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Abstract

Deepwater challenges and well control problems are important drilling issues, as operators move into deeper waters and more challenging environments. The deepwater technology and the complexity of deepwater operations have changed in the past years. To exploit deepwater hydrocarbon reserves, operators and contractors are working together to provide new technology, innovations and procedures to overcome most of the deepwater challenges.

This master thesis presents deepwater challenges and well control methods which are categorized into two major parts. The first section discusses deepwater challenges, environmental conditions, deepwater drilling facilities and deepwater field development. The second part discusses well control methods for deepwater drilling operations and high pressure, high temperature (HPHT) wells. Environmental conditions, hydrates, rig size, riser damage, well control problems, and drilling techniques are the major factors that affects drilling operations, production, day rates, drilling performance, efficiency, and cost of drilling operations.

Well control, to maintain a stable and safe well, is an important issue in deep water drilling operations. The main challenges in HPHT wells is hydrate formation, which results in plugging of pipelines and well control equipment. Also, narrow operating window between pore pressure and fracture pressure in deepwater fields is another major challenge. Some of the well control aspects presented in this section include kick causes, kick detection, kick tolerance, stuck pipe, surge and swab effects and the well kill procedures. Drillbench software is used to demonstrate well control behavior in HPHT conditions by analyze kick circulation out from the well. A comparison is made between a kick circulation with oil-based mud and water-based mud in HPHT wells.

The main goals of the operators are to achieve an optimal well control, increase access to deepwater reserves, improve wellbore integrity, reduce drilling costs and protect environments. With managed-drilling concepts, drillers can safely drill through narrow margins and reach target depths with a few casings.

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List of abbreviations

BHA – Bottom Hole Assembly
BHP – Bottom Hole Pressure
BOP – Blow Out Preventer
CRD – Conventional Riser Drilling
DDS – Dual Drill String
DEH – Direct Electric Heating
DGD – Dual-gradient Drilling
DM – Driller's Method
DP – Dynamic Positioning
E&P – Exploration and Production
ECD – Equivalent Circulating Density
ESP – Electrical Submersible Pump
FCP – Final Circulating Pressure
FCU – Flow Control Unit
FPSO – Floating Production, Storage and Offloading
GOM – Gulf of Mexico
HPHT – High Pressure High Temperature
ICP – Initial Circulating Pressure
KMW – Kill Mud Weight
LMRP – Lower Riser Package
MPD – Managed Pressure Drilling
NPT – Non-Productive Time
OBM – Oil Based Mud
OM – Original Mud Weight
POOH – Pulled Out of Hole
PVT – Pressure-Volume-Temperature
RBOP – Rotating BOP
RCD – Rotary Control Device
RDM – Reelwell Drilling Method
RDM-R – Riserless Reelwell Drilling Method
RIH – Run in a Hole
RKB – Rotary Kelly Bushing
RM – Conventional Riserless Method
RMR – Riserless Mud Recovery
ROP – Rate of Penetration
ROV – Remotely Operated Vehicle
SBOP – Surface Blow Out Preventer
SICP – Shut-in Casing Pressure
SIDPP – Shut-in Drill Pipe Pressure
SPP – Stand Pipe Pressure
THI – Thermodynamic Hydrate Inhibitors
TLP – Tension Leg Platform
TVD – True Vertical Depth
VIV – Vortex-induced Vibrations
W&W – Wait and Weight
WBM – Water Based Mud
WOB – Weight on Bit

1 Introduction

1.1 Background

This thesis work presents deepwater challenges and well control. Bai and Bai (2010) provides a detailed explanation of deepwater and ultra-deepwater well. An offshore oilfield is a deepwater well, if the water depth ranges from 200 m to 1500 m (656-5000 ft), while ultra-deepwater well is considered to be more than 1500 m (5000 ft).

Most of the world's hydrocarbon reserves are found in deepwater environments. Such fields include the US Gulf of Mexico (GoM), US East Coast oilfields and Libra located in Santos Basin off the coast of Rio de Janeiro, Brazil.

Fig. 1.1 illustrates offshore oil production in the GoM from shallow and deepwater fields.

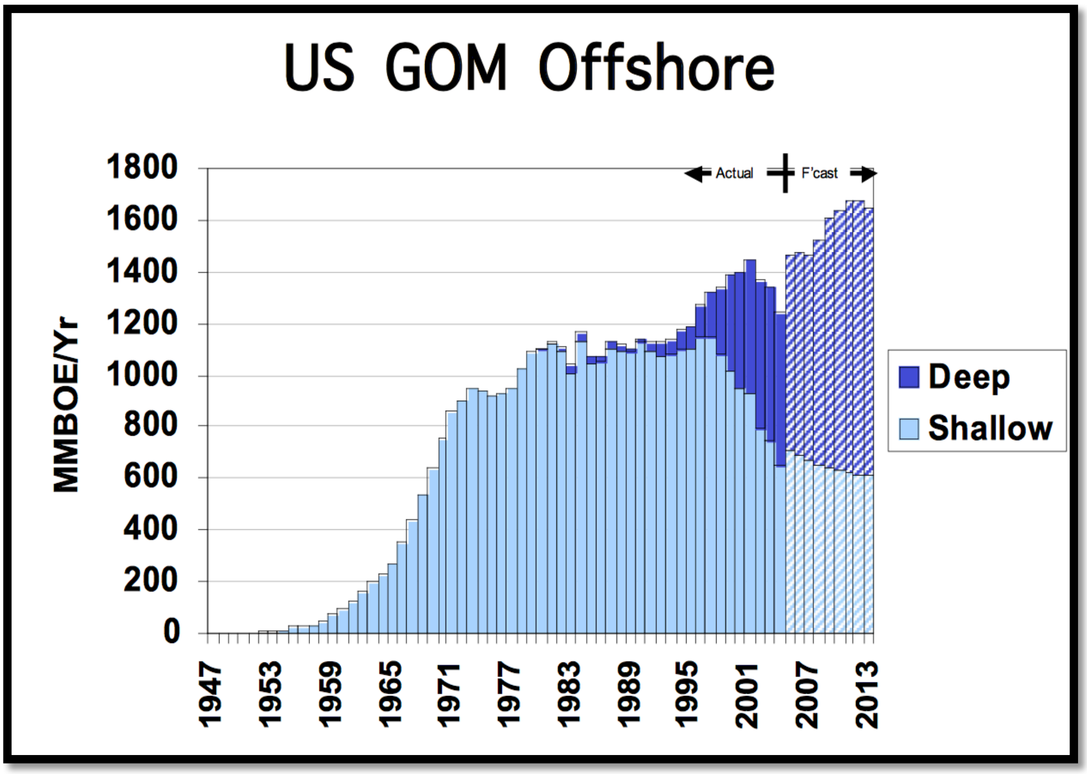


Fig. 1.1—The US GoM oil production (Conser 2007).

Fig. 1.1 shows that exploration and production (E&P) have expanded over the past 20 years. Deepwater and ultra-deepwater wells split considerably between 2007 and 2012, but exploration and development drilling of the GoM did not show any slowdown. The US GoM oil production in 2011 was a record year. Deepwater drilling and oil production in the region peaked between 2011 and 2012 at 1.65 million barrels a year. In 2011, approximately 500 deepwater and ultra-deepwater wells were drilled globally, causing an additional growth in the number of deepwater wells.

However, the oil prices caused by the economic downturn have reduced by more than 40% in 2014. The decline in the oil prices could be attributed to slow economic activities and oil glut. America and Russia have become the world's largest oil producers. Finally, Saudi Arabia did not want to restore the oil prices because Saudi Arabia tend to have more than 900$ billion in reserves. This makes Saudi Arabia and their Gulf allies tolerate lower oil prices. The cost of producing a barrel of oil and gas varies widely across the world.

Fig. 1.2 illustrates the average cash cost to produce a barrel of oil or gas equivalent in 2016.

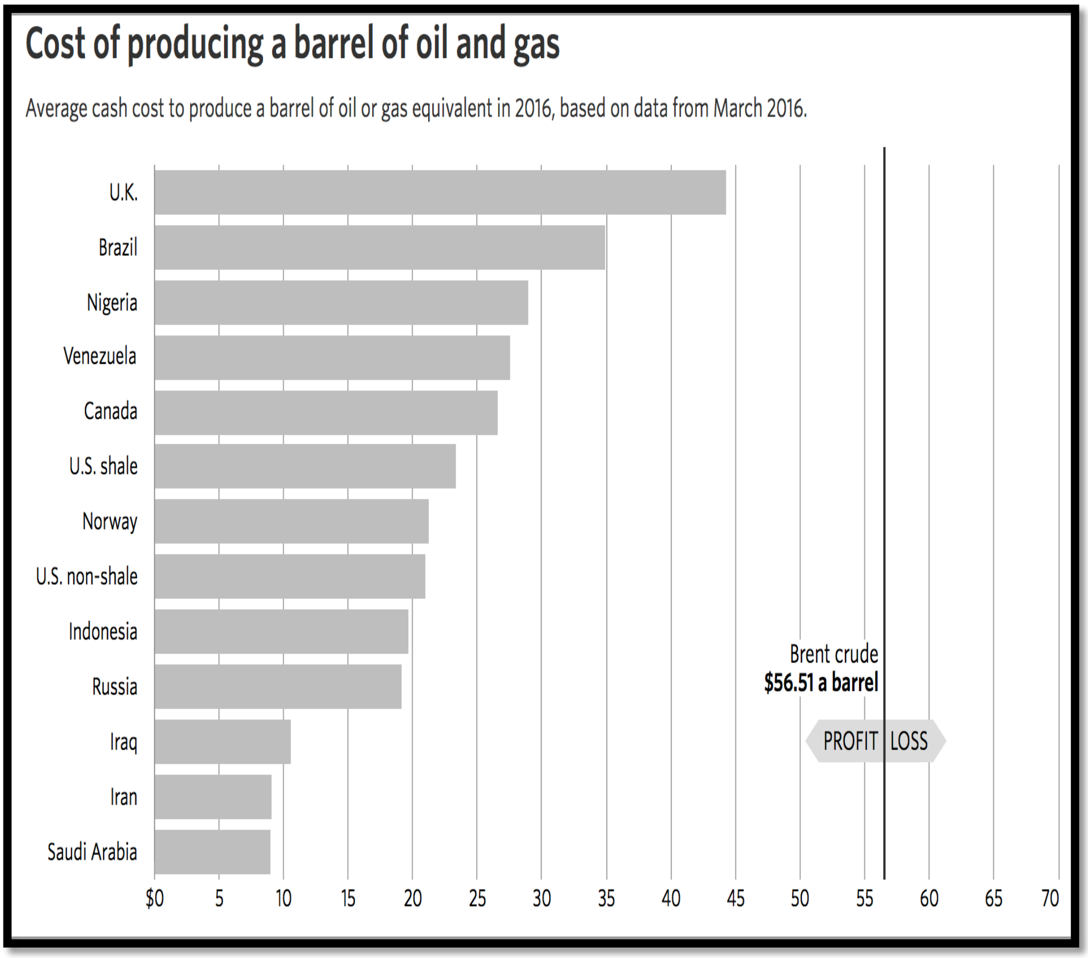


Fig. 1.2—Average cash cost to produce a barrel of oil or gas equivalent in March 2016 (The Wall Street Journal 2017).

Fig. 1.2 shows that the average oil production cost in the Middle East is less than USD 12 per barrel. By contrast in other regions, the average production cost is between USD 18 and 44 per barrel. The average cost includes additional expenses such as gross taxes on profits, capital spending on infrastructure and marketing, production costs on investments, and administrative and transportation costs. Newer and more complex projects require more money on production and investments on field development (The Wall Street Journal 2017).

Douglas-Westwood (2015) forecasts show that offshore and deepwater hydrocarbon productions will increase despite the fall in oil prices. The growth forecasts are presented in Fig. 1.3.

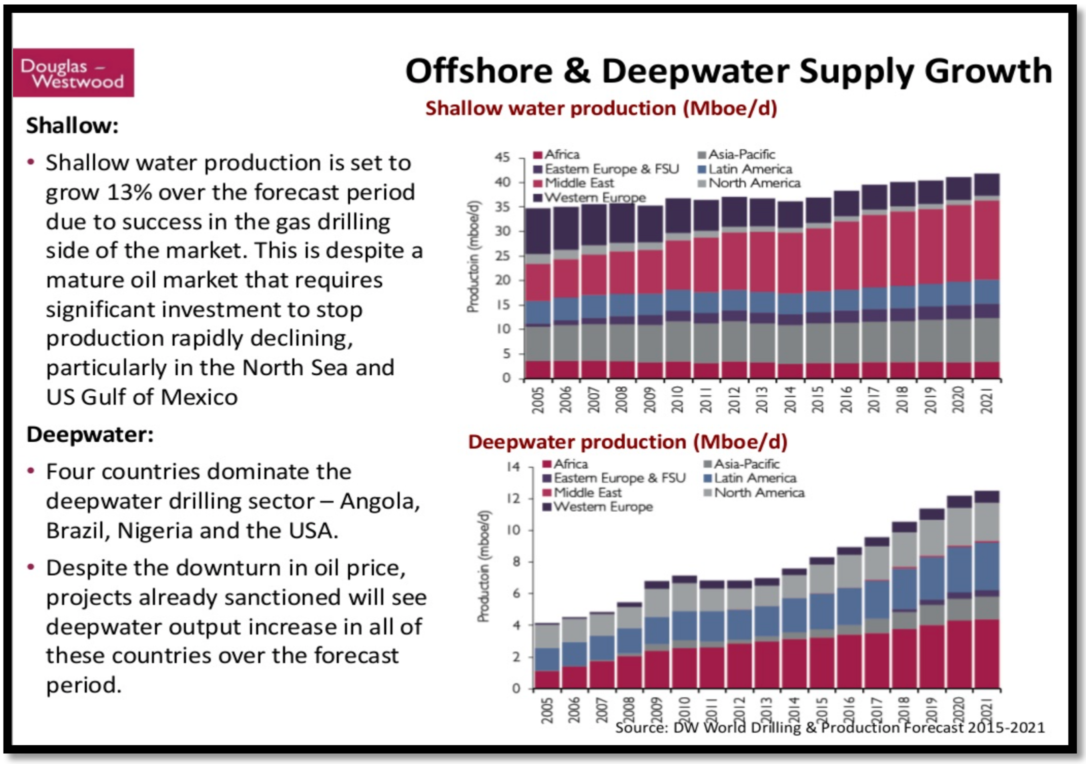


Fig. 1.3—Offshore and deepwater oil production forecasts (Douglas-Westwood 2015).

Fig. 1.3 shows that during economic downturns, it is expected that oil production will increase. A major key factor is that deepwater production wells are the most highly productive wells in the oil industry. Deepwater projects are typically the most valuable projects, and their funding are secured several years ahead of first day of production. These projects will recover capital investment even in a low oil price field. That means that offshore projects that are near completion when oil prices start falling are still going to move into production phases. Douglas-Westwood (2015) shows that project reengineering, cost cutting for equipment and services, and a relatively stable oil prices will lead to 42% increase in the number of deepwater projects expected to be approved between 2017 and 2018 compared to the period between 2015 and 2016.

1.2 Problem Statement

The success recorded in past offshore exploration and drilling operations have encouraged operators to drill in deeper water depths and new frontier areas, that are very challenging to explore.

Nelson et al. (2013) showed that exploration is very risky in many deepwater fields, and drilling successes vary between 10 and 15%. Keeping this in mind, the drilling operators cautiously choose their drilling prospects and make every effort to reduce the risk. However, only 38% of deepwater new field wildcats drilled between 2007 and 2012 were technically successful. The key to the success is a well-planned exploration strategy, which can be achieved by focusing on specific deepwater fields. The prices of new discoveries remain extremely high because deepwater projects and their capital investment with technological complexity provide longer payout periods and lower returns on investment. A typical deepwater discovery requires a development period of five to eight years before starting production. The exploration period adds the total time needed to start production and generate revenue.

Fig. 1.4 illustrates variety of challenges drilling in deepwater fields.

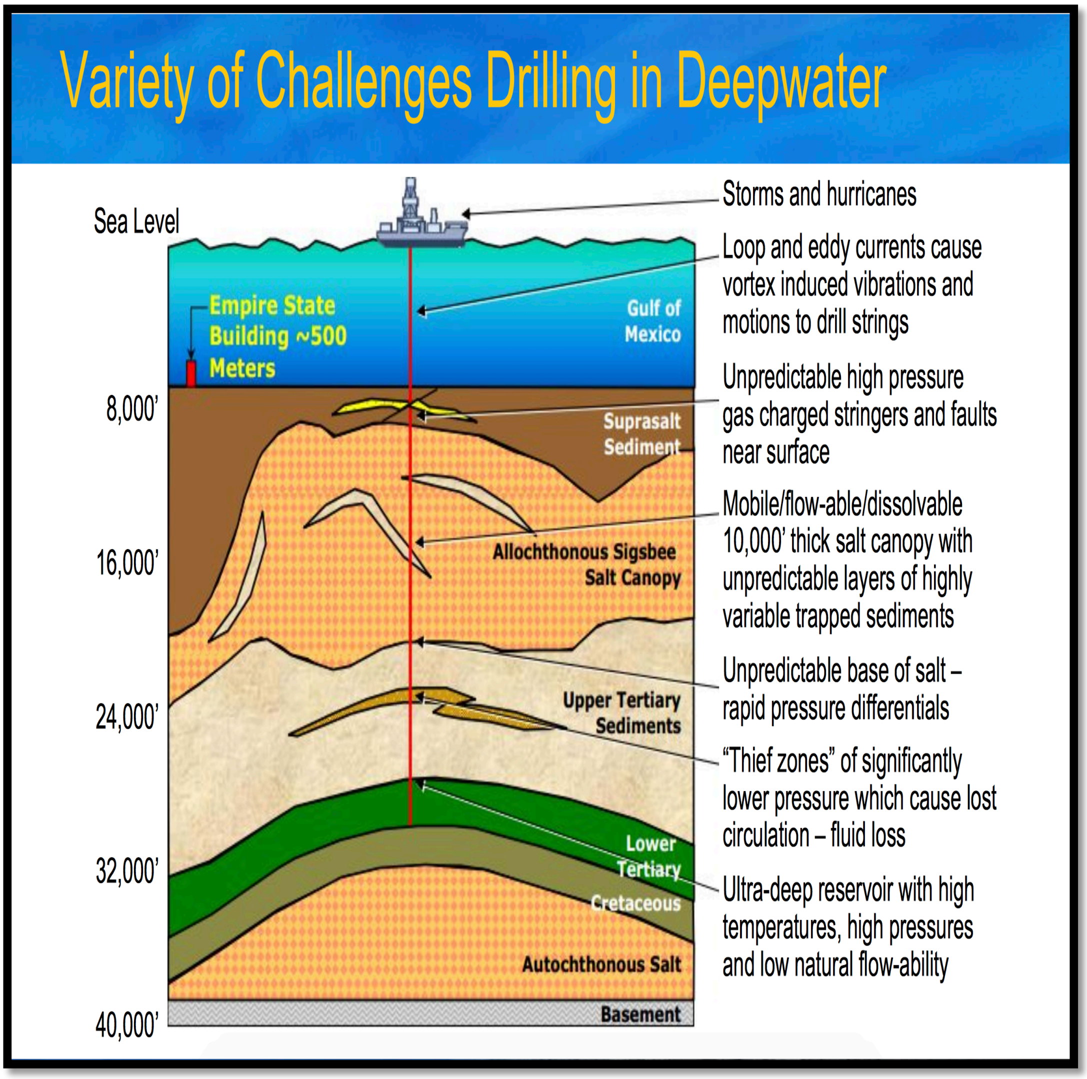


Fig. 1.4—Variety of challenges drilling in deepwater well (Drummond 2013).

From Fig. 1.4, deepwater drilling challenges include drilling equipment problems, weather conditions (strong waves, storms, currents etc.), high pressure, high temperature (HPHT) conditions, hydrate formation (when water temperature drops to freezing point on the seabed), and well control.

Cromb (1999) showed that recent deepwater projects should maximize ultimate recovery for being economically preferable. Therefore, newly discovered deepwater wells are capable of high flow rates and the wells should be designed in such way that they can withstand high pressures. The cost of deepwater wells requires the industry to rely on new technology to optimize the capital expenses on deepwater projects. Completion design and equipment reliability play a major role in the success of deepwater operations. However, there are major risks in using drilling equipment and technology that have not been tested in in high pressure and high temperature (HPHT) environment.

Most of the problems during the life cycle of a well include formation damage, lost reserves, safety and environmental exposure. Therefore, to achieve the goals, the risks and problems must be minimized.

Operators and contractors are facing certain deepwater challenges. As water depth increases, the drilling window between formation pressure and fracture pressure becomes narrow. Therefore, well control is very important in challenging areas, especially in HPHT environment because lower fracture gradients reduce the kick tolerance margin. The kick detection and circulation kick out of the hole in a safe manner are ones of the major aspects of well control operations for any deepwater drilling operation.

The present work will focus on the different deepwater challenges and well control for conventional drilling, dual-gradient drilling (DGD), controlled mud level (CML) system, riserless mud recovery (RMR) and Reelwell Drilling Method – Riserless (RDM-R). The challenges and well control problems will be analyzed in deepwater environment and provide best possible solutions.

1.3 Objective

The main goal of this study is to evaluate deepwater challenges and well control according to various environment conditions, identify possibilities of reducing the negative impact on the environment and lower the cost of drilling operations. Deepwater risk assessment will potentially help E&P companies to develop right solutions and low-cost and low risk strategies in future projects.

1.4 Methodology

The problems discussed in this thesis will give possible solutions to deepwater drilling challenges and well control. The results can help the operators and drilling companies in making right decisions.

The materials used in the work are collected from previous master theses, technical papers, presentations, journals, and other academic literature. Discussions with my supervisor, Dr. Udegbunam, provided useful insights into the study.

2 Deepwater Environment Conditions

The deepwater projects require safe and efficient development. To understand the ocean environment and its behavior with a system and operations, it is necessary to have all important information from environment in planning and development of the deepwater field. The deepwater environment problems can lead to high expenses and risk and can interfere with making right decisions.

Wind, tides, waves, storms and currents are the most common dynamic conditions in aquatic environments and require a good monitoring in offshore fields. In the early stages of exploration, design and planning of a field, water depth, pressure, temperature, sea floor topography, and environment activity are main conditions for deepwater production because marine weather conditions impact oil and gas operations, drilling and production.

2.1 Metocean Forecasting and Analysis System.

Fugro (2017) provides a detailed explanation of oceanography and meteorology (metocean) forecasting and analyzing system for deepwater environment. The metocean system is used to predict and analyze atmospheric and physical ocean conditions including ocean currents, waves, tides, wind and other atmospheric parameters. A metocean conditions reduce costs, provide a good operational planning of a field, and enhances safety and operational efficiency during drilling in deepwater environment. New technologies with metocean forecasting and analysis system can significantly increase upcoming deepwater projects efficiency, because the technology is more reliable for design oceanography and meteorology forecasts for drilling operations.

Metocean forecasting and analysis system Fugro (2017), which include:

- Monitoring over integrated environmental and mooring load.
- Monitoring over floating vessels and platforms affected by waves, currents, winds, motions and stresses.
- Environmental motion monitoring.

Fugro's structural monitoring services are specially designed and performed for deepwater marine riser operations during well planning and management:

- Monitoring during float over heavy lift, transportation and other construction activities.
- Monitoring and measurement of stress and fatigue in structures and pipelines.
- Monitoring of marine riser, pipeline load and vortex-induced vibrations (VIVs).

When deepwater drilling increases within water depth, it is moving into HPHT environments where more currents impact on drilling operation. The information in such areas is limited. To enhance safety and efficient operation, availability of the metocean system with new technology will increase the development of the field by providing operators and regulators with more accurate information and calculations. The metocean system cannot always solve problems during deepwater drilling operations, when the operation is heading deeper in the seawater, because there is rapid increase in hydrostatic pressure. The temperature and pressure results in increase on density with increasing water depth. Therefore, new innovations with new models should be designed within deep-sea weather conditions in a safer and economical manner. The development of a safe and efficient deepwater infrastructure requires contemporary progress both in weather prediction and in the development of engineering systems.

2.2 Loop Current Eddy in the GoM.

Conser (2007) showed that the industry had tried to characterize loop current eddy in the deep GoM field. The deepest areas of warm water related to the loop currents and the rings of currents that have been separated from the loop currents are usually called loop current eddies.

Fig. 2.1 shows the eastern GoM loop current.

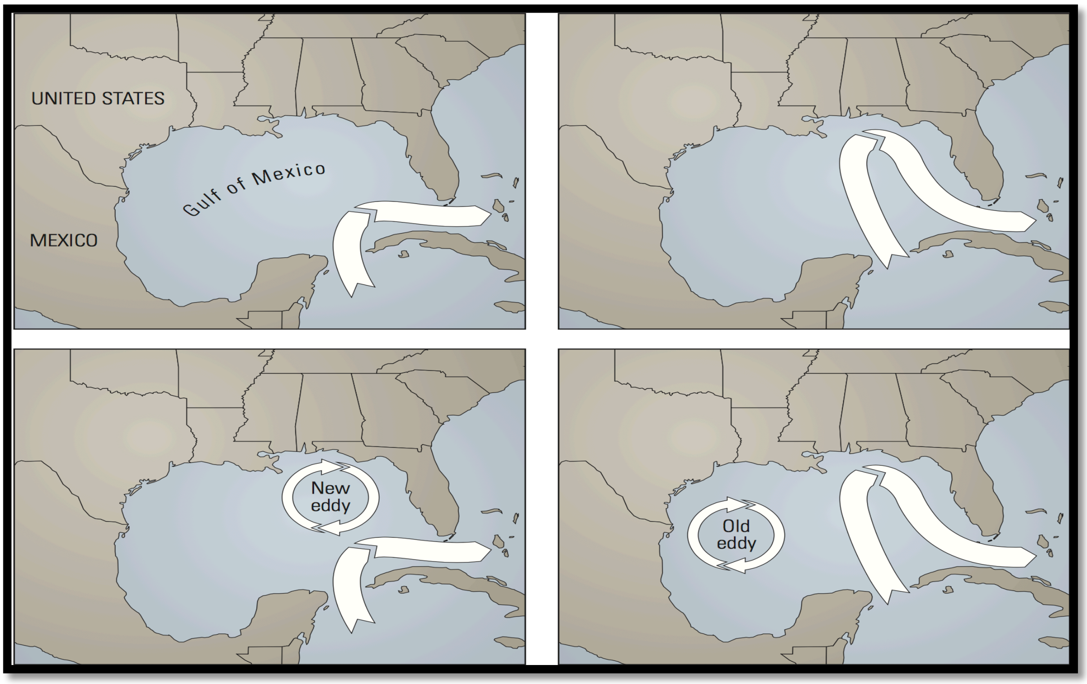


Fig. 2.1— The eastern Gulf of Mexico loop current (Cummings et al. 2014).

From Fig. 2.1, the loop current is a cyclical high-current zone in the GoM that breaks off the gulf stream and may create a short loop which can be seen on a top left corner of the picture or the loop may be elongated. On the left bottom of the figure, when the loop is long, it pinches off a spinning body of water which can be called an eddy. On the right bottom of the figure, eddies move westward and eventually lose energy in the western Gulf. The cycle of loop and eddy currents occur several times a year.

The loop current creates positioning and riser-management problems. Even if the rig position is maintained, the loop current can create a riser angle that makes drilling operation difficult. The strong currents push risers laterally and makes it difficult to land risers in blowout preventer (BOP). The deepwater drilling industry has developed special equipment to support and guide drilling risers, however this equipment is very expensive, therefore, some mobile drilling units cannot perform drilling in deepwater areas with strong currents (Bybee 1999).

The warm waters of the loop and eddy currents provide more energy to hurricanes and allow them to become stronger. Therefore, hurricane is a major problem, which affects deepwater operations by making dynamic positioned rigs move away from the storm path. During the hurricane condition, to secure the well and recover the riser may require some time before the storm will affect the rig floor. To reduce abandonment time, the use of a freestanding riser, have been proposed to the industry but have not been proven reliable yet (Bybee 1999).

Ocean models should be calibrated and checked in real time. The development of weather systems and collecting data is very expensive and require a lot of resources. Over the time, ocean model development will be increased among drilling operators and the new technology will provide high-fidelity model with less uncertainty.

2.3 Vortex-Induced Vibrations

The main barrier between the drilling fluid and ocean environment is the marine riser.

In the deep waters of the GoM, West Africa, and Brazil, where oil and gas exploration and production continue to grow, vortex-induced vibrations (VIVs) are the largest contributor to the overall riser fatigue damage. Marine risers for deepwater wells are subjected to strong ocean currents, wind, and vortex-induced vibrations. Large waves and cyclic forces which are generated by the waves during an operation, can cause fatigue damage to the riser and wellhead.

The illustration of VIVs is shown in Fig. 2.2.

