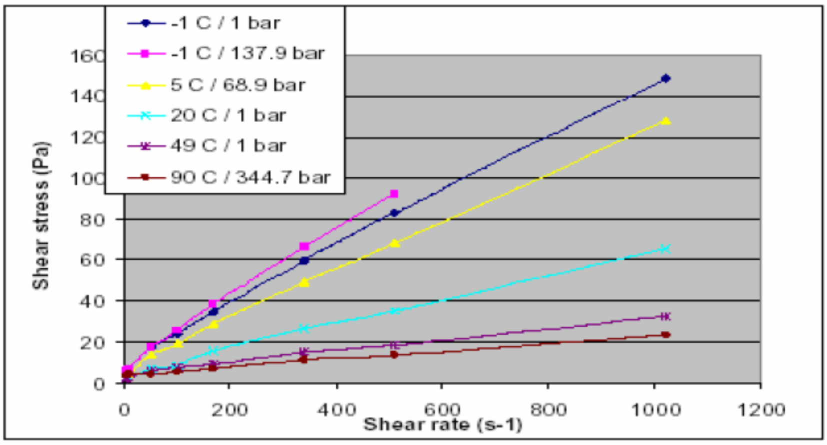


Figure 2.7 Rheograms at different pressure and temperatures for unweighted OBM, ratio of oil/water is 80/20 (Davison et al., 1999)

Figure 2.7 displays few outcomes that, hydrostatic pressure estimation needs PVT data of mud, as well as an accurate downhole temperature simulation profile; a drilling fluid's compressibility is dependent upon its base fluid.

(Zamora & Power, 2002) assessed the inability of RP 13D API formulas to meet the critical drilling field data in, since these formulas must combine the effect of temperature and pressure on rheological properties and density.

2.7 Rheological Parameters

During the drilling operations, the drilling muds rheological properties of gel strength, yield point are tested to characterize the drilling fluid behavior. These characteristics depends on the corresponding shear rates and also the sample volume and viscosity that measured by rheometer. The most commonly defined rheological properties are the rheological parameters and rheogram.

The parameters that represent the Bingham plastic fluid are yield point and plastic viscosity, the parameters for the power-law fluid are consistency (K) and index of power law (n). There are four major types of flow: Newtonian, plastic, Pseudoplastic and Dilatant fluid, as demonstrated in figure 2.8 below.

In the figure 2.8, the four types of rheological fluid are described:

1) Plastic fluids described by YP and PV in accordance with the shear stress, τ, and shear rate, γ.
2) Pseudoplastic fluids, τy = 0.
3) 3) Newtonian fluids, PV = constant and τy = 0.
4) 4) Dilatant fluids.

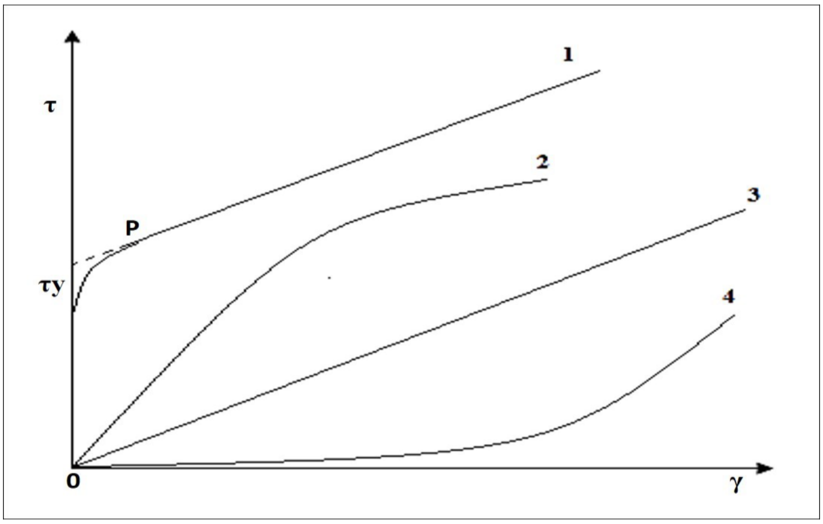


Figure 2.8 Rheogram displays types of rheological fluids (Awele, 2014)

In drilling operations, good behavior of shear thinning to the mud is needed, that means the mud has high internal force at low shear rate, while the mud will have low internal force at high shear rate. It also describes that the apparent viscosity is decreasing as shear rate increases. The behavior of shear thinning is normally recognized by ratio of (YP / PV). The higher the YP / PV the more preferable the behavior in shear thinning. It will be noted from the diagram shear rate and shear stress (Figure 2.8) that YP and PV are essential parameters for drilling mud. If additional nanoparticles change YP or PV, will influence the using while drilling. If adding NPs increases PV: 1) it increases the ECD and 2) it increases the pump pressure. A decrease will impact on drilled cuttings carrying capacity. Again, if adding NPs rises YP, similar effect can occur but moderate. Yield point increasing is good in case of drilled cuttings carrying capacity. It is the stress needed for the initial fluid flow after the blockage of circulation. It is necessary to measure the mechanical parts wear rate of the defined fluid system due to fluid friction coefficient flow as it can predict the rotational velocity of the drilled pipe.

1. **Concentration**

The Change or addition of fluid additives has a concentrational influence depending on density and viscosity.

2. **Gel strength**

Describe the gel limit related to yield stress as dependent to concentration of additives.

3. **Pressure loss**

It affects the Fanning friction factor, which is dependent of the Reynolds number and roughness of pipe wall.

4. **Friction reduction**

In order to reduce friction loss, shear thinning is the outcome of structural viscosity reduction and the friction reduction mechanism is the outcome of the elastic properties of polymers that allows to keep the turbulent flow kinetic energy.

5. **Electrochemically:**

The growing in temperature rises electrolyte ionic activity and salt solubility which may exist in mud. The direction and magnitude of these changes, and their effects on mud rheology, vary with the particular mud's electrochemistry.

Thixotropic condition depends on shear rate, shear stress, time and torque. The thixotropic fluid viscosity based on shearing time and shear rate, since the structural component differs over time with relative to the fluid 's past shear trend (Awele, 2014).

2.8 Tips to Improve performance of Drilling Fluids

Downhole fluids are often viewed as an ancillary element of a drilling process. They can affect significantly the success or failure of a well. Drilling staff need to understand the challenges as well as the possible solutions.

1. Drilling fluids are necessary to decrease the additional pressure exerted during drilling operations on the wellbore. The best way to do that is to use a thin, low-rheology fluid which generates the lowest incremental pressure. But HPHT fluids in particular are high density and must support the added solids.

2. Due to extreme temperatures and contaminants the drilling in HPHT wells can be tricky. Staff have to understand how the well's temperature and pressure profile will affect the fluids proposed. The mud system may need to be treated by arrangement rather than on-the-fly due to problems of well control.
3. Typically, drilling fluids cost 5 to 10 % of the total well cost . The ability of the mud to influence the final cost of the well is significantly greater than this. Misapplied or incorrectly operated fluid systems can lead to a significant overrun to planned AFE. The margin for error in HPHT wells is lowered further. In such demanding environments, the main driver should be the technical performance of the fluid, not the cost.
4. A fluid product may stabilize at 400 ° F for an hour but will it remain stable if it is exposed for that temperature for 1-3 days? When designing HPHT wells, it is essential to ensure that the fluid and fluid additives are stable under the most extreme conditions expected for the maximum expected time. If the product decomposes thermally, the fluid system will have different chemistries acting and you no longer know what the result of those chemical reactions is going to be.
5. Field experience can tell you, with conventional wells, which fluid systems and products are performing satisfactorily under specific project conditions. Yet the industry pushes technical boundaries every day. There may not be many similar wells drilled with HPHT projects to assist in the selection and design of liquids. In this situation, thorough laboratory work must be completed, and more critical will be the detailed drilling, well and mud programs. Having 1-2 robust backup plans, too, is wise. HPHT wells can get from a smooth run to a very difficult process very quickly, so it's important to know what you're going to do if things don't go 100 percent as planned (McCourt, 2007).

3. CHAPTER THREE: WELLBORE INSTABILITY

The purpose of this chapter is to understand the idea of transient pore pressure and effect of temperature on stability of wellbore after drilling and evaluate whether wellbore stability in HPHT wells can cause serious problems. The final part of the chapter also includes the solution of the various forms of stability of wellbore and related problems of wellbore stability and its prevention.

What is wellbore Instability?

It can be described as “Borehole instability is the unacceptable condition of an open hole duration which does not sustain its gage size and shape and/or integrity of the structure”

3.1 Wellbore Instability in HTHP wells

Wellbore Instability has major effects during drilling under high temperature and pressure conditions, as instability of wellbore is a normal feature of inadequate mechanical stress and physiochemical interfaces, and pressure generated while material and surface support is exposed during the Wellbore Instability (WI) well drilling phase is recognized when the diameter of hole is marked different from size of bit and the hole doesn’t keep its structural integrity. Concisely put, an over-gauge or under-gauge hole means instability of wellbore (Osisanya, 2012). In addition for oil and gas wells to be successfully drilled, it is crucial to formulate mud of a sufficient mud weight to preserve the stability of the hole, to avoid the influx of formation fluid in the wellbore and to reduce the loss of mud (Rabia, 2001).

Wellbore instability is becoming a significant issue for horizontal and extended reach wells, particularly by pushing into the fully open side hole section and in certain scenarios by cap rocks of shale, a buildup section of open hole .More recently drilling advancements, such as under-balanced drilling methods, high-pressure jet drilling, horizontal wells reentry and several laterals from the a single horizontal or vertical well often eventually lead to difficult stability issues of wellbore (Martins et al., 1999), (Kristiansen, 2004), (Tan et al., 2004).

3.2 Wellbore stability related challenges:

Appropriate measurements of the pore pressure from nearby wells revealed the presence of an over pressure shale right over the reservoir. This reality and the approximately overburden gradient suggested that very small mud-weight window could be found in the way to the reservoir. The challenge for the calculation of the pilot well's mud-weight window was mainly because of the absence of laboratory testing of rock mechanics on core of overburden for calibration of strength and new log calculated mechanical parameters. Not all logs from the overload are available, which is often the case because logging is preferably performed near to that in the sections of reserve, which means that all the data between the few logged points before approaching to the reservoir are implicit in high uncertainty. Rock ethics (shale volume), porosity, permeability and strength are lacking in general, or entirely conjectured. Moreover, in the absence of consistent prolonged leakage tests in the surrounding wells to the reservoir (rarely performed for obvious costs and time), any plotted fracture gradient would be extremely conjectural by nature. The lack of image logs creates it difficult to establish horizontal stress orientation (Rommetveit et al., 2010).

3.3 Borehole instability

Previously mentioned instability of the borehole as well as its parameters suggesting that the hydraulic and chemical factors are related to geo-mechanical issues. instability of wellbore in oil and gas is well described as the unfavorable situation of an open hole interval which doesn't retain the gauge size , shape or integrity of structure, thereby leading the drilling operation to large problems and challenges that will result in additional costs and non-productive time that enhances with its intensity. (Rabia, 2001).

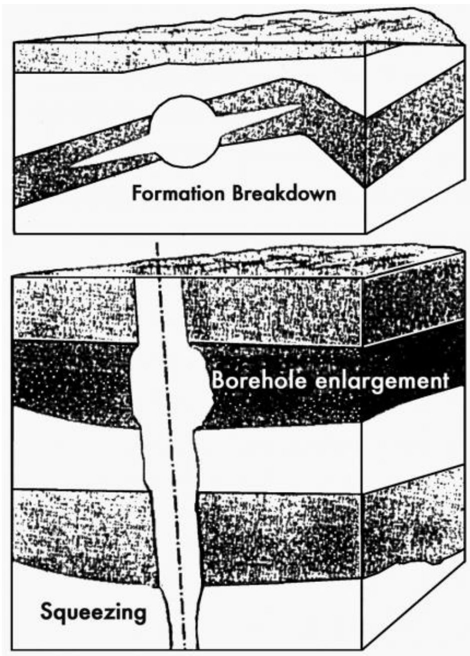


Figure 3.1 Borehole instability types

A drilled formation before drilling often has a state of equilibrium between the strength of the rock and the stresses in situ imposed to it, regardless of whether in both conditions; vertically from the overburden pressure or horizontally from the confining. Drilling process, however, disturbs the balance and weakens the mechanical stability. In addition, the introduction of foreign fluids as drilling fluid will begin an association with the rock and fluid formation (Larry W. Lake, 2006).

3.3.1 Borehole instability origins

There are three main reasons for instability of wellbore

1. **Mechanical failure**: Tend to result from in-situ stress disruption, usually equivalent to the weight of mud as well as its hydrostatic pressure. Mechanical failure however is compressive failure due to shear stress because of extremely low mud weight (collapse, slough), or failure in tensile stress due to normal stress and in result achieve very high mud weight (fracturing).
2. **Erosion:** This was caused by friction whilst drilling fluid on the wellbore wall.
3. **Chemical:** The interaction of borehole fluids with rock formation and fluids has an effect on the mechanical strength of the wellbore.

3.3.2 Types of Borehole Instability and Related Problems

Borehole instabilities has four different types (Pašić et al., 2007):

- Hole Closure/narrowing
- Enlargement of Hole / washouts
- Fracturing
- Collapse

Figure 3.2 Shows the problems of hole instability.

