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EXECUTIVE SUMMARY

The Bureau of Safety Environment & Enforcement (BSEE) has contracted MCS Kenny to execute a Technology Assessment and Research Project (TA&R) in the areas of Blowout Preventer (BOP) stack sequencing, monitoring and kick detection. The project has been developed to assess three key areas of a BOP, including:

Topic 1 - Ram Sequencing and Shearing Performance

Topic 2 - BOP Monitoring and Acoustic Technology

Topic 3 - Kick Detection and Associated Technologies

This report addresses Topic 3 and covers the following areas:

- State of the art industry kick detection technologies
- Frequency and causes of kicks
- Analysis into kick detection technologies required/available

There are many kicks encountered while drilling in spite of all the kick detection technologies available to the industry. Exploration drilling has more frequent kicks than development drilling as exploration drilling is done in less known formations. Based on a review of documented kick information all indications are that the Mean Time Between Kicks (MTBK) has decreased in recent years. The duration between kicks increased from 77 BOP days to 160 BOP days for US Gulf of Mexico (GoM) exploration wells (non shallow water) based on data sets from the period 1997-1998 and the period 2007-2009. This equates to a 50% reduction in kick frequency [75].

While the frequency of kicks appears to be reducing they still account for a significant percentage of non-productive time. Lost circulation, stuck pipe, wellbore instability and well control incidents (kicks) accounted for a third of the non-productive time in the GoM prior to Hurricanes Ivan, Katrina and Rita [29] with kicks accounting for approximately 9% of this time.

The seriousness of kicks cannot be understated, especially as uncontrolled kicks can have disastrous consequences. From the available literature low mud weight led to the highest number of kicks (43 kicks out of 81 total kicks). Gas cut mud led to the second highest number of kicks (15 kicks out of 81 total kicks). Swabbing led to the third highest number of kicks (10 kicks out of 81 total kicks) [75]. Other less frequent, but still important issues, included drilling break and leaking through cement.
In a study performed by the Bureau of Ocean Energy Management, Regulation and Enforcement there were 39 blowouts in the GoM during a 14 year period from 1992 to 2006, 18 of these blowouts are potentially attributable to cementing failures [69]. It is important that proper tests be conducted to ensure stability of the composition of the cement slurry. In addition thorough testing of the cementing process to address issues of shrinkage, contamination, and fatigue stress are also recommended.

The “human factor” is an essential variable in the drilling process, and it manifests itself in numerous ways, including the area of kick detection. Many of the industries experienced personnel are retiring with the knowledge and ability to recognize well conditions. While technology is being introduced to combat this the younger crews do not have the proper experience to sense a kick. In some cases it may be more than 40 minutes before a kick is recognized. Enhanced training methods (plus new technology) should help to reduce this time frame and prevent blow outs. All rig personnel should have the proper training respective of their duties and should include training on kick detection, well control while running casing, how to perform proper negative test, cementing operations and misinterpretations of cementing results. It is also essential that the personnel train on the equipment used in the field. Most companies have their own internal customized well control training which their personnel have to take regularly to qualify to work on the well control equipment of that company. One of the service companies interviewed sends their personnel to well control training on a test rig where they are told to circulate a gas kick out of the well. This hands on training gives the people an exact idea on what to expect when there is a kick in the wellbore and solidifies the class room training.

Kicks should be reported and tracked by all companies to better understand the kick indicators for the GoM. Some key indicators that should be reported include number of kicks, response time to recognize a kick, number of cementing failures and number of gas alarms which occurred before the kick.

There are numerous kick detection technologies available in the market. No single system exists to deal with all kick detection problems. Systems will always need a level of custom design to suit the condition of a particular well. Measurement While Drilling (MWD) tools can be used to monitor the acoustic properties of the annulus for early gas-influx detection. For water-based mud systems, this technique has demonstrated the capacity to consistently detect gas influxes within minutes before significant expansion occurs. Further development is currently under way to improve the system’s capability to detect gas influxes in oil-based mud.

Pemex was challenged with heavy mud loss in the GoM while drilling at the Canterell field. With the sudden mud loss, the team employed MWD equipment and were initially sceptical of the transmitted
data. The telemetry tool which was installed in the BHA maintained signal strength and delivered high quality real time data to the surface to assist in the guidance of the drilling plan thus saving valuable time and minimizing potential risks [70].