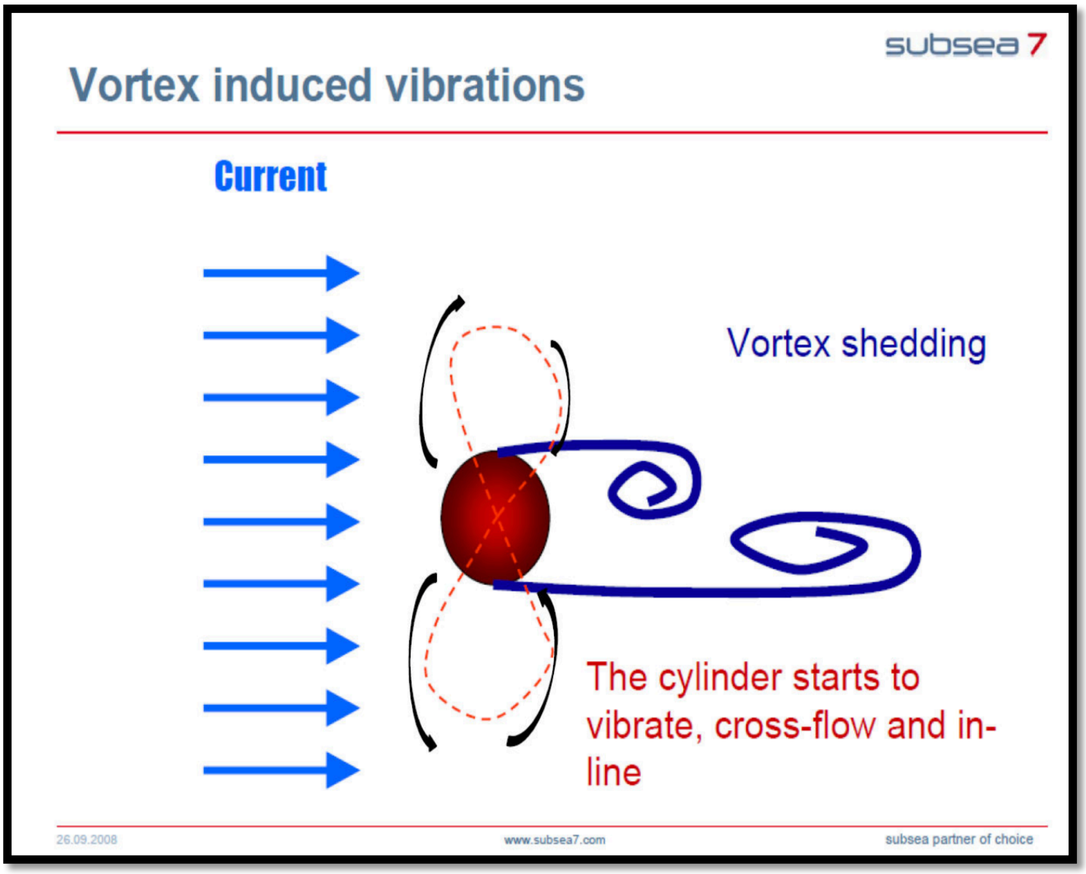


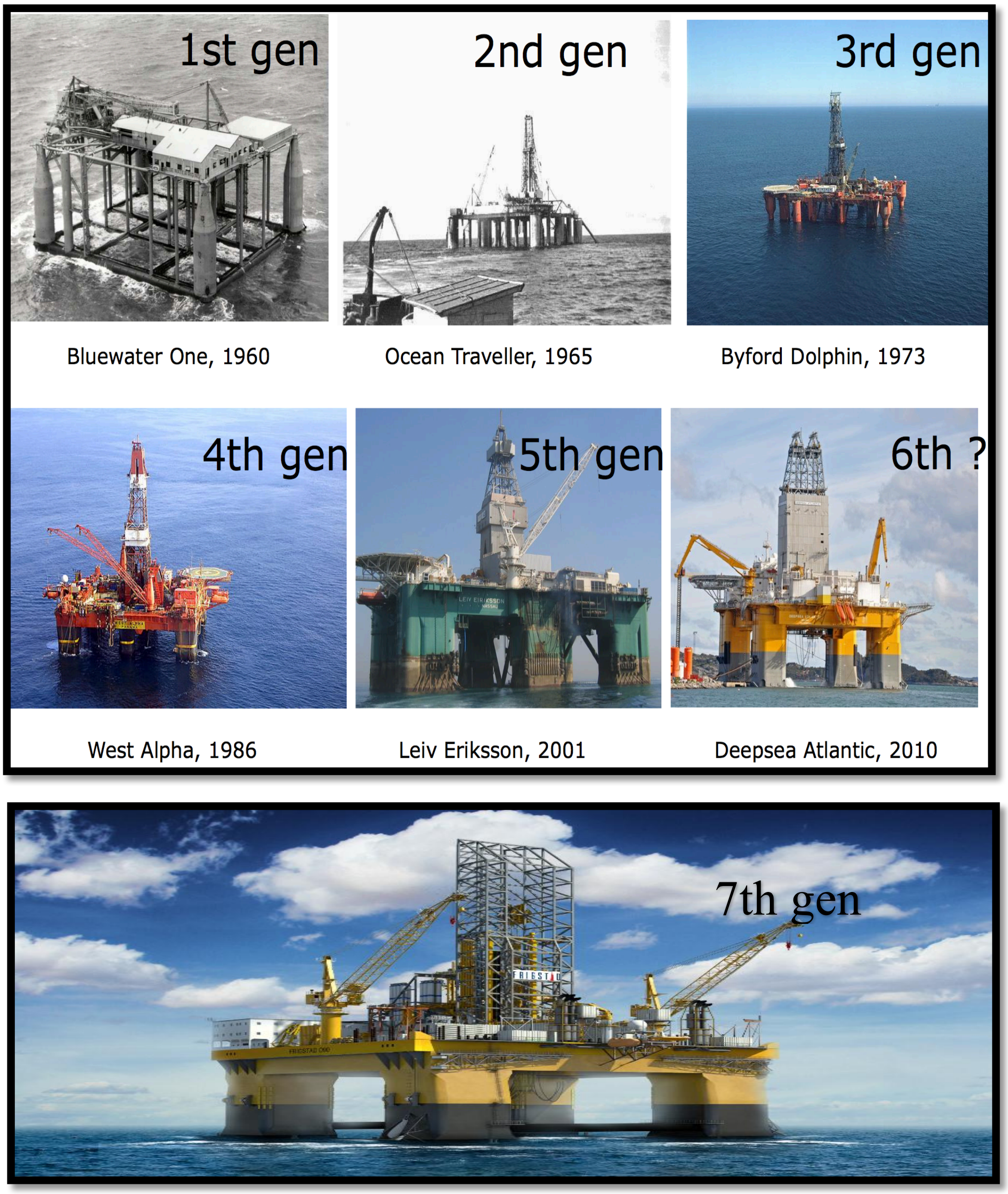
Fig. 2.2— Vortex-induced vibrations (Karaunakaran 2017).

VIVs are a lateral force movement in deepwater drilling where vortex shedding interacts with the structural properties of the marine riser, leading in large amplitude vibrations in in-line and cross-flow directions. The vessel offset caused by current, results in large bending moments by creating one of the major loads at the seabed during drilling. The tensioning system and the rig structure should be checked against the required tension and bending stress combined with load effects for designed riser system during drilling and cementing.

Cummings et al. (2014) showed that, to avoid fatigue damage caused by VIVs, helical fins should be placed along the length of the marine riser as each section is lowered from the rig floor to the seabed. Helical fins break up the currents and prevent creation of vortex-induced vibrations.

3 Deepwater Drilling Facilities

There are several common drilling rig types that are used in offshore operations. Many of the offshore drilling rigs have been classified by "generations". Generation indicates the year that the drilling rig was built and its water capability. Fig. 3.1 illustrates the different generations of the drilling rigs for the past 50 years.



Frigstad Deepwater, 2015

Fig. 3.1—Semi-submersible drilling rigs (Nergaard 2015).

Fig. 3.1 shows that every 10th year it is a new generation of semi-submersibles offshore drilling rigs and the size of offshore drilling rigs have been increased during last years. Nergaard (2015) presented different generations of the floating rig:

- First generation: early 1960s and water depth approximately 200 m
- Second generation: from1969 to 1974 and water depth approximately 300 m
- Third generation: early 1980s and water depth approximately 500 m
- Fourth generation: 1990s and water depth approximately 1000 m
- Fifth generation: from 1998 to 2004 and water depth approximately 2500 m
- Sixth generation: between 2005 and 2010 and water depth approximately 3000 m
- Seventh generation: 2015 and water depth approximately 3600 m

Fig. 3.2 shows deep-sea challenges of semi-submersible rigs.

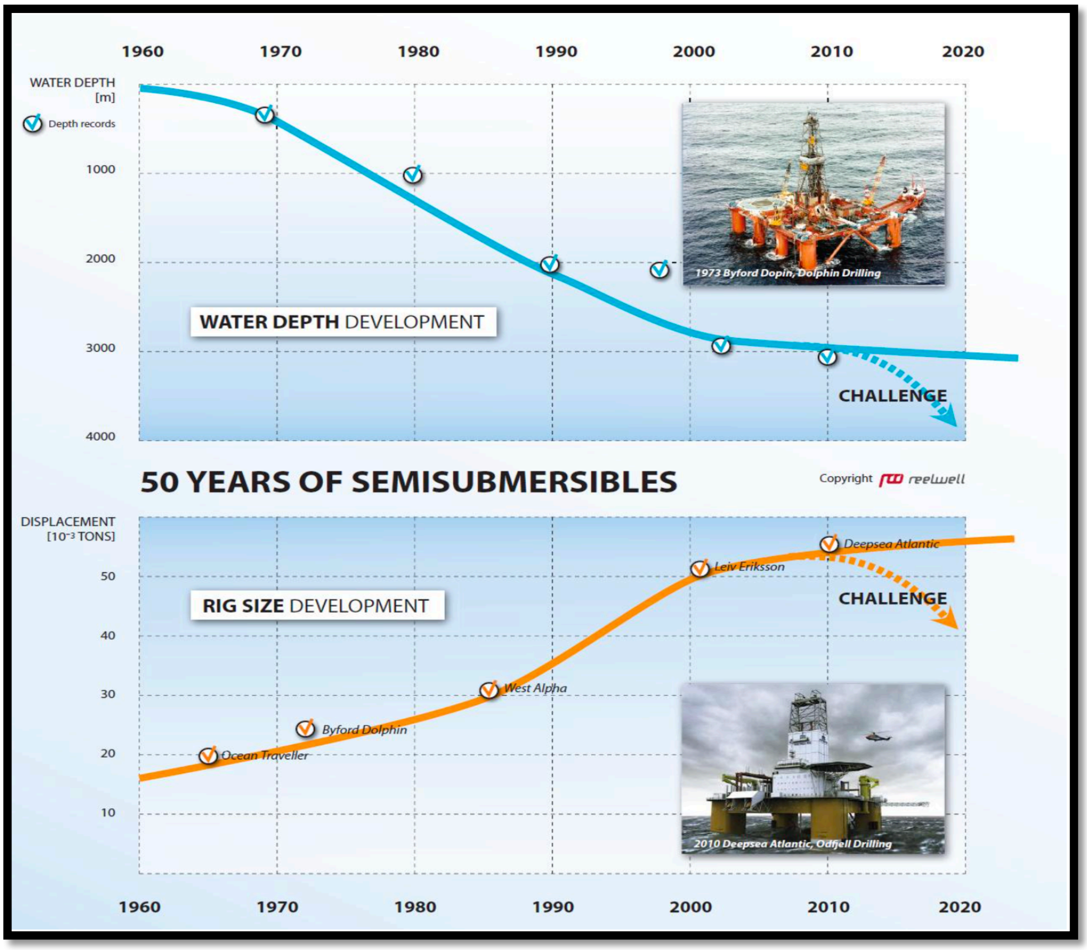


Fig. 3.2—The deep-sea challenges of semi-submersible rigs (Reelwell 2012).

Fig. 3.2 shows that the size of the drilling rigs has tripled in the past 50 years, and their design has become more complex and expensive for the industry. This applies to installation of facilities, providing access to the seabed and to overcome the distance from the seabed to the surface. The main goal is to reduce the rig size while water depth increasing. The final goal is to use less equipment while still being able to drill the same type of wells safely at a fraction of the cost. It is very important for the industry to perform drilling safely and as quick as possible by reducing size of drilling rigs leading to reduced daily operating cost i.e. rig day rates and costs for the drilling operators.

3.1 Types of Offshore Structures and Drilling Rigs

There are several common offshore structures and drilling rigs which are used in deepwater fields. Fig. 3.3 presents different types of drilling rigs.

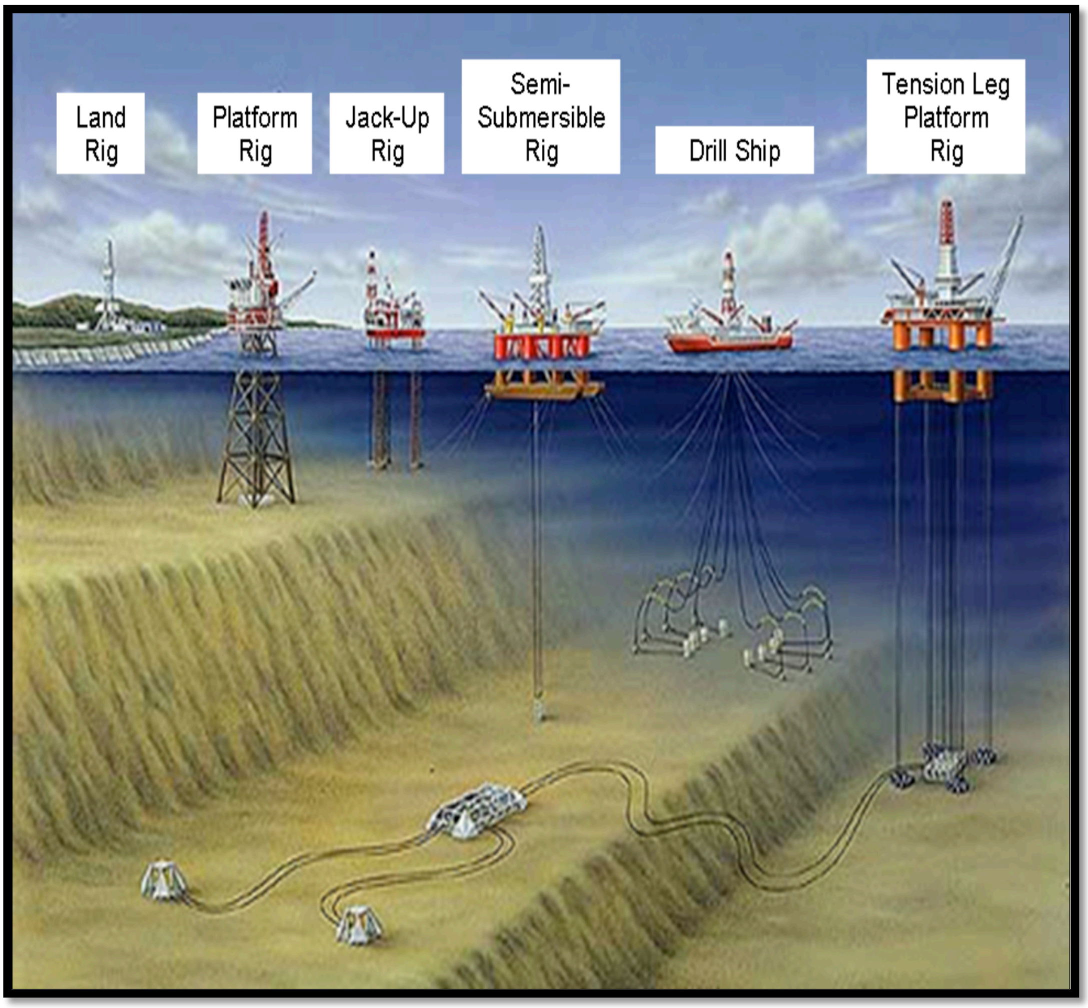


Fig. 3.3—Land and offshore drilling rigs (Group 2011).

3.1.1 Offshore Moveable Drilling Rigs

Offshore moveable drilling rigs are used in E&P and can be moved from one location to another. The offshore moveable drilling rigs have much lower operational cost compare to fixed platforms, and this makes them more economically preferable to use. There are several types of offshore moveable rigs.

- Bottom-supported type.
- Floating drilling rig type.

Bottom supported units (barges or jack-ups) are not suitable for deepwater fields and will not be covered in this thesis because barges and jack-ups most of the time are used in shallow waters. Floating vessels such as semi-submersible, drill ships, tension leg platforms (TLP), and floating production, storage and offloading (FPSO) are specially designed for deepwater fields and will be considered in this work.

3.1.2 Semi-Submersible Drilling Rigs

Semi-submersible rigs are specialized marine vessels that used in deepwater and ultra-deepwater fields. These rigs are designed with good stability characteristics for deepwater environment with capability to provide own power and ability to drill in water depth of 2400 m. Anchors, submerged portion of the vessel and dynamic positioning system provide stability for the semi-submersible rig during drilling operations (Group 2011).

3.1.3 Drill Ships

Drill ships are mostly used in challenging and complex deepwater wells. In the upcoming few years, it is expected that the demand for drill ships will increase in terms of utilities and serviceable functionalities. A drillship has good mobility and can move quickly under its own power from place to place compared to semi-submersibles and other moveable platforms. Drill ships can save time sailing between oilfields worldwide. For example, for a drill ship, it will take about 20 days to move from the GoM to offshore Angola. In contrast, a semi-submersible rig should be towed, and it can take up to 70 days to reach the location (Group 2011).

3.1.4 Tension Leg Platform

Tension Leg Platform (TLP) is a buoyant platform and used for deepwater production and drilling. Position of TLP is achieved by means of tension tendons (steel pipes). Tension tendons are used to attach the structure and to the seafloor. TLP is perfectly suited for water depth greater than 1400 m. The marine risers, with weight of drill strings and surface production trees, provide a good access to the wells during production and drilling operations. The platform can be used only up to a maximum water depth. Beyond its operational limits, TLP will be affected by hydrodynamic forces and vertical riser loads (Group 2011).

3.1.5 Floating Production, Storage and Offloading

An FPSO is a floating rig adapted to deepwater locations where the use of seabed pipelines for transporting hydrocarbon are not cost-effective. One of the advantages of the FPSO is that water depths present no limits to the floating rig (Fjelde 2013).

FPSO rigs give best possible solution for smaller oilfields that can be depleted in a few years. Once the oilfield is depleted, the FPSO can be moved to a new location. This reduces the time and costs of field development.

Fig. 3.4 shows FPSO with a disconnectable riser turret mooring.

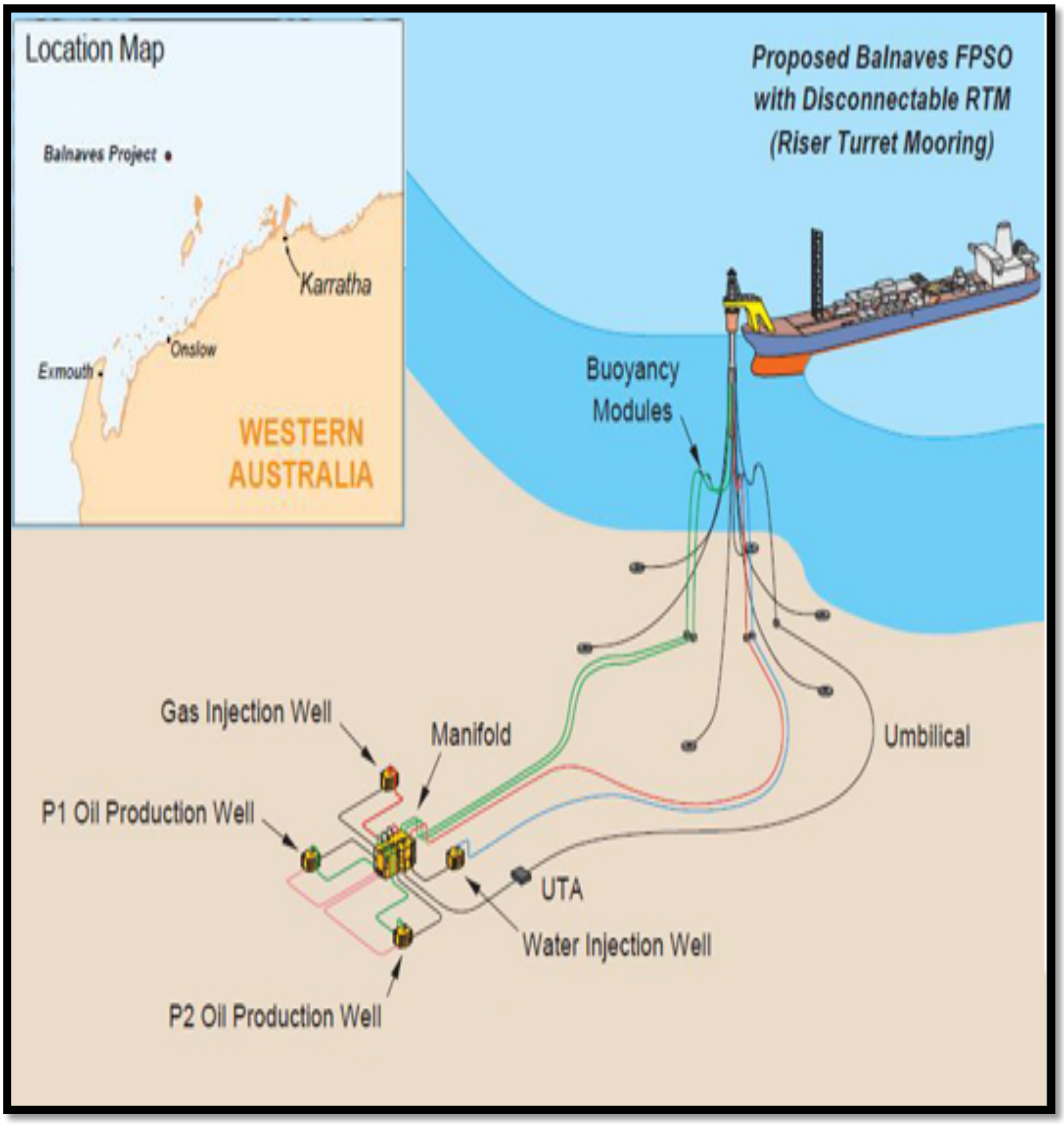


Fig. 3.4—Proposed Balnaves FPSO (News 2012).

Fig. 3.4 show the proposed Balnaves FPSO with disconnectable riser turret mooring system near Western Australia. The main components of the FPSO include:

- Umbilical is a control cable, which transmits power and control signals to a well.
- Flow lines used to carry produced fluid from the manifold to the FPSO.
- Clusters main function is that the reservoir fluids collected from the wells are channeled to a manifold which is tied back to a host platform.
- Manifold main function is to gather the oil or gas from the wells. Hence reduce the number of upstream flow lines and control umbilical to the production platform. 4 wells can have one or two flow lines. The manifold provides hydraulic supply, electrical power, and optical communication. A production manifold contains valves and pipes which designed to mix and send produced fluids.

3.2 Dynamic Positioning System

Moveable drilling rigs commonly use dynamic positioning (DP) systems in the world's offshore hydrocarbon reserves. Association (2017) provides a detailed description of DP system. DP is a computer controlled system, which automatically supports position of the drilling vessel's stability during drilling operations in a deepwater and ultra-deepwater wells with propellers and thrusters. The drilling vessels is positioned with the wind, motion sensors and gyrocompasses. The data collected are analyzed with computer, and the information is used to keep the rig stable.

The main advantages of DP:

- Perfect mobility makes easy to change drilling rigs position.
- No anchor handling tugs are required.
- Independent on water depth.
- Quick set-up.
- Unlimited by obstructed seabed.

The main disadvantages of DP:

- Complex systems with thrusters.
- High costs of installation and high fuel costs.
- Chance of drive-off and drift-off.
- Underwater hazards.
- High maintenance of the mechanical system is required.

3.2.1 Problems with DP

Bybee (1999) demonstrated that all drilling rig operations in deepwater wells should consider that DP may stop working at any time. However, there are major problems with DP such as drive-off or drift-off.

3.2.1.1 Drive-off

Drive-off happens when the rig is powered to a position away from the well. To avoid this situation, sealing off the well should be performed by blowout preventer. The marine riser should be released from the wellbore to prevent damage in the riser system, wellhead or casing. Thruster system malfunction or failure within DP system may cause drive-off which affect the drilling rig (Bybee 1999).

3.2.1.2 Drift-off

Drift-off happens when all thrusters lose its power and are incapable to keep the drilling vessel stable on location. Compared to the drive-off situation, the marine riser must be disconnected and the well integrity protected. Blackout can lead to drift-off situation meanwhile keeping an appropriate available power margin. In this case, power management will reduce potential occurrence for a blackout (Bybee 1999).

3.2.1.3 Consequences of Drive-off and Drift-off

The riser or wellhead system may be damaged if the marine riser is not disconnected fast enough during drive-off or drift-off events. To prevent this situation, an emergency disconnect must be performed between the lower marine riser package (LMRP) and BOP by releasing the riser and sealing off the well (Bybee 1999).

3.2.2 DeepDrift Simulator

Julian Soles and Michael O´Sullivan (2017) developed a vessel-riser drift-off simulator, DeepDrift. The simulator is specifically designed for DP drilling vessels.

DeepDrift provides a fully riser and vessel analysis that simultaneously determines the drift-off of the vessel and the riser drift-off response. This approach significantly reducing the simulation time and increasing the solution accuracy (Julian Soles and Michael O´Sullivan 2017).

An example of the operator interface can be seen in Fig. 3.5.

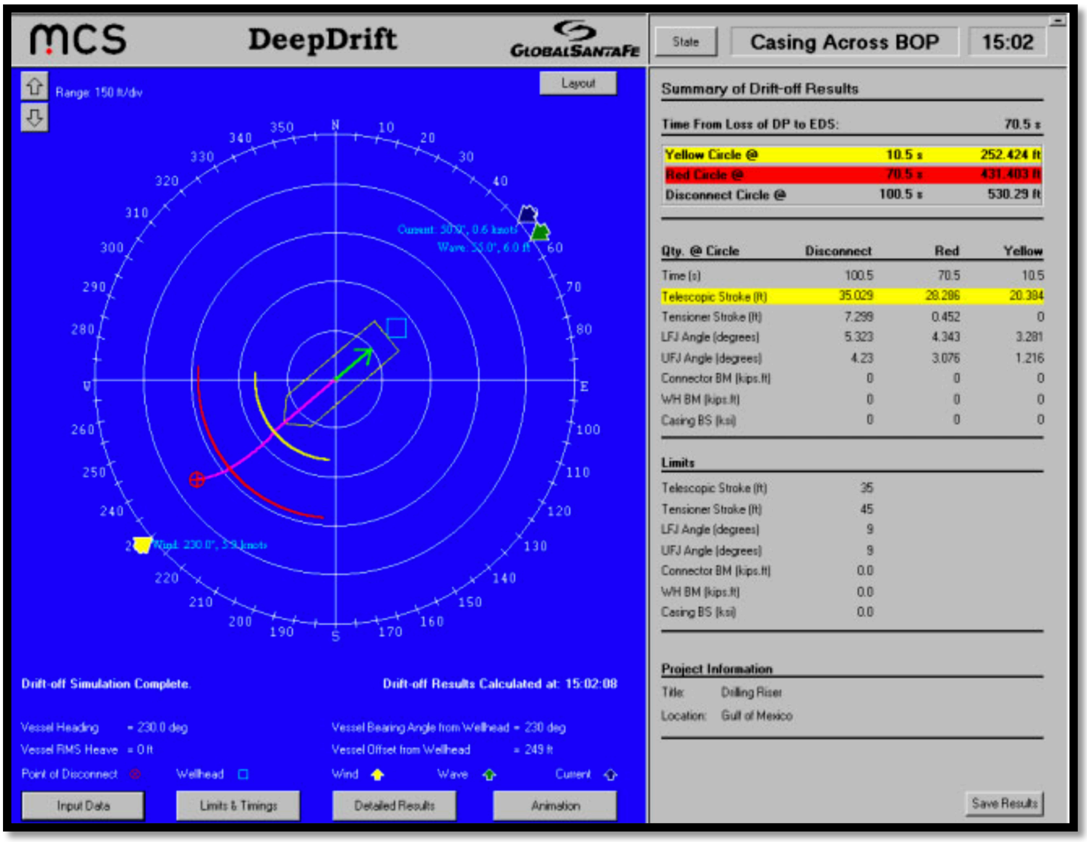


Fig. 3.5—DeepDrift Interface (Julian Soles and Michael O´Sullivan 2017).

DeepDrift interface forecast the vessel drift-off path during power failure. The simulator gives offset alerts based on the metocean conditions, and this helps to maximize the operating margin while enhancing riser integrity (Julian Soles and Michael O´Sullivan 2017).

The DeepDrift simulator is easy to use to minimise the chances of inlet errors and provide correct predictions. The simulator requires the inlet parameters such as:

- Wind speed, current profile and wave height
- Drilling units’ position
- Riser operational condition.

4 Well Control

Well control is a critical issue in deepwater drilling and should be considered during planning, designing and well constructing.

The three major well control problems include:

- Kicks
- Lost circulation
- Stuck pipe

In the worst case scenario, this can lead to a blowout. A good example is the Macondo incident on 20 April 2010 in the GoM, where explosions occurred aboard Deepwater Horizon. The main purpose of the well control is to prevent blowouts and wellbore stability problems.

Fig. 4.1 illustrates the Deepwater Horizon blowout in the GoM.

Fig. 4.1—Deepwater horizon in flames after the explosion (BP 2010).

Fig. 4.1 shows an uncontrollable blowout caused by the explosions on the semi-submersible rig. Eleven crewmen were presumed killed in fire incident. On 22 April 2010, Deepwater Horizon sank, causing the largest oil spill in the US waters.

4.1 Kick Occurrence

The kick occurs during following conditions (Belayneh 2014b):

- Wellbore pressure < pore pressure
- A reasonable level of permeability
- Presence of formation fluids.

The different causes of kick are listed below (Belayneh 2014b):

- Low mud weight
- Swabbing
- Improper fill up during tripping-in and tripping-out
- Lost circulation
- Gas cut mud

4.2 Well Kick

A kick is an unintended inflow of formation fluids (gas and oil) into a wellbore during drilling operation. A kick occurs when well pressure due to hydrostatic mud column and associated friction pressure is lower than pore pressure. The higher formation pressure tends to force formation fluids into the wellbore. A kick situation must be considered during drilling operation because kick is a critical problem for the oil industry. If a kick is not brought under control, a blowout can be the final disastrous result.

Fig. 4.2 illustrates a kick condition, where pore pressure is greater than well pressure.