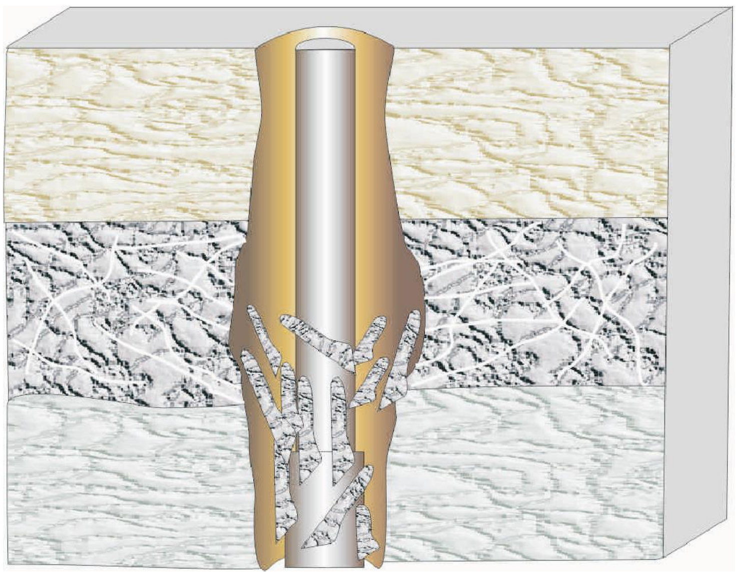


Figure 3.2 Drilling by faulted formations or naturally fractured (Pašić et al., 2007)

3.3.2.1 Hole closure

Closure of hole is a time-dependent operation of instability in the borehole. This is often related to as creeping under overburden pressure, yet it usually appears in regions of plastic flowing shale and salt. Troubles relating to the closure of the hole are:

- Torque and drag increase
- Increase in sticking of potential pipe
- Increased difficulty of landing of casing

3.3.2.2 Hole enlargement

Hole enlargements are typically named washouts since the hole is undesirably bigger than expected. Hole enlargements are constantly influenced by:

- Hydraulic erosion
- Mechanical drill string abrasion
- naturally Sluggish shale

The problems related to enlargement of the hole are as follows:

- Increasing difficulty in cementing
- Enhancement in potential deviation in the hole
- Increased hydraulic requirements for efficient cleaning of holes
- Increase in possible issues while operations of logging

3.3.2.3 Fracturing

Fracturing happens when the pressure of the wellbore drilling fluid surpasses the pressure of the formation fracture. The possible concerned issues are loss of circulation and potential kick incidence.

3.3.2.4 Collapse

The borehole failure happens if the drilling fluid pressure is very low to hold the drilled hole structural integrity. The problems associated with this are sticking of pipe and well potential loss.

3.4 Borehole stability problems in HPHT wells:

Problems with borehole stability insistently persist the bane of oil and gas drilling operations. It is crucial to know the properties of drilling fluid that contribute to these problems. The results of the build-up and filtering of mud cake help explain damage to formation and stability of wellbore. The increase of drilling in high-pressure temperature regions (HPHT) forces studies to predict invasion of filtering and bridging of particles. Only some studies have analyzed the formation of filtration and filter cake in HPHT situations in which various mud and bridge solids could be evaluated.

There are many experimental approaches being used by industry to measure wellbore reinforcing effects in oil-based muds and investigate impact on particle bridging, permeability and filtrate invasion. To optimize the Particle Size Distribution (PSD) for the pill design of wellbore strengthening, a specific image processing method is used. To demonstrate the effect of particle bridging, HPHT filtration experiments were done on four real sandstone cores with permeability ranging from 15.9 -1130 md at different time stages. To verify the bridging efficiency, Using Scanning Electron Microscopy (SEM), even more rock cores and mud cakes were examined.

The analysis indicates a considerable decrease in cumulative loss of fluid (in some cases up to 100 per cent). Low permeability of mud cake in the range 10 -2 to 10-3 MilliDarcy has been produced which can be very useful for applications of wellbore reinforcing. Optimized particle size distribution of LCMs provided successful bridging of pore spaces for core samples. It has shaped ultra-thin, firm mud cake which can protect differential sticking, excessive torque and drag on drill pipes. More filtration research is currently going on using other forms and concentrations of LCM as well as verification of field tests (Agboola, 2015).

3.5 Causes of Wellbore Instability in HPHT wells

Different factors likewise and reservoir properties and drilling mud chemistry influence the wellbore instability in deep-water gas well. Properties of Drilling fluid might be utilized to directly influence stabilization of wellbores. Physicochemical interaction with both the formation, Filtration behavior vs density of mud (Hoffers et al., 1994),(Ghajari & Sabkdost, 2013),(Yang et al., 2016) are the drilling fluids properties which may be optimized to effect stability of wellbore. There were also reported problems of wellbore instability during drilling in naturally fractured formations. Many of the observed formations possess micro-scale and macro bedding planes and natural fracture networks which diminish the compressive strength of both the formation and the productivity of the formation matrices (Fekete et al., 2015). In the formation the natural fractures alter wellbore stress and decease the formation's fracture resistance.

3.5.1 Shale Instability

Many formations of deep-water gas are shale formations, which are the key source of wellbore instability problems. Shale formations are sedimentary fine grained rocks consisting primarily of clay, silts and occasionally sand particles. Formations of shale range through clay rich, poor formations to the formations of shaly-siltstone which are heavily cemented (J. M. Shaughnessy et al., 1999). They possess relatively low permeability and very high mineral content of clay. About 75 per cent of drilled deep-water formations are shale formations and perhaps the cost of drilling is extremely high due to shale instability issues. The causes of instability of shale are chemically and mechanically induced instability as a result of interaction among both formation of mineral compositions and drilling fluids (J. Shaughnessy et al., 2007) as shale minerals and drilling fluid communicate, the formation of pore pressure and mechanical strength in the wellbore region are changed. Capillary pressure, pressure diffusion, osmotic pressure near the wellbore and wellbore fluid invasion at the time of overbalanced drilling are the factors which contribute to the wellbore issue (J. Shaughnessy et al., 2007), (Santos, 1997).

Typically, a positive pressure difference is maintained in normal drilling operation. This tends to cause drilling fluid to flow in the formation (circulation loss) and in the formation, chemical interaction with the minerals likely to lead to shale instabilities. An improvement in the viscosity of drilling fluid or some special material like as Gilsonite may be utilized to seal off micro fractures within a formation to avoid this problem. With water-based drilling mud in the shale formation, drilling with a positive differential pressure would allow fluid pressure to permeate the formation. Because of the formations of saturation and low permeability, the drilling mud filtrate penetration in the formation will significantly raise the pore pressure across the wall of wellbore.

The rise in the pressure of the formation pores would reduce the effective pressure of the drilling mud and may contribute to instability of wellbore. Many systems of polymer water-based drilling fluid were designed to avoid hydration of the shale which are used instead of oil-based drilling fluids and synthetic fluids (Santos, 1997), (Maury, 1994).

Under compaction and uplifts may result to instability in the wellbore. These formations could even collapse if drilling fluid with inadequate mud weight fills the drilled open-hole section. These formations are best stabilized by making sure the short time open-hole exposure and adequate mud weight while drilling by the formations.

3.5.2 Gas Hydrate associated Problems

Gas hydrates are like ice crystalline compounds that form when high pressure and lower temperature water molecules and, molecules of light gas exist together. Methane, ethane, n-butane, propane, hydrogen sulfide, carbon dioxide and nitrogen are some of the gas hydrate formers (Ghajari & Sabkdost, 2013) Although many deep-water gas wells come across problems with hydrate because the ambient pressure and temperature situations are appropriate for the hydrate formation.

The molecules of water needed for hydrate formation normally come from the gas influx produced water formation or drilling fluids (Ghajari & Sabkdost, 2013), (Long et al., 2014). The rises are generally isolated in deep-water gas wells when BOP stake, choke and kill lines are revealed. The gas could produce hydrates and block the stack of BOP, chock and kill-line when the gas kick takes place.

The formation of hydrates during deep-water gas well drilling can cause chain of unwanted effects like as chock plug and kill line which prevent them from being used in the circulation of well; plugging formation at or below the BOPs that help protect monitoring of well-bore pressure under the BOPs; plugged formation across the drilling string in the raiser, BOPs or casing, that avoids the movement of drill string ; plugging of the formation from the drill string to the BOPs, which restricts complete closure of the BOP, and plugging the formation of a closed BOP in a ram cavity preventing the BOP from opening completely.

3.5.3 Fractures, Faults and Mobile Reservoir Layers

In natural fractured formations with macro/micro bedding planes, wellbore instability issues were also reported.

Natural fracture networks diminish the compressive strength of formation and the productivity of the formation matrices (Fekete et al., 2015), (Nmegbu & Ohazuruike, 2014). This changes the stress of the wellbore and decreases the fracture resistance of formation. Near to fault areas, reservoir layers can be disintegrated into the various segments that are trapped in the wellbore and can lead to drill string jamming. This issue is prevalent in areas of tectonically active and fractured limestone (Nmegbu & Ohazuruike, 2014). These fractures can lead to the drilling of fluid invasion by shale formations, minimize the formation strength, and lead to wellbore collapse. While compressed as a result of overload, mobile layers towards reservoir could even rapidly squeeze in the wellbore. Mobile layers act as plastic material deform under increased pressure. The deformation might reduce the size of wellbore and affect download instruments like BHA, logging tools and even case strings, as illustrated in Figure 3.3. This is more often when salt formations are drilled. Drilling fluid could be used to stabilize such formations with enough mud weight.

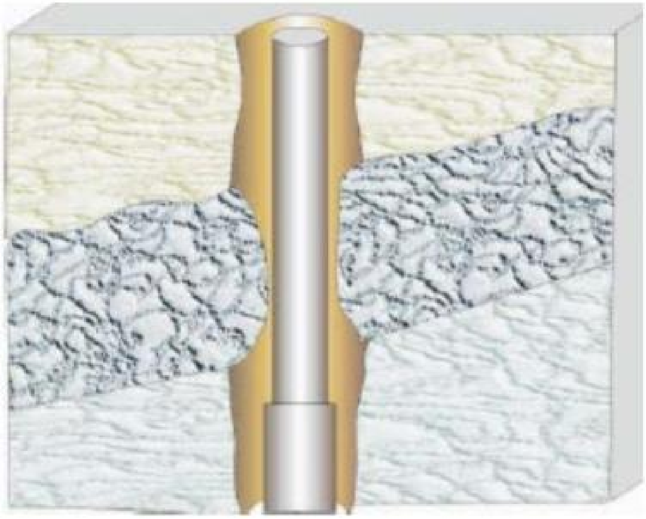


Figure 3.3 Drilling through mobile reservoir layers (Nmegbu & Ohazuruike, 2014).

When compressed or stretched rock layers are caused by earth movement, tectonic stress is produced. The compressed or stretched rock formations are affected by the overburden of the tectonic plate moving. As tectonically stressed rocks are drilled, the layers across the wellbore will collapse and cause great instability in wellbore. In the rock strata, the hydrostatic pressure necessary for the wellbore section to stabilize could be higher than the pressure of the formation fracture (Nmegbu & Ohazuruike, 2014) , (Fekete et al., 2015).

In mountainous regions, this phenomenon is very common. The good practices for the stability of such formations are to run casing strings as early as possible and ensure that the wellbore is filled with enough drilling fluid all the times. Unconsolidated formations can easily fit in the open hole section during drilling, with small or no bonding between the particles or the pebbles. When the drill string is separated or case strings are not instantly executed, the formation may collapse, as illustrated in Figure 3.4. If mud cake and mud overbalance hydrostatic pressure are insufficient, the loss circulation might happen. Loose particles like sand could fall in the open-hole segment and pack the tools of down hole. It would result to drag and torque and ultimately to increased instability of wellbore (Nmegbu & Ohazuruike, 2014). This is a growing phenomenon in low formation. The best approach to stabilize such formations is always to guarantee that the appropriate mud cake is provided by filling the open-holes with suitable drilling fluids.

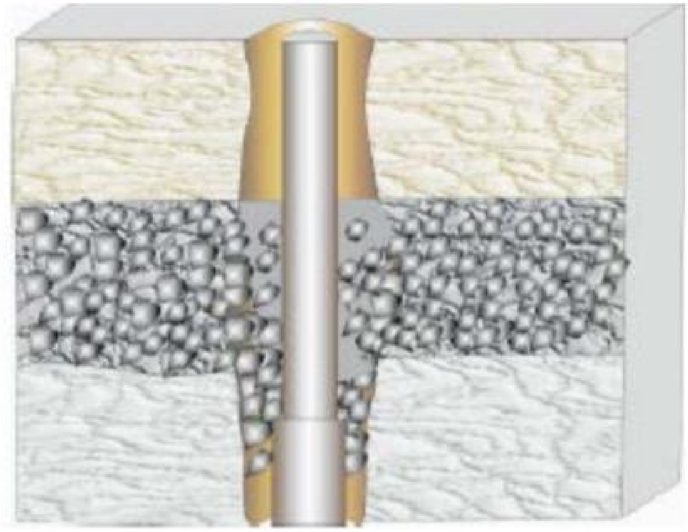


Figure 3.4 Drilling through unconsolidated formations (Nmegbu & Ohazuruike, 2014)

A list of wellbore instability symptoms that are mainly caused during the drilling thru wellbore collapse or convergence, production or completion of a well is seen in table2. They are divided into two groups, direct and indirect. Direct instability symptoms are usually involve over-gauge or under-gauge hole observations, though quickly observed from caliper logs (Mohiuddin et al., 2001). Caving from the wall of wellbore, circulating to the surface, and filling of the hole after tripping affirm that spalling processes occur in the wellbore. Massive amounts of cuttings and/or cavings, in excess of rock volume that could have been unearthed in a gauge hole, likewise confirms the enlargement of the hole. Supplied the fracture gradient has not been surpassed and vuggy or naturally fractured formations have not been found, a necessity for cement volume exceeding the calculated volume of the drilled hole is however a direct indication that enlargement has taken place (McLellan & Wang, 1994).

Table 3.1 Symptoms of Wellbore Stability

Direct Symptoms	Indirect Symptoms
Over-size hole	High drag and Torque (Friction)
Under-gauge hole	Drill string hanging up, Coiled tubing or casing
Excessive cuttings volume	Excessive Circulating Pressure
Surface Cavings	Pipe Stuck
After filling hole filling	Increased Vibrations in drill-string
Excessive volume of cement required	Failure of drill-string
	Problems od deviation control
	incapability to run logs
	Gas leakage in the annular as a result of poor cementing job

	Keyhole seating
	Enhanced doglegs

3.6 Prevention of Borehole-Instability

Total borehole instability prevention is unreasonable, primarily because the rock could never be returned to its original conditions (Pašić et al., 2007). The drilling engineer however diminish the troubles of borehole instability by implementing good practice. The following practices comprise.

- Selection and maintenance of suitable mud-weight
- The proper hydraulics use to regulate the equivalent circulation density (ECD)
- Proper selection of hole-trajectories
- The application of borehole fluid compatible with the drilled formation

The following are extra field practices:

- Reducing time spent in open hole
- Use of offset-well data (use of the curve)
- change in the monitoring trend (circulating pressure, torque, drag, fill-in during tripping)
- Sharing and collaborating information (Pašić et al., 2007)

4. CHAPTER FOUR: DRILLING OPERATIONS AND THEIR EFFECT ON HPHT WELLS

Underbalanced drilling (UBD) and managed pressure drilling (MPD) are becoming new options to use over the past 20 years instead of technology of conventional drilling. This new technology fills the gap of some problems, but innovative ideas and techniques are still needed to overcome the risks of blowouts and the problems of well control.