Coriolis sensors provide a measurement of mass, volume flow rate, density and temperature with minimal loss in accuracy. Currently the Coriolis sensor is restricted to be used onshore or on the offshore drilling rig to function properly. Development of the Coriolis to be used subsea to detect the influx of flow rate is needed as this would signal the driller of any influx at the seabed, thus allowing more time to change drilling operations to alleviate any well control procedures. Some of the limitations of the Coriolis meter is it is effective only in a closed loop system and low flow rates. It is not very effective at high flow rates or when there is gumbo because the flow has to be bypassed.

Managed Pressure Drilling (MPD) has been used and perfected for many years for shore based drilling and is now being utilized in offshore drilling. Petronas implemented automated MPD offshore Myanmar in 2008 using the first closed loop, multiservice control system. As there was not an MPD system available to suit their project requirements, Petronas decided to mesh technologies from different companies to safely drill their wells. The final result integrated the use of automated pressure control, automated kick control, micro kick detection and bottom hole pressure and delivered it in real time. This included the use of the following items: managed pressure drilling, pressure while drilling, wired drill string, coriolis flow meter and systematic drilling [78].

Statoil initiated a planning process to use MPD by employing a special team to conduct rig surveys, determine the placement of equipment, understand the wellbore dynamics and develop MPD procedures and guidelines for conventional HP/HT use of MPD. The findings led to the following modifications; inclusion of a Rotating Control Device (RCD), MPD manifold unit, intelligent control unit, Coriolis flow meters, automated chokes and MPD sensors in the flowline and mudpit areas. Some of the operational and economic advantages realized were a reduction in drilling days which led to substantial savings through accurate detection of influxes and monitoring of pressures [50].

Dual Gradient Drilling (DGD), a form of MPD, uses a subsea Mud Lift Pump (MLP) located above the BOP and will be implemented by Chevron in the GoM. DGD is considered to be safer than conventional drilling methods and allows the drillers to drill so called “problem wells” where the window between the pore pressure and fracture gradient is narrow. This system's equipment has been classified/certified by ABS and DNV [11].

AGR's EC Drill and EC Drill+ is one type of Controlled Riser Mud Level system and can be effectively used in water depths over 1,000 ft with placement of a subsea pump from 500 ft. to 3,000 ft.
deepwater wells have been drilled using EC Drill. AGR's EC Drill and EC Drill+ has been classified/certified per DNV-OS-E101 and peer reviewed as per DNV-RP-A203, Qualification of new technology [11].

Transocean's Continuous Annular Pressure Management (CAPM) system was installed on the Discoverer Enterprise in July 2009 and is ready for use on Transocean Enterprise class rigs or other rigs with some modification. The estimated date for CAPM deployment is scheduled for year 2014. This system's equipment has been classified/certified by DNV DVR for Equipment Installation [11].

There is a strong industry support for standardization of general practices of flow and kick detection. One example of this is the IADC's MPD Selection Tool which helps to familiarize users with MPD techniques, MPD's relative capabilities and the type of technologies available depending on the user's objectives. Enhancement of standards, NTL’s and CFR's will further improve the general practices for MPD.

A key area that should be addressed is the specific training requirements for personnel on the different MPD techniques and equipment. MPD training should include, when to utilize different MPD procedures in various scenarios, review of MPD operations and procedures, MPD equipment/control systems, operational challenges using conventional well control methods versus MPD methods and familiarization on how to use MPD equipment during a kick scenario.
1.0 INTRODUCTION

1.1 GENERAL

This report is written in response to Objective 2 of the Bureau of Safety and Environmental Enforcement (BSEE) Broad Agency Announcement Number E12PS00004 regarding Assessment of Subsea BOP Well Control Technology.