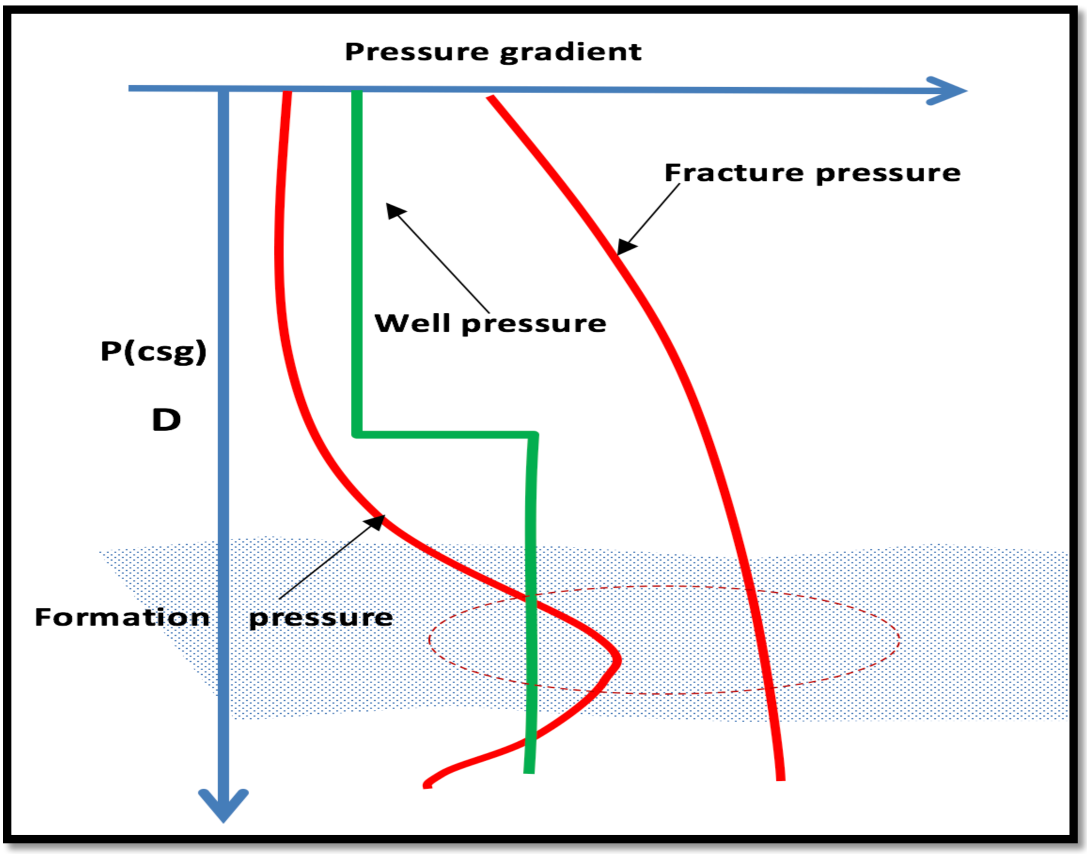


Fig. 4.2—An illustration of a kick situation (Belayneh 2014b).

From Fig. 4.2, to maintain the well control and perform safe drilling operation, the well pressure should be kept between the pore pressure and fracture pressure. A kick will occur if the well pressure crosses the formation pressure which leading to a well kick.

$$P_{pore} < P_{well} < P_{fracture}$$

During a kick event, gas has a capability to pass through the BOP and move into the riser before the kick can be detected. During the shut-in procedure, some gas can be trapped in the BOP stack. This gas should be handled properly, otherwise gas will be released through rotary Kelly bushing (RKB) and can lead to an accident. After the kick has been handled properly, the gas trapped in the riser and BOP can be safely circulated out of the well to the surface throughout a diverter valve (Belayneh 2014b).

In deepwater environments, well control during kick events is very challenging because of mud losses (lost circulation) into the formation.

4.2.1 Low Mud Weight

Low mud weight is one of the major causes of the kick. Well pressure should be greater than pore pressure during conventional drilling. If mud weight is too low, the formation fluid will flow into the well and cause a kick. It is very important to keep mud weight inside the pressure window all the time. To avoid underbalanced drilling and low mud weight, the reasonable solution will be to increase the mud weight (Belayneh 2014b).

4.2.2 Swabbing

Swabbing occurs during tripping operation when a drill string is pulled out of hole (POOH). The reduction in wellbore pressure can force formation fluids into the wellbore and cause a kick. Circulation during POOH can minimize the swab effects. The procedure is called "pumping out of hole" and commonly used in HPHT wells. To avoid kick events, it is important to perform swab and surge calculations during well planning to find a safe operational window (Belayneh 2014b).

4.2.3 Improper Fill up during Tripping-in and Tripping-out

Hydraulic calculations should be performed just before tripping-in, otherwise fluid level may drop in the well and cause a kick. During tripping-out, the hole should be filled up with a mud, otherwise pore pressure will exceed the well pressure and cause a kick (Belayneh 2014b).

4.2.4 Lost Circulation

Thief zones of significantly lower pressures, where mud losses occur, may cause level in a wellbore to drop and lead to a kick.

During run in a hole (RIH), well pressure increases. This leads to fracturing of the formation and loss of drilling fluid into the fractured formation. Fractured formations increase the potential risk of lost circulation and well control incident. Reduced pump rate and mud weight will prevent fracture pressure from been exceeded. To avoid surges, which cause lost circulation, avoid fast tripping and break mud gel before initiating circulation (Fjelde 2013).

There are some serious consequences of lost circulation. They include high kick probability, poor hole cleaning, and possible well collapse. Therefore, it is very important to identify potential loss circulation zones in the early stages prior to drilling operation. Also, potential low pressure zones should be isolated with casing. Other measures include equivalent circulating density (ECD) control, proper hole cleaning, and the injection of lost circulation materials into fracture zones (Fjelde 2013).

4.2.5 Gas Cut Mud

Drilling through gas formation zone may cause a reduction in hydrostatic pressure and lowering the density of drilling fluid because of amount of gas in the well. The reduced mud weight will cause bottomhole pressure (BHP) to decrease and hence the inflow of formation fluids into the wellbore (Belayneh 2014b).

4.3 Kick Detection

In deepwater drilling, kick detection is very important in completing well without any problems and time loss. The most effective approach is to detect the kick before it happens and control it in a safer manner. Kicks can be detected with several different indicators.

4.3.1 Primary Indicators

4.3.1.1 Pit Gain

A kick can be detected from an increase in pit level when the volume of drilling fluid coming out of the wellbore exceeds the volume of drilling fluid pumped in. The mud flow rates in the wellbore can be measured with a flowmeter. For example, if the pit gain is higher than pump rate, then there might be a kick in the well (Belayneh 2014b).

4.3.1.2 Increase in Return Flow Rate

An increase in the return flow rate due to the presence of a formation fluid in mud is a possible indication of a kick.

4.3.1.3 A Well is Flowing after Mud Pumps are Stopped

A well that is flowing, after mud pumps are stopped, is an indication that formation fluid has entered the well. Belayneh (2014b) demonstrated that HTHP conditions can show a similar behavior because of so called U-tube effect caused by high temperature which expands the drilling mud.

U-tube effect during drilling operation is defined in the Choe and Juvkam-Wold (1998) as "when subsea pump inlet pressure equals the seawater hydrostatic pressure, while the drill pipe is filled with heavy drilling mud. Therefore, when the surface pump is stopped, the fluid level inside the drill pipe will drop until the hydrostatic head inside the drill pipe above the sea floor is approximately is equal to the hydrostatic head".

4.3.2 Secondary Indicators

4.3.2.1 Drop in BHP

Hydrostatic pressure decreases when the light weight formation fluid flows into the well (Belayneh 2014b).

4.3.2.2 Drop in Stand Pipe Pressure

Hydrostatic pressure decreases when more formation fluid flows into the well, leading to a drop-in stand pipe pressure (SPP) (Belayneh 2014b).

4.3.2.3 Drilling Break

An increase in rate of penetration (ROP) when overbalance decreases normally occurs in sand formation. A flow check can be performed after getting a drilling break to determine if the formation is flowing. ROP varies within different types of formation. For example, soft formations (sandstones) provide a lower resistance because of sand composition (Belayneh 2014b).

4.3.2.4 Increased Hook Load

Any invasion of lighter formation fluid into a wellbore can cause a reduction in buoyant force. An increased weight acting on the drill pipe will cause the hook load to increase (Belayneh 2014b).

4.4 Well Control Equipment

Fig. 4.3 shows a schematic of well control equipment.

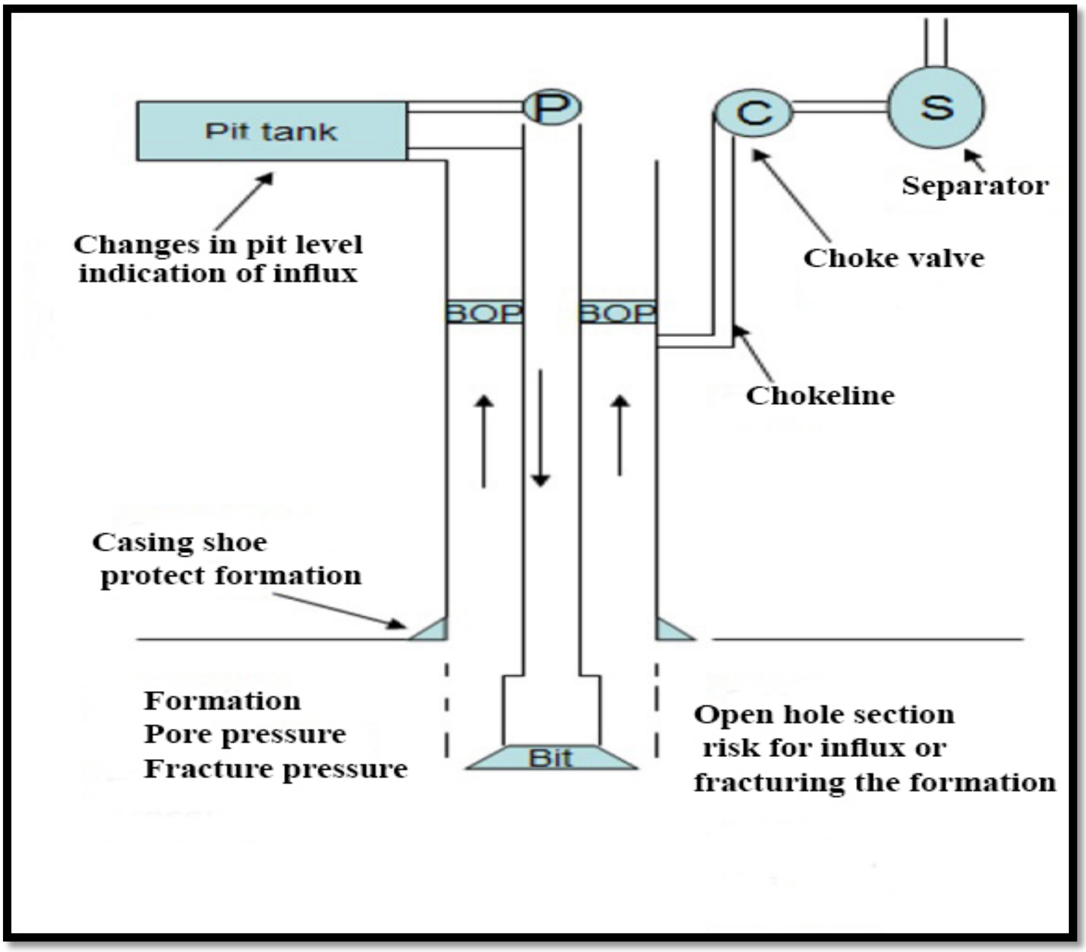


Fig. 4.3—An schematic of well control equipment (Fjelde 2013).

The operational sequence of well control equipment:

- The drilling fluid migrate downward inside the drill pipe and up the well in the annulus to the pit tank which is located at the surface. The pit tank measures the pit volume.
- The BOP seals off the well in case of an influx.
- The choke valve control the well pressure and the choke line transports well fluids out of the well when the BOP is closed.
- The separator separates the gas from the mud.

During the kick, the next operational steps are to stop operation, close the BOP, wait until well pressure has increased and the inflow has stopped. Circulate the kick out through the choke line and choke valve, and use the choke valve to control the BHP, which must be kept above the pore pressure to avoid a new kick. A new and heavier mud is then placed in the well to control the pore pressure.

4.5 Kick Simulations

Nes A (1998) showed that gas in a deepwater riser during a kick has been studied with advanced kick simulations. The following scenarios were simulated:

- Gas is migrating up in the riser
- Pumping with gas in the riser
- Swabbed (concentrated) kick vs. drilled (distributed) kick
- In what proportions gas would be trapped in the mud.

Belayneh (2014b) demonstrated that computer models have been developed to describe and analyse kick phenomena. To verify the models, models need to be compared to real data from experiments. Simulators can be used to design well control issues, provide more realistic kick tolerances, evaluate and predict different kick scenarios, develop well control procedures, swab and surge effects.

Advanced kick simulators gradually are used more and more in well control planning and evaluations of challenging wells. Real-time kick tolerance evaluations for critical wells are now under development. Advanced kick models also are integrated with advanced hydraulic models into real-time modelling systems for managed pressure, dual-density, and standard drilling systems Rolv et al. (2006).

4.6 Kick Tolerance

Kick tolerance is the maximum gas kick volume, that can be circulated out without exceeding the weakest formation pressure in the wellbore (Lapeyrouse 2013).

The weakest formation in the well is below the last set casing shoe. Lost circulation or a blowout can occur if the well pressure at the casing show will exceed the fracture pressure. This means that kick tolerances can affect the casing design (for example, depths at which different casing shoes are set).

Kick tolerance is affected by kick size, formation pressure, mud weight, density of influx and circulating temperature. If the well cannot handle the kick sizes defined by the volumes, the last casing shoe should be set deeper (David et al. 2003). Fig. 4.4 illustrates casing shoe pressure for different kick sizes.

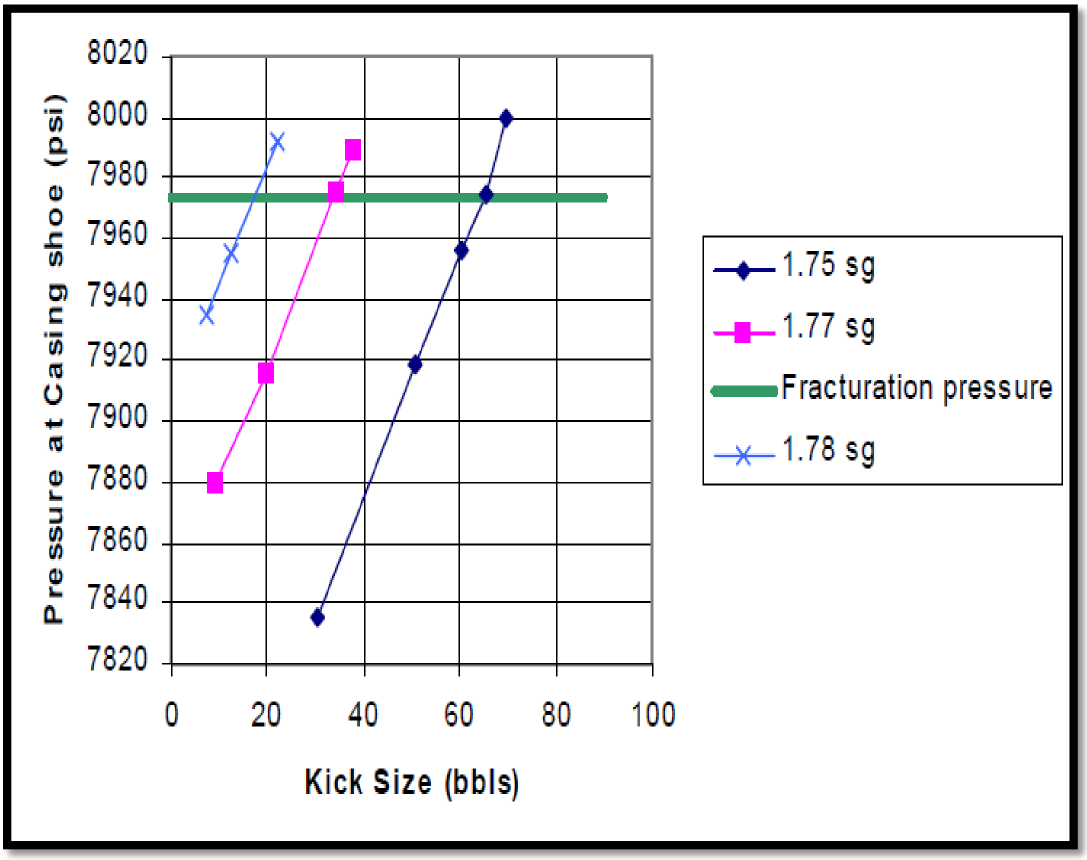


Fig. 4.4—Casing shoe pressure for different kick sizes (Aadnoy et al. 2009).

From Fig. 4.4, the kick tolerance curves are generated with an advanced dynamic kick simulator. The analyses are performed with three mud systems of different densities. The graph presents the casing pressure as a function of kick size. When the kick size increases, the casing pressure also increases. When the mud density increases (from 1.77 sg to 1.78 sg), the casing pressure reaches the fracture pressure and increases even at a lower kick size. If this is the 12 ¼-in section, the requirement is 25-50 bbl. Thus, drilling cannot be achieved in this section to planned depth. Possible solution will be set the casing earlier. Drilling with the lighter mud density (1.75 sg) shows that the well can tolerate a higher kick size (e.g. 65 bbl) (Aadnoy et al. 2009).

4.7 Stuck Pipe

Stuck pipe is known to be a severe event that can be quite expensive and, in the worst case, may lead to well plugging and side-tracking.

Fig. 4.5 presents three main causes for stuck pipe Fjelde (2013), which includes:

- Mechanical related
- Formation related
- Differential sticking

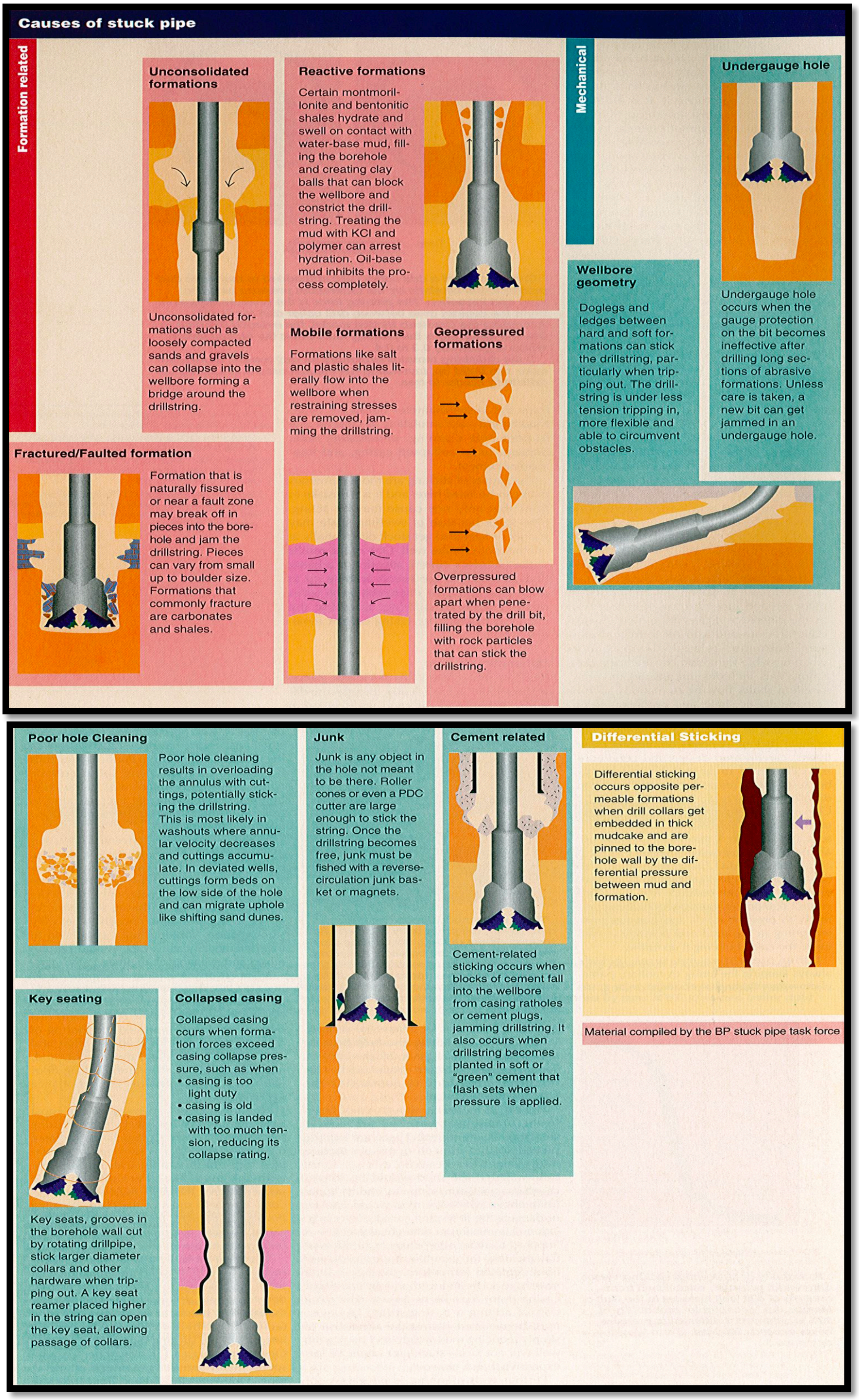


Fig. 4.5—Different causes of stuck pipe (Louise Bailey 1991).

4.7.1 Mechanical-Related Stuck Pipe

Mechanical-related stuck pipe may be due to poor hole-cleaning, collapsed casing, junk and well geometry.

Stuck pipe can occur when cutting transport is critical. A proper flowrate is required to avoid this problem, rotation of drill string is very important too and can be very helpful. Wiper trips can be used when hole-cleaning efficiency is questionable. Drilling through different formation types of different hardness can also be very problematic.

Ledges is one of main problems among others that can occur during drilling in soft, fractured, and hard formations leading to stuck pipe. Jar is a drilling tool that can induce large axial shocks in the drill string to get loose in stuck pipe situation. If the drill string is stuck while moving up, applying jar down with maximum trip load can prevent stuck pipe. Torque can be applied also with caution while jarring down. If the drill string is stuck while moving down, jar up with maximum trip load without applying any torque in drill string can prevent the stuck pipe. When the drill pipe is free, back reaming is often used to reduce the risk for tight hole conditions (e.g. clear some ledges) (Formulas 2014).

4.7.2 Formation-Related Stuck Pipe

Formation related occurs when unstable formations squeeze around a drill pipe. Fjelde (2013) includes formations:

- Unconsolidated formations (e.g. sand)
- Boulders
- Fractured formations (e.g. around the fault)
- Mobile formations (e.g. salt)

Drilling through shales can be problematic. Among these problems are geo-pressured shale (over-pressured shale) and reactive shale. Geo-pressured shale has a higher pressure than nearby sandstones. A higher mud weight is required to drill through these layers. While drilling through reactive shales, an inhibited mud (salt) should be used to reduce shale shelling problems. In this case, oil-based mud (OBM) should be used instead of water-based mud (WBM) because OBM inhibits the process completely. Salt formations are plastic and will move into the hole. With unstable formations, it is important to seal these sections as soon as possible. A high mud weight will also be a good solution to reduce this problem (Fjelde 2013).

4.7.3 Differential Sticking

Differential sticking occurs in permeable zones because of the pressure differential between mud and formation. During the differential sticking, drill collars get stuck in thick mud cake and are pinned to the borehole wall. To avoid this problem, mud weight must be reduced because heavy mud weight will increase hydrostatic pressure and differential pressure (Fjelde 2013).

4.8 Swab and Surge Effects

Pressures variations occur during tripping operations. The swab pressures occur during tripping-out and surge pressures during tripping-in. It is important to follow tripping speed because underbalance situation during tripping-in, can lead to a kick. The mud weight should be adjusted to account for temperature and swab effects (Belayneh 2014b).

4.8.1 Swab Effect

Fig. 4.6 illustrates the swabbing effect when well pressure approaches pore pressure.

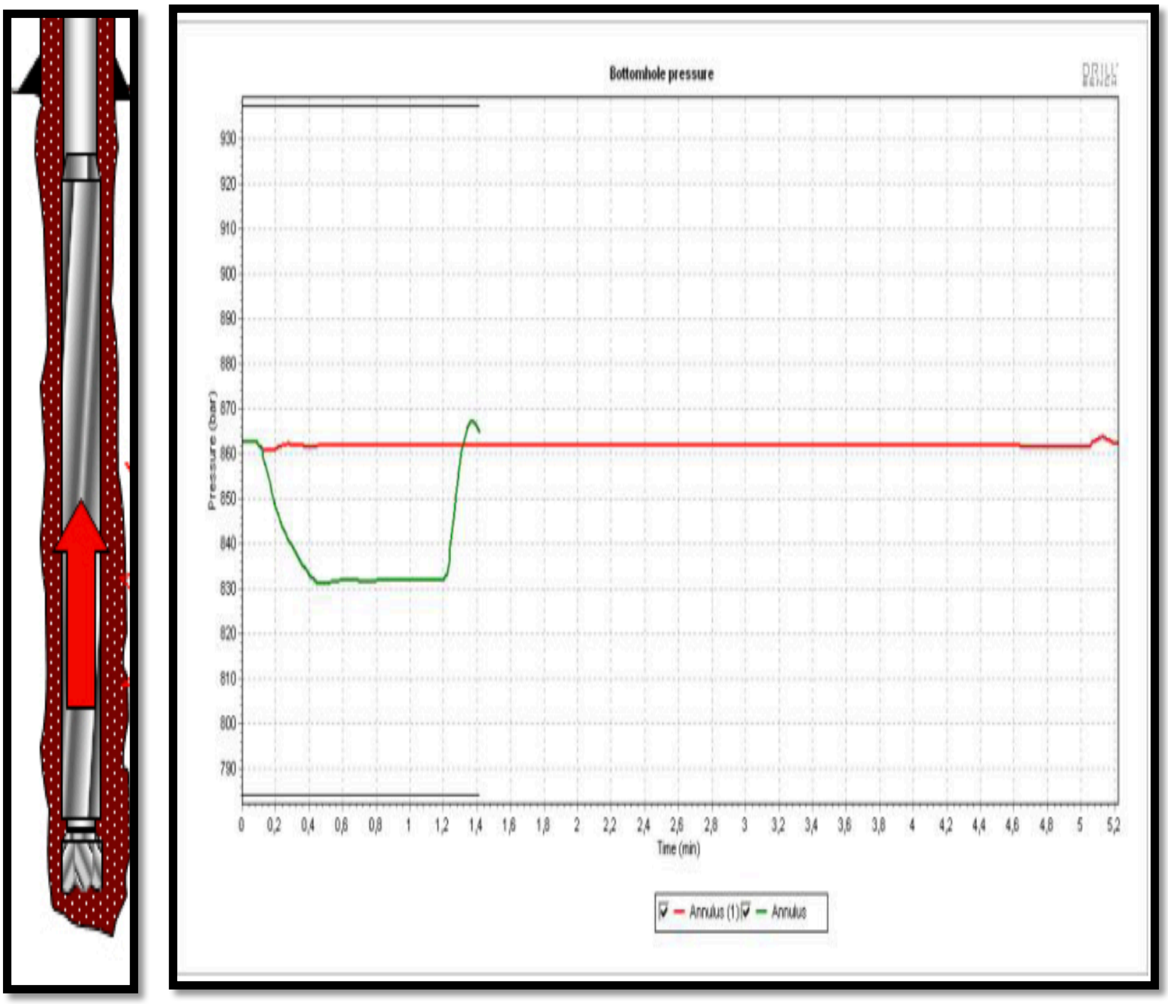


Fig. 4.6—An illustration of swab effect in the 8½-in section (Hamarhaug 2011).

The simulation presented in Hamarhaug (2011) showed that, during POOH, the well pressure decreases. The red curve represents the BHP while pulling drill pipe slowly and the green curve shows fast pulling of the drill pipe. The effective hydrostatic pressure is reduced when swab pressure is negative. Therefore, well collapse and kick may occur. During swabbing with circulation rate of 500 lpm, there is a higher BHP drop, so the tripping speed is very important. During swabbing without circulation, the BHP is lowered to the static mud weight condition. This is because the low-density formation fluid is mixed with the mud and decreases the density of the drilling fluid. The pressure drop across the bit is influenced by the pump rate, so an increase in pump rate gives a smaller pressure drop during POOH at a higher speed. To avoid this problem, a higher flow rate during tripping-out should be used. In HPHT wells, it is a common procedure to circulate the well while POOH to eliminate the effect of swab pressures. Simulations are very useful to find the optimal rate since this will depend on the mud properties and rheological behavior of the mud.

4.8.2 Surge Effect

In HPHT wells will small margins well pressure may exceed fracture pressure and cause lost circulation. This can be seen in Fig. 4.7.

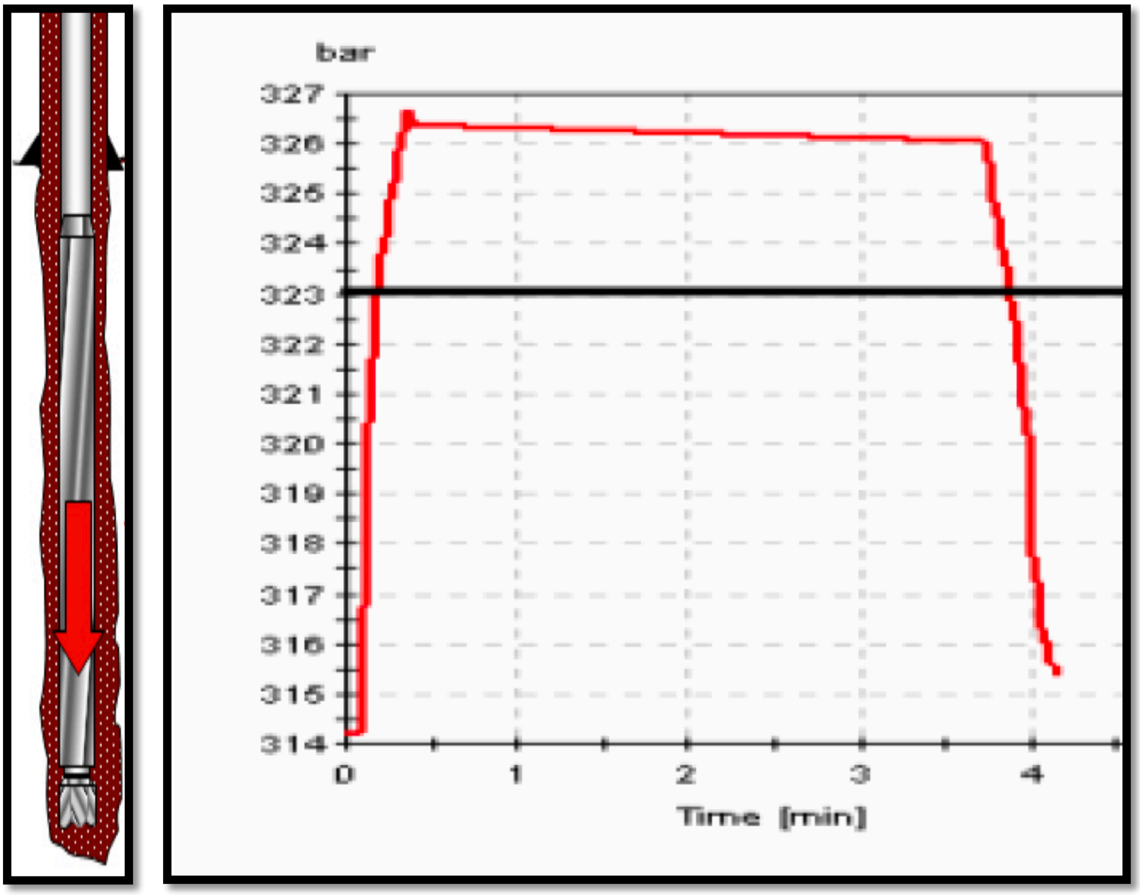


Fig. 4.7— Surge effect (Belayneh 2014b).