4.1 HPHT working Conditions:

It includes special equipment, appropriate tools and training to work under HPHT conditions. Advanced planning is an essential part of effective operations; it is often necessary to employ modified operating procedures to address the concerns of HPHT. While errors caused in conventional wells can result in routine loss of time, exceptional diligence is required to prevent disastrous effects for equipment and staff from HPHT operations.

In the ongoing discovery of new hydrocarbon sources, developing tools to suit HPHT conditions and acquire knowledge in working with such conditions continue to allow the petroleum industry to work in deeper depths and in hotter wells.

4.2 HPHT Well construction

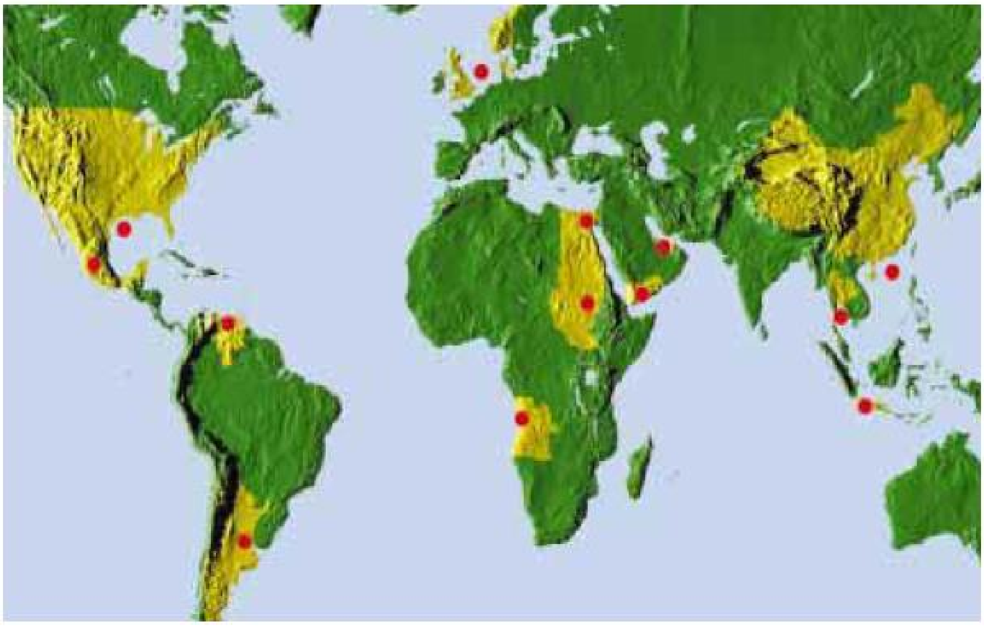


Figure 4.1 Location of HPHT wells worldwide (Adamson et al., 1998).

Well construction principles in HPHT are not substantially diverse from that used in less challenging wells, but issues persist due to conditions which limit the used materials range and influence the performance of the equipment. The error margins are small and there are big failure potential consequences.

Despite the challenges, attention in those wells continued to rise, and observed a steady increase in the number of HPHT wells. Reservoir pressures exceeding 10,000 psi were exploited in several parts of the world especially in gas search High-temperature wells in Qatar, Sudan, Ras al Khaimah, and elsewhere had drilled in the reservoirs where temperatures surpass 300 ° F. Exploitation of reservoirs of 500 ° F (260 ° C) in China is planned in 1998.

There are even more challenging circumstances in which high temperature and pressures, as in the USA, Angola, Yemen and the North Sea, are observed together. This is not uncommon in these regions for temperatures exceeding 350 ° F to present with pressure gradients that require mud weights exceeding 16 PPG (1.9 gm/cc).

Many issues of HPHT well drilling, and completion continue to demand specific attention. Secondary well control, for instance, depend on surface equipment that be able to operate accurately in sevee conditions. Blowout preventer (BOP) elastomers and flexible hoses should be rated to handle the pressure and temperatures for long time to vacate a rig in case of worst situation.(Adamson et al., 1998).

4.3 Temperature & Pressure Challenges & effects on the HPHT Wells

4.3.1 Temperature Challenges

The geothermal gradient on Earth averages approximately 1.4° F/100 ft or 2.55° C/100 m. At that gradient, the threshold of 350 ° F will involve a well depth greater than 6,000 m as shown in figure 4.2. Nevertheless, downhole temperatures most often influenced by natural conditions or outside impacts. Near localized geothermal locations can quickly increasing downhole temperatures faced during drilling.

Steam injection can greatly increase downhole temperatures at extreme shallow depths, utilized to help producing heavy oil. Wells drilled in deep and ultra-deep waters usually contains lower geothermal gradients than the average Earth's. Deepwater wells thus often include high pressure and temperatures below the HT threshold (Smithson, 2016).

Techniques for mitigation of high-temperature depend on both the type of operation and the equipment. Wireline and LWD systems use high-temperature electronics. Barrier for temperature like Dewar flasks may be placed around the tool, though time constraints restrict the operations type which can be conducted by the use of flasked tools. In the Tool seals the Temperature resistant elastomers are used.

Tools utilized in LWD activities typically have lower rating of temperature as compared to the ones available for wireline processes. Due to the continuous circulation of drilling muds thru the BHA, the tools are generally subjected to lower temperatures than those existing in formation. In severe cases, drilling muds can be cooled to protect sensitive BHA components before they are circulated downhole.

The majority of high temperature wells are drilled with oil-base mud. It has developed unique high-temperature OBM which constantly keeps the rheological properties of the mud at elevated temperatures. OBM thermal characteristics are one trade-off to use OBM type. Drilling Wells with OBM generally have higher bottom - hole temperatures than wells drilled with WBM and subjecting downhole tools potentially to high operating temperatures.

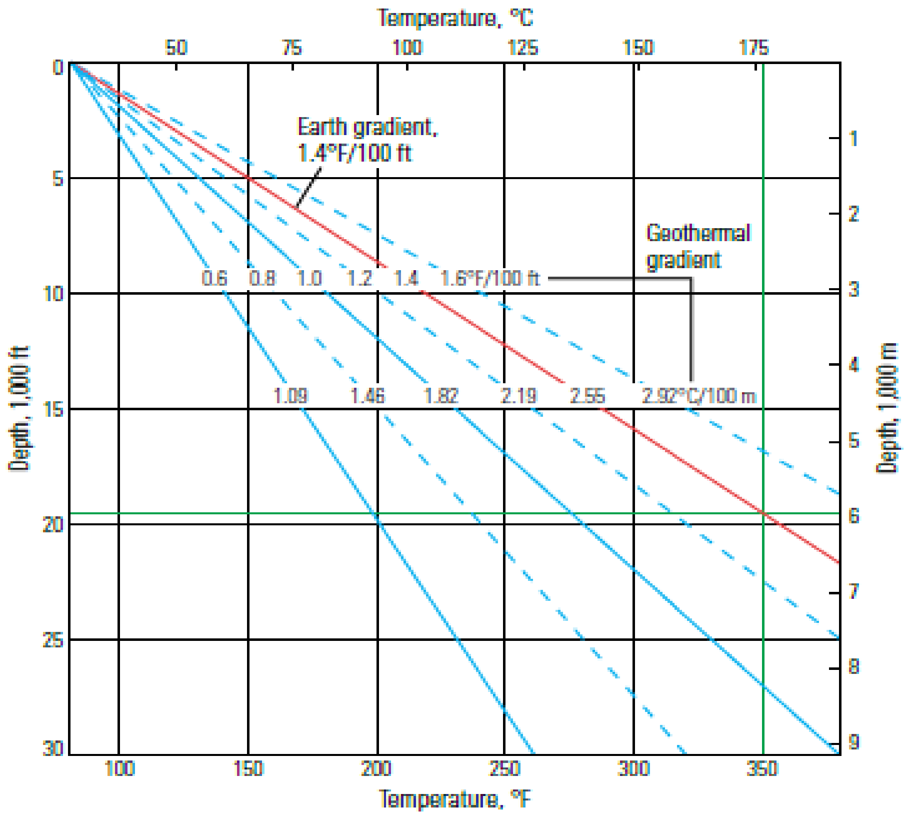


Figure 4.2 Geothermal gradient of earth .

To approach the threshold of HPHT at 350°F (vertical green line) and geothermal gradient of Earth 1.4°F/100 ft (red line), the depth of well would be almost at 6,100 m (horizontal green line). The gradient of temperature differs depending at subsurface conditions and is not generally linear as illustrated in figure 4.2 above (Smithson, 2016).

4.3.2 Pressure Challenges

Drillers are generally the first to deal with the downhole pressure, the fluid pressure within the reservoir rocks pores in particular. Pore pressure rises as depth increases as formations have to overload them (Figure 4.3). Pore pressure follows the increase rate in pore pressure against depth which can change quickly over geological features.

The engineers are using weighted drilling mud to avoid entering formation fluids into a wellbore during drilling. The hydrostatic pressure created by the drilling mud in the wellbore counteracts the pressure from the formation pore and prevents fluid inflow. Drillers therefore have to predict the pressure of formation before drilling into a formation.

By using a hydrostatic gradient, engineers often evaluate pressure depends on the sea-water density for determining a normal pore pressure. To reach the HPHT threshold of 15,000 psi, such a well will involve a depth greater than 35,000 ft. Nevertheless, hydrostatic pressure higher than the predicted one by the normal pressure gradient is usually need to overcome pore pressure of reservoir due to geologic features and varying overburden forces.

It is not uncommon to drill high pressure wells by the use of mud density which are more than usually twice density of sea-water. Over-pressed formations, those with higher pore pressure than normal, may be exist at shallow depths. Today's ultra-deep wells can reach depths of more than 10,700 m and their hydrostatic pressure increases more than 30,000 psi. These extreme pressures are exposed to drilling assemblies, wireline logging tools, LWD tools, well testing and completion tools, and well-intervention tools.

Design engineers are focusing on sealing and metallurgy to minimize the effects of high pressure. The oil and gas industries adopted metals and alloys usually used for the nuclear energy and aerospace sectors. However, the using of these materials in applications of oil and gas is often constrained by limitations of the wellbore size. This is particularly favorable for Deepwater wells where some of the high pressures are encountered, logging and drilling tools should resist high pressure and similarly should be suitable for wellbores of small diameter that are common for ultradeep wells. Materials used in the sealing parts can seal toward extreme pressure, often at high temperatures, and without fail, they might just have to withstand several pressure cycles.

The downhole pressure related risks are not just for the equipment being used here. When testing, completion, and processes of production are conducted at the surface with high pressure, a potential risk to personnel that are working along with the equipment will present. To afford such risk and make safe performance of wellsite operations, engineers use equipment designed to operate above the anticipated maximum-pressure. The maximum full-system pressure based on the lowest rated element in the full string (Smithson, 2016).

To guarantee the properly designed equipment used, operators must know in advance the highest possible pressure. Pressure control capabilities impact directly on equipment design choices. Pressure hardware is rated for maximum anticipated-pressure, the ratings dictate material thickness and selection, configuration of elastomers, mechanisms of sealing and components for pressure control. The equipment is calibrated above the maximum pressure before using it to ensure operations can be carried out safely.

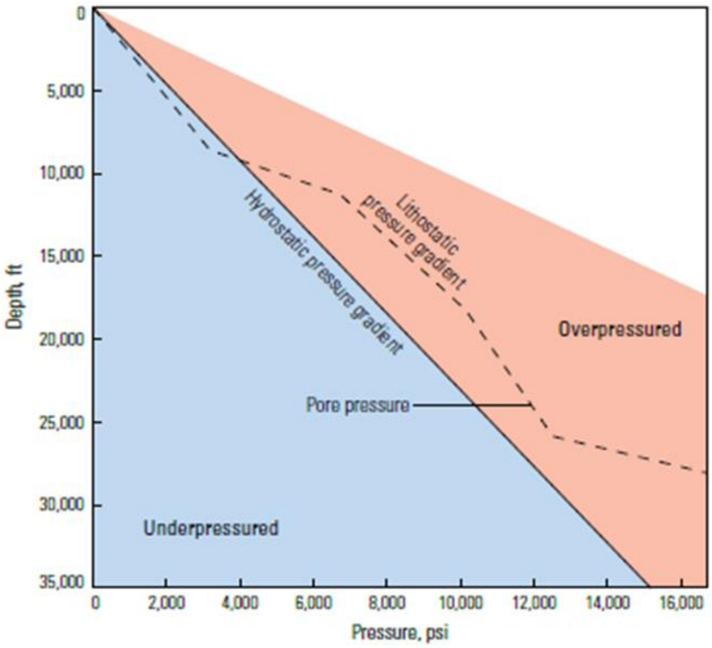


Figure 4.3 Pressure gradients.

The black line is hydrostatic pressure gradient, is 0.43 psi/ft. Dashed black line represents the gradient of lithostatic pressure. Under pressured reservoirs (blue) may contain pressure lower than the hydrostatic gradient; over pressured (pink) have pressures more than the hydrostatic gradient (Smithson, 2016).

4.3.3 Temperature effect

Temperature of mud can rapidly change, based on the drilling process, at a particular depth in the well. When mud pumps are turned on, cold mud cools down the annulus lower part, while flowing hot mud heats up the upper part of it. These volume changes may be interpreted as a "false kick" incident due to temperature increasing (Rommetveit et al., 2003)

4.3.4 Pressure effect

Variations in pressure in HPHT wells are increased compared with traditional wells. There are some explanations for that (Rommetveit et al., 2003).

1. As the mud density increases the hydrostatic pressure will change more.
2. Changes in frictional pressure may occur, due to variations in wellbore rheology.
3. Frictional pressure would be higher. Changes in rheology cause the flow regime to a transition from laminar to turbulent flow.
4. More critical pressure by surge and the swab.
5. Mud rheology is based on the history of the shear. During circulation, breaking gels induce rapid peak pressure in the lower hole (Rommetveit et al., 2003).

4.4 Drilling Tools in HPHT wells

HPHT wells classification was defined by the limitations of drilling equipment and the tools provided on the market by manufacturers. The electronic tools and seals may be coated or used with metal seals to resist the effects of temperature when temperatures do not pass 400 ° F. The tool's exposure period is critical. The large percentage of tools and equipment used in Ultra HPHT wells were unable to function because the duration of high temperature exposure is less than the time of travel to bring it down. (Ruiz, 2016).