The project has been developed to assess three key areas of a Blowout Preventer (BOP), including:

- Topic 1 - Ram Sequencing and Shear Performance
- Topic 2 - BOP Monitoring and Acoustic Technology
- Topic 3 - Kick Detection and Associated Technologies

1.2 OBJECTIVE OF THE REPORT

This report addresses Topic 3 and covers the following areas:

- State of the art industry kick detection technologies
- Frequency and causes of kicks
- Analysis into kick detection technologies required/available

1.3 ABBREVIATIONS

AFE       Application for Expenditure
API       American Petroleum Institute
BSEE      Bureau of Safety and Environmental Enforcement
BOP       Blowout Preventer
BHA       Bottom Hole Assembly
BHP       Bottom Hole Pressure
CAPEX     Capital Expenditure
CAPM      Continuous Annular Pressure Management
CBHP      Constant Bottom Hole Pressure
CFR       Code of Federal Regulations
CMP       Controlled Mud Pressure
DGD       Dual Gradient Drilling
DNV       Det Norske Veritas
EMT       Electromagnetic Telemetry System
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<td>ECD</td>
<td>Equivalent Circulating Density</td>
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<tr>
<td>GoM</td>
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<td>HPHT</td>
<td>High Temperature High Pressure</td>
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<td>HSE</td>
<td>Health Safety Environmental</td>
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<td>IADC</td>
<td>International Association of Drilling Contractors</td>
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<td>ICP</td>
<td>Initial Circulating Pressure</td>
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<td>Lbs</td>
<td>Pounds</td>
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<td>LCM</td>
<td>Loss Circulation Material</td>
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<td>LRRS</td>
<td>Low Riser Return System</td>
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<td>LWD</td>
<td>Logging While Drilling</td>
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<td>MGS</td>
<td>Mud Gas Separator</td>
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<td>MLP</td>
<td>Mud Lift Pump</td>
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<td>MTBK</td>
<td>Mean Time Between Kicks</td>
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<td>MMS</td>
<td>Mineral Management Service</td>
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<td>MODU</td>
<td>Mobile Offshore Drilling Unit</td>
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<td>MPD</td>
<td>Managed Pressure Drilling</td>
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<td>MUX</td>
<td>Multiplex Control System</td>
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<td>MWD</td>
<td>Measurement While Drilling</td>
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<td>NPT</td>
<td>Non-Productive Time</td>
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<td>NTL</td>
<td>Notice to Lessee</td>
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<td>OCS</td>
<td>Outer Continental Shelf</td>
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<tr>
<td>OEM</td>
<td>Original Equipment Manufacturer</td>
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<tr>
<td>OTC</td>
<td>Offshore Technology Conference</td>
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<td>PLC</td>
<td>Pro Logic Controls</td>
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<td>PM</td>
<td>Preventative Maintenance</td>
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<td>Pressurized Mud Cap Drilling</td>
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<td>Rotating Control Device</td>
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<td>Riserless Mud Recovery</td>
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<td>ROP</td>
<td>Rate of Penetration</td>
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<td>SC</td>
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<tr>
<td>SDS</td>
<td>Surface Disconnect System</td>
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<td>SG</td>
<td>Specific Gravity</td>
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<tr>
<td>SICP</td>
<td>Shut In Casing Procedure</td>
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<td>SIDPP</td>
<td>Shut In Drill Pipe Pressure</td>
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<td>SONAR</td>
<td>Sound Navigation And Ranging</td>
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<tr>
<td>SPE</td>
<td>Society of Petroleum Engineers</td>
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<tr>
<td>SPU</td>
<td>Solids Processing Unit</td>
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<tr>
<td>TM</td>
<td>Trip Margin</td>
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<tr>
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<td>Total Vertical Depth</td>
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<tr>
<td>UB</td>
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2.0 WELL CONTROL

2.1 PRIMARY WELL CONTROL

Primary Well Control is maintained by ensuring that the pressure due to the column of mud in the wellbore is higher than the pressure in the formation being drilled. The hydrostatic pressure provided by drilling fluid should be more than the formation pressure but less than the fracture gradient while drilling. If the hydrostatic pressure is less than the reservoir pressure, reservoir fluid may enter into a wellbore. This situation is called "Lost Primary Well Control".

If the mud weight is higher than the formation pressure then the wellbore could be fractured which could lead to a loss of circulation. When fluid is lost into the formation, the mud level in the wellbore decreases which results in a reduction of overall hydrostatic pressure. In a worst case scenario, the primary well control can be lost and wellbore fluid can enter into the well. Typically, a slight overbalance of hydrostatic pressure over reservoir pressure is normally desired. Proper overbalance of drilling fluid needs to be maintained over the formation pressure so as not to fracture formations.