As show on the left side of the figure, drilling string is running downward. This results a temporarily increase in well pressure. The pressure depends on the drilling fluid properties, the velocity of the pipe, movement and the length of the pipe. The figure on the right side shows the simulation results obtained from Drillbench. In this simulation, the drill string was running 30m liner at the speed of 10/min. During simulation, the pressure development at the casing shoe has been observed, where the fracture gradient at the weak point was 323bar. As shown on the figure, the well pressure at the casing shoe before swabbing was 314bar. Due to swabbing the well pressure increases and stabilises at 326bar. This results in lost circulation. To manage surge induced problem, it is important to do kick tolerance simulation study during planning phases. By doing so, one can determine the appropriate tripping speed along with the right flow rate, to avoid fracturing. It is important to note that, since the operational window in deepwater is narrow, the knowledge of formation pressure, fracture gradient, reservoir fluids, and the well pressure are important for safe operation.

4.9 Well Control Methods

For a well to be killed successfully, the pressure in the formation must be kept under control during the entire kill operation. Well control covers different activities such as:

- Kick detection
- Circulating kick out of the well

The two widely used well control methods are the Driller's Method (DM) and the Wait and Weight (W&W) Method. The main principle of both methods is to keep BHP constant because BHP will prevent further influx into the well (Belayneh 2014b).

4.9.1 Driller's Method

The main principle of DM is to kill the well while keeping BHP constant. During a kill operation, BHP is the sum of hydrostatic pressure, well friction and choke pressure. When influx is circulated out, the constant BHP will keep the well pressure between pore pressure and fracture pressure (Belayneh 2014b).

Fig. 4.8 shows well pressure development during kick circulation with the DM.

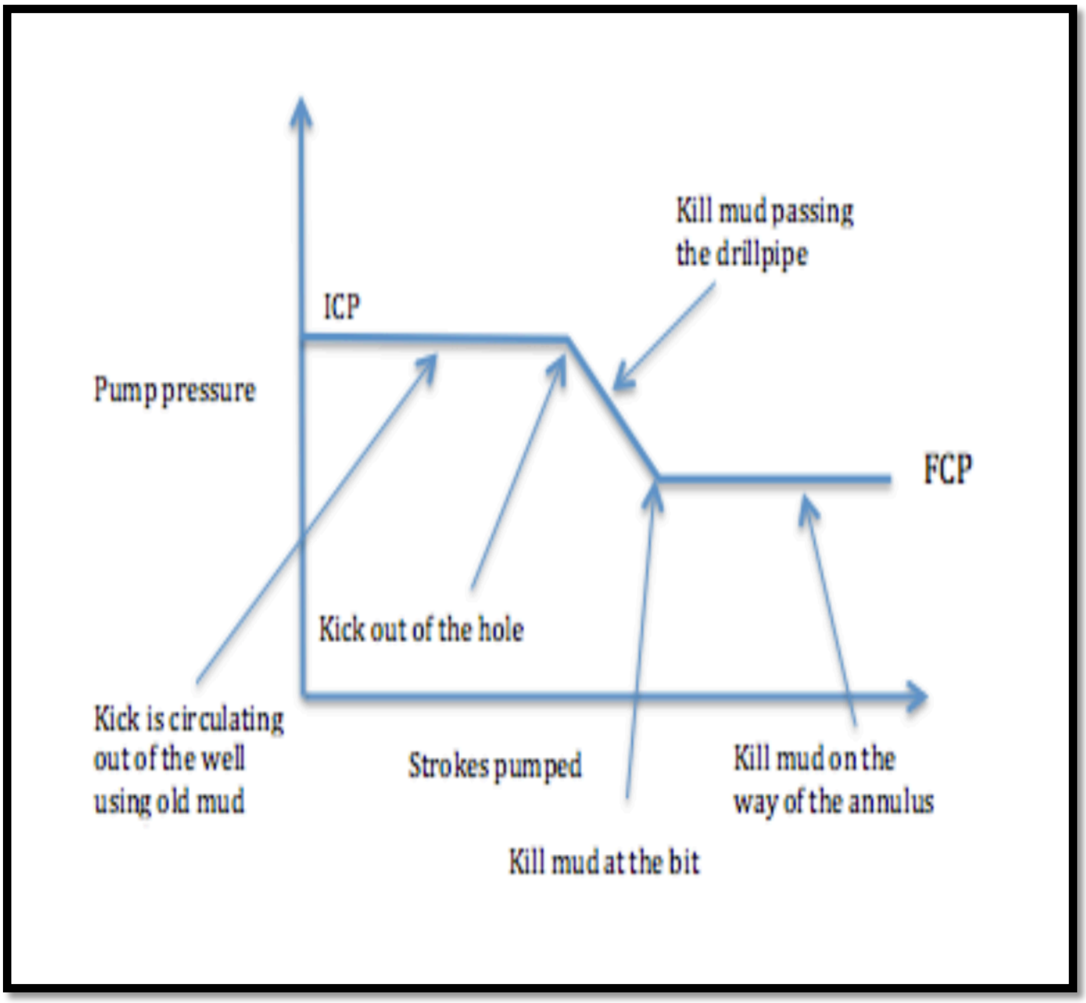


Fig. 4.8—An illustration of driller's method (Belayneh 2014b).

From Fig. 4.8, can be seen that, when the gas migrates up in the well, the BHP and drill pipe pressure at the top are kept constant. The first circulation removes influx with original mud weight, keeping the initial circulation pressure (ICP) constant. The drill pipe pressure will not decrease during the first circulation. The main purpose is to remove the kick from the annulus. When the first circulation is complete, kill mud is mixed and pumped through the drill pipe, to initiate second circulation. It is important to keep casing pressure constant when circulating kill mud through the drill pipe. The drill pipe pressure should be kept constant to maintain constant BHP until the kill mud is circulated out of the annulus.

The second circulation involves two steps:

1. Fill the drill string with kill mud, keeping the pressure in the kill line constant and equal to shut-in drill pipe pressure (SIDPP).
2. Circulation the kill mud out of the annulus to the surface, keeping the pressure of final circulation pressure (FCP) constant.

When the pumps are shut down, the drill pipe pressure and casing pressure should be zero if the well is successfully killed.

4.9.1.1 The Driller's Method Calculation Formulas

Eq. 1 gives the pump pressure to start the kill procedure (Belayneh 2014b).

$$ICP = P_{c1} + SIDPP \qquad (1)$$

ICP — initial calculation pressure (psi)
P_{c1} — pump pressure at the kill rate speed (psi)
SIDPP — shut-in drill pipe pressure (psi)

Eq. 2 gives the kill mud density is calculated with the SIDPP (Belayneh 2014b).

$$KM = OM + SIDPP / (0.052 * TVD) \qquad (2)$$

KM — kill mud weight (ppg)
OM — original mud weight (ppg)
TVD — true vertical depth (ft)

Eq. 3 gives the pump pressure needed when the kill mud is down at the bit (Belayneh 2014b).

$$FCP = P_{c1} * KM / OM \qquad (3)$$

FCP — final circulation pressure (psi)

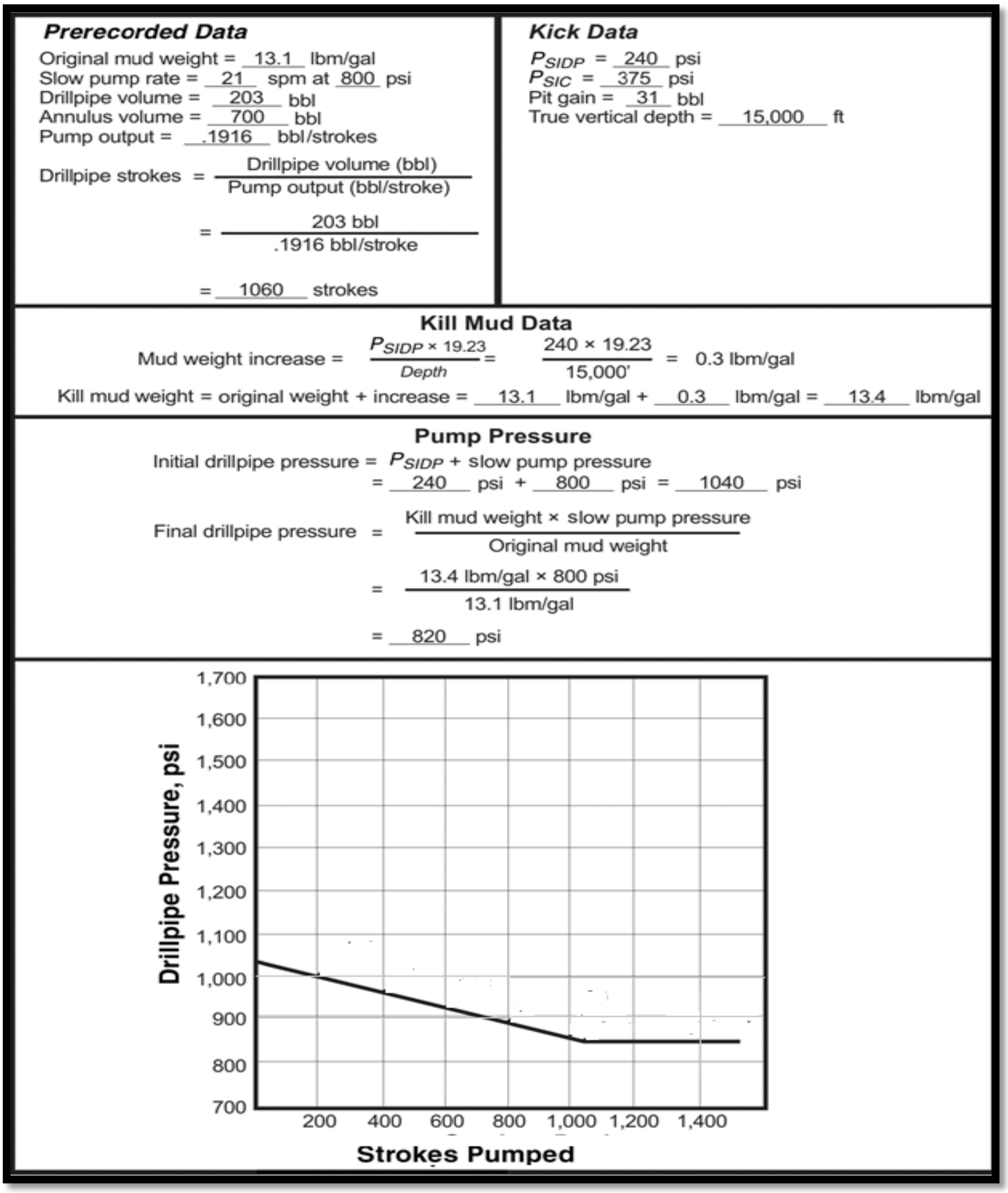
4.9.2 Wait and Weight Method

The main idea of the W&W method is to perform a kill operation in one circulation by pump kill mud into the well and at the same time the kick is circulated out of the well through annulus.

While pumping kill mud from surface into the drill pipe, a drill pipe pressure schedule should be calculated and followed, to reduce high annular pressures associated with gas kicks. The drill pipe pressure is kept constant through proper choke adjustment until kill mud is circulated out of the annulus to the surface.

Belayneh (2014b) summarized the W&W procedure

- After the well has been secured and pressures have stabilized, complete kill sheet including kill graph. The kill sheet example is shown in Fig. 4.9
- Casing pressure should be maintained at a constant pressure while bringing the pump to kill rate speed. As soon as the pump is on line and running at proper kill rate speed, casing pressure must be returned to its correct value.
- When pump is up to kill speed the choke is manipulated to keep the drill pipe pressure at ICP.
- Pump kill mud down drill pipe keeping casing pressure constant and allowing drill pipe pressure to fall from ICP to FCP.
- When kill mud reaches the bit the drill pipe pressure should be at FCP. Continue pumping kill mud, keeping drill pipe pressure constant at FCP until the kick is circulated out and kill mud reaches the surface.



Prerecorded Data

Original mud weight = 13.1 lbm/gal
Slow pump rate = 21 spm at 800 psi
Drillpipe volume = 203 bbl
Annulus volume = 700 bbl
Pump output = .1916 bbl/strokes

$$\text{Drillpipe strokes} = \frac{\text{Drillpipe volume (bbl)}}{\text{Pump output (bbl/stroke)}} = \frac{203 \text{ bbl}}{.1916 \text{ bbl/stroke}} = 1060 \text{ strokes}$$

Kick Data

P_{SIDP} = 240 psi
P_{SIC} = 375 psi
Pit gain = 31 bbl
True vertical depth = 15,000 ft

Kill Mud Data

$$\text{Mud weight increase} = \frac{P_{SIDP} \times 19.23}{Depth} = \frac{240 \times 19.23}{15{,}000'} = 0.3 \text{ lbm/gal}$$

Kill mud weight = original weight + increase = 13.1 lbm/gal + 0.3 lbm/gal = 13.4 lbm/gal

Pump Pressure

Initial drillpipe pressure = P_{SIDP} + slow pump pressure
= 240 psi + 800 psi = 1040 psi

$$\text{Final drillpipe pressure} = \frac{\text{Kill mud weight} \times \text{slow pump pressure}}{\text{Original mud weight}} = \frac{13.4 \text{ lbm/gal} \times 800 \text{ psi}}{13.1 \text{ lbm/gal}} = 820 \text{ psi}$$

Fig. 4.9—A kill sheet for wait and weight method (Belayneh 2014b).

When all the calculations have been performed, the mud density is raised immediately to the calculated kill mud density. When the kill mud volume is ready, the pumps are started, and the choke slowly opened, while keeping the annular pressure constant until the pump has reached kill rate. The choke is then regulated in such way to decrease the drill pipe pressure until the kill mud reaches the bit, where the final circulating pressure is reached (Belayneh 2014b).

Fig. 4.10 presents the W&W method.

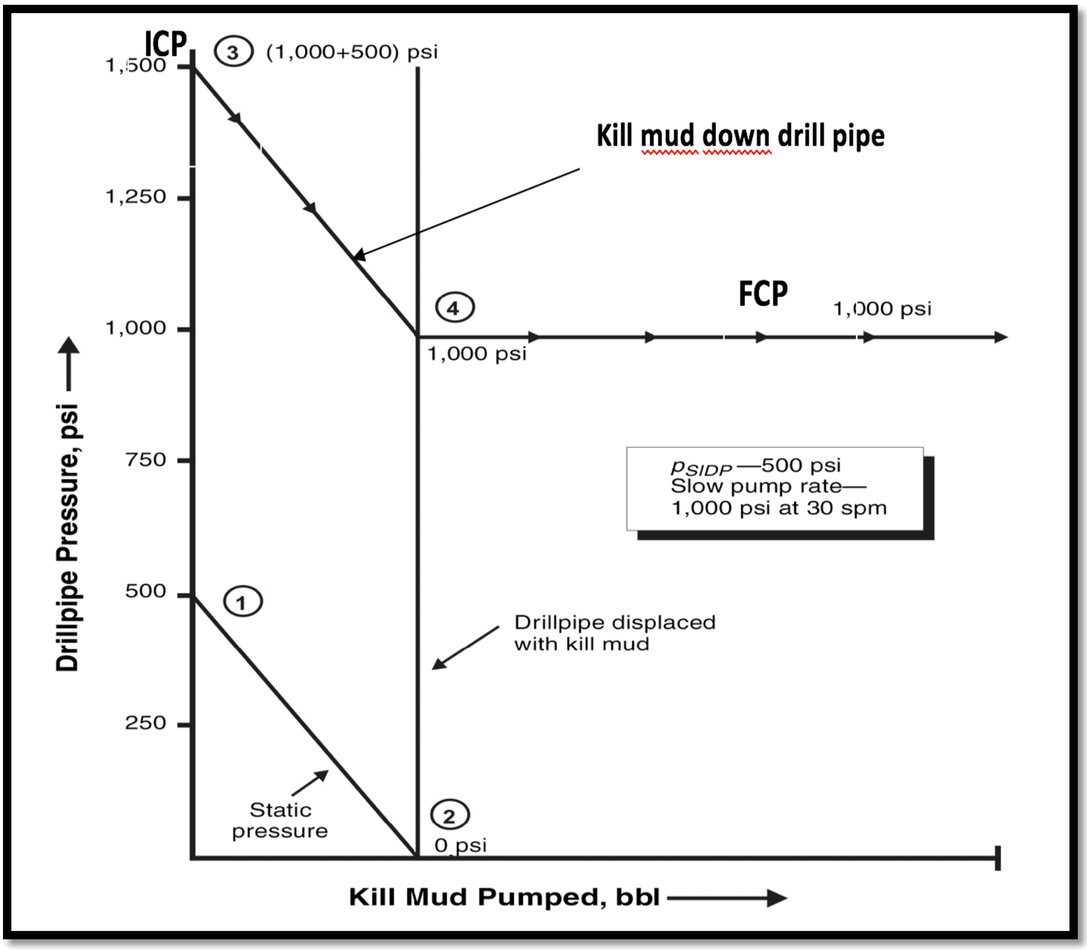


Fig. 4.10—Kick circulation with wait and weight method (Belayneh 2014b).

Fig. 4.11 shows the one-circulation of the W&W method. Point 1 represent kill mud weight which is calculated by SIDPP. The kill mud weight is increased to kill density in the suction pit. As soon as the kill mud is pumped downward, the static drill pipe pressure decreases until it reaches Point 2 (the drill pipe pressure is zero). That means that the heavy mud has killed the drill pipe pressure. Point 3 represent that the ICP in the drill pipe is the total of shut-in drill pipe pressure plus the kill-rate pressure. When the kill mud is pumped down on a bottom of drill pipe, the circulating pressure decreases until the pumping pressure remains at Point 4. From the time kill mud is at the bit until it reaches the flow line, the choke is used to control the drill pipe pressure at the FCP. The driller ensures the pump remains at the kill speed (Belayneh 2014b).

4.9.3 Differences between DM and W&W Method

4.9.3.1 Deviated Hole versus Tapered Drill String

Calculations for W&W method is very simple when the wellbore is vertical and when only one size of drill string is used. When the proper drill pipe is not calculated in W&W method, BHP will not be constant. The main advantages with W&W method is lower pressure at the casing shoe. If the calculation is calculated wrong the casing shoe or weak formations to higher pressures compared with the DM may be exposed (Contractor 2007).

4.9.3.2 Hole Problems

The main problem is that the pipe might get stuck when the drill pipe is in static condition without performing circulation, which leads to hole cleaning problems.

To kill the well with the W&W method, the kill mud should be mixed before circulation is established. With DM, the circulation can start as soon as the well is shut-in casing pressure (SICP) and SIDPP is established. This will reduce the time for the drill pipe is being static (Contractor 2007).

4.9.3.3 Fluid Mixing Capability of Rigs

Drilling all over the world are performed with rigs type with limited capacities. Kill mud weight may not be able quickly prepared and pumped at a desired rate during W&W method, leading to limitations performing in W&W method. The Driller's method may be preferred under these circumstances to avoid excessive increase in surface and shoe pressures due to gas migration (Contractor 2007).

4.9.3.4 Complications and Friction Changes during Well Control

Some complications may occur during a well kill operation. With the W&W method, the pressure schedule must be recalculated immediately, if there are one or more bit nozzles are plugged. With the DM method, the choke operator response is very simple, if one or more of the bit nozzles are plugged while killing the well when the kick is circulated from the hole. The casing pressure is kept constant while the drill pipe pressure can be increased. When the drill pipe pressure is stable, the new circulating pressure is constant during the rest of the first circulation (Contractor 2007).

4.9.3.5 Deepwater Wells

Most of hydrate problems occur in the BOP and choke (kill) lines and may be encountered during W&W method in deepwater wells without circulation.

W&W method circulates out the influx and pump kill mud into the well in one circulation. DM may be a solution to prevent hydrate formation because circulation can be established quickly (Contractor 2007).

4.9.3.6 Time to Kill the Well

The W&W method involves one circulation while the DM involves two circulations. Therefore, time to kill the well can be reduced by use of W&W method. Time may not be significant since extra circulations are required for complete removal of the gas influx. (Contractor 2007).

5 Deepwater Drilling Challenges

5.1 Deepwater Field Development

The development of oil and gas fields in deepwater environment requires specialized and designed equipment. The main purpose of the subsea equipment is to safeguard the environment, and taking advantage in use of the subsea hydrocarbons economically possible. Deepwater equipment is very complex and expensive with limited approach in field development. Lack of experience makes field development and production technology very difficult to perform. Any maintenance and repairing of well control equipment is very expensive. This high expense can give in economic breakdown of the deepwater field development. Field development Aadnoy et al. (2009), which includes:

- Alternative floating-production-platform designs
- Subsea production equipment for high seawater hydrostatic pressure and low temperature
- Control systems for deepwater production equipment
- Deepwater remotely operated vehicle (ROV) equipment
- Installation and suspension equipment for deepwater equipment and risers
- Risers for high axial and transverse loads
- Deepwater platform-mooring systems

Oil & Gas Journal (2006) presented some challenges associated with deepwater field development projects. They include:

- High investment costs (capex).
- Introduction of new technology elements or usage of known technology in new conditions.
- Long lead times for spares and installation resources.
- High consequences of operational failure.
- Flow assurance.
- Fabrication, installation, and operation in new deepwater frontier basins.
- Deepwater development may be in countries with high political instability.

Oil & Gas Journal (2006) showed that deepwater developments depended on flow lines and risers to make production much as possible. The maintenance and integrity of flow lines and risers is a high risk and a cost which cannot be ignored. Therefore, it should be considered in a high level especially for deepwater fields. Most of the new oil and gas fields are deepwater fields and development of these fields requires a strict requirement for the various systems functions. Therefore, flow assurance is prioritized and play a major role in the deepwater fields because flow assurance is critical for flow lines and risers in deepwater environment and it can be costly. Blockages caused because of wax, hydrates, and sand can shut down production and be very expensive to remove unless certain measures are designed and performed into the facilities. Potential multifunction of risers, flow lines, and umbilical cables are undoubtedly some of the most critical concerns associated with equipment components of the floating production systems being developed for deepwater field developments. Well intervention is a major technical and economical challenge which is carried out in deepwater environment. To perform a well maintenance is very important for a well, because lack of well maintenance and experience can put endanger flow assurance.

Oil & Gas Journal (2006) explained that deepwater field developments required large oil and gas reserves, and the total number of wells should be kept small to make the deepwater project economically valuable. The drilling capex can be typically more than 50% of the total capital expenditure. Therefore, the oil recovery per well needs to be high along with a high production rate per well, it is typically between 10, 000 and 15, 000 B/D.

Deepwater filed development project revenue and cost risks are influenced by the following factors: field reserves; reservoir complexity; development design and engineering; oil and gas price volatility; drilling and well completions; subsea infrastructure, flow lines, and risers; processing facilities and support structures; transportation and storage; and project schedule. The risks above can be managed and reduced by selection of different field development plans and as project implementation methods of the deepwater well.

5.1.1 Buoyant Wellhead in Field Development

Aadnoy et al. (2009) showed that buoyant wellhead can be used in field development and can influence the design, drilling and production of wells. The benefits of using buoyant wellhead in field development include:

- Improved operational environment and easier well access for subsea production equipment
- Makes a well much easier to easier to access during well intervention
- Small expenses in well and intervention
- Less risk of hydrate formation

The main function of the buoyant wellhead is to eliminate challenges associated with handling vertical riser loads and hydrodynamic forces, by making deepwater wells adopt the geometry of shallow-water wells, such that the wellhead is positioned between 200 m and 500 m below surface (Aadnoy et al. 2009). A buoy is used to suspend the wellhead and BOP at the desired depth and after that the well may be treated same way as in shallow water. After the wellhead is positioned at shallow depth, further drilling, completion, production and well intervention can use equipment specially designed for such depth. The seabed casing provides strong anchoring for the extension and buoy.

5.1.2 Development Overview and Challenges in Parque das Conchas Oil Field

The main challenges in the development of the heavy oil field, Parque das Conchas, in Brazil was to find a best solutions which can reduce costs and time during the development and planning phases. Stingl (2010) showed that the best solution can be accomplished by:

- To understand and identify sufficient potential oil reserves.
- Designing a suitable drilling and completion program to make connection of the sand packages and optimize the inflow performance in a field.
- Designing subsea systems for production, separate the produced fluids at the seabed, and perform the production back to the FPSO unit.
- Perform a detailed flow assurance strategy.
- Develop a strategy to reduce cost and ensure high quality system.
- Develop a management control process plan to ensure success in field development.
- Ensure the equipment, testing and fabrication program.
- Coordinating the complex offshore installation, hook-up, commissioning, and integrated system start-up activities.

Challenges above was required the designing and testing in deepwater conditions to ensure a successful and safety development. Stingl (2010) demonstrated that the major drilling challenges during the field development in Parque das Conchas are:

- In a depth between 900 and 1000 mTVD below mudline resulted in the need to start the build-up section near the mud line. Building the 16-in. hole to 40 ° in 550 mTVD was found to be impossible in soft Pliocene and Miocene sediments using the original bottom hole assembly (BHA).
- Building the rates in the 12 ¼-in. section was a challenging and difficult to perform, especially in the soft sands particles. Induced fractures, opening of minimum-stress faults and the presence of high permeability sands resulted in significant loss.
- The high net to gross reservoir model predicted from the vertical well control, and the need for gravel pack sand control, lead to a completion interval design with a straight-line well path inclined near 88 ° for the 9.5-in. reservoir section. Because of stratigraphic and structural complexity and a lower NtG, the changes in the well trajectories had to be made.

The use of 2D and 3D seismic data, rate of penetration (ROP) and weight on bit (WOB) gave best solutions and new methods in understanding of the well control and designing the BHA. Mud weights were reduced, drilling fluids modified, and BHA configurations met the drilling requirements (Stingl 2010).

The drilling and completion in Parque das Conchas were operated with FPSO Espirito Santo and with the third-generation rig with surface BOP (SBOP) technology. The main benefits of SBOP is cost savings and reduced rig deck capacity. The detailed explanation of SBOP is discussed in a section 8.3. The use of third generation rig with SBOP made a huge benefit in drilling because such technology doubled the water depth drilling capabilities of the Transocean Arctic 1 rig. This helped in significant cost savings comparing to a fourth or fifth generation rigs (Stingl 2010).

5.2 Deepwater Drilling

Many of deepwater challenges are associated with long distance between the drilling unit and the top of the well (wellhead and BOP) including the working environment, which plays a huge role in well control equipment at deepwater depths.

The drilling riser with choke lines expands the drilling rig capacity requirements because of high load exerted on drilling unit. Buoyancy of riser elements can be used to reduce the effective weight of the riser, but this is not relevant due to expected high costs.

Aadnoy et al. (2009) provides that there are several operational and safety challenges associated with the installation of BOP ate the seabed:

- A gas kick may be undetected and this can lead that gas will be present in the riser before the kick will be detected and the BOP is closed.
- Makes difficult to use kick control methods because size of choke and kill lines are very tall and this cause large amount of pressure loss during kick circulation out of the well.
- The large amount of drilling mud in the riser (i.e. large diameter of the riser) affects: increase in bottom-up circulation time; time to condition the mud system increases; the amount size of cuttings in the riser, which may settle and block the BOP; and the time needed to perform a controlled riser disconnected.

If the BHP decreases, the well may collapse and it can lead to an underground blowout. The riser margin is needed to compensate for a reduction in BHP during an accidental disconnection. When the well is underbalanced, the riser margin cannot be maintained in deepwater drilling with a wellhead positioned at the seabed. This happens because there is a heavy deep leak in the riser, or if the riser must be pulled quickly from the wellbore during emergency. To prevent the well from flowing, closing the BOP is necessary. In this case with the buoyant riser, the riser margin maybe be maintained in shallow water because of short drilling riser (Aadnoy et al. 2009).

5.2.1 Buoyant Wellhead

Aadnoy et al. (2009) demonstrated in several studies that buoyant wellhead helps to avoid several operational and safety-related challenges in deepwater drilling. With buoyant wellhead, it is possible to detect a gas influx in the early stages before it reaches the BOP. After the influx has been detected and the well has been shut in, the gas influx can be circulated out from the well in safe and economical manner according to kick circulation method. Because size of choke and kill lines are short and provide average amount of pressure loss during the kick circulation, this makes easy to use kick control methods. The time needed to circulate bottom-up samples, and time to condition the mud system and the risk of large mud discharge to environment will not be present with buoyant wellhead because of the length of the riser is short.

With buoyant wellhead in place, the wellhead remains at a shallow depth even when there are unexpected events during the drilling operation. In addition, a station-keeping system (i.e. a fiber-rope taut-line mooring) is required in floating rigs and production vessels to keep operation more stable. During drilling, the riser is exposed to drag forces which cause high bending stresses on the wellhead and BOP. Therefore, with a long deepwater riser, the BOP, wellhead and conductor need to be designed to tolerate high stresses. With the buoyant wellhead, the BOP and wellhead will not suffer high stresses (Aadnoy et al. 2009).

With a long deepwater riser, a controlled disconnect of the marine riser takes a long time because of the time needed to displace the larger riser mud volume with seawater and the time needed to hang off the drill string in the wellhead and BOP. Riser reconnect usually takes a long time because of the lack of lateral control of the lower marine riser package (LMRP). By use of the buoyant wellhead, the riser disconnects and reconnects will approximate those in shallow water (Aadnoy et al. 2009).