It is required to take intervals of movement and mud conditioning to make a trip out or a bottom trip. As described above, it is important to take the drilling mud under rigorous laboratory tests and the good rheological characteristics that enable the development of hydraulic models. Pumping and stability of fluid temperature in short time periods will avoid of weighting agents settling and additive degradation.

When a temperature more than 185 ° C is verified with static conditions, the opportunity of real-time logging is quite low, and the use of drill strings without bottom tools / rotary systems must be deemed a priority, as no service provider can guarantee optimum operation of the tools in these range of temperature. That is why, regarding the well trajectory, in Ultra HPHT steps, using slick drill strings, pendulum drill strings and short lock drill strings may be not only the last but possibly the only choice. The design team must realize that despite using modern tools using thermal coatings and ceramic materials, these are incredibly costly, limited in operation and dangerous to use due to the time it takes to repair or change the assembly (Ruiz, 2016).

Drilling experience recently acquired for the latter stages or target steps with temperatures exceed 190 ° C has helped to achieve an economic balance (tools cost / equipment and operation time) with the best choice not to use logging during drilling (LWD)or measuring during drilling tools (MWD) and drilling with the assembly of short lock and wireline logging. But this considers a risky decision, which a multidisciplinary community must test on the basis of the successful design period (Figure 4.4).

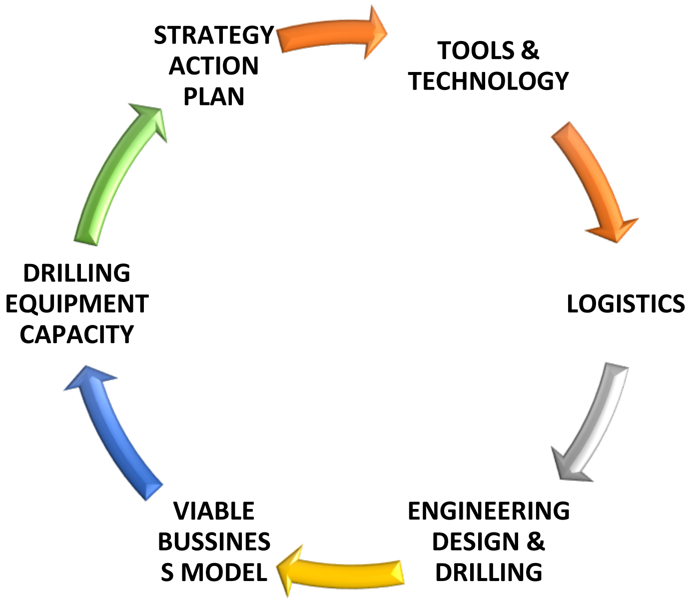


Figure 4.4 Effective Design Cycle.

Represents each of the important parts for building and integrating reserves into an effective exploratory project. These parts are the disciplines needed to successfully design an exploration well of high risk (Ruiz, 2016).

4.5 Drilling Operations under HPHT Conditions

A drilling fluid called mud is pumped -down the drill string in drilling operations and start to flow while the drill bits in the bottom hole. Seen in (figure 4.5), taking cuttings collected from the well flows up in the annulus of the well at the moment. This is often used to sustain the pressure on the annulus at an expected stage. Regulating pressure in whole operations is severe, because the pressure is within a certain range. In fact, it must be more than pore pressure in order to stop an unfavorable influx to the well adjacent formations, to reduce the fracture pressure of adjacent formations to prevent well fracturing (Malloy & Roes, 2007).

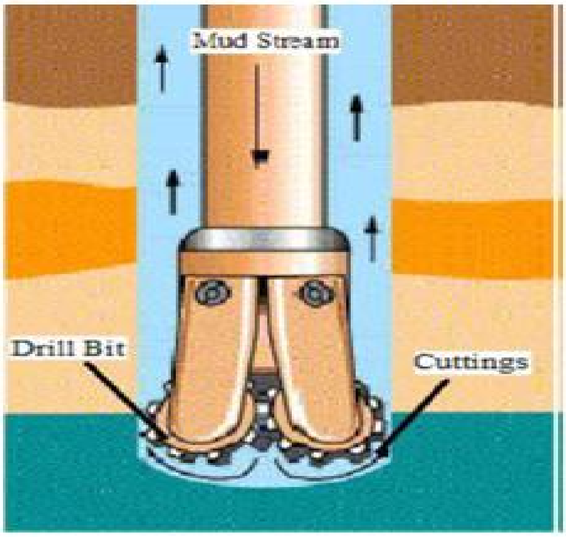


Figure 4.5 mud circulation in hole

Gas and oil industry is represented by two technologies of fluid which are; Underbalanced Drilling predates and Managed Pressure Drilling (MPD). But there are some similarities in some techniques, as seen in figure the implementations are different for various styles such as underbalanced drilling, conventional drilling and MPD. In this part I concentrate on explaining the significance of UBD and MPD operations in the HPHT wells.

The goal of Underbalanced Drilling and managed drilling pressure techniques for Environments with High Pressure High Temperature (HPHT) is only created to provide it separately and independently. It indicates there is some confusion pertaining to this operation's technique (Malloy & Roes, 2007), (Stone & Tian, 2009).

Over the past three years, significant developments have been made in the results of managed pressure Drilling (MPD) technologies to enhance well control, operating safety and performance concerns of high-pressure high-temperature wells (HPHT) and drilling in deep water. Underbalanced drilling (UBD) is employed in depleted, tight formations and for exploitation of shale gas and production improvement of well control where early kick indications are detected and MPD techniques are implemented on the structures at narrow margins to sustain a steady bottom hole pressure.

The latest developments of modern methods are successful advancements in managed pressure drilling technologies by utilizing these HPHT methods progresses to serious by UHPHT and XHPHT drilling (Stone & Tian, 2009).

4.5.1 Underbalance Drilling technology (UBD)

Underbalanced Drilling (UBD) technology is mostly distinct from (MPD) but identical in several respects. UBD operations are purposely engineered to work while the formation pore pressure is greater than the pressure of the bottom hole. The benefits of drilling through a pore pressure higher than hydrostatic heading are mostly decreased disruption to the rock, improved penetration rate (ROP), and less risk for circulation problems and differential stick. Disadvantages involve a possible decrease in stability of wellbore, environmental issues with respect to toxic gases in high pressure conditions and rising costs (Stone & Cress, 1997).

As the (BHP) is less than formation (pore) pressure, influx fluids within the wellbore is a normal part of the process. (UBD) facilities are fitted with surface machinery capable of managing such influx. A sealed circulation mechanism stops the fluids of the wellbore from touching places where there are humans and potential causes of ignition. However, UBD is not advised where there is a chance of released gases like H2S gas that release concentrations on the surface of ground.

While UBD had performed on land since years with perfect consequences, due to the safety issue of allowing influx fluids of formation to the surface and state of the process flaring of hydrocarbon in the offshore industries was reluctant to adopt the technology. The major variation among (UBD) and (MPD) is that the fluid formation will influx to surface in (UBD), but not in (MPD).

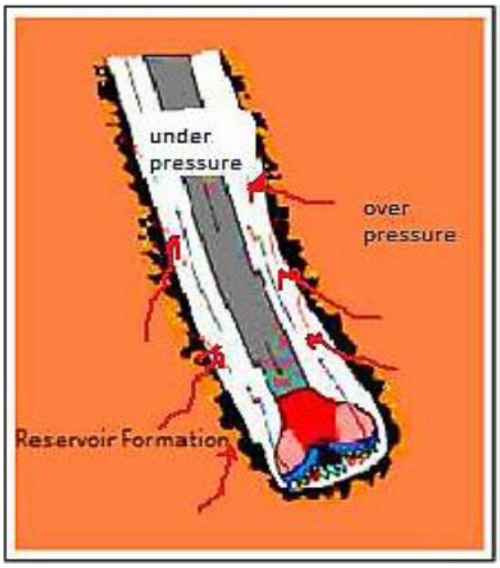


Figure 4.6 Under-balanced Drilling UBD (Stone & Cress, 1997)

4.5.1.1 Using underbalance drilling

The formation fluids influx should be managed in underbalanced drilling technology in order to prevent problems with the well control. In the above scenario, the fluids in the surface will move to a closed system to monitor the wells and hold the closed system of (BOP) while drilling. This case is illustrated in the figure below, as shown below (stone1997).

There are six categories of (UBD) techniques “that is used if the need for UBD technique while service is needed” which are listed below:

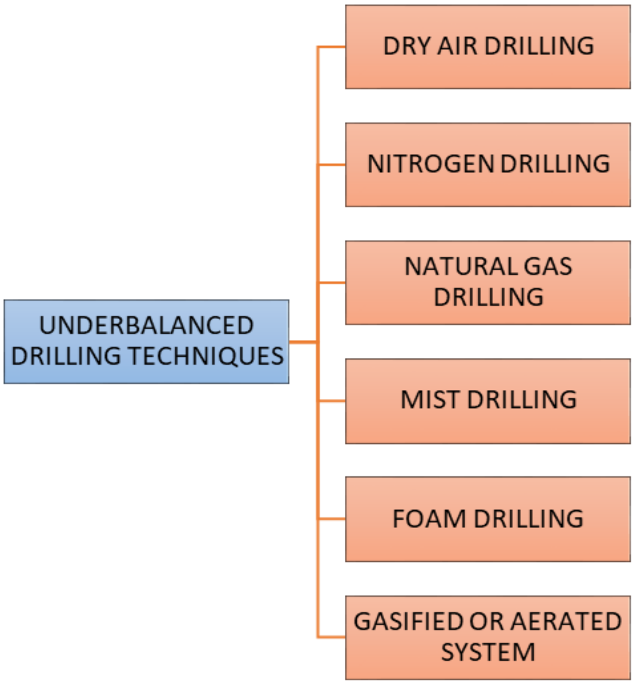


Figure 4.7 UBD technology techniques diagram

4.5.1.2 Limitations and benefits of UBD

Benefits

- Formation damage reduction
- Rate of penetration increasing
- Stimulation job reduction
- Bit life increasing
- Loss circulation reduction
- Environmental damage will be less
- Differential sticking probably reduction

Limitations

- Failure to keep underbalanced conditions during the drilling process.
- Concerns of wellbore stability.
- Cost of operation increasing.
- Difficult operation in zones that have high permeability.
- The opportunity for hazard.

4.5.1.3 Improper cases for Underbalanced Drilling technology

Underbalanced drilling is not good using for all natures of reservoirs as it is mentioned, therefore there are some cases or kinds of reservoirs which are not appropriate for (UBD). This is the list of situations where underbalanced drilling can't be done (Gaurina-Medimurec et al., 2006);

- formations of reservoir with pore pressure is high and with permeability is high also are not appropriate to the underbalanced drilling technology, since there are often a high rate capacity that needs additional equipment at the surface rendering it inefficient and other safety concerns are involved with such reservoirs. On the other side, overbalanced drilling may be successfully applied to these reservoirs.
- Continuous underbalanced requirements in shallow reservoirs are also impossible to manage, so underbalanced drilling can be difficult extended to shallow reservoirs.
- Underbalanced drilling is therefore not appropriate to swelling shale and formations which be unstable as wellbore stability is a major problem through the whole drilling operation in such environment.
- Formations that involve large percentage of H_2S fluids are not ideal in underbalanced drilling. High levels of H_2S bring complexity to device design for under-balanced drilling and pose risk to safety (Gaurina-Medimurec et al., 2006).

4.5.2 Variations between UBD and MPD

In narrow margins (UBD) and (MPD) may be utilized where standard drilling is not appropriate. UBD is primarily used to minimize formation damage as well as improve efficiency, whereas MPD can be used to tackle similar purely drilling problems and more effectively drill.

Both (MPD) and (UBD) are used to reduce the well-building period for making some field drilling, evaluation and growth that is too expensive in the industry today. Many workers attempting (MPD) in fractured carbonate formations, since this improves drilling effectiveness. Both (UBD) and (MPD) may have the benefits and drawbacks of well protection and mud losses costs associated with NPT.

Well control in the preparation of well is the most critical question. MPD doesn't mean primary well control, but it can improve problems of well control as well as safety issues, particularly for wells with (HPHT) environments in extreme conditions and drilling operations in deep water and even in fractured formations where the drilling mud is lost is essential to the overall, and often high hydrocarbon concentrations into the wellbore (TEmeh, 2002).

4.5.3 MPD definition

An efficient drilling mechanism in which the pressure in annular profile is accurately controlled in the wellbore. The goal is to decide the environmental down pressure limits as well as to control the annular. Accordingly control the annular hydraulic pressure model. MPD is meant to prevent the continuous influx of fluids from formation and it reaches the surface (Gala & Toralde, 2011).

Alternatively, utilizing a mixture equivalent circulating density, density of mud and backpressure, MPD drills overbalanced when sustaining slightly constant or accurate pressure of the bottom hole. To achieve this, the equilibrium of pressure in a closed system is kept as shown in the figure.

While the price of oils decreasing, the demanding of drilling rigs for offshore will increase in rates of rig daily this reason will push for more efficient drilling. When we want to reduce (NPT) in offshore then we will use (MPD) technology. MPD lead to reduce costs of drilling. It is conducive to drilling challenging wells in mature environments with narrow windows of pressure.

In 2005 Hannegan reported, 75 percent of all U.S. land-based wells are drilled at either one part with (MPD), (UBD), or other form of compressible fluid type.

This figure was around 10 percent ten years prior (Medley & Reynolds, 2006). The offshore industry has seen growing amounts of applications for (MPD) technologies during the last few years.