2.2 SECONDARY WELL CONTROL

When the primary well control fails, the BOP is used as the secondary well control. The BOP must be used with specific procedures to control a kick such as the driller's method, wait and weight method, lubricate and bleed method and bull-heading method. Without proper well control practices and procedures, the BOP is just another heavy piece of equipment.

2.3 TERTIARY WELL CONTROL

When the primary and the secondary well control programs fail, tertiary well control should be followed. Tertiary Well Control uses detailed methods to control the well in case of failure of the primary and the secondary well control methods. Below are the different types of tertiary well control utilized:

- Drilling a relief well to a nearby well that is flowing and kill the well with high density mud.
- Pumping of higher density mud rapidly to control the well with equivalent circulating density.
- Plugging the wellbore using heavy weight agents or barite to stop the flow.
- Plugging the wellbore by pumping cement [49]
2.4 MANAGING A KICK

This section describes the different methods employed by drillers to bring kicks under control.

2.4.1 Wait and Weight Method (Engineer’s Method)

The Wait and Weight Method involves only one circulation. The influx is circulated out, and the kill mud is pumped in one circulation. While pumping kill mud from surface to bit, a drill pipe pressure schedule has to be calculated and followed. The drill pipe pressure is held constant thereafter until kill mud is observed returning to the surface.

The Wait and Weight Method is sometimes called the Engineer’s Method because it involves more calculations compared with the Driller’s Method [31].

2.4.2 Drillers Method

Driller’s method involves two circulations. In the first circulation, the drill pipe pressure is consistently maintained until the kick is circulated from the well. In the second circulation, the kill mud is pumped in to the drill bit while maintaining the drill pipe pressure schedule [55].

2.4.3 Volumetric Method

The volumetric method is used when normal kill procedures are not possible from the bottom of the hole. This may be due to the following reasons:

- If the drill string is out of the hole then drill pipe pressure is meaningless.
- If effective kill circulation is not possible due to the drill string being washed out or twisted off, or if the bit nozzles are plugged.
- Two main principles are followed during this procedure:
  - Constant BHP is maintained by allowing a measured volume of drilling fluid to escape from the annulus as the influx moves up the hole.
  - As gas expands, casing shut in pressure increases. Excessive pressure is avoided by bleeding off controlled amounts of drill fluid, without reducing BHP to a point that would allow further influx.

2.4.4 Concurrent Method

With the Concurrent method, circulation commences immediately and the mud is gradually weighted up as circulation proceeds. This will continue until the final required kill mud reaches
surface and the well is dead. Some of the disadvantages of this method are that there are higher pressures imposed on the annulus and the barite mixing and mud weight may not be consistent throughout.

2.4.5 Bull Heading

Bull heading is recommended in very special cases and should only be used when the normal circulation method for kick control is thought to be too dangerous due to large influx, excessive surface pressures and gas volumes. In certain cases, bull heading could possibly create larger problems than what it might solve.

2.4.6 Stripping

This procedure is recommended when the drill string is partially or completely out of the hole. The principle of this technique is to maintain the BHP constant with the well closed and while running drill pipe. This will be achieved by using combined stripping and volumetric method (control of the gas migration while pipe is stripped in the hole).

2.4.7 Off Bottom Kill

An off-bottom well kill must be attempted if bull heading and stripping to bottom cannot be carried out in a safe or practicable manner. Off-bottom well kill involves circulating mud of a certain weight with the bit at the present depth. Due to the fact that this procedure is abnormal in the extreme, every care must be considered independently and a strict procedure should not be used. However, written guidance is needed and this follows in the form of an outline procedure in addition to key points which must be considered prior to attempting an off-bottom kill.

2.4.8 No Circulation Possible

This procedure is recommended when circulation cannot be established (i.e., string, choke lines plugged), when the string is completely out of the hole and when stripping operation cannot be followed. The basic principle of this technique is to maintain the BHP constant with the well closed. This will be achieved by bleeding off a certain volume of mud in order to allow and control the gas expansion/migration.
3.0 WHY KICKS OCCUR

3.1 INTRODUCTION

The flow of formation fluids (gas, oil, saltwater) into the wellbore during drilling operations is called a kick. When the wellbore pressure is lower than the formation pressure then this could lead to a kick. If this phase is not identified and not controlled the kick will intensify allowing more formation fluids into the wellbore thus significantly reducing the wellbore pressure. If this cycle continues the potential of a blowout is greatly accelerated. The escalation to a potentially catastrophic blowout event may be due to failure to detect and/or manage the kick, tripping too fast, not allowing the cement to set the casing and equipment failure(s) etc. This section explores some of these reasons in more detail.