Economic effects on drilling is obtained from the buoyant wellhead and savings on the drilling-vessel per day rate. The increasing request for deepwater rigs has increased day rates. Drilling time may be saved by installing buoyant wellhead, which makes drilling more economical (Aadnoy et al. 2009).

5.3 Borehole Instabilities

Borehole instabilities affect both vertical and directional wells. Vertical stress is the most important stress compared to minimum and maximum horizontal stresses. The exception is when drilling is performed in salt areas. Directional wells show high collapse pressure gradients because of well inclination. Therefore, the use and demand of higher mud weights keep the borehole walls stable and prevent borehole collapse (Rocha et al. 2003).

Well trajectory in deepwater wells should be designed in such way that borehole instability will be reduced. However, the common approach of lifting the kick off point to reduce the angle of deviation from the vertical is not always possible due to the reservoir characteristics (Rocha et al. 2003).

5.4 Flow Assurance

Flow assurance has been developed because conventional approaches are insufficient for deepwater production due to extreme distances, depths, and temperatures.

Hedne (2014) shows that, because high pressures and low temperatures are involved, flow assurance is a critical and important task during deepwater field development. Flow assurance refers to the design, strategies and principles for ensuring safe, successful and economical flow of hydrocarbon stream from a reservoir to the point of sale.

Fig. 5.1 presents a schematic of flow assurance.

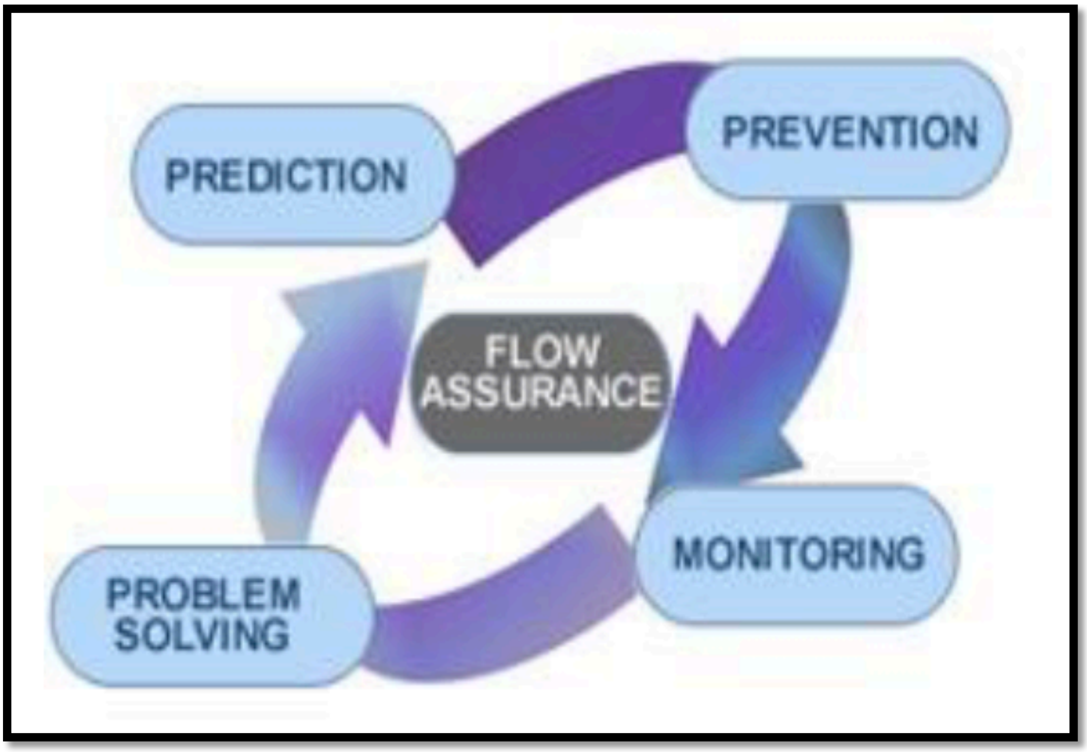


Fig. 5.1—A scheme of flow assurance (Belayneh 2017).

Fig. 5.1 shows that flow assurance includes problem solving, prediction, prevention and monitoring. Flow assurance includes thermal investigation of pipelines, to ensure operational temperatures are above hydrate formation temperature. Another important aspect of flow assurance is the evaluation and handling of solid deposits such as hydrates, asphaltenes, wax, scales, and emulsion.

5.4.1 Flow Assurance in Jubarte Field

The Jubarte field Colodette et al. (2008) is located in the Campos basin of Brazil, while other oilfields are located in Santos basin off the coast of Rio de Janeiro and consist of heavy oil.

These hydrocarbon reserves are found in a challenging HPHT environment. The thermal insulation of flow lines prevents asphaltene precipitation in produced fluids. In addition, the Christmas tree is coated with thermal insulation to prevent the hydrate formation.

Inorganic deposits of clay clog up an electrical submersible pump (ESP) and impair its performance. The ESP is the most efficient pump in lifting large amounts of heavy oil from the deepwater field, where gas-oil ratio is low. The use of ESP makes the deepwater fields economical to exploit (Colodette et al. 2008).

Fig. 5.2 shows the FPSO vessel and ESP installation in the Jubarte field.

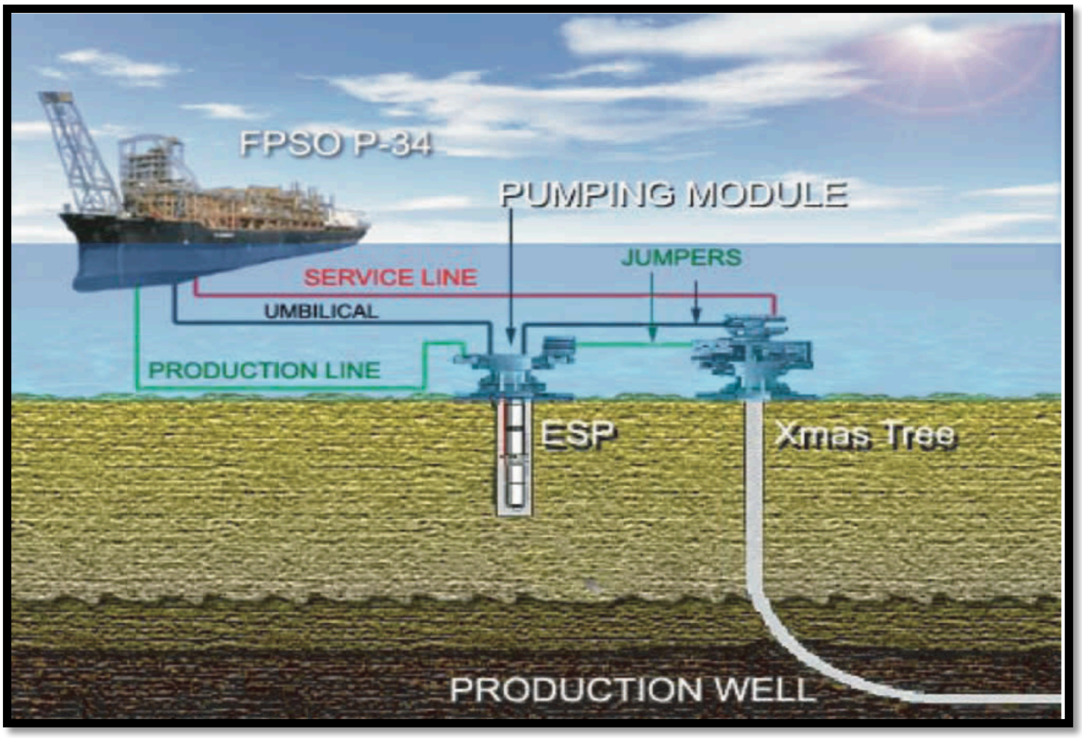


Fig. 5.2—The production system for Jubarte field (Colodette et al. 2008).

The ESP is equipped with mandrels and gas lift valves. The main benefits with ESP is that ESP tends to reduce production losses and improve lifting system large amounts of heavy oil. In heavy oilfields with low reservoir pressure it is essential to maintain enough power to lift drilling fluids to the surface. The common way in Norway is to install gas-lift systems. In Jubarte field, ESPs shows higher production potential compared to the gas-lift system, because it is expected to lift large amounts of water and heavy oils. Gas-lift systems may be installed as a backup while pumps are out of order. The pumping system consists of an adaptive base (PAB) and a pump module that might be installed 200 m away from the well. The pumping module allows by-pass of the ESP if desired. Placing pump outside the well reduces costs and makes intervention more convenient (Colodette et al. 2008).

One of the major issues of using ESPs during the production in the Jubarte field is scale removal because pump conditions accelerate the kinetics of sulphates precipitation. The scale deposition leads to the malfunction of many pumps. The temperature and big superficial area at pump impellers increase precipitation and facilitate crystal growth. This growth of crystals causes a sensible degradation in pump performance and increases the risk of locking. To avoid this problem, continuous injection of antiscale chemical product through umbilical and performing the chemical injection through manifold, was prescribed and required. Teflon coating of pump impellers is one of the possible solutions (Colodette et al. 2008).

Another issue with ESPs is sand production. To avoid pump locking it is important to control the sand production during deepwater drilling. Main treatment in this case will be lower completion choice, which includes either open hole gravel pack or stand-alone screen. To prevent erosion the use of ROV-operated erosion monitoring sensor is proposed. The use of ESP showed good results in reservoir characteristics and proved to be very useful as lifting method (Colodette et al. 2008).

5.4.2 Flow Assurance Challenges

Table 6.2 presents an overview of flow assurance issues and evaluations for any production system.

Table 5.1—Flow Assurance Challenges (Irmann-Jacobsen 2011).

Potential issues	Part of scope	Influence of system design	Evaluations / studies to be performed
Hydrate formation	Yes	Yes	• Develop hydrate strategy • Requirement of insulation • Freezing valves • Anti-surge line • Drainage of compressor • Deadlegs • Ensure monoethylene glycol distribution
Hydrates water injection line	Yes	Yes	• Hydrate formation in water injection line has been performed and included in hydrate strategy
Multiphase flow Branching	Yes	Yes	• Branching • Ensure monoethylene glycol distribution • Ensure liquid distribution • Flow regime
Fluid properties	Yes	Yes	• Fluid composition is used in the different simulations tools. Such HYSYS steady state, OLGA, CFD and HYSYS dynamics • Calculations input to hydrate formation and gas access
Sand production	Yes	Yes	• Erosion • Sand accumulation
Thermal requirement	Yes	Yes	• No-touch time • Cool down time: is several hours that the operator has before to start-up a preservation scheme.
Riser slugging and stability	No	Yes	• Simulations by OLGA and Flow Manager to investigate oscillation velocities related to sand transport and process control • Gas lift

6 HPHT Well

A high pressure and high temperature well is defined in the NORSOK010 rev 3 D-010 (2004) as “a well where the expected shut-in well pressure is higher than 690 bars and the static temperature is above 150 °C.”

The high pressures and temperatures makes the design, drilling and operation in deepwater environment very challenging. Gas development fields can be considered as HPHT wells most of the time because of high temperatures exist together with high pore pressures. Such fields include GoM and the North Sea. High temperature conditions will cause expansion in the drilling fluid, while high pressure cause compression in fluid. HPHT environment affects lower equivalent circulating density (ECD) of the drilling fluid and estimation of the BHP (Aadnoy et al. 2009).

The number of deepwater wells is increasing, however high pressures and temperatures influence casing design, equipment, drilling fluids, cements, well control, connections, materials and completions. Most of HPHT issues can be solved by different methods and studies (Aadnoy et al. 2009):

- Pore pressure prediction and the limitations of porosity-based prediction techniques allows better well control.
- Pore pressure prediction ahead of the bit, this new technique called vertical seismic profile (VSP) allows measure the acoustic impedance, the estimation of lithological changes ahead of the bit. However, this approach cannot be used alone when pore pressure builds up and when sharp impedance change.
- Study of mechanical behaviour of the reservoir rock when the rock is subjected to changes in pore pressure and stress.
- Study of wellbore instabilities during drilling.
- Methods for estimating of geothermal temperature which is very important in casing design.

6.1 Temperature Effect in HPHT Wells

Temperature affects the properties of steel, cement and drilling fluid thermophysical properties. This also affects fluid rheology and pressure-volume-temperature (PVT) behaviour during well control. Temperature changes effect casing strings, the contents of the wellbore annuli and wellheads to move or grow. Also, changes in temperature cause thermal expansion of the tubing and casings because the tubing and casings are heated during production. Expansion of fluid in the tubing annulus when the temperature increases, causes annular pressure buildup (as APB). Logging, testing, and completions are affected as well when the temperature changes in the well Aadnoy et al. (2009).

Aadnøy (2006) showed that mud temperature and drilling fluid density changes with a deepwater depth, because temperature affects the drilling fluid density in high temperature wells. High temperatures tend to decrease the density of mud, so the effective mud weight at the bottom of a well will be lower than the value at the surface conditions. Potential risk of underbalance situation is higher. To prevent underbalance situation, increase the mud weight at the surface to stabilise mud weight at the bottom will solve the problem.

Aadnoy et al. (2009) showed that the temperature of the drilling mud changes quickly within operation, because there are static conditions present in the well and the mud temperature approaches the geothermal temperature in the well. During mud circulation in the well, the cold mud will cool down the lower part of the well, while the hot mud will be flowing from the lower part up to upper part of the annulus. The hot mud will be heating upper part of the annulus.

Variations in ECD and changes in the total mud volumes will be affected because mud density and mud rheology are changing rapidly in the well.

6.2 Pressure Effect in HPHT Wells

Most of deepwater wells have narrow margins between the pore and fracture gradients. Therefore, estimation of the depth and magnitude of pressure transition zones is very important.

This is affects casing setting depths, material and connections selection, mud design and on potential zones where influx can occur. Pore pressure can be estimated by seismic and geologic modelling and evaluation-analysis of well data. Direct measurements of pore fluid pressures, modular-formation dynamic testers or drill stem tests can be used in prediction and evaluation of pore pressure (Aadnoy et al. 2009).

Fracture pressure can be estimated by leakoff or formation integrity tests. Data from offset wells can be used to obtain a reasonable basis for fracture pressure. Geomechanical modelling will establish and provide the fracture closure and overburden stresses in a region when data are available to allow perform such modelling.

In a deepwater well, hydrostatic pressure variation can be higher compare to standard wells. This can be attributed to several factors Aadnoy et al. (2009), which include:

1. Changes in mud density composition is caused by temperature and pressure, which is leading to variation of hydrostatic pressure. Drilling with different circulation rates and stationary periods affect mud density distribution. Because of high pressures increase the density of the mud, effective mud weight on a bottom will be higher than in a surface.
2. The frictional pressure changes resulting from rheology variations.
3. The rheology caused by temperature effects can induce flow transition between laminar flow and turbulent flow. Loss in higher frictional pressure can be caused by turbulent flow.
4. Surge and swab pressure may be dangerous resulting from high viscosity and with increasing time-dependent gel strength in some muds.
5. During the initiations of pumps, gels have been collapsed and giving a rapid peak in the BHP, giving in critical effect in HPHT wells. Small margins and higher viscosities influence on HPHT wells.

6.3 Well Control in HPHT Wells

HPHT conditions affect well control equipment. The main reason is that most materials properties lose their capabilities when temperature increases. For example, H2S and CO2 affect material properties. Elastomers provide the sealing in internal well control equipment, so the well control equipment should be built to able to tolerate the high pressure and high temperature conditions. Well control equipment can be designed in such way that some section will operate at high temperatures while other sections operate at low temperatures. This requires new technologies and new types of materials. All materials and designs must be identified and qualified for HPHT service. To create seafloor equipment which enables to tolerate for example 30,000 psi and 500 °F and operate reliably in a deepwater environment requires hundreds of millions of dollars and may take many years of developing (Conser 2007).

Coolers at surface will reduce the temperature of the circulation fluids. Thermal modelling and testing is necessary before the installation of the equipment. HPHT wells equipment requires high volume surface gas handling systems with relevant temperature sensors and alarm systems. Mudline control require sealing components designed for aggressive conditions and equipment that can tolerate the various temperature and pressure (Aadnoy et al. 2009).

The main causes of well control incidents are:

- Mud properties are affected at high pressures and temperatures.
- Narrow margin between pore and fracture pressure.
- Gas influx in OBM.
- Barite sag in inclined and horizontal sections of the well.

Well flow simulators are commonly used for well control. Changes in mud properties may cause kick because mud rheological properties and density are dependent on temperature. Therefore, the evaluation and detection of the kicks are very important in HPHT wells.

Wellbore Breathing described in Aadnoy et al. (2009) is the flow of drilling fluid from the formation into the wellbore during connection (non-circulating period). During connection in deepwater wells, high friction losses can lead to an overbalance situation. Mud invasion into wellbore pressure may occurs when pumps are off, because BHP drops in noncirculating periods. The underbalance situation may lead to flowback, which can be interpreted as a kick. However, the well ballooning effect disappears when circulation resumes. The flowback effect is more common in tighter formations. Large volume of flowback may cause during a long non-circulation events, for example during trips. Typically, most of the flowback is of the invaded filtrate.

6.3.1 Undetected Kicks in HPHT Wells

Undetected kicks are major problem in HPHT wells because, large pressure makes well control incidents such as gas influx quite severe. The risk of undetected kicks occurrence can present in OBM because the large amount of gas can dissolve and hide in the OBM (David et al. 2003).

6.4 WBM and OBM in HPHT Wells

The most common used drilling fluids are WBMs and OBMs. In the deepwater wells, the upper sections are usually drilled with WBM. It is common to switch to an OBM in the lower sections. Drilling fluids consist of many components with different properties. These components are affect by pressure and temperature. For example, drilling mud density and viscosity vary with temperature and pressure (Fjelde 2013).

6.4.1 Kick in WBM

Hamarhaug (2011) demonstrated that pressures and gas volumes in the wellbore will be higher in WBM. The kick in WBM will migrate upward and increase well pressures. According to Boyles law, the kick will transport the BHP up in the well. Therefore, driller needs to react quickly to avoid fracturing of the casing shoe. During the gas expansion as the kick moves up in the well, the choke pressure and casing shoe pressure increase in the WBM. The volume of the kick below the casing shoe is larger compared to the volume of the kick in OBM, hence casing shoe pressure will be higher when using the WBM.

The main advantages of WBMs are the drilling fluids are cheaper, less health, safety environment (HSE) issues. It is easy to detect kicks in WBMs because gas will not fully dissolve in WBM at HPHT conditions compared to OBM materials (Fjelde 2013).

The WBMs provide less lubrication, increase problem with inhibit reactive clay swelling, thicker filter mud cake leading to differential stuck pipe and are less stable at HPHT conditions (Fjelde 2013).

6.4.2 Kick in OBM

In the master thesis Hamarhaug (2011) and references there, it is showed that in HPHT wells, handling a gas kick in OBM is more complex compare with WBM. The reason for this is that gas kicks are infinite soluble in the OBM due to solubility proportion of the gas in OBM. Drillbench dynamic simulator showed that the kick dissolved in the OBM system will stay at the bottom of the well until the mud is circulated of the wellbore.

The gas influx will dissolve in the drilling mud. In this case, there will be no observable change in pit volume until the gas starts to boil out at the surface. Therefore, the well should be shut-in immediately to circulate out the kick before it reaches the riser.

However, OBMs are more compatible with reservoir formations. They provide lower ECD, improved lubrication (less well friction), inhibit reactive clay swelling, thinner mud filter cake, and reduced risk of differential sticking and are more stable at HPHT conditions. OBMs also give lower maximum well pressures in the case of a kick. This reduces the risk of fracturing the formation at the last set casing shoe (Fjelde 2013).

The main disadvantages of OBMs are the drilling fluids are more expensive, health, safety environment (HSE) issues. It is also difficult to detect kicks in OBMs because gas will dissolve in OBM at HPHT conditions (Fjelde 2013).

6.4.3 WBM versus OBM

Table 6.1 presents differences between WBM and OBM.

Table 6.1—WBM vs. OBM (Fjelde 2013).

WBM	OBM
The kick is easily detected.	The kick can be undetected in the well and for high pressure the kick will be fully dissolved.
Maximum casing shoe pressure and choke pressure is higher in a well.	Lower maximum casing shoe pressure and choke pressure in a well.
In WBM, the kick occurs at surface before than kick occurs in OBM.	Requires fast action, there will be a large expansion in the well as the free gas starts to boil out from the mud. The well therefore needs to be shut in as quickly as possible.
The well pressures will increase all the time. During shut-in, the well pressure will increase until the kick is just below the BOP.	The kick will boil very quickly in the upper parts of the wellbore.
The kick migrates upward when the well is shut-in.	The kick will not migrate upwards when the kick is fully dissolved in the mud.

7 Hydrates

Hydrates formation is very common in deepwater and ultra-deepwater wells and can cause several major problems in deepwater drilling. Bellarby (2009) showed that formation of gas hydrates represents a significant risk to process safety as it can result in the plugging of both pipes and well control equipment. A hydrate is a crystalline compound formed when water molecules combine with another substance. The hydrate formation requires light hydrocarbons, water vapour, and low temperatures or high pressures. Increasing water depth provides a perfect condition for the formation of hydrates, when free water interacts with a gas. Once hydrates form a plug, the hydrates will not move under a pressure differential.

During the planning of deepwater wells, the operators should consider the chance of hydrate formation. To prevent the formation of gas hydrates, pre-well analysis and contingency plans are needed if there is a potential for hydrate formation. The hydrate stability zone varies with seabed temperature and geothermal gradient. It is the transition zone where transition from natural gas locked up in hydrates to natural gas in vapour form (Bellarby 2009).

Fig. 7.1 illustrates the hydrate stability zone in a geological formation.

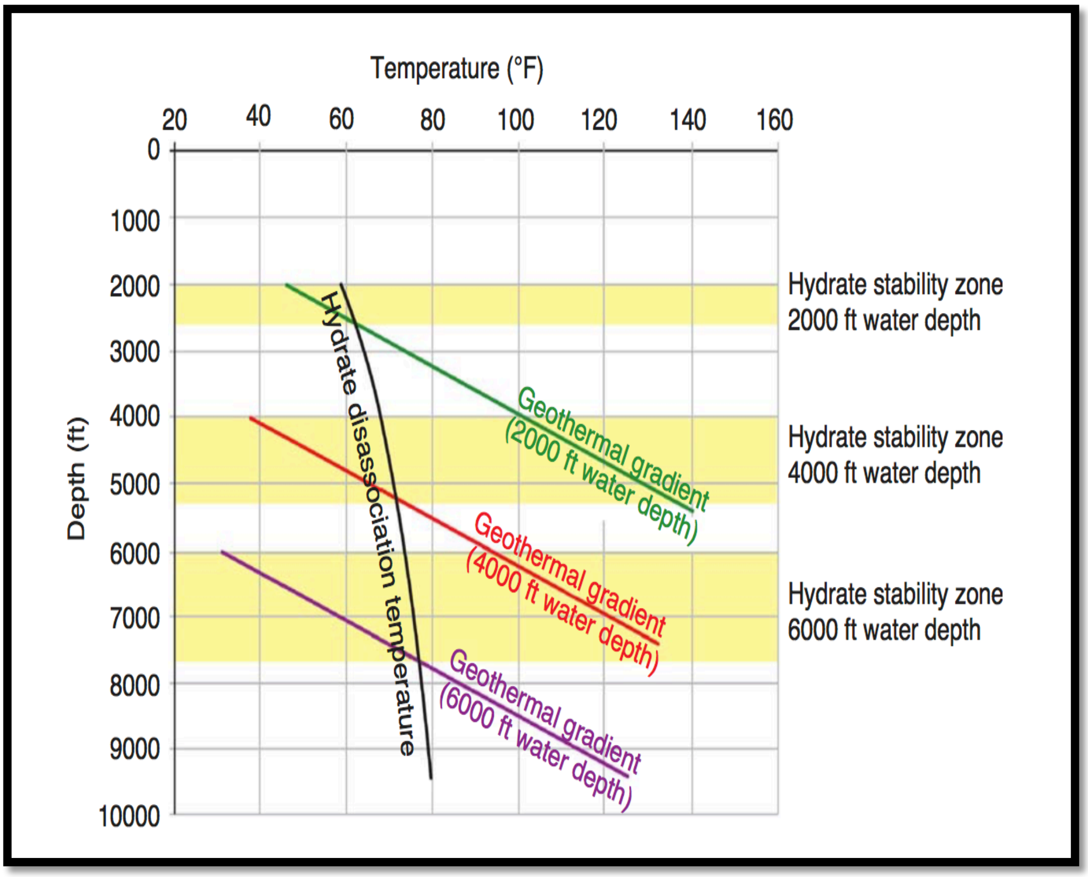


Fig. 7.1—Hydrate stability zones (Bellarby 2009).

Fig. 7.1 shows that drilling through these formations causes a release of hydrocarbons. This will reduce the well pressure and may lead to a kick. The hydrate stability area varies with seabed temperature and geothermal gradient. The base of the hydrate stability area marks the transition from natural gas locked up in hydrates to natural gas in vapour form.

7.1 Effect of Hydrate Formation during Well Control Operations

Hydrates can induce serious problems during well control operations as hydrates tend to block drilling equipment, drill pipes, mud return lines, drilling risers, flow lines and mud handling facilities.

Kinnari et al. (2015) discussed the effect of hydrate formation during well control operations. Hydrates can blog choke lines and interrupt well circulation. Also, hydrate plugs formed around BOP can cause the BOP system to malfunction during gas influx. Circulating the well with warm fluid in the BOP at the maximum pump rate adds heat from the wellbore and pumping machinery which melts the hydrates in the BOP and can prevent or delay hydrate formation. Contingency planning situation of formation gas hydrates during well control operations should consider long shut-in periods. During long shut-in periods when there is no wellbore circulation is presents, gas in the BOP is cooled to static mudline temperatures and can form gas hydrates. Therefore, hydrates will require several hours to form and plug the subsea equipment. High-salinity drilling muds will reduce hydrate formation for deepwater wells. High-salinity muds have been used in a several deepwater fields without operational problems.

Accumulation of hydrates will increase pressure in drill pipe. This can lead to a kick if there will be a leak or loss of the hydrate plug. Also, hydrates can form plugs around the drill string and in the riser, preventing the movement of the drill string. The hydrate plugs may occur:

- During drilling with WBM
- In well operations
- In flow lines during transport
- During processing of hydrocarbon fluids containing water

Improper removal of hydrate plugs can result in equipment damage. Therefore, it is very important to evaluate and handle hydrates in the early stages of formation.

7.2 Hydrate Control Methods

There are several methods used to inhibit and remove hydrate formation. They are hydraulic, thermal, and chemical methods Kinnari et al. (2015).

Hydraulic methods:

- Fluid displacement
- Gas sweep
- Depressurization
- Compression
- Dense phase

Thermal methods:

- Insulation
- direct electric heating (DEH)
- Bundles
- Heat tracing

Chemical methods (thermodynamic methods):

- EtOH / MeOH
- Glycols
- Low dosage hydrate inhibitors
- Salt

Process solutions:

- Gas dehydration
- Water cut reduction

No hydrate control measures:

- Operation within hydrate domain
- Natural hydrate transportability
- Natural kinetic Inhibition

7.3 Inhibitors

Hydrates have a strong tendency to agglomerate and to stick to the pipe wall and therefore plug the pipeline. Once the hydrates are formed, the hydrates can be dissolved by increasing the temperature or decreasing the pressure (Belayneh 2017).

Fig. 7.2 shows a general phase diagram, which illustrates the effect of inhibitors on hydrate prevention.

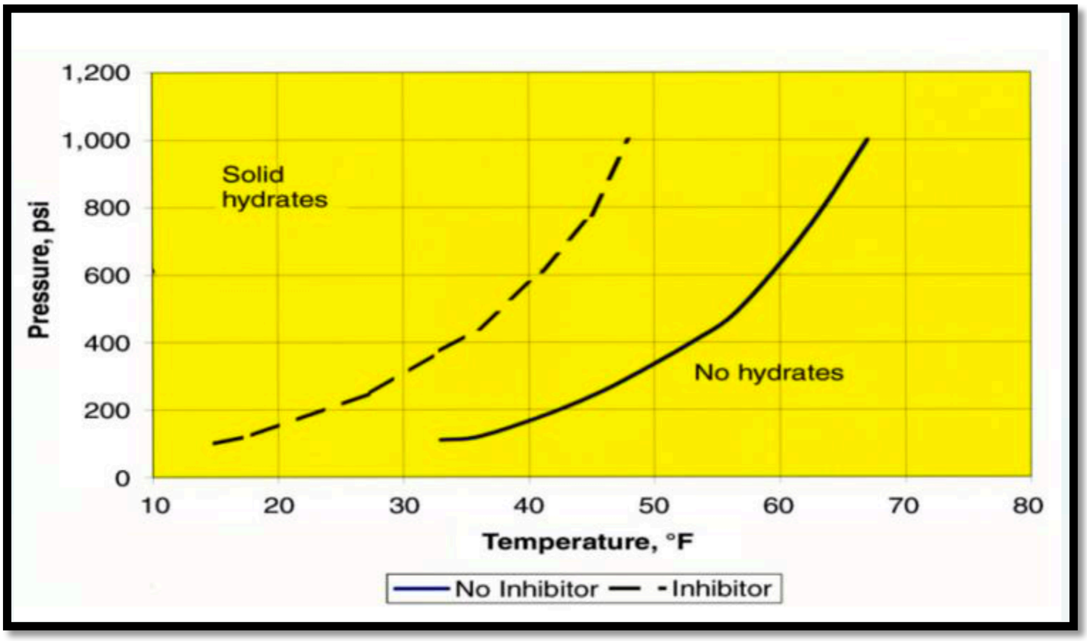


Fig. 7.2—A phase diagram of hydrate in pressure-temperature regime. (Belayneh 2017).

From Fig. 7.2, an addition of inhibitor shifts the hydrate stability curve to the left. This makes the dominant window less. Chemicals like glycol and methanol injected into the flow system in right proportions can prevent hydrate formation. This makes hydrate domain window smaller and extends the operational time window and makes hydrate management more efficient. Safe operation within hydrate domain is possible but for a limited time. During production shutdown and start-up, methanol injection is used as effective method for hydrate removal in certain instances.