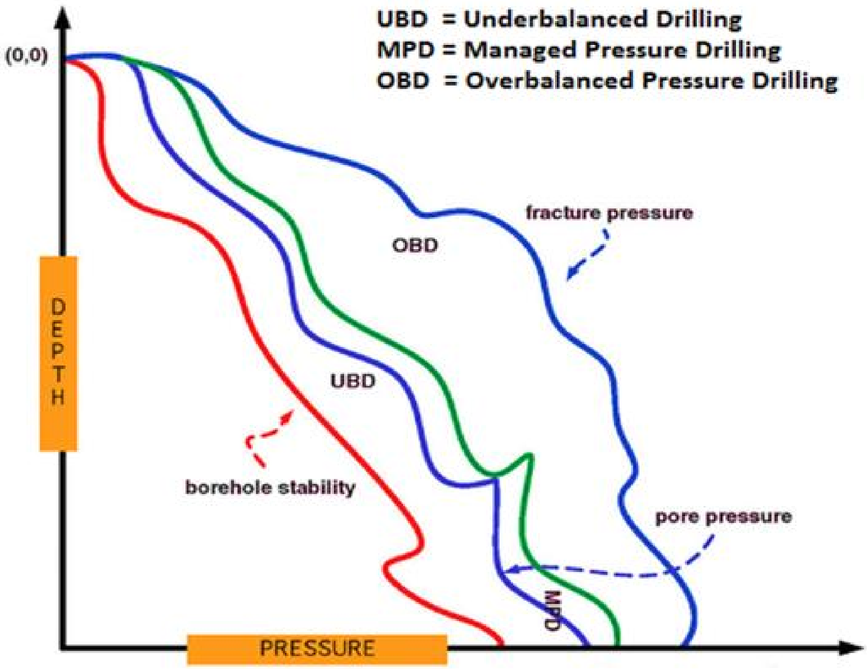


Figure 4.8 Drilling window; pressure vs. depth (Galla 2011).

4.5.3.1 Types of MPD

There are two types of MPD operation:

Reactive

- Practices of standard drilling are carried out, but the rig is fitted with (RCD), float and chock valves if there are sudden change in regime of pressure
- Successful on a well control basis as standby helps the down pressure of the hole at an uncertain time.

Proactive

- Used for minimizing drilling hazards and decreasing (NPT) through casing, fluid and open hole programs changes.
- From the beginning, the fluid and casing systems are built to take maximum benefits of the potential to monitor pressure changes in the well with greater accuracy. This group is sometimes named 'walk the line'.

This type of MPD has been performed on issue wells since years, it was only within the last few years the proactive MPD operations gained substantial publicity (Medley & Reynolds, 2006).

4.5.3.2 MPD Techniques

MPD comes in four main variants figure (4.9). Combinations of variants are commonly performed on the exact challenging future. It is anticipated that the use of many variants on the same target would become more common as the technique become much of a state in the brain's makers of drilling planning and as targets grow more challenging to drill (Bernt et al., 2009). The four major MPD varieties appear in the diagram below (Bernt et al., 2009).

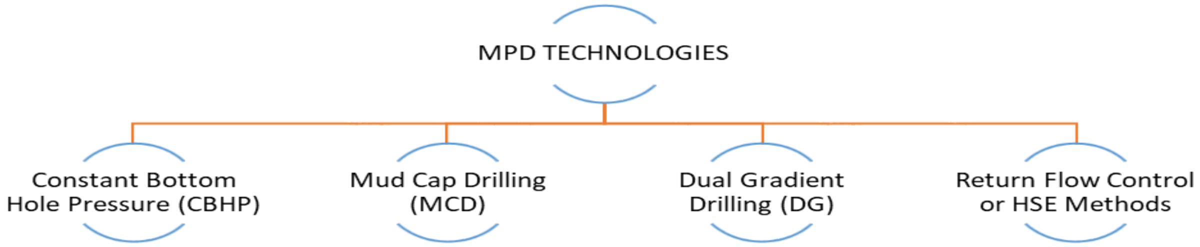


Figure 4.9 MPD varieties

4.5.3.3 Managed Pressure Drilling (MPD) in HPHT Wells:

Many of the existing resources of hydrocarbon opportunities worldwide would prove more difficult to explore than those experienced in the history. Indeed, many would say that the simple ones have been drilled up already. And with oil prices as today, it couldn't be more essential to drill safely and cost efficiently while providing a successful product well (Ali et al., 2014).

Taking into account all these, managed pressure Drilling can be regarded as a technique that can offer a significant improvement in cost effective drilling ability by minimizing unsustainable costs related to drilling usually associated with traditional offshore drilling, if the remainder of the world existing oil and gas scope is to be taken into account for conventional techniques

Managed Pressure Drilling (MPD) also as drilling technology is the product of the high (NPT) costs incurred by the near similarity between fracture pressures and formation (pore) pressures typical to deep-offshore/offshore, depleted reservoirs and (HPHT) as well as certain drilling operations on the land. (MPD) is an use the of wellbore pressure management methods, and involves a variety of concepts explaining procedures and equipment built to restrict loss of circulation, differential sticking and well kicks in an attempt to minimize the amount of extra casing strings needed to achieve complete depth (Ali et al., 2014).

The use of (MPD) variations in drilling across mud weight with narrow windows has lessened drilling risks, improved drilling efficiency, dramatically minimized drilling costs and made it possible to drill reserves prior estimated as economically undrillable The MPD approach called as Constant Bottom Hole Pressure (CBHP) typically refers the pressure in annular well is Which means the (BHP) is held inside a window enclosed by the fracture pressure and pressure of the pore. An additional back pressure from the surface through a rotating choke device (RCD) is needed to get this good control of the (BHP).

The back-pressure concept is very important to (CBHP) performance in managed Pressure Drilling and it has become necessary for drilling engineers to provide a method that can accurately measure the back pressure required to sustain (CBHP).

We need to estimate back pressure to sustain (CBHP) during drilling, using the MPD technology, based on the problem previously indicated. This is to ensure that the back pressure is established to a large degree of precision, such that the most time-friendly and cost-efficient approach to drill effectively into formations at narrow window of mud weight without losing protection and consistency is accomplished.

The optimization of the (MPD) modification of the (CBHP) was examined. The (CBHP) usually used to define steps taken to mitigate or reduce the impact (ECD) or loss of circulating friction in an attempt to maintain and within limitations imposed by the fracture pressure and the pressures of the pores (Ali et al., 2014).

4.5.3.4 Pressure control in MPD operations

The MPD system known as (CBHP) applies to a mechanism where pressure in an annular of a well is maintained at a particular depth steady or near steady, with the pumps on/off mud. Steady implies sustaining (BHP) inside a range defined by a lower and upper limit of pressure. Often known as the Margin is the variance between two limits. On the low boundary, the margin is usually encountered by the wellbore stability and pore pressure, whereas on the high boundary, loss of circulation, fracture pressure, differential sticking will bound it.

This relation can be mathematically expressed as;

$$P_p < P_{wbs} < BHP < P_{ds} \leq P_{lc} \leq P_f$$

Where:

Pp is a pore pressure

Pwbs is a wellbore stability

BHP is a bottom hole pressure

Pds is a pressure differential sticking

Plc is a pressure of loss circulation

Pf is a fracture pressure

Under-hole pressure is conventionally described as;

$$BHP = P_{hydrostatic} + P_{APL}$$

Where:

BHP is a bottom hole pressure

P hydrostatic is a Drilling fluid exerting hydrostatic pressure

PAPL is a loss of an annular pressure from the circulating drilling fluid

The above equation occurs while the pumps of mud are on and mud circulates. if the circulation stops or if pump off, PAPL = 0 makes the pressure of the bottom hole equal to the hydrostatic pressure only.

$$\boldsymbol{BHP = P_{hydrostatic}}$$

Hence;

The above equations describe the static and dynamic (BHP), in an opened system of circulation, in which the drilling fluid pumps while the surface tubing open towards atmospheric pressure from the wellhead. In a closed system the drilling fluid pumps under pressure out of the wellhead.

When the system is open, the way to sustain (ECD) at dynamic (BHP) is with the usage of circulation system which is continuous when the pumps of rig are off. This failure to sustain a (CBHP) in an open system restricts drilling with just the (PAPL) and hydrostatic pressure to control the pressure.

Apart from circulation system that is open under which the drilling mud pumps out of a well under atmospheric pressure, circulation system which is close will block the wellhead and adds back pressure of the surface to the mud in an annulus by limiting its flowing while a manifold of choke.

In a closed system, the bottom-hole pressure becomes;

$$BHP = P_{hydrostatic} + P_{APL} + P_{bp}$$

Where:

Pbp is a back pressure on the surface

Then we obtain while the pump is just off;

$$BHP = P_{hydrostatic} + P_{bp}$$

It is by controlling this back pressure that (BHP) is sustained at a constant magnitude from dynamic condition to static, means when pump on to pump off (Ali et al., 2014).

4.5.3.5 Aim of managed pressure drilling

MPD's major aim is to supply a tool, as contrary to conventional methods, of efficient, fast and accurate control of the (BHP). As we clarify in Figure 4.10, In (MPD), the annulus is sealing off at the upper and rotate control instrument to direct the flow of mud from of the annulus to an adjustable opening choke valve (Stamnes et al., 2008), (Godhavn, 2010).

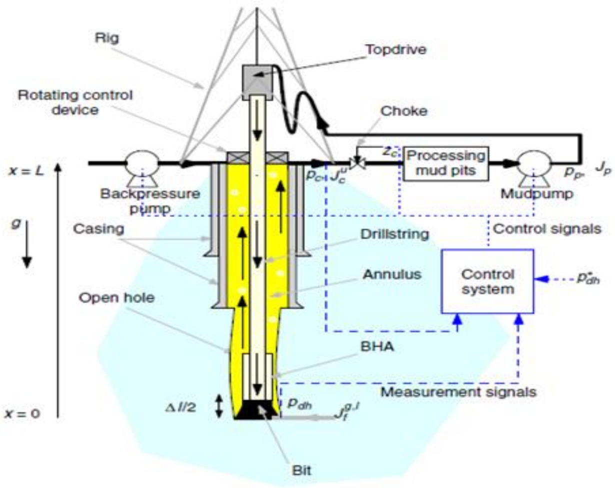


Figure 4.10 Simplified schematic of a drilling system with MPD equipment (Naderi Lordejani et al., 2020).

A model of design is often much easier than a model of simulation because it typically includes only the dynamics of mass transport, ignoring the drilling systems distributed nature (Pedersen et al., 2018). The following are many aspects of drilling which may be detrimental to an automated MPD:

- Pressure wave propagation: Controllers of Pressure usually rely on simple models wherein pressure dynamics are partially or totally ignored (Pedersen et al., 2018). In case of gas influx in the borehole, the important time scale related to these dynamics could be in the scope of tens of seconds, or even minutes. Not only the control performance can be deteriorated by such dynamics, but they can also create instability (Pedersen et al., 2015), if not taken into account for throughout the controller design phase.
- Flow dynamics in the drill string: In many cases, the flow dynamics in the drill string are neglected throughout the controller design stage, whether slow or fast. However, this part can make an important contribution to behavior of system. Thus, in practice the performance of the closed-loop from simulation studies can be even worse than expected if system aspects imposed by the string are neglected in the design model.
- Nonlinear drill bit behavior: When the flow path of drill string is neglected in the design model, the drill bit is replaced with an independent flow source. However, the flow via the bit is nonlinearly depends on the dropped pressure over the bit. This nonlinearity can be detrimental especially in the case of standpipe pressure control during gas influxes.

- Model variable structure: This variable structure is mainly induced by the existence of a non-return valve in the bottomhole assembly. Usually the non-return valve remains closed during operations such as pipe connection, changing system properties and behavior.

- Variations in the flow path cross-sectional area: These variations, particularly those in the annulus, may contribute significantly to the frequency response of a drilling system. These aspects can thus compromise control performance if not included in the design model (Stamnes et al., 2008).

4.5.3.6 Synergies between MPD and HPHT

Typically, the initial driver for MPD is a need to handle small margin sections, defined by a narrow area between the gradients of the pore pressure and fracture. That makes it an important in HPHT wells where the norm is narrow margins. Loss or gains, high gas levels, and/or problems with borehole instability on offset wells will typically have been observed. However, once an HPHT project has been introduced the MPD, additional synergies could be noted where MPD offers a solution to other conventional HPHT challenges. These synergies happen in four main areas as outlined below:

- Design of well
- Selection of mud weight
- Well control
- Drilling operations

4.5.3.6.1 MPD System Functionality

Designing an MPD system with the proper functionality is important to suit the application. During the rig modifying phase, reducing functionality in order to reduce costs or perceived complexity is often tempting. Nevertheless, a higher functionality level often proves valuable during the operation, especially when the conditions under the surface differ from the prognosis. The following functionality must be considered: (Cadd et al., 2017)

4.5.3.6.2 Upstream of MPD Package:

- Primary flow line from RCD to MPD choke: used during normal operations to receive returns and implement SBP.
- Secondary flow line from BOP to MPD choke: used to recover and apply SBP while the BOP is closed, whether due to the high gas levels, exceeding RCD ratings or in case of RCD leakage.
- MPD backpressure pump flow line: utilized to pump through the MPD chock to implement SBP throughout connections and any other pump-off activities like MPD flow controls.
- Flow line cement pump considers as redundancy for MPD backpressure pumps. Beneficial for tested offline pressure and line flushing.
- Trip pump flow line: designed to perform flow checks when the RCD bearings are configured but no SBP is required.

4.5.3.6.3 Downstream of MPD Package:

- Return line to rig flowline: Used during routine operations to take returns from the MPD package back to the circulation system.
- Return line to MGS: used to receive returns from MPD to the MGS once levels of gas are high. The preferred path is a direct line to an inlet of spare MGS. If it's not possible, a tie-in to the side of low-pressure in the choke manifold of rig would be the only choice for using the existing tie-in to the MGS. For this sort of setup, specific valve control is needed to ensure that the MPD and the systems of well-control in the rig are not in communication.