3.2 INSUFFICIENT DRILLING FLUID DENSITY

Drilling fluid density is used to control the Bottom Hole Pressure (BHP) of the well as a means of counterbalancing the formation pressure. Mud density is one of the most important drilling fluid properties because it balances and controls formation pressure. Air may enter the mud which will give incorrect mud weight. To properly calculate mud weight, a pressurized mud balance tool should be used. This will ensure the mud weight measurement is more accurate. Drilling returns are prepared for recirculation using a shaker to remove cuttings, a de-silter for fine materials, a de-sander for removing abrasive materials and a de-gasser to remove entrained gas.

3.3 CONSTANT VOLUME NOT MAINTAINED

Many kicks occur when the bit is off bottom while tripping. When the pumps are shut down before tripping, there is a pressure reduction in the borehole equal to the annular pressure loss. If the equivalent circulating density (ECD) and the pore pressure are nearly equal, flow may begin when circulation stops. As pipe is removed from the hole, the mud-level in the borehole falls causing a reduction in hydrostatic pressure resulting in a kick.

3.4 POOR WELL PLANNING

Drilling mud and casing programs influence well control. The use of these programs should have the ability to be flexible to allow the setting of deeper casing strings. If not, circumstances may occur where it is not possible to control kicks or lost circulation. Well control is a significant
part of well planning and it should not be overstated to the point that overall drilling effectiveness is decreased.

3.4.1 Cement Failure

In a study performed by the Mineral Management Service (MMS) (now the Bureau of Ocean Energy Management, Regulation and Enforcement), there were 39 blowouts in the Gulf of Mexico (GoM) during a 14 year period from 1992 to 2006, showing an average of 2.78 blowouts per year [69]. Of the 39 blowouts in the 14 year period from 1992 to 2006, 18 cementing failures were potentially the cause of the blowout. Proper tests should be conducted to ensure stability of the composition of cement slurry as well as verification from the cementing company’s corporate office or independent third party. The use of correct materials as well as quantity affects the outcome of the final mixtures stability. Other circumstances that could compromise the integrity of the cementing process are; shrinkage, contamination, centralization of the casing, testing that the cement was properly pumped to location where it was intended, checking the correct quantity was pumped as well as verifying if the cement is secure after being held under pressure for a period of 8-12 hours, depending on the method used or cement fatigue caused by stress. The cementing process and testing process should be more regulated and reported to ensure well control and the safety of the rig personnel [72].

3.5 Swabbing While Tripping

When pipe is pulled from the hole it acts like a plunger, with greater effects below the bit than above the bit. Swabbing results are dependent on the gel strength and fluid properties of mud. If the bit is balled-up, nozzles blocked, or a back-pressure valve is in the drill string, swabbing is increased if the condition of the mud cake is thick.

The rate that pipe is pulled out of the hole has an effect on swabbing. In logging units, programs provide a range of pipe pulling speeds and their corresponding swab and surge pressures. If swabbing does occur, the pipe should be run back to the bottom and the invading fluid circulated out. Surge pressures, when running into the hole (pipe or casing) may be sufficient to exceed the fracture pressure of a weak formation. The swab/surge pressure printout should be consulted, and the pipe should run in the well at a speed that produces surge pressures below the minimum fracture pressure. It is important to remember that this is necessary anywhere in the borehole, as pressures are transmitted to the open hole even when the bit is inside the casing [3].
3.6 **Circulation Loss**

Lost circulation events commonly take place as a result of the process utilized to drill a well. Conventionally, wells are drilled overbalanced in which drilling fluid is circulated down the drill string, through the bit and up the annulus.

Mud weight is the primary source of hydrostatic pressure in a well. When circulating through the wellbore, the mud contributes to a pressure in the wellbore that can be expressed in terms of the equivalent circulating density (ECD). In an overbalanced state, this ECD helps create a hydrostatic pressure in the wellbore that is greater than the pore pressure of the exposed formation. A drilling fluid of insufficient density may yield a hydrostatic pressure that is lower than the pore pressure which could lead to a kick.