7.3.1 Hydrate Management

Statoil has developed a new approach called "hydrate management" Kinnari et al. (2015) for handing hydrates, in contrast with the hydrate avoidance strategies.

Fig. 7.3 illustrates hydrate avoidance versus hydrate management.

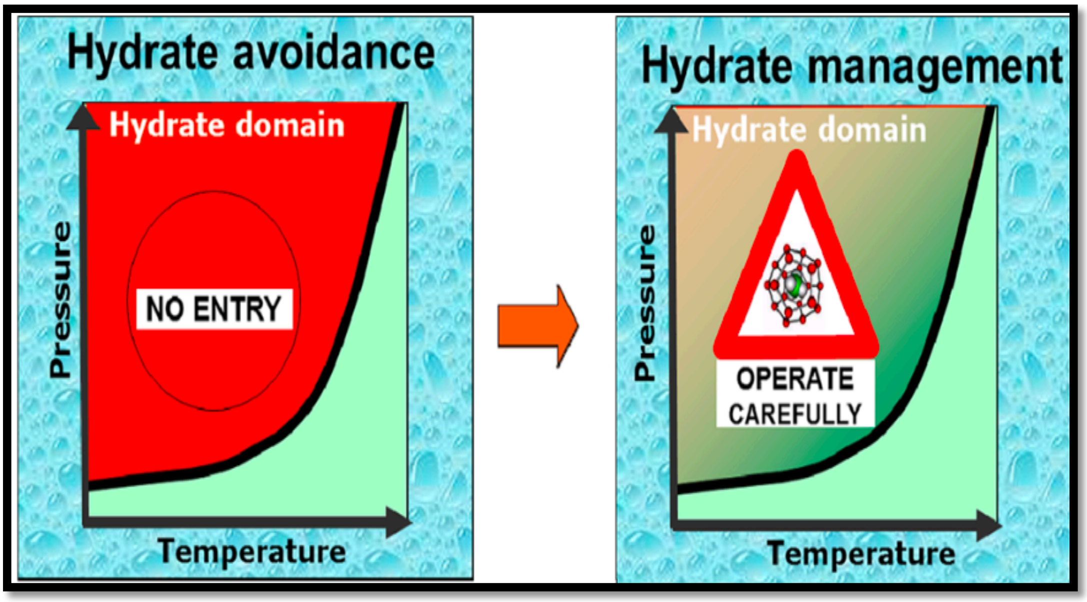


Fig. 7.3—Hydrate Avoidance versus Hydrate Management (Kinnari et al. 2015).

From Fig. 7.3, Kinnari et al. (2015) shows that hydrate avoidance forbids entry into the hydrate domain. In contrast, hydrate management strategy allows operations in hydrate domain if the risk is acceptable. Hydrate management is risk-based approach. The main issue is a plugging risk. To avoid hydrate-related problems, Statoil is working to gain more insights into the underlying processes and develop new improved strategies in hydrate management.

7.3.2 Mechanical Management

Hydrate plugs can be removal mechanically with coiled tubing. Coiled tubing may be used to perform depressurization when the removal of a substantial liquid hydrostatic head from hydrates is required. When inhibition is insufficient, hydrate plugs can be removed by the injection of methanol or glycol (Kinnari et al. 2015).

7.3.3 Thermal Management

Statoil has two types of heated pipeline systems specially designed for flow assurance purposes, heated bundles, and directly electrically heated pipelines. These technologies are effective, flexible, and provide operator friendly field concepts.

Thermal insulation management is very important. The insulation of well control equipment can be applied to provide cool-down time and arrival temperature. It is very important for complex well control equipment such as trees, manifolds, jumpers, and connectors during long shut-in situations because insulation decrease the rate of heat transfer. However, insulation cannot be used as advanced protection if the well control equipment is continuously heated by wellbore circulation or if there are no long shut-in situation occur.

Deepwater rigs include a floating material which is attached to the riser, leading to some degree insulation (Kinnari et al. 2015).

Heating of well control equipment with heat-transfer systems is an advance method for reducing the risk of hydrate formation in pipelines in all drilling operations. Subsea heating systems should be carefully designed and tested because decomposing hydrates can generate extremely high pressures. DEH provide the heat generated by applied electric current for hydrate plug removal. Efficiency depends on pipeline permeability and resistivity and cable-to-pipe distance. The use of heated bundles in plug removal is very simple, because the risk of obtaining high pressures is minimal given the uniform temperature profile (Kinnari et al. 2015).

7.3.4 Thermodynamic Hydrate Inhibitors

Thermodynamic hydrate inhibitors (THIs) are the most common chemicals used to prevent hydrate formation. The inhibitors change the thermodynamic properties of a fluid system, shift the hydrate equilibrium conditions toward lower temperatures and higher pressures. THIs melt away existing deposits of hydrates (Bellarby 2009).

The most common thermodynamic inhibitors are alcohols and glycol: methanol, monoethylene glycol, diethylene glycol, triethylene glycol, ethanol and salts are used for preventing hydrate formation in drilling mud. Temperature, pressure, and required degree of inhibition provide the right combination and concentration for mud composition. Pressure and temperature diagrams resulting from experiments also provide more accurate mud composition. The main disadvantages of ethanol are that it has higher boiling point, leading in accumulation of iso-butane fraction. To avoid this, control over ethanol usage is required. Fig. 7.4 shows the typical effectiveness of methanol and glycol in hydrate inhibition (Bellarby 2009).

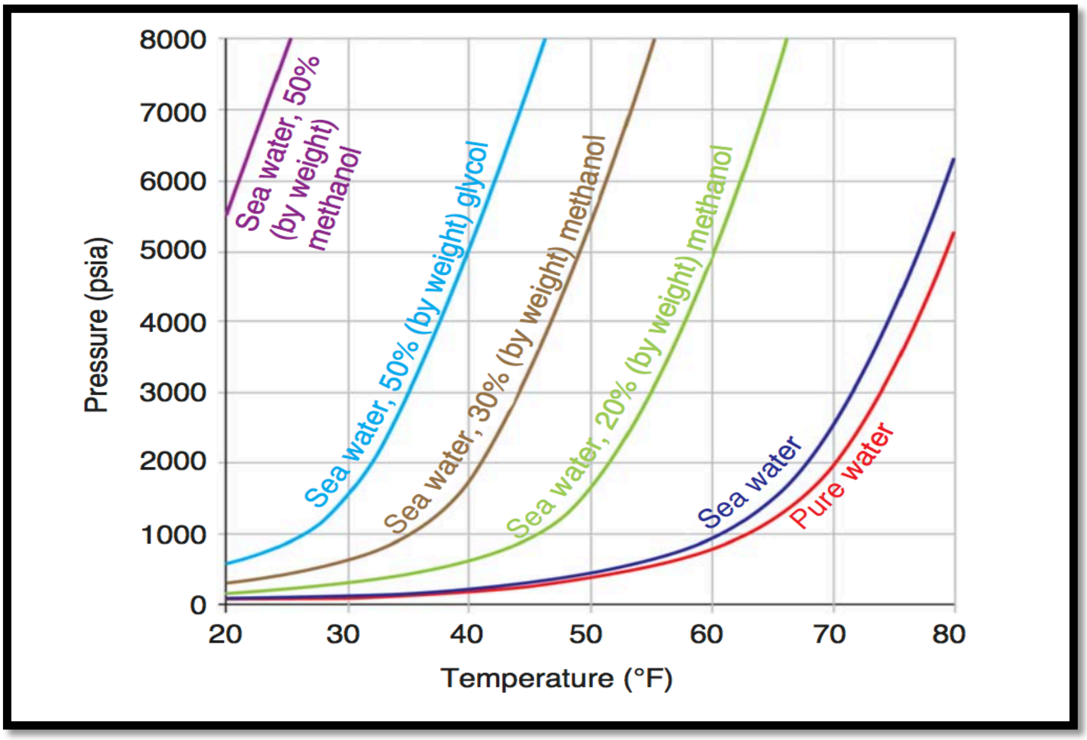


Fig. 7.4—Hydrate Inhibition with methanol and glycol (Bellarby 2009).

Plots like this are useful for creating the required dosage rate for inhibition of completion and intervention fluids. From the Fig. 7.4 can be seen that higher pressures and higher temperatures are require increase of volumes of inhibitors.

7.3.5 Natural Kinetic Inhibitors

Kinnari et al. (2015) showed that natural kinetic inhibitors can be used to delay hydrate formation by delaying the appearance of the critical nuclei (increase hydrate formation time). The use of kinetic inhibitors and anti-agglomerates during deepwater operations is a new technology. Copolymers and surfactants have limited effect on fluid properties and are usually used in low concentration. Once hydrate nucleation occurs, these inhibitors will not prevent further hydrate crystallization and agglomeration.

7.3.6 Anti-agglomerates

Kinnari et al. (2015) demonstrate that anti-agglomerates (crystals modifiers) are commonly used to prevent hydrate coagulation and growth, by slowing the rate of formation and agglomeration process.

Anti-agglomerates are ammonium salts (a major active component used in corrosion inhibitor). Kinetic and anti-agglomerates are effective in prevention of hydrate blockage for a limited period that the well takes to reach hydrate formation temperature. This is the main reason kinetic and anti-agglomerates are often used in deepwater subsea system. These chemicals, however, have not been used yet on the Norwegian continental shelf because of HSE requirements (Kinnari et al. 2015).

7.3.7 Hydrate Management Summary

The hydrate management strategies take advantage of the intrinsic properties of the fluid systems and the hydrodynamics. Understanding the effect of water distributed in the different parts of the production systems play a key role in determining the plugging risk. The concept of hydrate management is based on a large body of research and extensive field experience. It defines the basis for new design and operational procedures. Statoil will continue to improve hydrate control strategies to maximize production and reduce risks. The goal is to motivate other operators to develop and adopt hydrate management (Kinnari et al. 2015).

7.4 Hydrate Control Strategy for Pipelines

An effective hydrate control strategy is required to prevent hydrate formation in pipelines and risers. Fig. 7.5 illustrates hydrate control strategy for pipelines.

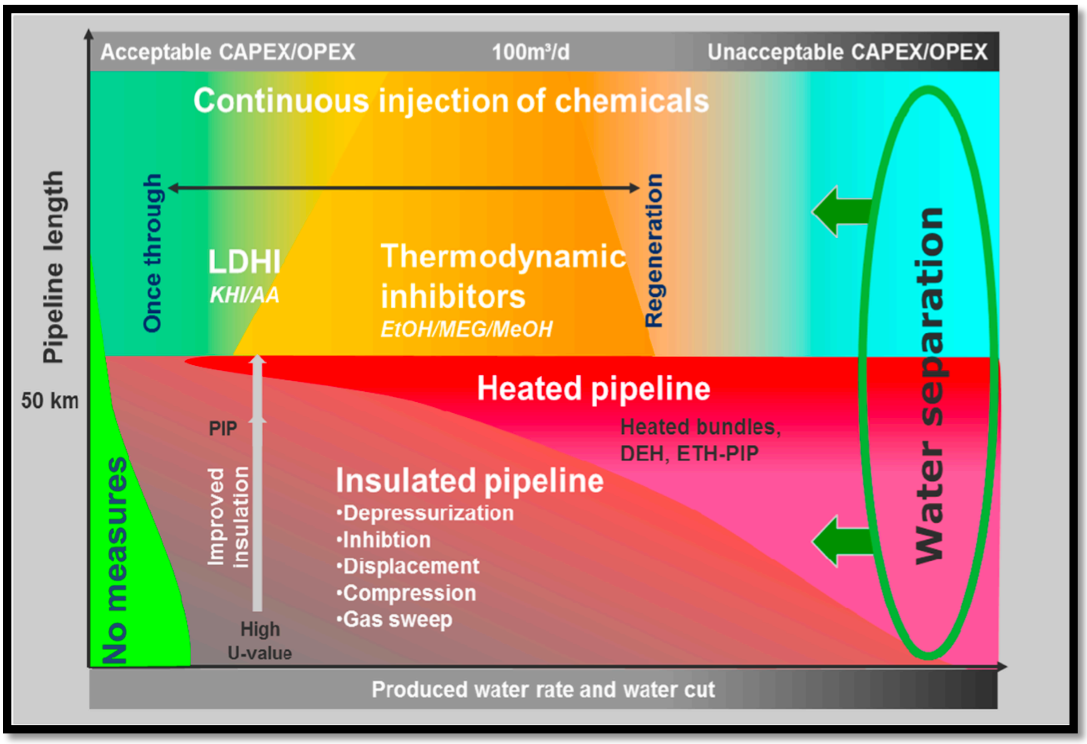


Fig. 7.5—Hydrate control methods for pipelines (Kinnari et al. 2015).

The horizontal axis is the water content, and the vertical axis is the pipeline length. From those two parameters, hydrate risk evaluation can be predicted because hydrate plugging risk increases with increasing water content and pipeline length. Fig. 7.5 provides each removal control method for a specific area. For example, pipeline of a length up to 20 km has a low hydrate plugging risk when the water content is low. Other factors such as pipeline profile and fluid properties should be considered as well. To avoid the hydrate blockage, requires inject the chemicals, stop the flow, reduce the flow and increase the flow. Continuous chemical injection may not be possible because of high cost or negative impact on environment.

The main hydrate plug removal methods for pipelines :

- Depressurization
- Heating
- Chemical injection
- Mechanical methods

Hydrate plug removal operations is very risky. To prevent the high risk, the use of technical expertise is needed to have a safe and effective plug removal operation. The most common way to remove hydrate plugs from a wellbore flow is by use of depressurization removal method. During depressurization flow is stopped and the line is slowly depressurized from both ends of the plug. The stability of hydrate temperature is always less than of the surroundings, at atmospheric pressure. Therefore, the heat flows from the environment into the hydrate plug resulting the plug melts radially inward, separating from the pipe wall (Kinnari et al. 2015).

7.5 Hydrate Control Strategy for Risers

Fig. 7.6 presents typical hydrate control methods for risers.

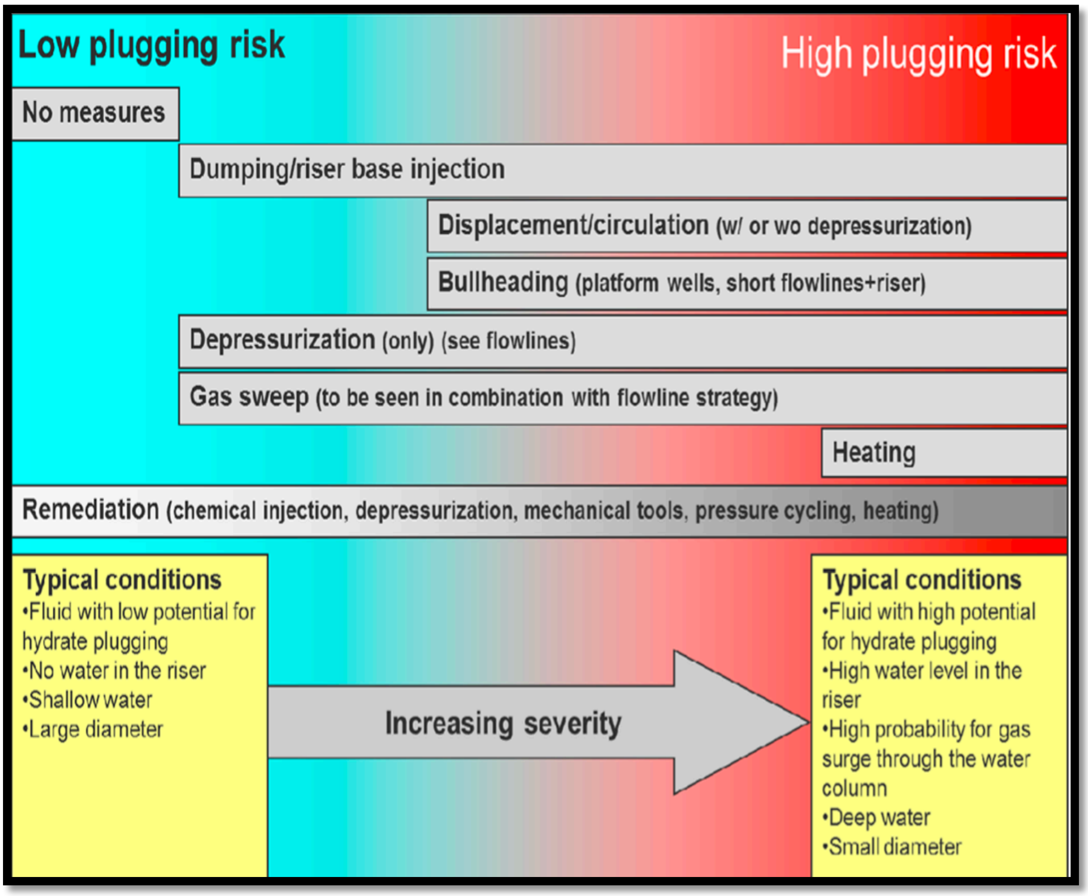


Fig. 7.6—Hydrate control methods for risers (Kinnari et al. 2015).

Fig. 7.6 shows different conditions and control options for drilling risers. Risers, especially flexible risers, have poor thermal performance. The use of water alternating gas injection strategy in risers requires special attention during the conversion process to avoid injecting large volumes of chemicals. Statoil mainly uses a gas sweep to empty the risers of liquids. Usually chemicals are not required during this operation. It is important that fluid is moved into a hydrate safe environment margin, moving liquids into a no heated pipeline increases plugging risk. High plugging risk increases with water depth, water level in the riser, diameter of riser etc. Heating, depressurization, bullheading, and gas sweep are the best options to prevent high plugging risk in the risers.

Kinnari et al. (2015) provides an example where, flow lines may have extremely good insulation providing a cool-down time of more than 24 h, while the riser cools into hydrate domain in less than 5 h. Other examples are heated flow lines and production loops which can be circulated with hydrate safe fluid. In these situations, risers often require more immediate actions than the flow lines. On one hand, it is desirable to postpone implementation of the hydrate control measures if possible. It is important to avoid hydrate plug formation in risers as this potentially has the highest safety risk. If the plugs are not eliminated, they can cause damage to the pipe and hence large economic losses.

7.6 Kicks with Hydrates

An advanced dynamic kick simulator is used to determine hydrate formation. The simulator uses dynamic temperature simulation, PVT calculations of the hydrocarbon influx, and hydrate formation program, to determine the interval temperature for hydrate formation. The dynamic kick simulator determines the chance of hydrate formation during the drilling operation. A combination of many different effects of well control will help to predict hydrate formation in the early stages (Aadnoy et al. 2009).

7.7 Methane Hydrates

Methane hydrates usually formed inside the drilling equipment and affect the drilling operations.

Dual-gradient drilling provides the best solution to control methane hydrate formation. Hydrate inhibitors added to the drilling fluid have capacity to prevent the formation of hydrates during drilling and production. When the methane hydrates are present in a wellbore, inlet subsea pump pressure will increase with increasing subsea pump rate to keep the inlet pressure constant. The pit gain warning includes increased subsea pump pressure and a decrease in surface pump pressure (Aadnoy et al. 2009).

Aadnoy et al. (2009) showed in his work that the subsea mud-return system provides the driller with backpressure control over the formation. The backpressure preventing the formation hydrates from other influxes. The drilling operation can be resumed after the methane hydrates are circulated from the wellbore safely.

8 Deepwater Drilling Concepts

New drilling technologies are being developed for deepwater environments as exploration moves to deeper water depths. The technical, economic, and safety challenges increases with water depth, and hence the need to develop more advanced solutions and technologies to meet these challenges. The main goals are to increase access to reserves, improve wellbore integrity, reduce costs, and safeguard environment. A slender well concept, drilling with SBOP and dual-gradient drilling are some of the deepwater drilling solutions.

One of the major challenges in HPHT wells during deepwater drilling is narrow operating windows between pore and fracture pressures. Fig. 8.1 shows formation pressure profiles in a deepwater well.

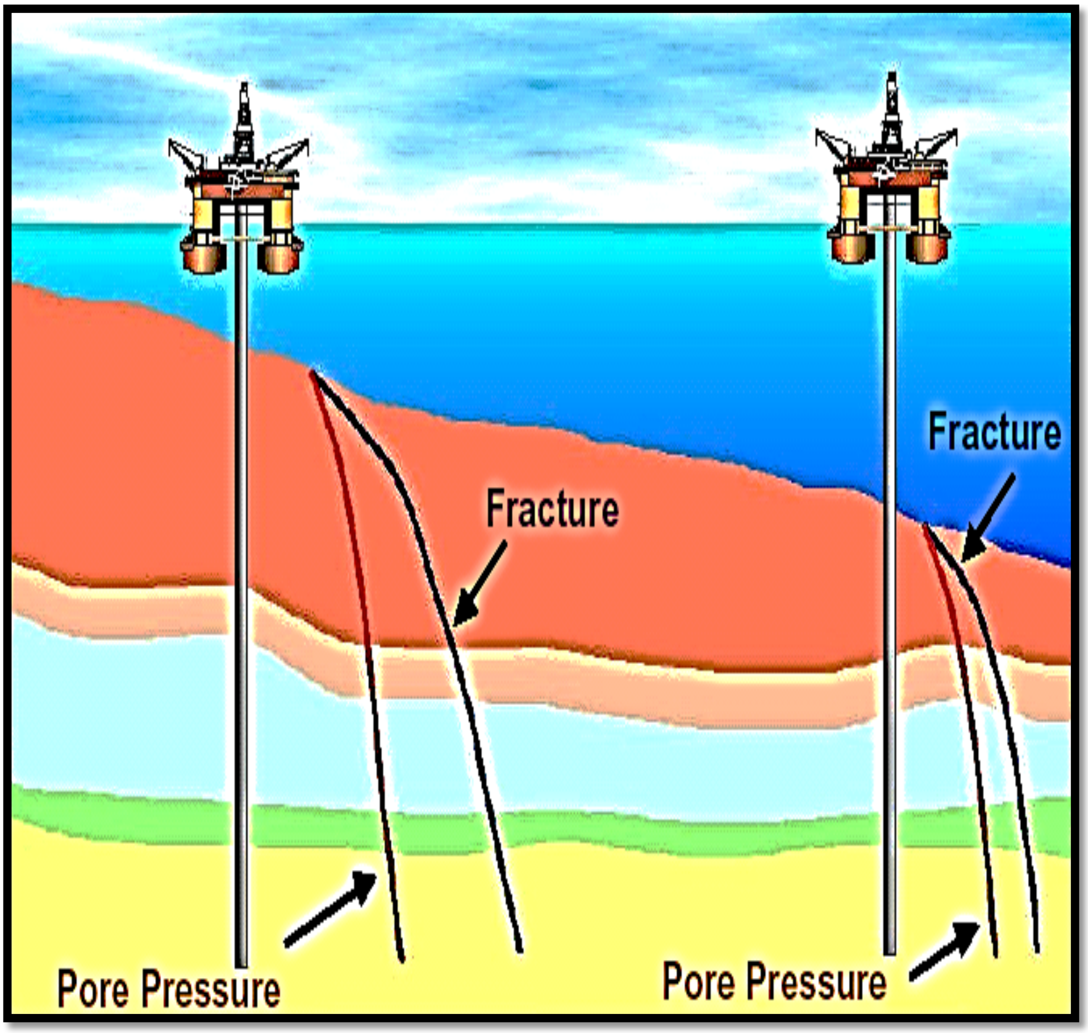


Fig. 8.1—Formation pressure profiles in a deepwater well (Belayneh 2014b).

Fig. 8.1 shows the margin between the pore pressure and fracture pressures gets thinner as water depth increases. The decrease in the fracture pressure gradient can be attributed to the reduction in overburden pressure gradient. Too low a mud weight may cause an influx of the formation fluid into the wellbore. Too high a mud weight will fracture the formation and result in mud losses to the formation. As a result of the narrow margin, more casings will be required to reach the target depth with traditional drilling approach.

Cummings et al. (2014) discussed drilling solutions for narrow margin fields. Drilling fluids that have flat rheologies that are independent of temperature and low-density cements can be used to reduce the hydrostatic pressure of fluid columns in deepwater wells. In some instances, when casing must be set above the targeted casing seat depth, drillers can avoid a reduction in the next casing size by underreaming—drilling out and enlarging the hole beneath the casing seat—and then setting casing that can be expanded to the size of the previous casing.

Flat-rheology drilling fluid, which has been used in the GoM since 2004, was designed to prevent mud losses to induced fractures resulting from the high ECD that is typical in cold deepwater drilling was defined by Schlemmer (2009).

Pressure while drilling has been an effective monitoring tool to predict unexpected annular pressure increase, allowing preventive actions to keep the hole clean without fracturing the formation. A kick, lost circulation, or stuck pipe can occur when well pressure crosses the operating window limits. To prevent the drilling problems, casing strings are set at intervals to keep the wellbore stable. However, this approach is very expensive, considering the cost of casing and time to run each casing.

Managed-pressure drilling (MPD) has been developed to "walk" the thin line between pore and fracture pressures and achieve target depth with a few casings. Dual-gradient drilling (DGD) is an MPD technique adapted for deepwater environments. In DGD, a marine riser is filled will a low-density fluid such as seawater to reduce internal pressure at wellhead. However, a drilling fluid of higher density is injected into a wellbore. This enables drillers to precisely manage well pressure and reduce number of casing setting points. Dual-gradient drilling concept will be discussed in detailed later.

8.1 Conventional Riser Drilling

Conventional Riser Drilling (CRD) is a traditional drilling method for deepwater wells. CRD provides pressure control in the well and keeps a return flow channel for mud and cuttings.

Schubert (2003) presented problems associated with conventional riser systems.

- Deck space limitations due to size of the marine riser.
- Weight and vessel size requirements to hold the increased riser weight.
- Large mud volumes contained in a riser.
- Challenges and problems with keeping the station from forces applied on the riser by ocean currents.
- Cost of mud to fill riser.
- To achieve required depth, large number of casing strings is required.
- Requires longer time during tripping in and out the riser.
- Challenges to drill gauge hole size.
- Many casing points requires because of narrow gap between pore and fracture pressures.

Fig.8.2 shows a conventional riser drilling system.

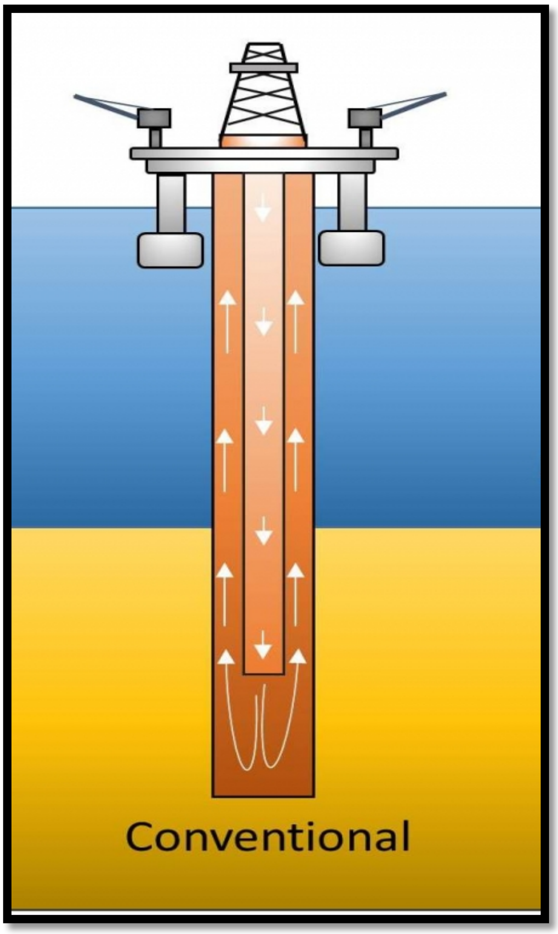


Fig. 8.2—Conventional drilling mud circulation (Products 2015).

Fig. 8.2 shows that, in conventional drilling, mud is pumped through the drill pipe, and the system returns mud to the rig floor via the marine riser.

As water depth increases in deepwater drilling operations, a marine riser and wellhead should be able to withstand high stresses, resist burst pressures resulting from high mud weight, water currents, and the movement of a submersible drilling vessel. Increasing size of marine riser and wellhead will help, but this leads to high drilling costs (Aadnoy et al. 2009).

The main disadvantage using CRD concept is that many casing points are required to reach the target depth. For example, to drill 10000 ft, the required hole size at the target depth many not be achieved with CRD. Elimination of two or three casing points will reduce wellbore size and wellhead and number of days required to drill the deepwater well. This can save an average of $1.0 million per casing point reduction.

8.1.1 Well Control in CRD

During kick circulation in CRD, high frictional pressure drop in the choke line will put excessive back pressure on the wellbore.

When the riser is disconnected in an emergency, well pressure will decrease due to a reduction in the hydrostatic mud column. In the case of riser disconnection, the subsea BOP should be able to seal off the wellbore before a well control procedure is started (Aadnoy et al. 2009).

8.2 Conventional Well versus Slender Well

A slender well concept is presented in Aadnoy et al. (2009). Fig. 8.3 compares conventional well and slender wells.

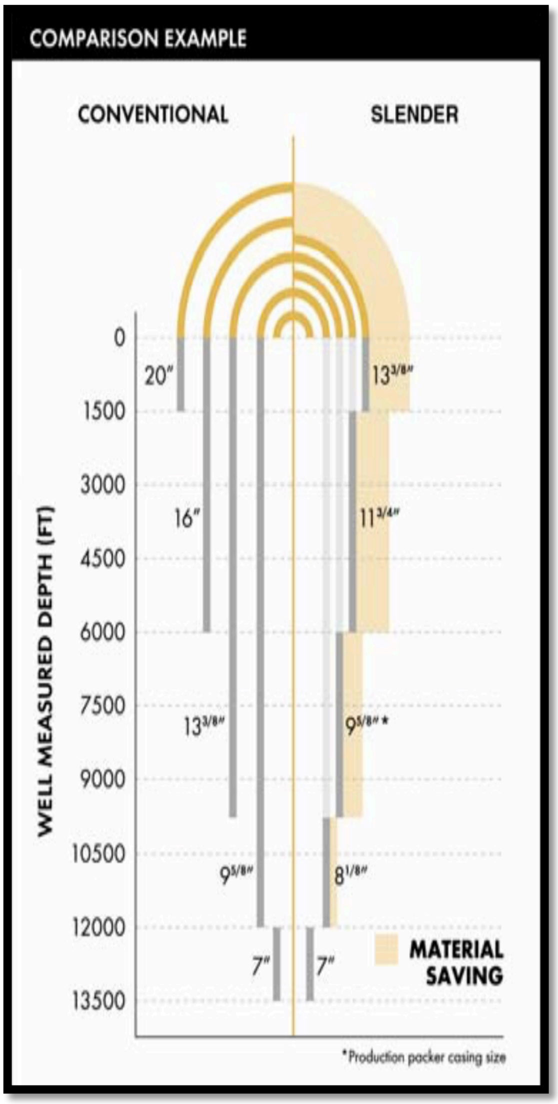


Fig. 8.3—A comparison between conventional and slender wells (Howlett et al. 2007).