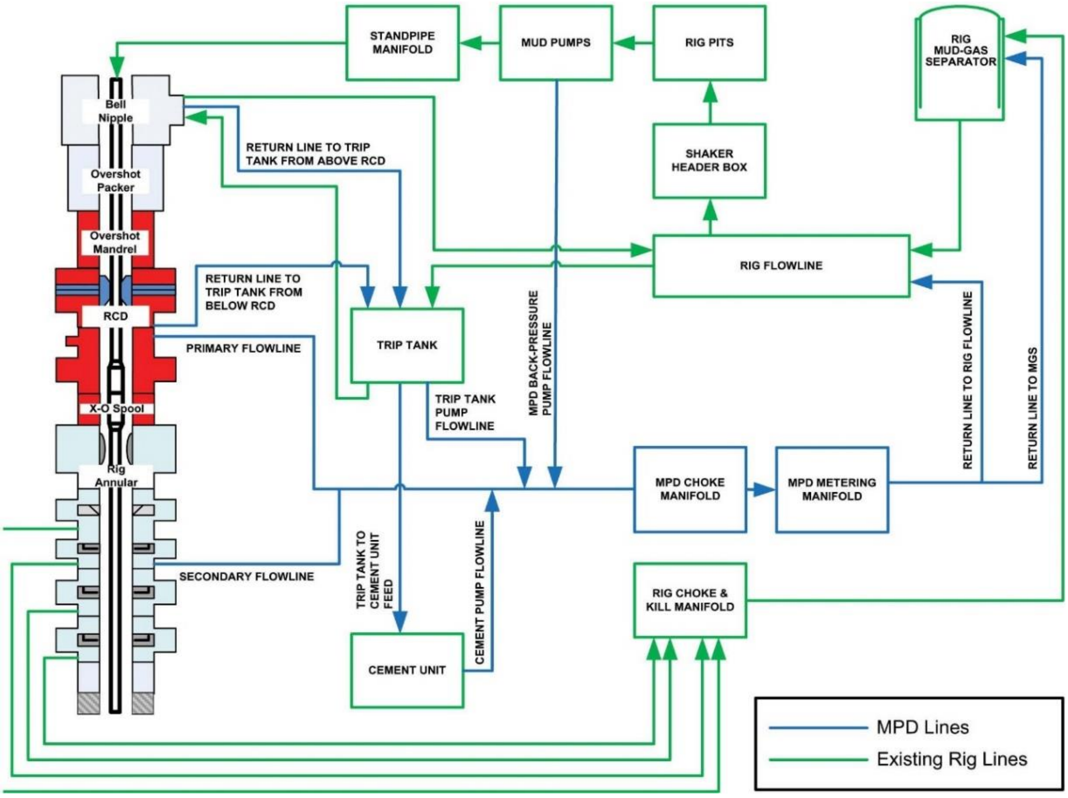
4.5.3.6.4 Auxiliary Lines and Equipment:

- Return line from above RCD to Trip Tank: being used to check leakage above RCD.
- Return line to Trip Tank from below RCD: being used for bleeding off trapped pressure between the BOP and RCD, for monitoring leaking above the closed BOP and for circulation in the trip tank below the RCD when exiting without the application of SBP.
- Trip tank to cement unit feed helps the trip tank to circulate in a closed loop when applying SBP. This is beneficial for MPD FITs and MPD flow checking because SBP is needed and control of the volume is important.
- PRV lines: Used to release excessive pressure. There is usually one upstream PRV of the MPD chokes, and one downstream part of the system is protected by PRV.
- Back-Pressure Control Valve: The Coriolis meter gives precise monitoring of the flow out, but the quality of data is sensitive to large gas levels and turbulence associated with the high pressure drops throughout MPD chokes. When encountering high gas levels, additional back-pressure must be applied downstream of the Coriolis meter through a back-pressure control valve (generally 100-200psi) (Cadd et al., 2017).

4.5.3.6.5 Electrical scope:

- Stroke Counters: All cement unit and mud pumps require extra stroke counters configured directly to the MPD system to transfer data. For calculating annular friction, the MPD hydraulics model depends on counting of real-time stroke, which specifies the needed SBP. Using the data system of the rig to take stroke counter data that introduces inappropriate lag time and will result in poor choke efficiency and BHP variability.

- Data transfer: extra cables are required for data transfer between third party systems, the control system of MPD and the data system of the rig. Interface tests should be performed in ahead of time so that troubleshooting time is allowed.



- Figure 4.11 Flow Diagram of MPD process (Cadd et al., 2017)

4.5.3.6.6 Importance of MPD in HPHT situations

Drill to the targets

- Exploration drilling, appraisal or difficulty of wells development, such as deep water, HPHT.
- Drilling non drillable tight gradients of pore / collapse / fracture pressure.
- Drilling non drillable fractured carbonates where it is impossible to circulate over-balance (Bernt et al., 2009).

Cost saving

- Decreases occurrence of loss/kick.
- Minimize spent time for dealing with events of well control.
- Detect kick/ losses at early time.
- Optimize the number of casing.

Safety

- Trip safely
- Mitigate the hazard of H2S from rig floor
- Drill safely the HPHT wells (Bernt et al., 2009).

4.5.3.6.7 Benefits of MPD Technology

The MPD system generally decreases the additional overbalanced pressure exerted to a formation while traditionally drilling. The technology will also help to control the ECD and help avoid any fluid from entering into the wellbore, but in the event that this happens, the surface backpressure adjustment (SBP) allows for a much faster response, minimizing the effects of the influx. Second, circulate the kick out of the well by maintaining the same drilling pump rate that minimizes kick circulation time and thus improves the overall drilling operations. So, it was possible to minimize or eliminate the unproductive time contributed to lost circulation, stuck pipe, well control events.

Other goals that can be accomplished with using MPD are:

1. Enhance safety by isolating and diverting the well 's returns.
2. Instant bottom hole pressure control to reduce the time required to change the mud system in case of kick / loss occurrence or incidents of stuck pipe.
3. Evaluating the actual pressure limits of the formation by checking real time data and identifying the actual drilling window by conducting tests of pore pressure and integrity tests of the formation.
4. Increasing the ROP and efficiency of drilling by reducing well overbalance and drilling near as possible to balanced conditions.
5. Developed flow monitoring and control system, inclusive of the rig pit volume, helps in early detection of kick.
6. Small inflows diagnosed early by MPD system are quickly and safely controlled, without interrupting the drilling operations. The increased number of Pore Pressure Tests performed enabled better characterization of the formation, in order to avoid the use of unneeded high pressures to maintain the well overbalanced.
7. Well shutting at RCD while keeping rotation to prevent stuck pipe, in case of well control within the MPD limitations (Muhammad et al., 2020).

4.5.3.6.8 HPHT wells hazards

Most of hazards associated with drilling HPHT wells have to do with over-pressed formations. Optimally, such wells will be drilled with sufficiently high mud weight to grant comfortable margin of safety over pore pressure. The job of the mud engineer is formulating the mud would therefore be comparatively straightforward: reduce damage to the formation and maximize rate of penetration.

Overpressed formation has become a big issue once the fracture pressure in the over-pressed zone is close to that. This outcomes in drilling conditions where kicks are easy to take and fractures may be inadvertently initiated, leading in hard to control fluid losses.(Adamson et al., 1998)

4.5.3.6.9 Future Optimization for Integrating MPD into HPHT Wells

MPD moves into HPHT drilling mainstream but remains a technology that is developing with significant guide for future advancements. MPD Providers, Contractors of drilling, and Operators should pursue the following developments to get better integration with HPHT operational activities:

- MPD control systems placed into rigs; Contractor of drilling is owned and operated.
- Enhancing hydraulic modeling of casings and liners to support Managed Pressure Assisted Cementing development.
- Smart PRVs which adjust their flow rate set points. The formation can be protected from over-pressure without changing the PRV settings manually when adjusting the flowrate.
- Coriolis meters for accurate flow-in readings, fitted to rig pumps. They would enhance the hydraulic model by discarding uncertainty about pump efficiency.
- Drill string NRVs with increased reliability, wash-out resistance and LCM robustness.
- Remote operating capacity to reduce the crew at the wellsite (Cadd et al., 2017)**.**

5. CHAPTER FIVE: WELL CONTROL & ITS APPLICATIONS IN HPHT

In oil industry operations, well control is an important aspect. Training of human resources on the well control is of utmost importance in order to perform safe operations. With oil and gas exploration, mostly no remaining fields able to be developed easily (Rui et al., 2017). Challenges for well drilling such as extended reach drilling more than (8000 m) sub-salt drilling, drilling in the high-pressure high temperature (HPHT) conditions, sub-salt drilling and Deepwater drilling are growing (Chen, Xuyue, et al., 2018).

5.1 Wells control problems in HPHT conditions

There are many well control issues, but we need to concentrate on the following under HPHT condition;

5.1.1 Pore pressure

In the well planning phase, the focus will be put on the realistic usage of pore pressure. The suggestions discussed here are hoped to help the engineer recognize columns of lithology clearer and conclude possible hole problems before creating a well project.

Understanding the pressures of formation is essential to the successful plan of the well. Exact values of the pressures of formation are used to build appropriate weights of mud to prevent structure fracturing and to avoid kicks of the well. The method of designing and choosing the grades and weights of the casing is largely based on the usage of exact formation pressure values. The configuration of cementing, the regulation of kicks, the placement of wellheads and Xmas trees, and even the ranking of rigs, depend on the pressures of formation found in the well.

It is commonly understanding that pre-drill estimation of pore pressure is a key factor of every investigation. This becomes more critical when we are concerned with a reservoir with high heat flow or HPHT (Rabia, 2001).

5.1.2 Hydrostatic pressure

Refer to the pressure of the fluid column. The hydrostatic pressure is a function of the fluid density and depth of the column or vertical height of fluid.

The hydrostatic pressure is written in mathematical terms as:

$HP = D \times \rho f \times g$

Where:

HP is a Hydrostatic pressure;

G is a gravitational acceleration;

ρf is a fluid density;

D is a column height or vertical height.

The density of fluid is typically measured as psi / foot, pounds /cubic foot (ppf), pounds per gallon (ppg), or as specific gravity during field operations.

Within the Imperial order of units, the hydrostatic pressure with psi (lb / in^2) while foot for the depth and density of fluid is measured in (pounds/gallon) ppg:

HP = 0.052 x Depth (ft) x ρf (ppg)

Pressures of the wellbore are calculated in terms of hydrostatic pressure, such as fracture pressure, pressure of the formation, overburden pressure and density of fluid.

Hydrostatic pressure is more appropriate to refer to the planning or drilling well. A pressure gradient is the pressure rate change relative to vertical depth unit (psi/ft) psi per foot. Should be remembered that the densities of fluid are always gradients, expressed in ppg or SG.

We can easily convert hydrostatic pressure into corresponding mud weights and pressure gradients.

HG = D / HP ... (psi / ft)

Conversion pressures of the wellbore into gradients for a certain datum, like ground level, seabed or sea level mean, is normal. The corresponding figure of pressure gradient apply for a straightforward contrast on the same basis of the overburden pressures, pore pressures, fracture pressures, equivalent circulation density (ECD) and weights of the mud. Furthermore, as the values are plotted or tabulated, pressure gradients using to explain differences in regimes of the pressure within a specific region.

As pressure gradients are used to describe wellbore pressure magnitudes, these are typically reported in ppg as Equivalent Mud Weight (EMW).

Pore pressure is described as the pressure in the rock pore spaces which acts on the fluids. It is normally referring to the pressure of the formation in the pores as a scientific definition. We can be described pore pressure depending on its magnitude either normal, subnormal or abnormal (Rabia, 2001).

5.1.3 Normal pore pressure

Normal pore pressure refers to the equivalent hydrostatic pressure for the column of fluid in the formation calculating from the surface to the subsurface formation, that means insomuch as the opened formation and it was allowed to fill out a column which have length equal to the formation depth, then the pressure at the bottom of the column is equal to the surface pressure and pressure of the formation.

Normal pressure of the pores is variable. The value of normal pore pressure differs with the soluble salt content, gases present, fluid type and temperature gradient. For instance, the value of normal pore pressure increases as the soluble salt concentration increases.

5.1.4 Abnormal pore pressure

It is possible to define abnormal pore pressure as like as any pore pressure higher than the hydrostatic pore pressure taking up the formation water. Often abnormal pressure is named geo-pressure or overpressure. Abnormal pressure may be considered as consisting of a normal hydrostatic plus an additional pressure quantity. Surface equipment of control for example, due to excessive pressure, blowout preventers are needed when drilling gas and oil wells.

Abnormal pore pressure may happen at depth from a few hundred feet to more than 25,000 feet. A mixture of diverse geological, geochemical, geothermal and mechanical variations is due to the cause of abnormal pore pressure.

Reasons of abnormal pore pressure:

As described in the following section, abnormal pore pressure is produced as a consequence of a mixture of geochemical, geological, geophysical and mechanical process. One can describe these reasons under (Rabia, 2001).

1. Effects at deposition;
2. Processes on diagnosis;
3. Tectonic effects;
4. Affects in structure; and
5. Thermodynamic effects.

5.1.5 Subnormal pore pressure

Formation pressure at a certain depth which is less than the hydrostatic fluid pressure is defined as subnormal pore pressure. Abnormal pore pressure are encountered more frequently than subnormal pore pressure, usually formed after a long period of formation deposition. Subnormal pressures may have not artificial reasons related to an area's geochemical, stratigraphic and tectonic nature, or may have been artificially caused by reservoir fluid change. The Southern North Sea Rough field is an indication of a depleted reservoir under a subnormal pressure.

5.2 Some differences between HPHT wells and standard wells

HPHT wells drilling faces particular challenges differ from standard wells:

1. High temperatures and pressures have a dynamic effect on mud properties, and it can have impacts on well control.
2. In sections of the well, small margins will dominate between fractures and pore pressures.
3. The circumstances are all above critical point for the influx of oil/ gas/ condensate; refer to the influx of hydrocarbons is infinitely soluble in the oil-based mud.
4. Limitless quantities of gas can solubilize in the mud and the influx of hydrocarbons in oil-based mud (OBM) will mix completely with the base oil.
5. Drilling of horizontal and inclined wells can lead to seriously barite sag results.
6. If oil-based mud is used even though the well is overbalanced, huge quantities of gas will flow into a horizontal part of a well (Rommetveit et al., 2003).

5.3 Well control operation phases

A well control is defined as a collective term for all measures which can be implemented to avoid un-controlled release of wellbore effluents into the surrounding environment or un-controlled underground flow (Rommetveit et al., 2010).

Well control may be addressed within different categories of operations consisting of; drilling, completion, workover, production and wireline activities, which are the subject of this analysis during overbalanced drilling of exploration wells.

Use the roles of primary (i.e. mud column) and secondary (i.e., BOPs) well control stages, keeping a well under control may be accomplished. If the primary barrier does not perform its purpose, the wellbore receives an undesirable influx of formation fluid. This process is called as happening kick (Fraser et al., 2014).

It is then necessary to initiate a secondary well control boundary that includes the discovery of the influx, containment and circulation of the invaded fluid formation out of the wellbore using BOPs (Khakzad et al., 2013), (Grace, 2017).

Well control processes may therefore be split into four phases: avoidance of kicks, recognition of kicks, blowout preventers, and killing operations, as indicated in Figure 5.1.