3.7 **Loss of Riser Drilling Fluid Column**

In an offshore floating drilling operation, the loss of the drilling fluid column in the riser may result in the reduction of hydrostatic pressure in the wellbore and may cause the loss of primary well control. Losing the hydrostatic column in the riser may be due to: accidental disconnect, displacement of riser with seawater or a low density fluid, damage to the riser or accidental “U-tubing” into the choke and kill lines.

3.8 **Human Factor**

There are many ways to describe “Human Factor” on a drilling facility. There are around 50-100 personnel working together on the rig. The average age of rig crews is getting lower as the newer rigs are having a hard time finding experienced personnel. Many of the industries most experienced personnel are retiring with the “old way” knowledge and ability to recognize well conditions. While electronics are being introduced on the rigs to capture information that was once hand calculated or physically sensed by the driller, the younger crew doesn’t have the proper experience to sense a kick.

A kick is usually recognized by the driller and then corrective action is taken to control the well. Kicks often occur and the time between actual occurrence of a kick and someone recognizing the kick could be up to, if not more than 40 minutes. Enhanced training methods and updated well control technologies should help to reduce this time frame and prevent blowouts.
All rig personnel should have the proper training respective of their rig duties. Well control training should be mandatory for all the rig crew to ensure that everyone has the same knowledge. Different types of training may include; how to detect a kick, well control while running casing, how to perform a proper negative pressure test, cementing operations and misinterpretations of cementing results. Training and experience on what to do when is a vital part of well control.

Providing good kick detection training to the operations personnel is invaluable. Most companies have their own internal customized well control training which their personnel have to take regularly to qualify to work on the well control equipment of that company. One of the service companies sends their personnel to well control training on a test rig where they are told to circulate a gas kick out of the well. This gives the people an exact idea on what to expect of their equipment when there is a kick in the wellbore. This hands-on drill solidifies the classroom training received by the personnel.

Kicks should be reported and tracked by all companies to better understand the kick indicators for the GM. Indicators that should be considered for mandatory reporting are number of kicks, response time to recognize a kick, number of cementing failures and gas alarms which occurred previous of the kick [69].

Development of a list of indicators and assigning a well control classification and reporting process to assist in regulating the safety of rig personnel should be considered. The standards should be written to discourage false reporting of kicks or all gas releases and the well control process that took place.

3.9 INTENTIONAL FLOW OR “KICK” FROM A FORMATION

3.9.1 Underbalanced Drilling Operations

Underbalanced Drilling (UBD) is an alternative method of drilling where the wellbore pressure is maintained lower than the formation pressure while drilling. The use of lightweight drilling fluids and/or nitrogen gas to maintain the bottom hole circulating pressure below formation pressure permits hydrocarbons to flow while drilling. Underbalanced Drilling equipment is designed to manage gas/liquid production from the reservoir and guide excess gas through pressure control equipment at the surface, encouraging hydrocarbon flow to the surface in a controlled and safe environment.
3.9.2 Drill Stem Test

Drill stem tests are typically performed on exploration wells, and are often the key to determining whether a well has found a commercial hydrocarbon reservoir. The formation typically is not cased prior to these tests, and the contents of the reservoir are frequently unknown at this point, so obtaining fluid samples is usually a major consideration. Also, pressure is at its highest point, and the reservoir fluids may contain hydrogen sulfide, so these tests can carry considerable risk for rig personnel. The most common test sequence consists of a short flow period, perhaps five or ten minutes, followed by a build-up period of about an hour that is used to determine initial reservoir pressure. This is followed by a flow period of 4 to 24 hours to establish stable flow to the surface, if possible, and followed by the final shut-in or build-up test that is used to determine permeability thickness and flow potential [51].
4.0 KICK FREQUENCY

4.1 INTRODUCTION

The four operational drilling problems most associated with non-productive time are lost circulation, stuck pipe, wellbore instability and well control incidents [29]. These four drilling problems accounted for a third of the non-productive time in the GoM prior to Hurricanes Ivan, Katrina and Rita (Figure 4-1), with Kicks accounting for approximately 9% of this time. This section investigates the frequency of kicks.