The main goal of slender well technology is to reduce riser size and cut drilling time and drilling costs. The elimination of one casing string will reduce drilling time and costs. The productivity from the field will be increased. The idea is to switch conventional well design to slender well design (e.g. reduce the casing size on the top section and keep the production section of the well to be the same). Smaller equipment leads to less deck space on the rig will be used and allowing the use of the second and third generation offshore drilling rigs which are less expensive than normally conventional rigs. More than 400 slender wells have been drilled in the Campos basin off the coast of Rio de Janeiro, Brazil. If the weight and space requirements will be reduced, medium to large sizes of drill ships or third or even second generation semi-submersibles rigs can be used in deepwater drilling. This is very important because most of the fourth-generation of semi-submersibles are in great demand and those types nowadays are currently under long term contracts (Aadnoy et al. 2009).

Advantages of slender well concept Howlett et al. (2007), which include:

- Faster drilling performance and reduced costs makes slender well concept very economically useful.
- Less cuttings and drilling fluids will be discharged into environment.
- Reduce risk during transportation and handling.
- Reduce the well abandonment process resulting from the lack of overlapping casing strings and potential leak paths at the top of the well.
- Performance of well integrity is improved by the capacity to use API casing and normal cementing techniques.
- Constructing wells from close gap liners reduces the telescoping effect in wells when compared to conventional techniques

8.3 Surface Blowout Preventer

Aadnoy et al. (2009) showed that SBOP is more efficient and safer to use, compared to subsea BOP.

The main idea is it avoid running the traditional and complex subsea BOP. Conventional subsea BOP involves significant downtime, with permanent electronic, and hydraulics problems. The main advantages of SBOP is cost savings, reduce rig deck capacity and allowing to use smaller rigs in deepwater wells. The SBOP concept provide easy maintenance and increased operational efficiency. The riser is a casing string in SBOP than a special flanged joint which reduce downtime. The use of SBOP in deepwater water means that lighter weights equipment will be handled at the drilling rig. Therefore, lower-cost third-generation rigs can replace the very expensive fourth- and fifth- generation rigs, leading to cost savings (Aadnoy et al. 2009).

For SBOP to function correctly, safely and effective, a management and dynamic system is required to reduce and controls risks in a deepwater environment. A hazard operation (HAZOP) is used before initiation of the operation. HAZOP identifies major potential accident hazards and risks. This process is used to manage risks during the operation and data and feedback (Aadnoy et al. 2009).

The SBOP have been used by many operators in deepwater environments. The main benefits with SBOP: less risk of blowout, less downtime, larger offsets, lower-cost rig (third-generation), more-reliable well-control system, reduction of VIV and fatigue, better hydrate management, and less discharge to the environment during emergency disconnection. Therefore, SBOP technology was successfully proved and used in the Far East. More than 140 wells were drilled in Kalimantan, the Andaman Sea and the Sulu Sea and 4 wells in Bo Hai Bay, China. Half of these deepwater wells were drilled in water deeper than 900 m (Aadnoy et al. 2009).

8.4 Managed Pressure Drilling

According to the International Association of Drilling Contractors (IADC), MPD is defined as "an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole-pressure-environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface" ((IADC) 2008).

Any influx incidental to the operation will be safely contained using an appropriate MPD process (IADC) (2008), which include:

- MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by managing the annular hydraulic pressure profile.
- MPD may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry.
- MPD may allow faster corrective action to deal with observed pressure variations. It can dynamically control annular pressures.

The main benefits of MPD techniques compared to conventional such as, better kick control, possible to drill wells which were considered undrillable, reduced risk and increased safety. One of the main challenges is the wellbore stability, drilling costs are higher, compared to conventional, possibility to have higher Torque and drag and increased weight of the string due to reduced buoyancy (Belayneh 2014a).

The use of MPD systems improve pressure control in narrower drilling margins. The demand of MPD systems is growing among the operators in the oil industry. The MPD system has been already utilized for drilling a deepwater well in the GoM. However, MPD system including new drilling equipment and risks. Applying MPD systems in HPHT environment, the high priority is well control and the conditions to which the riser is exposed. Deepwater projects in the GoM showed that MPD offers significant improvements over traditional drilling methods in the area of improving well control in deepwater drilling applications was showed by Weems et al. (2016)

Weems et al. (2016) presents the advantages of MPD over the conventional method. The main advantages are:

- The ability to stay within narrow pressure windows, minimizing amount of problems with kicks and mud loss. It is also makes easier to assess the upper boundaries of these windows.
- The ability in early kick detection
- Improved wellbore stability
- Elimination of wellbore breathing that occurs when the fracture gradient is exceeded and mud lost to the formation flows back when the pressure is reduced during connections.
- The ability to keep a small amount of backpressure on the top of the annulus. This calms down any effects from a small amount of gas compared to a conventional system.
- Avoiding conventional drilling Non-Productive Time (NPT) problems, such as lost circulation, kicks, nuisance gas zones and differential sticking.
- Increasing ROP and extend bit life, which cuts tripping and reduces NPT
- Enabling access to potential assets and reservoirs previously believed to be un-drillable.
- Reducing the number of casing strings and, in some cases set casing points deeper.
- Reducing health, safety and environmental effects and risks by controlling fluids and pressures all the times.
- Managed Pressure Drilling provide a lot of improvements over traditional drilling methods and improving well control in deepwater drilling areas.
- Many projects in the GoM field have demonstrated advantages of using MPD
- The gas influxes are more easily controlled and their position in the well is getting more predicted.
- Keeping pressure in the annulus stable all the time, prevents any gas enter the wellbore and being undetected.

However, MPD operations have several disadvantages:

- MPD operations are more expensive compared to conventional drilling.
- Lack of a well-established standards.
- Level of personnel training need to be very high.
- The complicity of operations is much higher compared to conventional drilling.

8.5 Dual-Gradient Drilling

DGD eliminates the impact of water depth on deepwater drilling, allowing operators to drill the reservoirs approximately 40 000 ft below the seafloor, which were previously thought to be impossible. The MPD technique is sometimes referred to "riserless drilling" with two different fluid-density gradients (Aadnoy et al. 2009).

Fig. 8.4 shows the dual-gradient pressure profile.

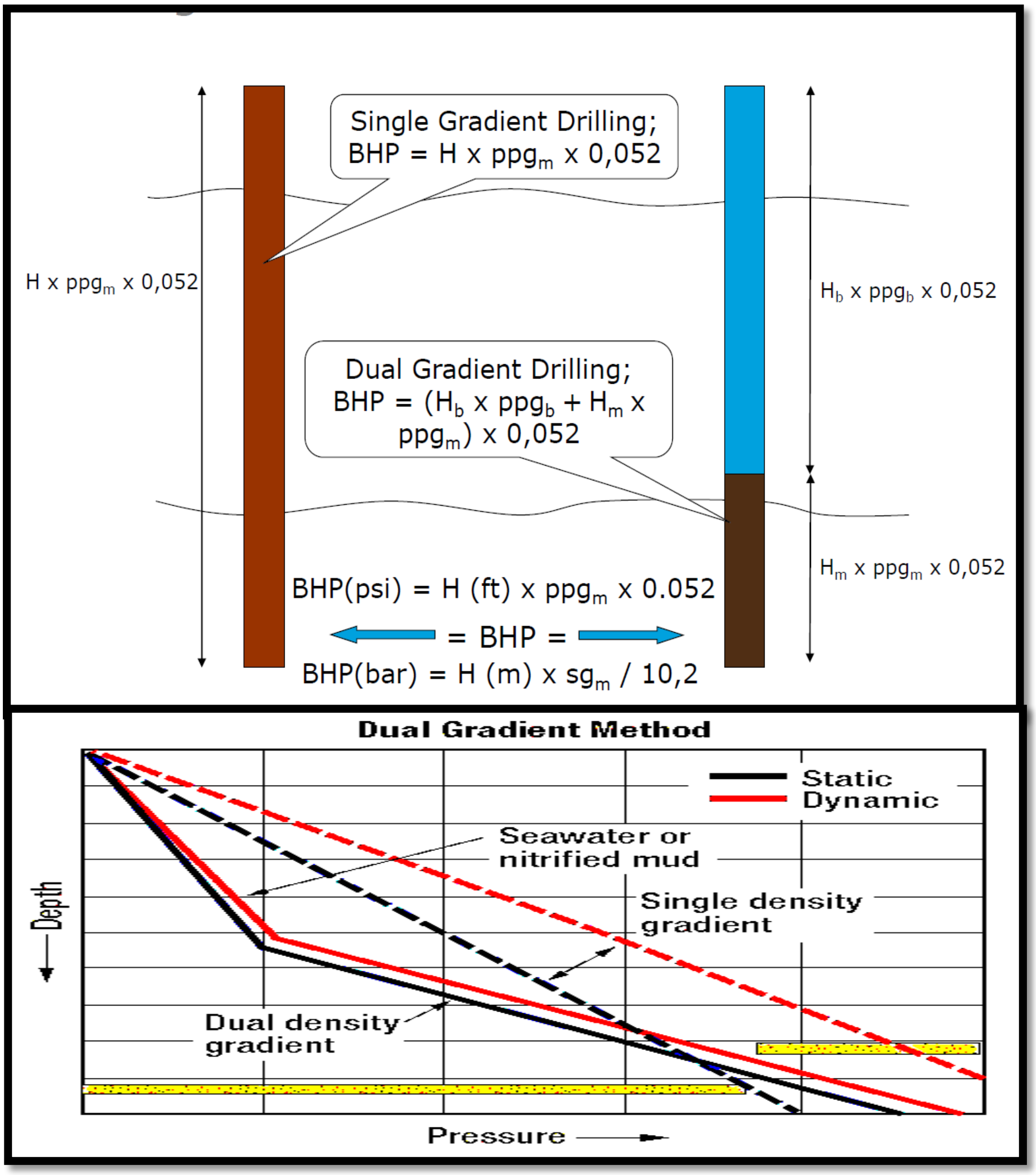


Fig. 8.4—The dual-gradient pressure profile (Belayneh 2014a).

Fig. 8.4 shows that a single density fluid will cause the wellbore pressure to exceed the fracture pressure and result in lost circulation. In dual-gradient drilling, a lighter fluid is used in a riser and a heavier fluid in the lower section of a wellbore. The two fluids are separated by a rotating control device (RCD), which provide a sealing around the drill string during drilling operation. This enables drillers to drill safely through a narrow operating window and reach the target depth with a few number of casings.

Fig. 8.5 shows a riserless DGD system.

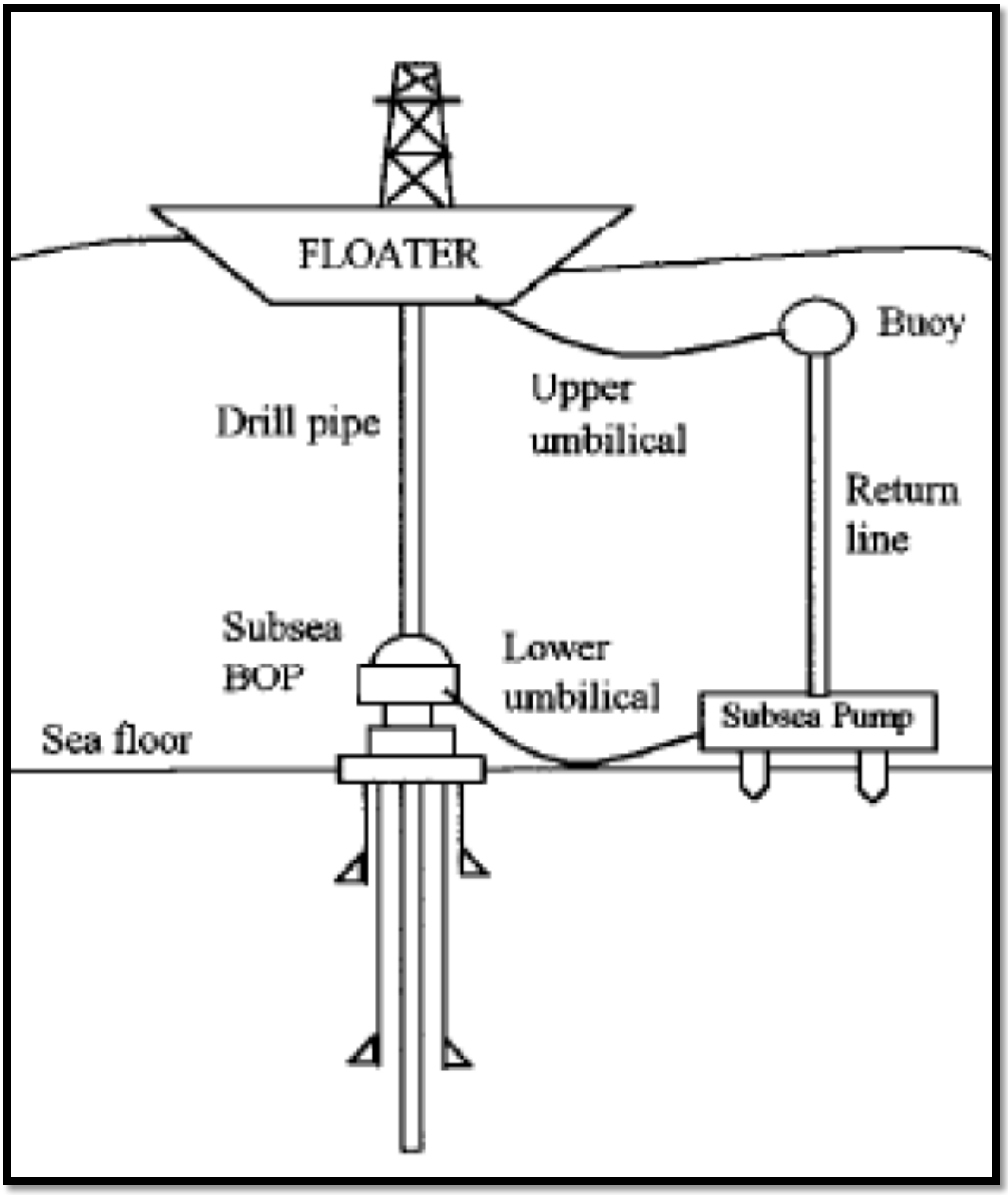


Fig. 8.5—An illustration of riserless drilling in deepwater well (Belayneh 2014b).

In the riserless DGD system, mud is pumped into the annulus through the drill string. The subsea pump then returns the mud and cuttings to the rig floor through the return line. To achieve dual gradients in the wellbore, the water pressure gradient is maintained at the wellhead with the subsea pump.

Fig. 8.6 compares riserless DGD and CRD systems.

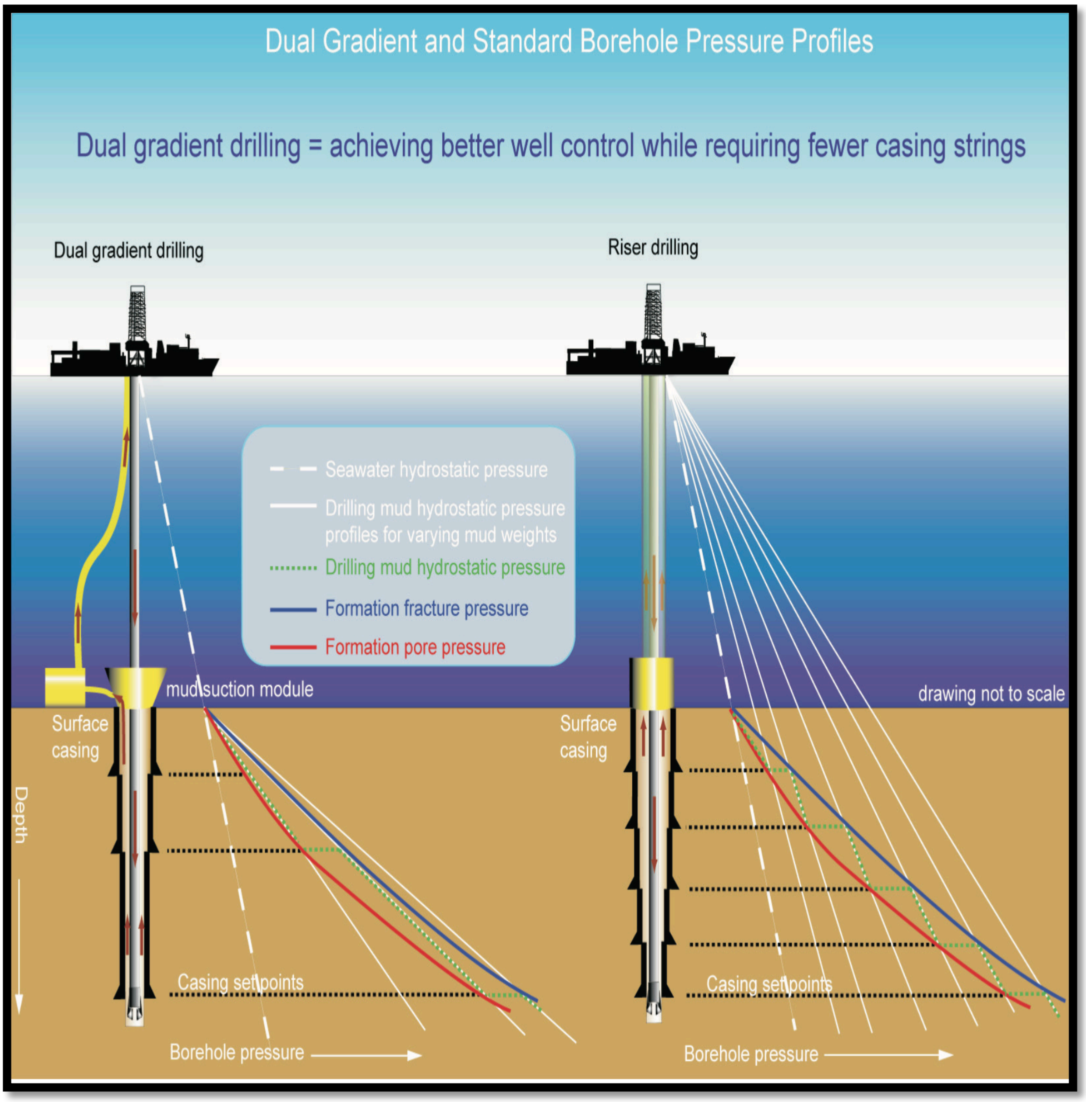


Fig. 8.6—A comparison between DGD and CRD (Myers 2008).

Fig. 8.6 shows that DGD achieves a better well control with a few casing strings compared with the conventional riser drilling.

8.5.1 Control Mud Level Systems

EC-Drill is a Controlled Mud Level (CML) system that is a variation of MPD technology. The EC-Drill system can be used off with floaters, drill ships and jack-ups vessels. It is installed with the marine riser and operates independently from the marine riser. With this technology, operators enable to drill and solve major challenges when drilling in deep waters, including drilling within a narrow pressure window (Drilling 2016).

The system provides early kick and loss detection. If there is unexpected increase in EC-Drill drill pump, there might be a kick. To avoid the kick, early kick detection reduces the size of the kick. Therefore, the kick can be circulated out from the wellbore safely. If there is unexpected decrease in EC-Drill drill pump, there might be a loss. The decreased mud level in the marine riser, reducing hydrostatic pressure. This helps to prevent the loss (Drilling 2016).

The main benefits with EC-Drill Drilling (2016), which include:

- Reduces ECD effect
- Maintain a constant BHP
- Drilling of HPHT wells
- Possible to drill in narrow pressure windows
- Possible to drill deepwater wells with riser margin.
- Improved hole stability
- Can be switched to conventional drilling at any time.
- Achieve longer casing strings by drilling with heavier mud and reducing the mud level.
- Provides saving in rig time and costs when drilling deepwater wells.
- Reduced number of casings
- Reduced risk of stuck pipe
- No RCD needed
- Ability to operate in harsh environment.

Fig. 8.7 shows EC-Drill MPD system.

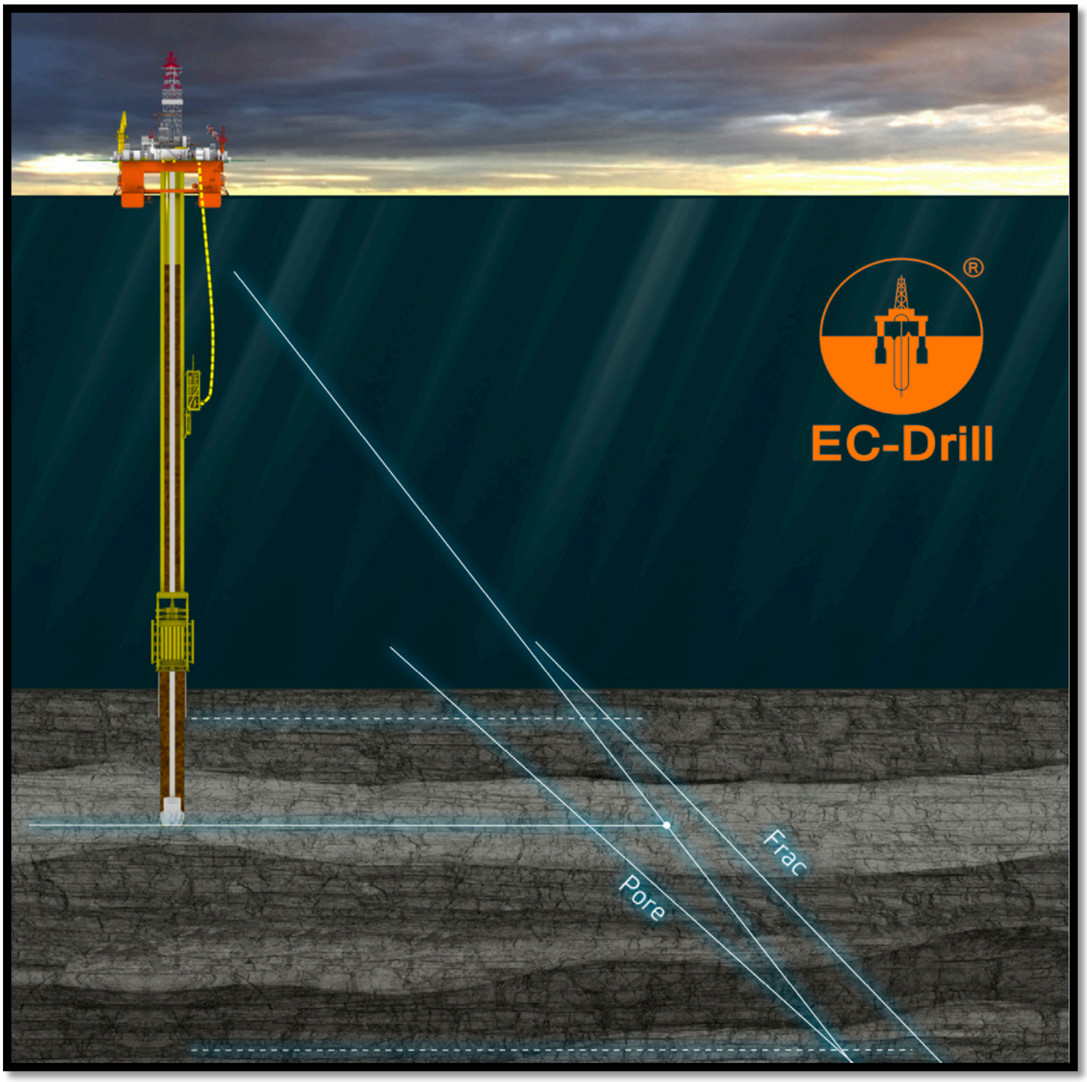


Fig. 8.7—A schematic of EC-Drill Managed Pressure Drilling (Drilling 2016).

To maintain constant BHP just above pore pressure can be achieved by regulating mud level in the riser. This is very efficient when the drilling window is narrow, or when the pressure gradients are most uncertain (Drilling 2016).

8.5.1.1 EC-Drill Case Study in Shah Deniz field

Drilling (2016) helped BP to successfully drill Shah Deniz field, in Caspian Sea.

The main advantages demonstrated Drilling (2016), which include :

- Desired target depth was achieved.
- Wellbore was in a good condition and ready for perfect cement job.
- Time and cost savings as pressure regime-related non-productive time was reduced.
- No influx occurred despite there being a high-pressure formation and narrow pressure window.
- Formation integrity test was successfully performed at 800 mTVD (2,625 ft) by introducing pre-designed a high-density pill to the riser from the top according to a well-devised volume plan. Wellhead pressure sensor was used for observation during the test.
- A new kill procedure was in place should the formation flow; kill mud could be pumped into the wellbore via the return line through the subsea disk pump if the drill string was not in the wellbore.

8.5.1.2 EC-Drill Case Study in GoM

Godhavn and Gaassand (2016) demonstrated that instant kick detection demonstrated in GoM can be achieved more quickly and reliably compared to conventional well control methods. The two new kick indicators can improve detecting of kick during drilling and connections by use of riser pressure sensors and subsea pump speed performance. These riser sensors are the first indicators that detects influx in 40 to 60 seconds. This is much faster compared to conventional methods (Drilling 2016).

However, a real gas influx was taken without being seen on the new MPD system. The kick was handled and verified by the ECD Management procedure for transition from drilling with a reduced riser level to well control, where the BOP is closed and the ECD-M system is isolated Godhavn and Gaassand (2016).

During the operation, the installed equipment did not show any problems. The first 1000 ft were drilled with a reduced riser level pumping for almost 600 hours without any drilling operations downtime (Godhavn and Gaassand 2016).

EC-Drill will enable the full benefits of the technology including accurate pressure control reducing downtime related to wellbore instabilities.

8.5.2 DGD Systems Based on Lightweight Fluids

In DGD systems, a low-density fluid such air and inert gas is injected into the riser to lower the hydrostatic mud pressure above the RCD. Aadnoy et al. (2009) described the DGD system based lightweight fluids.

The presence of a narrow operational margin between pore pressure and fracture gradient is associated with some drilling problems, such as loss circulation and well control events. The use of lightweight fluids will able to drill deepwater wells successfully and managing the narrow pressure window. Lightweight fluids can avoid loss circulation and minimize formation damage, especially in depleted deepwater reservoirs.

For achieving DGD condition, the use of lightweight mud consists of injecting hollow spheres into the riser at the bottom of the marine riser to maintain pressure in the subsea wellhead equal to the hydrostatic pressure of the seawater at the same water depth. The injected mud at the sea floor reduces the density of the return mud in the marine riser. To maintain hydrostatic pressure equivalent to that of the seawater at the seafloor, the diluting material must be added at a proper concentration to decrease the density of the drilling fluid to a value that fulfills this DGD requirement. After the mud, cuttings and the hollow-spheres gets to the drilling rig it is transferred to a separator system. It is necessary to separate the material from the drilling fluid at surface to maintain the proper properties. The separator system separates the hollow spheres from the mud and these spheres can be reused after being extracted at surface (Aadnoy et al. 2009).

Fig. 8.8 represents of hollow-spheres in DGD system.

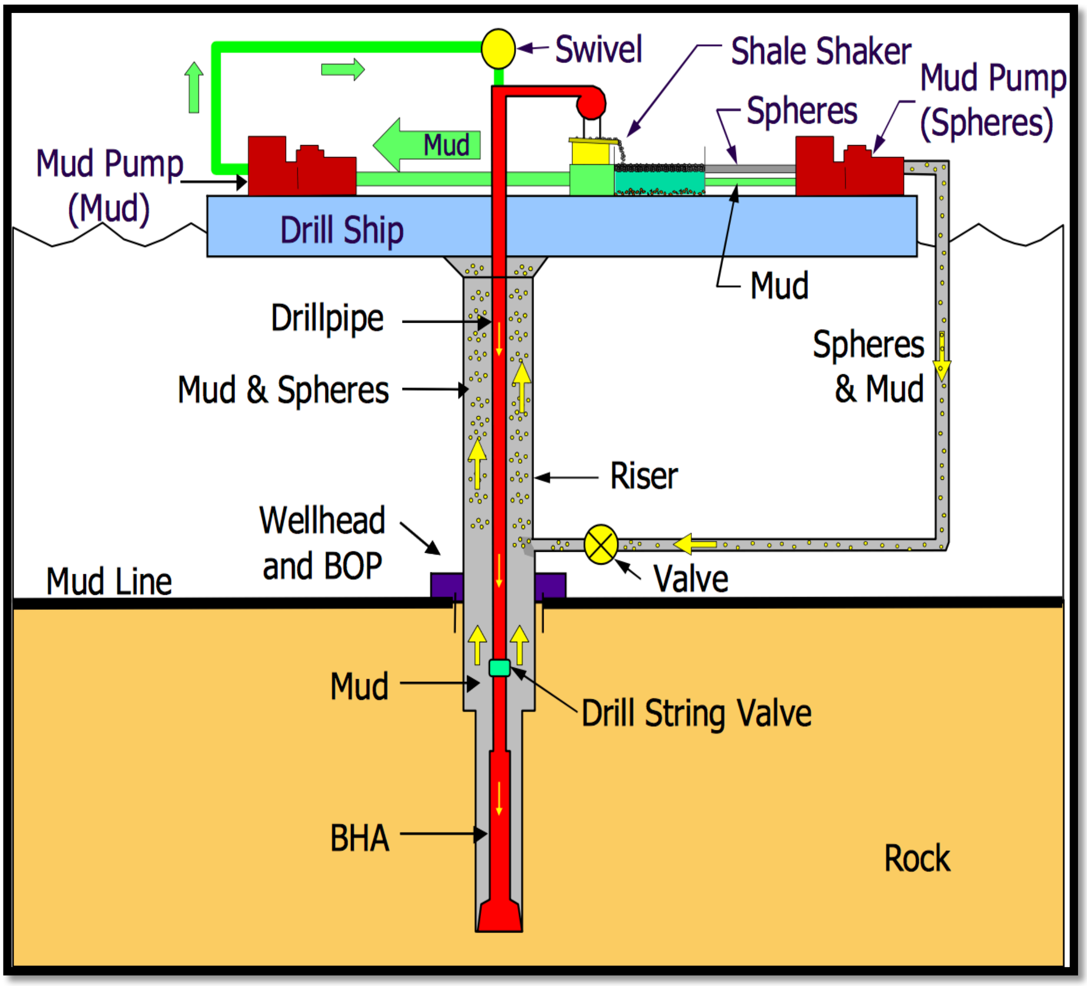


Fig. 8.8—Hollow-spheres in DGD system (Cohen and Deskins 2006).