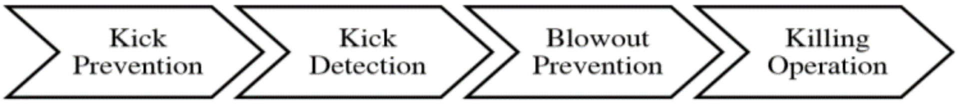


Figure 5.1 phases of well control process (Khakzad et al., 2013)

5.4 Fundamental principles of well control

Well Control function can conveniently be subdivided into three major groups:

5.4.1 Primary well control

Primary well control involves the usage of fluid density drilling to give adequate pressure to avoid the invasion of fluid formation in the wellbore. Ensuring that primary control of the well is maintained is great importance. This relates to the following:

A) Apply sufficient density of drilling fluids.

B) Well controlled at all times fulfill with sufficient density fluid.

C) Continuous monitoring of the active volumes, in particular during tripping.

D) Variations in volumes, density and flow rate of wellbore drilling fluids are observed automatically, and reasonable action is taken (Louisiana state university, 2010).

5.4.2 Secondary well control

In case of the primary control cannot be maintained correctly, Secondary well Control is the appropriate usage blowout prevention equipment to control the well. Early detection and fast shut-in of alarm signs are the secret to successful control of the well. In taking effective measures, the quantity of formation fluid reaching the wellbore and the quantity of drilling fluid being removed from the annulus are reduced. The volume of a kick and its severity depend on:

a. Permeability of the formation.
b. Underbalance degree.
c. The duration of the well is still underbalanced.

Fewer kicks keep providing lower pressure on the choke or annulus, both at initial closure and afterward when the kick is circulated to the choke.

5.4.3 Tertiary well control

The third line of protection is described by tertiary well control. Where main or secondary well control (hydrostatic and equipment) cannot control the fluid formation. In case secondary control cannot be maintained properly due to wellbore conditions or inability of equipment, specified emergency procedures may be applied to avoid inability of control.

Such steps are referred to as "Tertiary well Control" which typically contribute to the well being abandoned in part or in whole. There is no established tertiary well control stages that will work in most cases unlike primary and secondary controls. The processes to be implemented depend on the specific operating conditions that are encountered, and particular recommendations with regard to proper tertiary well control procedures cannot be provided till the conditions lead to loss of secondary control are determined (Louisiana state university, 2010).

For example, an underground blowout. But it's not always used as a qualitative term in well control. 'Uncommon well control activities' mentioned below are regarded as follows:

a. Loss circulation.
b. Plugged and stuck off bottom.
c. The drill string is taken with a kickoff the bottom.
d. Gas percolation without expansion of the gas.
e. Drill hole in string.
f. No pipe sits in the hole.
g. Excessive pressure at the casing.
h. In a kill process, the drill string plugs off.

Also, we could consist operations such as stripping or snubbing into the hole or drilling response wells. We need to don't forget the shut-in situation of the well, this determines the method of control for the well. There are also two commonly employed methods. These imply the use of:

- Cement plugs
- Barite plugs (Louisiana state university, 2010).

5.5 Well control methods

There are usually two classes, non-circulating and circulating techniques. (Figure 5.2) illustrate the common operations to monitor kicks. The first stage during the kick occurrence would be to shut in the wellbore and begin checking when there are leaks in manifolds or blowout preventer etc. Second stage, the static initial casing pipe pressure (SICP) and static initial pressure of drill pipe (SIDPP) will be reported till the pressure stabilize and the pit gain is reported.

Obviously the third stage depends on the method of killing upon which the decision was made. The circulation will then continue by keeping the choke or (casing) pressure with (SICP) magnitude and raise the pump to the "kill rate" level. When the pump is with the speed of kill and the casing pressure with (SICP) level, the circulating (pump) pressure must be recorded. The Initial Circulating Pressure (ICP) refers to the circulating (pump) pressure, which should be maintained till pumping the fluid of kill.

ICP = KRP + SIDPP

Where

ICP is an initial circulation pressure, psi;

SIDPP is a static initial drill pipe pressure psi;

KRP is a killing rate pressure, psi.

ICP would be the required pressure used for the circulation of a well at a specific amount and to keep it from affects kicking or flowing (Rabia, 2001)

The case where this magnitude does not accept with measured values, a rapid determination on the shutdown pressure will be taken whether it is right or not, which may be incorrect due to gas movement. Gages and pump capacity may always be tested for the weather they are operating properly or not, or our estimates are not accurate at times. Seek again if any insufficiency continues with closing the well.

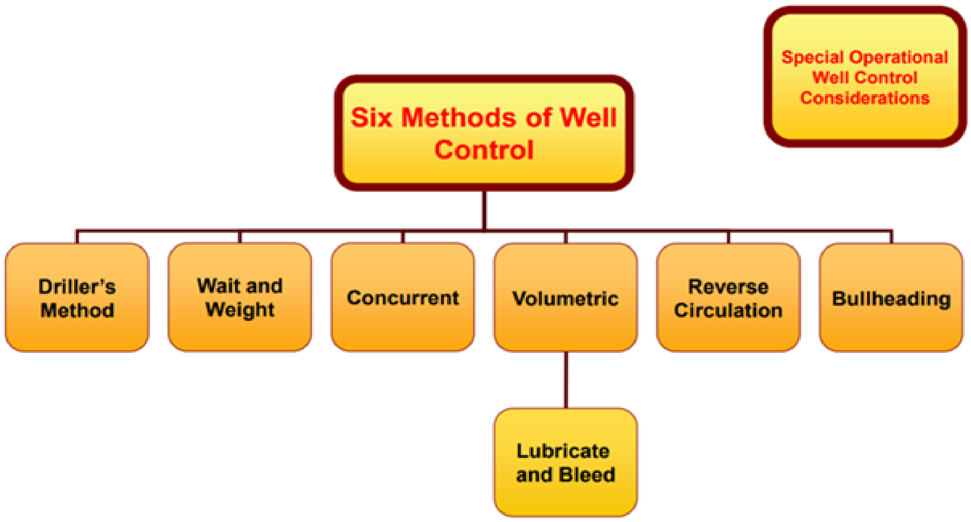


Figure 5.2 well control methods (Darwesh et al., 2017)

5.5.1 Driller's method

When a sign of the kicks is given the driller will starts using this method as a beginning ability to respond. It is not difficult to apply and it's used with migration at high rates order to wells control which can cause problems with shut in the well (Darwesh et al., 2017)This procedure is also helpful if we do not have adequate weighting content, staff and/or facilities on site to restrict our service.

5.5.2 Wait and weight method

It is a kick kills technique more easily and holds the pressure at the surface and wellbore not higher than any other technique (Grace, 1994). Compared to the driller technique, this technique provides excellent objectives with the requirements of better combining drill crews and facilities. Calculating the amount density of the killing fluid would be the first function and will then circulate the killing mud. Therefore, this technique has been called engineer or Wait and Weight technique.

5.5.3 The variations between the wait and weight & Driller's methods in the killing process of the deep water

When a kick is detected in a well, the influx must be excluded in a controlled way without allowing the formation fluids to enter further in the wellbore. In general, there are two techniques for coping with the matter of well control which are the Driller's technique and the W&W technique. All techniques are built to sustain a bottom hole pressure is constant and marginally higher than or equal to the formation pressure (Carlsen et al., 2013).

The Technique of Drillers requires two circulations, using the basic drilling fluid for circulating out of the influx in the first circulation. The well is killed in the second circulation by pumping the killing mud. The W&W process, on the other side, uses just one circulation, through which the killing mud is pumped into the well to circulate out the influx and maintain the equilibration between formation pressure and the pressure of wellbore pressure. The choice of the proper well killing procedure is important to satisfy the desire for safe well control process (Skogdalen et al., 2011).Using an improper method to kill a well will increase the time of process and cause real construction problems. More essentially, it increases the risk of a blowout accident, due to the loss of control operation onto the pressure of wellbore. In addition, the following considerations should be addressed in the control operation for the conventional well before taking a decision (Avignon & Simondin, 2002) which are:

- The time consumed during the total operation.
- Whether the maximum surface pressure is below the maximum working pressure of the wellhead equipment during the killing method.
- Safety at circulation of the weak formations.
- The complexity of the construction that is killing well.

Comparisons of different onshore killing techniques have been decided to make by analyzing the pressure for both casing surface and casing shoe (Fleckenstein & Mitchell, 1991). However, deep water well control is faced with more complexities compared with the well killing process of onshore processes. Because of the impact of the inverse gradient of temperature of the seawater there is a much complicated wellbore temperature field. Several numerical simulations had developed over the last few years to estimate the temperature in deep water wells (Stiles & Trigg, 2007). The circulating temperature of deep water wells in the Indonesia, Gulf of Mexico, Brazil and West Africa has been investigated by some measurements. These areas have a mean of the depth1200 m (Ward et al., 2001). Therefore, the small choke but long line leads greatly to frictional losses while circulation and this should be considered when studying the wellbore pressure (Zhang et al., 2012). The pressure of choke increases significantly, when the column of gas moves to the line of choke in order to make up for the drop in the effective height of the fluid column. This poses considerable safety matters during construction (Rezmer-Cooper & Lindsay, 1994). The well killing process in deepwater requires a much important and sensible choice for killing method.

5.5.4 Characteristic of surface pressure

For a well killing process, the action of surface pressures, including choke pressures and drill pipe, is essential because they can reveal the real condition of the bottom hole pressures. The balance between the formation and bottom hole pressures can be done through control of the choke and drill pipe pressures while the operation of well killing.

Differences of the chock and drill pipe pressures are linked with the situation of the mud of killing and gas column according to the Driller's technique and the W&W technique methods. The numerical equations of the choke pressure (Pa) and drill pipe pressure (Pd) can be written as equations (1, 2), considering the effect the friction reduction of choke line, gas expansion and circulation temperature during well killing in deep water:

$$Pd(t) = PB - Pmp(t) + Pd(t) \quad \ldots\ldots \quad 1$$

$$Pa(t) = PB - Pma(t) - Pa(t) - Pcl(t) \quad \ldots\ldots \quad 2$$

Where:

PB refer to the bottom hole pressure, pa;

Pa, Pd, Pcl refer to the pressure losses in the annulus, drill pipes and chock line, Pa;

PB refer to the pressure at bottom hole, pa;

t is a circulation time, s;

Pma and Pmp are the hydrostatic pressure of fluid in the annulus and drill pipe, Pa.

These pressure losses and hydrostatic fluid pressures in the two aforementioned equations change with the time of circulation because of the influence of gas expansion and the movement of the killing mud (Feng et al., 2016).

5.5.5 Advantages and disadvantages of W&W method

Advantages

- Lowest pressure at the casing.
- Lowest pressure on the casing seat.
- Less lost, if not over killing, circulation.
- Killed only one circulation when pollutant strings out onto washed out parts of the hole.

Disadvantage

- Needs the maximum non-circulating period as heavy mud mixes.
- Pipe may stick when not rotating due to settling of shale, sand, salt, or anhydrite.
- Needs a bit more arithmetic.

5.5.6 Advantages and disadvantages of driller's method

Advantages

- Enough for teaching and understanding.
- Few computations.
- The contaminant is rapidly washed out to avoid sand accumulating around drilling assembly (in case of the salt water).

Disadvantage

- Lower friction (kick) of the shoe casing.
- Low pressure to the annular (kick).
- Requires two circulations.

Kick tolerance

kick tolerance means the maximum volume of formation fluid influx which can shut in and circulated out of the well without breaking down the weakest point of the well exposed to the circulation event (Karahasan et al., 2017).

The determination of high pressure high temperature (HPHT) offshore kick tolerance of the deviated gas well drilling remains, however, a challenge for the gas and oil industry because of the existence of the (HPHT) well section's narrow safe mud weight window, complicated borehole temperature profile, high frictional pressure loss and influx distribution.

Well killing kick tolerance volume and the volume kick tolerance for shut in may increase with inclination of wellbore for the highly deviated part, and highly of the deviated wellbore which have a higher volume of kick tolerance than the vertical wellbore. Under this circumstance the volume of kick tolerance of well killing excesses for the geothermal gradient with other parameter values trying to set constant while the rate of increase is not noticeable. This research offers a realistic method for enhancing proper control in drilling of strongly deviated gas wells offshore (HPHT) (Karahasan et al., 2017).

Although kick tolerance is a basic issue for casing design, the pattern to the kick tolerance measurement differs. A simple concept of kick tolerance may be defined as "the maximum amount of inflow which can be shut down and circulate to the surface without increasing the intensity of the casing shoe's fracture formation. Ultimate pressure loads on the casing and equipment at the surface in addition to the mud gas separator efficiency and volume would also be a take into account relevant to kick tolerance, but the intensity of formation fracture at the casing shoe is usually the primary criterion for the expression kick tolerance. The fundamental suppositions of reservoir pressure, kick strength, strength of formation and composition of the influx, approach and margins will affect kick tolerance calculations (Mosti et al., 2017) .

5.6 Causes and Indications of well kick and blowout

5.6.1 Kick causes

Kick or blowout can come out of one of the flowing:

- Formation pore pressure more than mud weight.
- Mud cut by oil, gas or water.
- Loss circulation.
- Swabbing through tripping.
- Failure to maintain the hole full while tripping.

5.6.2 Well kick indications

Early alarm signs are:

- Change in the pressure of pump.
- Sudden excess in drilling rate.
- Water, gas or oil cut mud.
- Excess in surface the volume of fluid, commonly referred to as an excess in the flowrate or an excess in pit level.
- Decreasing in the weight of drill pipe (Grace, 2017).

5.7 Incidents of High pressure high temperature (HPHT) wells

The main characteristics of offshore HPHT wells are the decreased kick tolerance, the existence of a narrow margin among the fracture pressure gradient and formation pore pressure gradient (Nordin et al., 2012). This characteristic of the HPHT wells offshore introduces a series of challenges for incidents well control. Current studies recorded incident rate of the well control of (4 to 5) percent for conventional drilling while a rate of (100 to 200) percent was reported for non-conventional drilling such as HPHT drilling (Auwalu et al., 2015). It means that non-conventional wells such as wells with HPHT have a very large rate of accidents. In recent time, even horizontal HPHT gas wells are being drilled to maximize production, with many more highly deviated HPHT gas wells. That adds difficulty, challenge and risk to the operation of the well.