![Pie Chart: TVD <15,000' vs TVD >15,000']

<table>
<thead>
<tr>
<th>Water Depth</th>
<th>TVD &lt;15,000'</th>
<th>TVD &gt;15,000'</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wells</td>
<td>549</td>
<td>102</td>
</tr>
<tr>
<td>Average TVD</td>
<td>11,563 ft</td>
<td>17,982 ft</td>
</tr>
</tbody>
</table>

Differentially Stuck Pipe: 11.6% 11.10%
Lost Circulation: 12.70% 12.80%
Well Instability: 4.30% 2.50%
Kick: 8.20% 9.70%

| Trouble Subtotal | 36.80% | 36.10% |

| Hole Problems (Drilling Days) | 4264 / 17641 24% | 1703 / 7680 22% |
| Cost Impact ($/ft) | 71 / 291 24% | 98 / 444 22% |
| Days to TD | 8 / 32 25% | 22 / 81 27% |
| ROP | 116 / 363 32% | 68 / 236 29% |

Figure 4-1: Incidents while drilling Deep Gas Wellbores (1993 – 2002 in the GoM in Water Depth Less Than 600 Feet) [29]

4.2 FREQUENCY OF KICKS

In a 1999 Sintef study [80], the authors investigated the documented frequency of kicks during a period from 1997 to 1998. From Table 1 it is seen that the number of wells between kicks ranged from 1.5 to 2.8 wells for exploration and development drilling respectively. Confirming that exploration drilling has more frequent kicks than development drilling, as less is known
about the formation. The mean time between kicks (MTBK) ranged from 77 BOP days to 111
BOP days during development and exploration.

Table 1: Sintef Mean Time Between Kicks (not incl. shallow kicks), US GoM wells spudded in
1997 and 1998 [80]

<table>
<thead>
<tr>
<th>Phase</th>
<th>No. of Kicks</th>
<th>No. of wells</th>
<th>BOP –days in service</th>
<th>MTBK (wells between kicks)</th>
<th>MTBK (BOP – days between each kick)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Development drilling</td>
<td>9</td>
<td>25</td>
<td>1000</td>
<td>2.8</td>
<td>111.1</td>
</tr>
<tr>
<td>Exploration drilling</td>
<td>39</td>
<td>58</td>
<td>3009</td>
<td>1.5</td>
<td>77.2</td>
</tr>
<tr>
<td>Total</td>
<td>48</td>
<td>83</td>
<td>4009</td>
<td>1.7</td>
<td>83.5</td>
</tr>
</tbody>
</table>

In the most recent information available, a 2012 Exprosoft study [75], the authors investigated
the documented frequency of kicks during a period from 2007 to 2009. As seen in Table 2 the
mean time between kicks (MTBK) ranged from 2.78 to 7.57 wells between kicks for exploration
and development drilling respectively.

Table 2: Exprosoft - Mean Time Between Kicks (MTBK) (not incl. shallow kicks), US GoM wells
spudded in 2007 and 2009 [75]

<table>
<thead>
<tr>
<th>Phase*</th>
<th>No. of kicks</th>
<th>No. of wells</th>
<th>BOP-days in service</th>
<th>MTBK (wells between kicks)</th>
<th>MTBK (BOP-days between each kick)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Original</td>
<td>Sidetrack or bypass</td>
<td>Total</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Development drilling</td>
<td>7</td>
<td>42</td>
<td>11</td>
<td>53</td>
<td>3223</td>
</tr>
<tr>
<td>Exploration drilling</td>
<td>74</td>
<td>133</td>
<td>73</td>
<td>206</td>
<td>11833</td>
</tr>
<tr>
<td>Total</td>
<td>81</td>
<td>175</td>
<td>84</td>
<td>259</td>
<td>15056</td>
</tr>
</tbody>
</table>

When comparing the results of Table 1 and Table 2 the kick frequency is seen to be significantly
lower in the most recent study, only approximately 50%.