Cohen and Deskins (2006) demonstrated that the main benefits of using the hollow spheres in DGD system is that the hollow spheres are incompressible. They can be easily and safely mixed with the drilling mud during operations. However, hollow spheres can breakup and separate the hollow spheres from the drilling mud can be very difficult.

8.5.3 Advantages of DGD

Some of the advantages of riserless drilling concept provided by Choe and Juvkam-Wold (1998):

- Improved well control performance led to an improvement in enhanced safety and environmental performance. The quick kick detection provides circulating kick out of the well in safe and economical manner.
- Riserless drilling reduces number of casing string and drilling cost in term of cost of casing, cost of cementing, time during running cementing and casing.
- Theoretically there is no limit on water depth
- Smaller return lines can be used.
- Mud volume requirement is reduced.
- Space and weight requirements are reduced.
- Decrease of non-operational time
- Decrease of casing points
- No riser loss in case of emergency disconnection
- Adequate hole size at target depth for high production rate expected
- Extension of the capacity of existing drilling units
- Possible rig upgrade

All those advantages provide rig upgrade, cost and time savings.

8.5.4 DGD Challenges

The introduction of new drilling technologies often encounters operational and regulatory challenges. In addition, they should be able to offer significant advantages over conventional technologies. For instance, equipment-commissioning problems (electrical and commissioning delays) can interrupt DGD operation. Another challenge is the training of drilling personnel and surmounting initial industry resistance. Because DGD systems are a closed system, a leak at the wellhead may hamper safe drilling operation. To prevent this problem, drillers should ensure there is a tight sealing around the drill string and that the mud lift system is in good condition. This is to guarantee that returning mud and cuttings are effectively and safely diverted to mud return line (Aadnoy et al. 2009).

8.5.5 Well Control and Kick Detection

Kick detection and circulation are important well control problems in deepwater operations. The best measure, however, is to avoid formation fluid influx through effective well pressure management. A kick should be detected as quickly as possible in the early stages and controlled in a safe manner.

Table 8.1 shows a summary of possible kick detection methods for riserless DGD.

Table 8.1—Kick Detection Methods for Riserless DGD (Choe and Juvkam-Wold 1998)

Kick Detection Method	Still Valid for DGD
Pit gain	Yes
Return rate increase	Yes (enhanced)
Well flows with pump off	U-tubing
Fluid fill-up on trips	Complicated
Drilling break	Yes
Increased hook load	Yes
Drop in BHP	Yes
Drop in SPP	Yes (enhanced)

Table 8.1 shows the primary indicators (pit gain, return rate increase, wells flows with pump off and fluid fill-up on trips) and the secondary indicators (drilling break, increased hook load, drop in BHP and in SPP). Return rate increase and pit gain volume can be used with secondary kick indicators such as increased in hook load and drilling break. Because of effective hydrostatic pressure inside the drill string is higher comparing in annulus, there will not be any kick with flow until the two pressures reach equilibrium. Therefore, it takes some time before to notice if the kick is present in the well or not. Tripping of the drill pipe should start after U-tubing to make the procedures very simple and therefore proper hole fill-up during tripping can be used. It is very challenging because it is hard to measure the exact mud level inside the drill pipe. To predict kick on early stages can be performed by monitoring flow rate. Drop in SPP shows that there is a kick potential. MWD tools may be combined with other kick indicators to prevent kick occurrence (Choe and Juvkam-Wold 1998).

For riserless dual-gradient drilling, a kick cannot be circulated out directly through a choke line kill line because of the higher mud density. The subsea pump controls pressure drop in the return line. A kick should go through the subsea pump first and then it can be directed to choke or kill lines so that pressure at the wellhead is maintained as desired without breaking down the formation. Riser loss is eliminated in RD because heavy drilling mud is high enough to balance formation pressure with the seawater gradient from the sea floor to the surface.

Choe and Juvkam-Wold (1998) provides a summary of well control in riserless drilling (RD) compared to CRD. The main differences between the two drilling methods are:

- U-tubing effect in RD happens when surface pump is shut down, and it can take up to 30 minutes before equilibrium is obtained.
- The kick detection methods are the same.
- Differential flow rate at the wellhead and lower SPP makes kick detection easier and faster in RD.
- Kick can be stopped by use of surface and subsea pumps in RD. The shutting-in the well is not necessary.
- SIDPP can be estimated without shutting-in the well.

- Constant BHP can be achieved by adjusting subsea pump inlet pressure. This makes easy to control surface choke pressure within wide operational ranges.
- Wellbore pressures below mud line and bottomhole pressure will not be affected by choke pressure in a surface.
- Well control training for riserless drilling leading to successful well control operations.

8.5.6 Well Control: Modified Drillers Method

To prevent a further influx after kick has been detected in wellbore and maintain the well control, the subsea pump rate is return to the pre-kick rate which is maintained and equal to the surface pump rate. The BHP should be kept constant above pore pressure to prevent the influx. The maintained and returned subsea pump rate creates backpressure acting on the fluids inside the wellbore and increasing the BHP until it is balanced. During circulation of the fluids, drill pipe pressure will be balanced by changing the subsea pump rate. The circulation will be started until all the kick fluids are removed from the wellbore. After the pressure is balanced and stabilized within right pumping rate, it is important to record it. After the kick fluids have been removed from the wellbore, the hydrostatic pressure will be increased on the bottomhole section resulting from circulation of a kill weight mud. During the influx, the subsea pump pressure increases to maintain inlet pressure while the output surface pressure is decreases Aadnoy et al. (2009).

If the kick occurs, the annular flow rate of the drilling fluid will increase by an amount equal to the influx rate. During the subsea pump operation at a constant inlet pressure, the pump rate increases which provide a good sign of a kick occurrence. Circulation kick out from the wellbore can be used by same procedures as in conventional drilling Schubert (2003).

8.5.7 DGD versus Pump-and-Dump

DGD technology can easily control shallow hazards, such as methane hydrates, shallow gas zones and shallow water flows compared to pump-and-dump. Most of the shallow hazards can be found in deepwater environment and cause problems during drilling, completion operations and, at the worst case, affect the stability of the wellbore and the safety of the personnel on rig site. It has already been shown that DGD is promise in managing the narrowing pressure window in deepwater environments and ultimately reducing costs, improving wellbore integrity and increasing production capacity. Specifically, the application of this technology to the tophole portion of the wellbore can lead to safer operations, reduced costs and a more technically stable wellbore by providing proactive control over shallow hazards (Hughes 2011)

Typically, large tophole sections in deep and ultra-deep waters, for example the GoM, is drilled with WBM using Pump-and-Dump. The riserless drilling technique is described in Aadnoy et al. (2009). In this technique, the return mud and drilled cuttings are dumped on the seabed around the wellhead. Therefore, the cuttings will not be return to the surface. The Pump-and-Dump method can safely be employed to obtain the desired 20-in casing setting depth, below the deepest, high risk potential shallow water flow zone.

The Pump-and-Dump method has limited well control and depends on accurate seismic data to avoid shallow hazards. The kick detection methods are poor and unreliable, therefore, to avoid the kick, visual kick detection is needed. In addition, Pump-and-Dump does not offer dynamic methods of controlling kicks or the formation of methane hydrates in wellbore when they do occur (Hughes 2011).

Fig. 8.9 compares Pump-and-Dump and Riserless Mud Recovery.

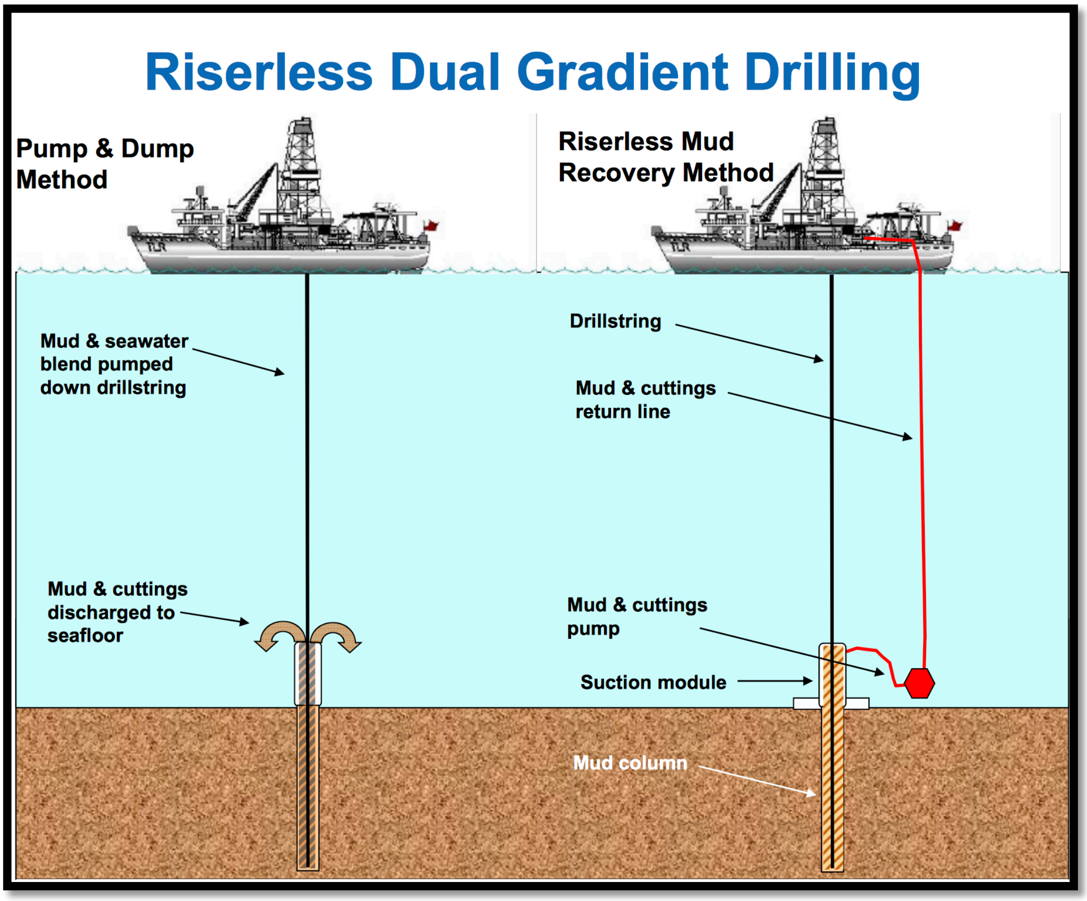


Fig. 8.9—A comparison between Pump-and-Dump and RMR (Hughes 2011).

Riserless Mud Recovery (RMR) system is reduce risk, enables to drill better quality wellbore. This DGD system allows to return mud and drilling cuttings to the rig floor before the marine riser is run in a hole, without discharge drilling cutting to the seabed. Collected and reused drilling mud reduces the amount of mud required to drill an offshore well. With RMR there is no Pump-and-Dump.

RMR system offers a complete solution in cost-effective manner, allowing the drilling of deepwater wells up to 3657 m. The riserless drilling concept was AGR Subsea AS.

RMR had been used in Azeri Field in the Caspian Sea to recover mud from seabed and save fluid costs. The number of casing strings was reduced, which reduced well costs.

A Riserless dual-gradient (RDG) system has been successfully field tested in offshore deepwater environments (Hughes 2011).

8.5.8 Conventional Drilling versus Dual-Gradient Drilling.

As for general deepwater operations and for applying dual-gradient technology, a smaller rigs size types may be used compared to conventional drilling. Perhaps the main benefits are time and cost savings because the necessary amount of casing strings is reduced. This allows to increase size of the final tubing, that increases production flow rates and reduces the amount of time to spend on drilling.

8.5.9 The Future of DGD

As operators move into water deeper depths, the number of unexplored hydrocarbon reserves will increase, and dual-gradient drilling represents the future for deepwater drilling. An advancement in DGD systems, considering operational safety and ease of use, will significantly improve deepwater drilling operations compared to conventional technology.

8.6 Reelwell Drilling Method – Riserless (RDM-R)

Reelwell Drilling Method – Riserless (RDM-R) was developed by Reelwell AS deepwater drilling applications. |

The technology is based on dual-gradient drilling that provides optimum well control, resulting in long reach wells without the use of a riser in deepwater environments, and significantly reduce drilling fluid requirements. The RDM-R uses less time to circulate out a kick. The benefits include no marine riser, no riser tensioners and associated systems, less fluid volume and pumping capacity, improved safety related to MPD with no pressurized equipment on surface. It is also enclosed circulation system with longer sections, the risk for blowout is reduced through riser. Therefore, the BOP running time is reduced also Reelwell (2012).

Fig. 8.10 illustrate a RDM-R system for a deepwater well.

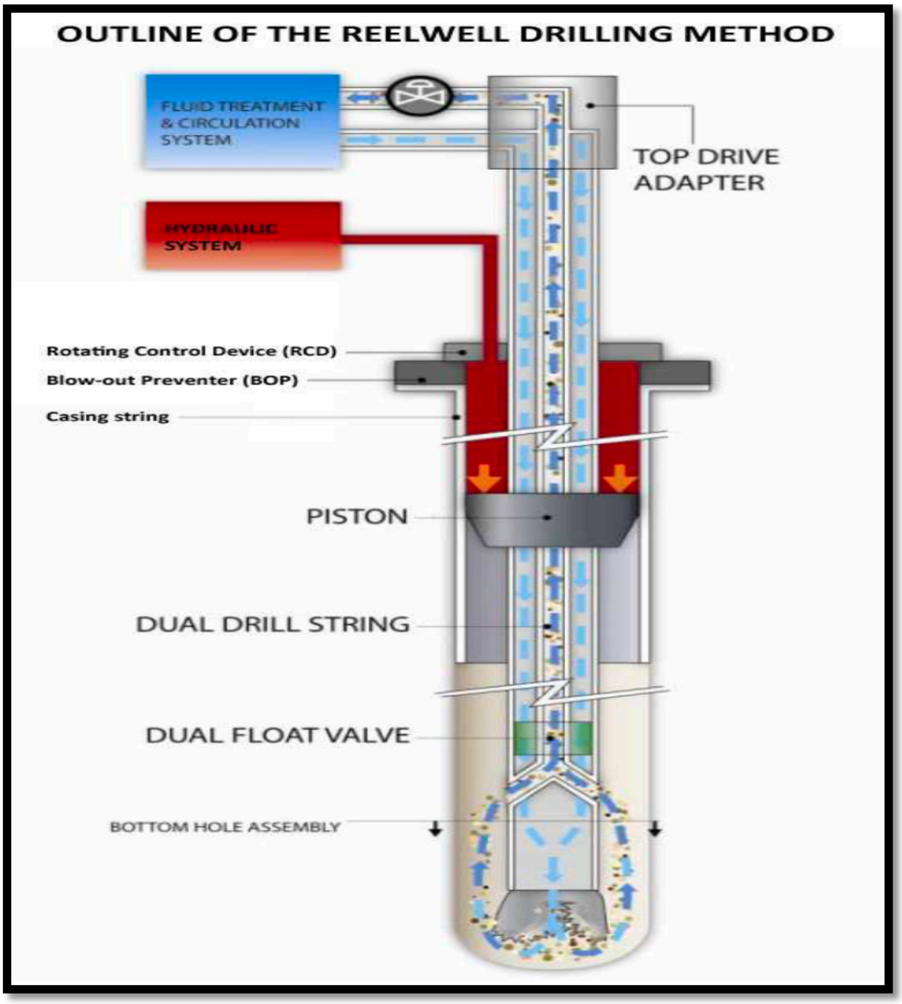


Fig. 8.10—A schematic of RDM-R System (Mirrajabi et al. 2010).

Fig. 8.10 shows a schematic of RDM-R system. The description is presented in Mirrajabi et al. (2009). The RDM-R technology is based on a dual drill string (DDS) in which mud is pumped down to the drill bit through the drill string annulus, while the return mud and drilling cuttings are transported to the rig floor through the DDS inner pipe. A rotary control device (RCD) is installed on top of the BOP and provides a sealing around the DDS to prevent fluid flow up the well annulus. A conventional BHA is connected to the DDS. Mobile offshore drilling unit makes the operation independent of a marine riser system because the return flow is flowing back to surface through the DDS inner pipe. During deepwater drilling, drilling fluid volume is reduced as the volume of the marine riser is removed. The drilling cuttings will not accumulate in wellbore annulus, since all the cutting returns to surface through DDS inner pipe. This is makes easier to hold the pressure in the well annulus stable, therefore, it makes easier to monitor and control it. Pressure in the well annulus with mud flow is controlled by computer system from the surface.

RDM-R was developed to address many deepwater challenges such narrow pressure windows and wellbore instability in extended reach wells. The technology eliminates the use of marine riser and makes possible to drill in ultra-deep waters.

8.6.1 RDM-R Applications

Fig. 8.11 shows applications of RDM-R in deepwater drilling.

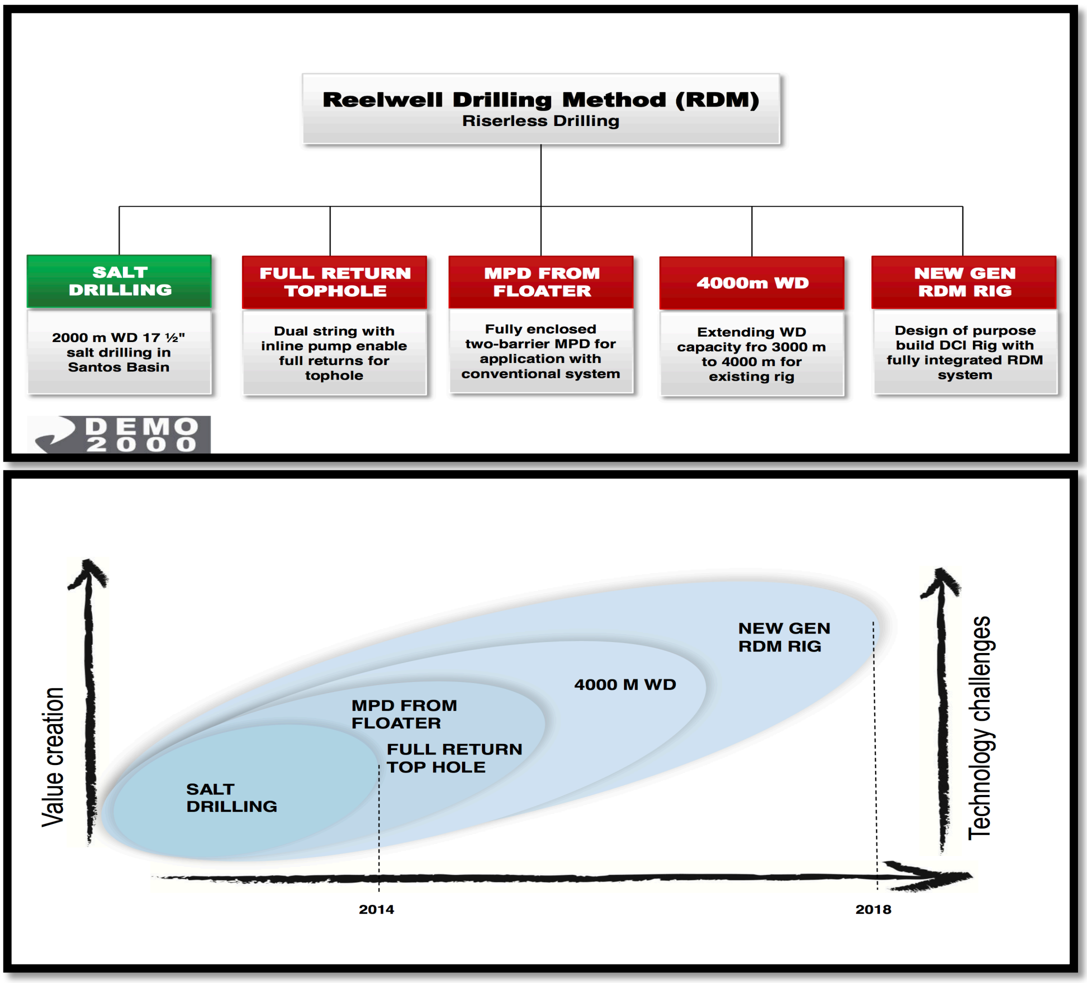


Fig. 8.11—Applications of RDM-R in deepwater drilling (Reelwell 2012).

The main goals with RDM-R is the aim of drilling in deepwater and ultra-deepwater well, to reach 4000 m water depth without upgrades. Also, design the new generation RDM rig with fully integrated system which will reduce dayrates, cost savings and time consumption

8.6.2 Well Control Method for RDM-R

During a kick, the influx will be circulated out through the DDS inner pipe. The DDS inner pipe is designed to withstand any pressure increase affected by the influx.

When a kick is observed, the drill pipe is pulled off bottom to shut in position, rotation is stopped and pumps are shut off to check if well flows - as for conventional drilling. Any pressure increase at the RCD will be checked after the pumps are stopped to ensure well is not flowing.

8.6.3 RDM-R versus Conventional Drilling

RDM-R has a few advantages over conventional drilling such better hole cleaning by removing drilling cuttings from the wellbore, less formation damage by avoiding loss of annular fluid and low costs on drilling fluids.

Fig. 8.12 compares CRD and RDM-R systems for deepwater wells.

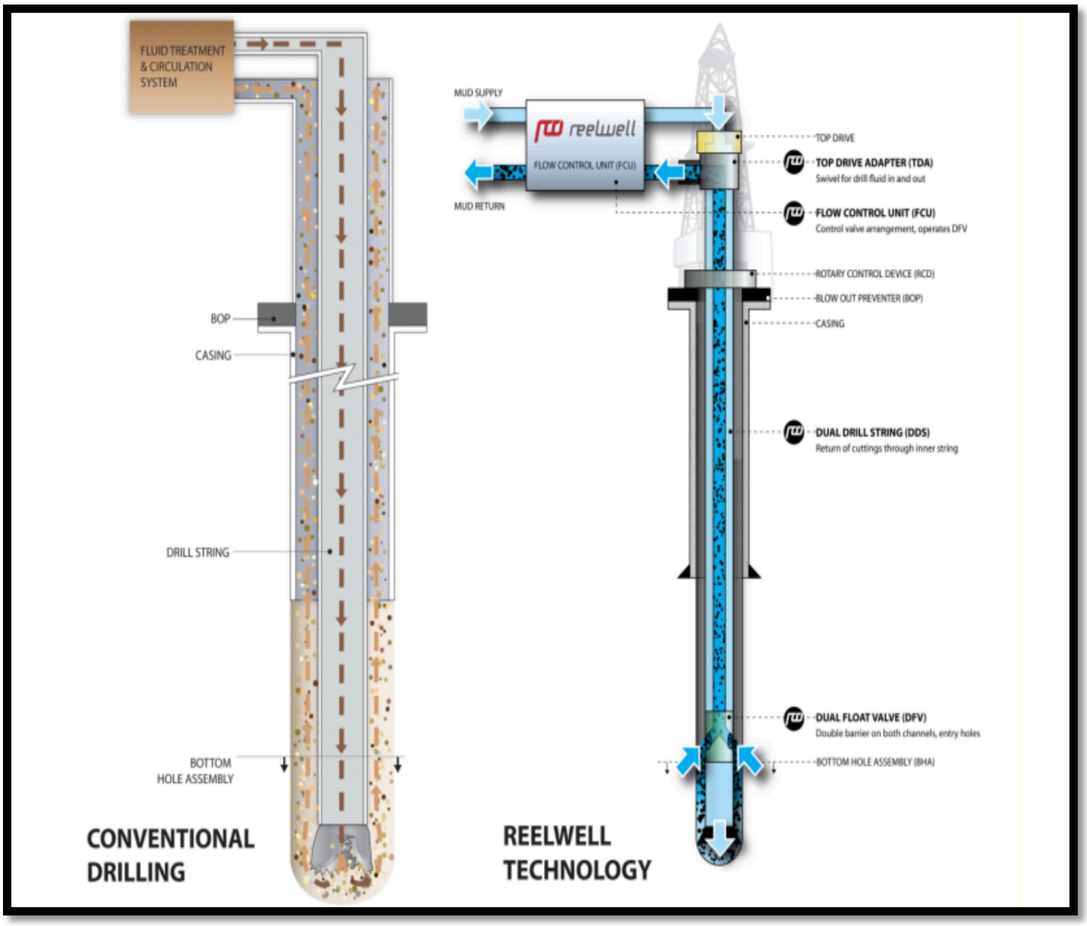


Fig. 8.12—Conventional drilling vs. RDM-R technology (Vestavik 2009).

Fig. 8.12 shows that the RDM-R system employs a closed-loop circulation system in contrast with the conventional drilling.

8.6.4 Advantages of RDM-R Drilling

The main advantages of RDM-R concept are that less casing string is required. Heavy drilling mud in well adjust the well pressure so it allows to drill longer sections before setting a new casing.

The flow control unit (FCU) controls the returning flow and pressure. This makes is possible to detect various amounts of influx and fluid loss in the wellbore. This is very beneficial during deepwater drilling in which pressure margin and kick tolerance is reduced.

The environment is safer during an emergency disconnect of marine riser because of less pollutants (drilling fluids) may enter the environment.

The RDM-R technology also reduces drilling time and cost. Deepwater drilling requires a lot of time for running and pulling the riser. This requires the use of a large and expensive drilling vessel which increases drilling costs of deepwater wells. RDM-R reduces the overall time because the system is riserless (Mirrajabi et al. 2010).

The riserless system avoid the large volume of mud to fill the marine riser. Therefore, the volume of drilling mud during drilling and kill mud in well control is reduced.

RDM-R uses lower flowrate compared to CRD because the fluid velocity in the DDS inner pipe is significantly higher. This significantly saves power and fuel costs for the drilling vessel.

Weight and space requirement and station keeping parameters are reduced. In CRD the size of the wellhead and riser increases, which increases the weight and space requirements for offshore moveable drilling vessels. In deepwater environment the weight of the marine riser filled with mud is increases leading in vessel tensioning system will not able to tension the riser. This results in more cost spend on drilling vessels, such as keeping a drilling vessel in operational range. With RDM-R the large volume of drilling mud required to fill up the marine riser is avoided. Therefore, mud tank capacity will be reduced, which result in more available space or even use of a smaller drilling vessel. Mud treatment system may also be reduced as the flowrate is reduced. The use of chemicals and mud mixtures during operation is also reduced due to smaller total mud volume (Mirrajabi et al. 2010).

With increasing water depth, tension system with higher tension capacity is required to withstand forces waves, current, riser weight, and weight of mud in the riser. The riser is not used in RDM-R and the expensive tension requirement is not necessary, leading use of cheaper and smaller floating rigs (Mirrajabi et al. 2010).

The kick detection time is improved for RDM-R because the FCU controls returning flow and pressure and detects any amount of influx or loss of fluid. This is very important because kick tolerance margin is significantly reduced in deepwater drilling. Overall costs and day rate on smaller rigs is lower compared to bigger offshore moveable rigs (Mirrajabi et al. 2010).

8.6.5 Reelwell Drilling Method, Conventional Riser Drilling, and Conventional Riserless Method

Table 8.3 presents the simulation results Utheim (2014) with RDM-R, CRD, and conventional riserless method (RM).

Table 8.2—Comparison of the Three Drilling Methods

	RDM-R	CRD	RM
Time to kill the well	8.3	15.6	13.6
Kill mud volume	$\approx 160\ m^3$	$\approx 400\ m^3$	$\approx 250\ m^3$
Time to kick detection	Fast	Kick can be prevented without shutting in the well by use of surface and subsea pump	Long
Rig space	Smaller rigs	Larger rigs	Smaller rigs
Overall costs	Low	High	Low

The results show that drilling with the RDM-R technology improves safety, reduce costs, and enhance efficiency. The RDM-R technology also saves a lot of time during kick circulation, time needed to kill the well with required kill mud volume. The costs are significantly reduced by 45%.

- The use of smaller rigs with lower day rate
- Wait on weather time reduced
- Non-productive time reduction due to precise and reliable well control tools.
- Reduced kill mud volume
- Neglect the need of the riser

Conclusions

This thesis focuses on challenges encountered in deepwater operations and well control. These challenges are associated with exploration, drilling, and exploitation of hydrocarbon reserves found in challenging deepwater environments. The main goal is to find out how different deepwater challenges impact on drilling, well construction production, costs, time, and find the most efficient ways to overcome these problems.

Some of the deepwater challenges include harsh environment conditions, narrow pressure margins, well control problems, field development, flow assurance, and formation of hydrates. Handling these challenges will allow operators to exploit deepwater hydrocarbon reserves in a safe and cost-effective manner. Avoiding many deepwater challenges will help to develop the right solutions and low-cost and low risk strategies in future projects.

Hydrate formation is one of the major flow assurance problems in HPHT wells. Developing flow assurance strategy that will reduce cost and ensure safety and maintain the integrity of flowlines should be a top priority for the industry.

For HPHT wells, gas influxes in WBM shows larger pressures and gas volumes at surface of wellbore during the well kill procedure compared to when the gas influx is present in OBM system. The results from swab and surge effect simulations with Drillbench simulator show that operators should pay special attention when swabbing and surging in deepwater where the window is narrow. The appropriate speed and flow rate needs to be optimized by using advanced simulators such as Drillbench.

Narrow pressure margins between pore and fracture pressure can be managed with MPD techniques such as dual-gradient drilling, controlled mud level system, riserless mud recovery and Reelwell Drilling Method – Riserless. With the MPD techniques, drillers can reach target depths with a few casing strings and avoid drilling problems associated with handling narrow operating windows in deepwater fields.

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