For the influx flowing up into the well (Figure 5.3), the fluid in the construction portion and vertical portion should be greatly expanded although the expansion in the extremely deviated portion is not apparent. This results in a big pressure change in the wellbore.

Therefore, the potentially weakest point of the well-exposed circulation event can be not only the casing shoe but also the extremely deviated open hole portion, blowout preventer, casing, and chock valve. In addition, the high temperature down the hole and the high loss of frictional pressure add complication. A variety of experiments on kick tolerance have been published over the last several years (Feng et al., 2016), (Jin et al., 2016).

Nevertheless, much of the prior kick tolerance simulations are for traditional vertical wells, and little of them consider the impacts of influx allocation, complicated temperature at borehole, and strong loss of frictional pressure of the strongly deviated HPHT gas wells offshore. Prior kick tolerance models could also not be relevant to exploration of extremely deviated gas wells offshore HPHT. A volume kick tolerance model appropriate for the drilling of extremely deviated gas wells offshore HPHT was introduced in this research focused on the capability of the pressure bearing of the highly deviated casing shoe, open pit, BOP, casing and choke valve. At the same time conditions impacting the kick tolerance volume were studied too.

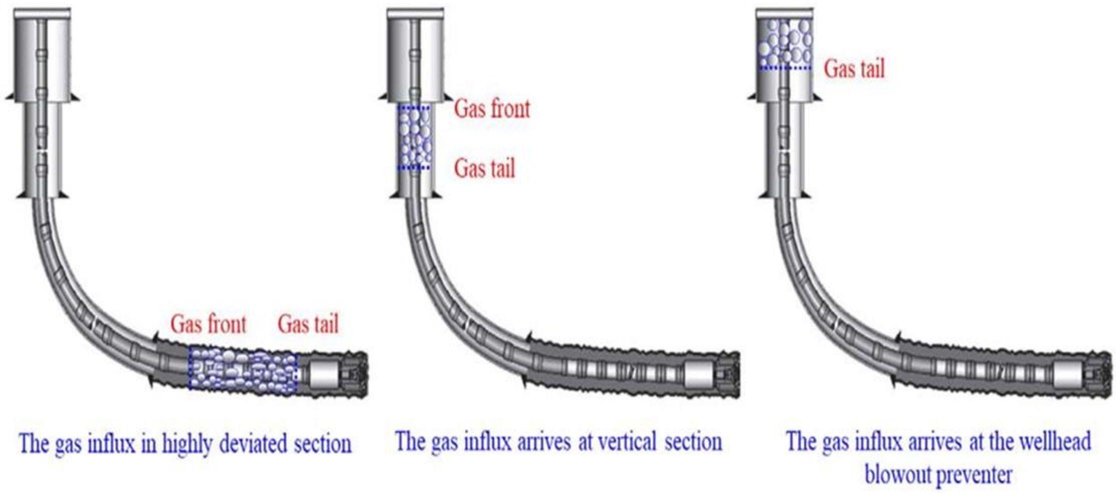


Figure 5.3 Gas influx fall through multiple parts of the well (Chen, Yang, et al., 2018)

The volume kick tolerance is described as the difference among the allowable maximum volume of influx and the pit gain to ensure no danger of killing or shutting in well. The higher kick tolerance volume, the better it would be to destroy or shut in the tube. In the extremely deviated open hole portion of the extremely deviated gas wells offshore HPHT, the sudden excess in formation pore pressure that narrow down the operating window, and the gradient profile of the fracture pressure is often complex. the lowest formation gradient of fracture pressure can be deeper than that of the casing shoe as shown in (figure 5.4). In addition , because of the horizontal wellbore or highly deviated , the measured kick tolerance volume may range from above the weak point (sometimes, not always, the weakest point would be the casing shoe) to the bit depth , which means that the well will tolerate an infinite kick volume without falling down the formation weak point. When this happens in horizontal hole or highly deviated part where the possible kick volume may be high, it is necessary to test the allowable maximum volume of influx for the related applied loads on the choke valve, the casing and the BOP (Figenschou et al., 2012).

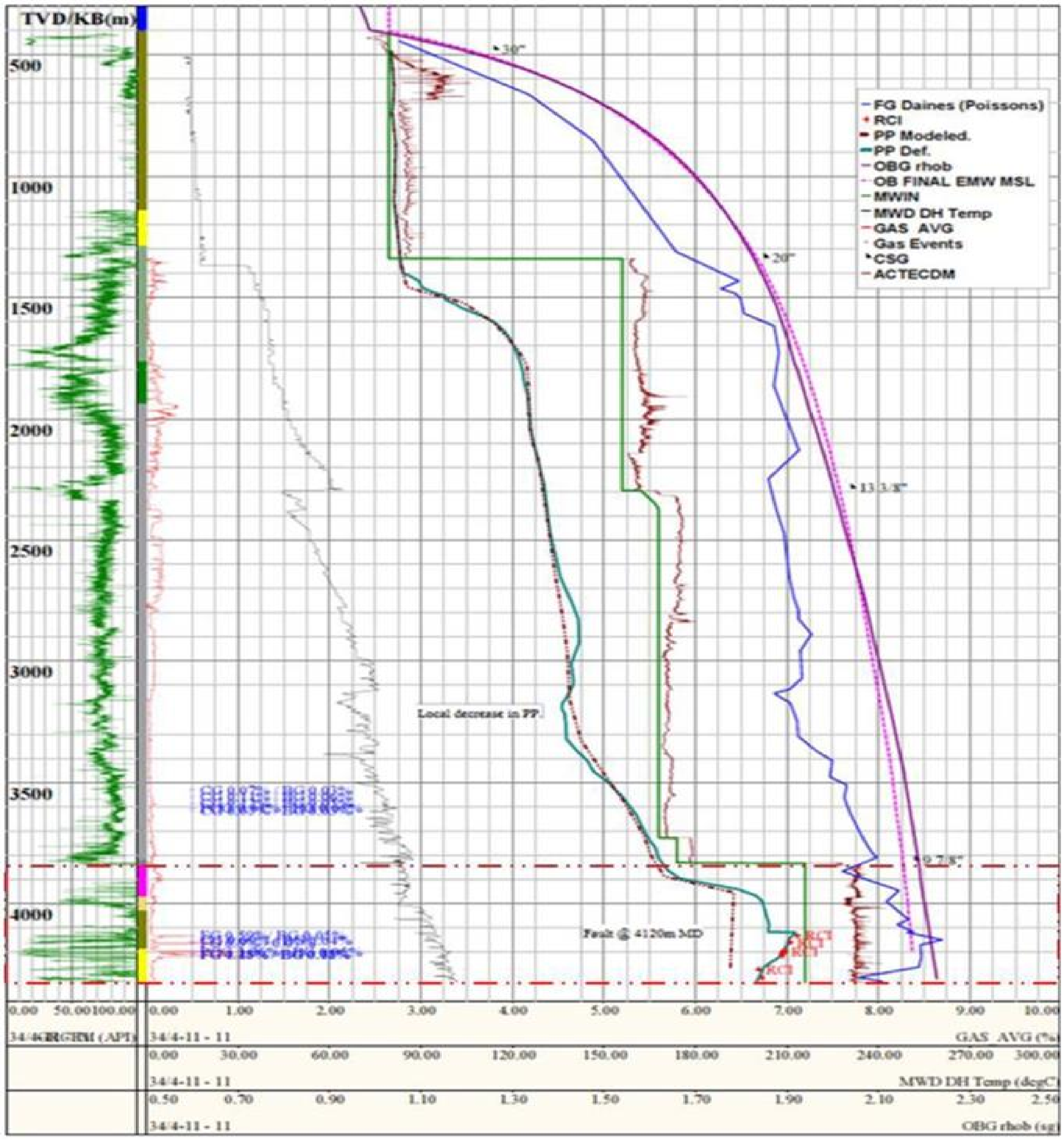


Figure 5.4 Fracture pressure gradient and pore pressure gradient for HPHT wells (Figenschou et al., 2012)

The system of well control for highly deviated gas wells offshore HPHT as seen in Figure 5.5.

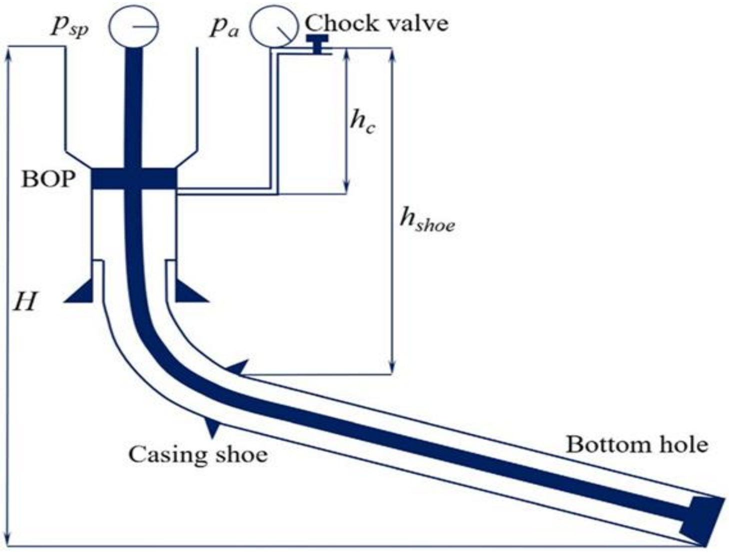


Figure 5.5 The system of well control for highly deviated gas wells offshore HPHT

As shown in the early part, it is important to test not only the capacity of pressure bearing for the casing shoe but the capacity of pressure bearing for the deviated open hole too, BOP, casing and choke valve to calculate the shut in pressure maximum (Figenschou et al., 2012), The increment volume of mud in pit means at the bottom hole there is an influx. When the gas invades at the bottom of the hole, the allowable maximum bottom of the hole will equal the pore bottom ole pressure , figure 5.5 (Chen, Yang, et al., 2018).

5.8 Well Control Incidents that can be best prevented and controlled with greater comprehension

The pit gain is a key parameter for detecting potential kicks during drilling of the deeper sections of a well. A change in the amount of mud may be misinterpreted as a benefit or a loss because it is simply attributed to changes in pressure inside the mud itself. To be able to distinguish real kicks, it's necessary to recognize the mud volume change.

In HPHT wells the condition is getting worse than in other fields. Several of the explanations are:

- The average amount of mud could be greater and thus differences in the active amount may be greater because of large changes in pressure and temperature.
- Increasing the limits for fracturing in the well.
- All differences in temperature and absolute temperature increase with the depth. The same goes with variations of pressure and absolute pressure.
- Recognition of influxes at the early time mitigate surface treatment of very significant quantities of gas.

- Oil based mud flashing and gas solubility.
- Decreases the increased risk of swabbing in heavy mud.
- Detection and prevention of ballooning borehole (Rommetveit et al., 2003).

Conclusions

High Pressure and High Temperature Wells will continue to cross the limits of available technology, in order to achieve the demand of future of Oil & Gas. On the basis of this thesis study it had been concluded that HPHT wells are becoming much more substantial, even though we move towards the relatively narrow margins the deeper depths with harsh environments where the pressures and temperatures are relatively high.

Hole instability is a key problems faced during drilling HPHT wells. Many deep-water gas wells face problems with hydrate because the ambient pressure and temperature conditions are appropriate for the hydrate formation. Also, many formations of deep-water are shale formations, which are the key source of instability of wellbore. The causes for instability of shale are chemically and mechanically induced instability as a result of interaction among both formation of mineral compositions and drilling fluids. The drilling fluids properties might be optimized to influence stability of wellbore.

Drilling fluid is considered as important part in HPHT wells drilling. High temperatures have significant effect on the rheology of mud which is directly related to drilling efficiency by influencing cuttings suspension and hydraulics of well. It is important to have a well-designed mud program. Water-based mud (WBM) used to drill at all intervals above the portions of the reservoir, then mud system turned to a synthetic oil-based mud (SOBM) before reaching the reservoir. The process of planning hydraulics and designing fluids depends on determining how wellbore temperature and pressure conditions affect the rheology of fluid. Ignoring these effects in calculation is bound to obtain error results.

Drilling technologies plays an essential role in the case of HPHT drilling like Managed Pressure Drilling (MPD) and Underbalanced Drilling (UBD). The managed pressure drilling has the ability to mitigate drilling risks, alongside improving the drilling performance and increase production rates. It also improves and enhances the reserves, allowing drilling in areas that were previously economically un-drillable harsh environments & deeper depths, due to above mentioned advantages of MPD, the transition for companies to start using MPD is smoother and it is like active well control tool for drilling HPHT wells.

MPD is a developing idea that is supported with unique techniques benefits and limits. The combination of such techniques and limitations lead MPD to be an irreplaceable technology that has the ability of regulate drilling risks, improving performance of drilling and increase rate of production in the same project and, at the same time. Similarly, Underbalanced drilling can be performed in a different way, it has a wide range of suitable fluids of varying density and characteristics and different techniques that can be used for specific formations like fractured and high permeable zones.

At the time of performing these drilling operations the major and most important function is controlling the well. During operations influx is tries to enter the wellbore called kick. I have discuss the causes of kicks and well killing methods. It is noticed during connections that there is a noticeable drop in pressure that can impact the pressure into the well.

The drop in pressure encountered during connections may significantly result to an underbalanced condition where we can obtain an inflow of fluids from formation. It can also be noticed that the pressure drops in small hole sections when connections increases. Undetected kicks in wells with HPHT condition can be a big challenge. Therefore the influx of gas will dissolve completely in the OBM without having a noticeable rise in the pit gain. When the well is circulated, the kick starts to move up into the well as even the kick would not be felt until free gas begins to bubble out from the solution. When it comes to well control, the stage where the free gas begins to boil is crucial.

In OBM and WBM a kick can behave differently under closed in situations. Although the kick can resolve in the OBM, under closed conditions this should reside at the bottom of the well till the well is circulated. While the kick will start to move upwards in WBM which will lead to enhance pressure in the well, the kick will bring the BHP up into the well. It thus means one would have to respond rapidly in order to avoid casing shoe fracturing.

At last I studied well control capabilities in HPHT conditions, BOP’s selection on pressure and temperature ratings and therefore it is highly recommended to train properly the drilling crew members because it’s not very easy to carry out HPHT drilling without having a sufficient knowledge of the well control. The drilling crew members should be given special briefing about the different situations that may possibly happen during the operation and the ways to deal with such situations.

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