Kicks were encountered at all the different well depths, thirty seven or 46% of the kicks occurred
deeper than 20,000 ft TVD and the deepest kick occurred at 27,860 ft TVD (Table 3).
Table 3: Well depth (TVD ft) when kick occurred [75]

<table>
<thead>
<tr>
<th>Well depth when kick occurred (TVD ft)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 8000</td>
<td>7</td>
</tr>
<tr>
<td>8000 - 13000</td>
<td>15</td>
</tr>
<tr>
<td>13000 - 20000</td>
<td>22</td>
</tr>
<tr>
<td>&gt; 20000</td>
<td>37</td>
</tr>
<tr>
<td>Total</td>
<td>81</td>
</tr>
</tbody>
</table>

The most significant contributors to the kick occurrence in this study are presented in Table 4.

Table 4: Kick Incidents [75]

<table>
<thead>
<tr>
<th>#</th>
<th>Type of Kick</th>
<th>Number of Kicks</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Mud weight low</td>
<td>43</td>
</tr>
<tr>
<td>2</td>
<td>Mud with gas cut</td>
<td>15</td>
</tr>
<tr>
<td>3</td>
<td>Swabbing</td>
<td>10</td>
</tr>
<tr>
<td>4</td>
<td>Unknown reasons</td>
<td>5</td>
</tr>
<tr>
<td>5</td>
<td>Gains and losses in Annular</td>
<td>3</td>
</tr>
<tr>
<td>6</td>
<td>Losses in Annular</td>
<td>3</td>
</tr>
<tr>
<td>7</td>
<td>Drilling break</td>
<td>2</td>
</tr>
<tr>
<td>8</td>
<td>Leaking through cement</td>
<td>2</td>
</tr>
<tr>
<td>9</td>
<td>Trapped gas in BOP</td>
<td>1</td>
</tr>
<tr>
<td>10</td>
<td>Temperature expansion due to well open for a long time</td>
<td>1</td>
</tr>
</tbody>
</table>

This section has only touched on kick frequency at a high level. A comprehensive review of GoM kick statistics is presented in the Exprosoft report [75].
5.0  **KICK INDICATORS**

5.1  **PRIMARY INDICATORS**

Some of the primary indicators of a kick include; gain in pit volume, fluctuation in pump pressure and/or flow rate, increase in drilling penetration rate, etc. These are discussed in more detail in this section.

5.1.1  **Increase in Pit Volume**

A gain in the total pit volume at the surface, when there is no mud being added at the surface, indicates either an influx of formation fluids into the wellbore or the expansion of gas in the annulus. Fluid influx at the bottom of the hole shows an immediate gain of surface volume due to the incompressibility of a fluid. The influx of a barrel of gas while drilling will push out a barrel of mud at the surface, but as the gas approaches the surface expanding gas will increase the mud pit level. This is a positive indicator of a kick, and the well should be shut-in immediately any time an increase in pit volume is detected [52].

5.1.2  **Increase in Flow Rate**

An increase in the rate of mud returning from the well above the normal pumping rate indicates a possible influx of fluid into the wellbore or gas expanding in the annulus. Flow rate indicators like the “FloSho” measure small increases in rate of flow and can give warning of kicks before pit level gains can be detected. Therefore, an observed increase in flow rate is usually one of the first indicators of a kick. This is a positive indicator of a kick, and the well should be shut-in immediately any time an increase in flow rate is detected [52].

5.2  **SECONDARY INDICATORS**

5.2.1  **Drilling Break**

Drilling break is caused due to a sudden increase in the rate of penetration during drilling. When this increase is significant (two or more times the normal speed, depending on local conditions), it may indicate a formation change, a change in the pore pressure of the formation fluids, or both. It is commonly interpreted as an indication of the bit drilling sand (high-speed drilling) rather than shale (low-speed drilling). The fast-drilling formation may or may not contain high-pressure fluids. Therefore, the driller commonly stops drilling and performs a flow check to determine if the formation is flowing [52].
5.2.2 Gas Cut Mud

A drilling mud that has gas bubbles in it which results in reducing the density of the mud and causing a kick. A gas cut is inferred only if the mud returning to the surface is significantly less dense than it should be [52].

5.2.3 Decrease in Circulating Pressure

Invading formation fluid will usually reduce the average density of the mud in the annulus. If the density of mud in the drillpipe remains greater than in the annulus, the fluids will U-tube. At the surface, this causes a decrease in the pump pressure and an increase in the pump speed. The same surface indications can be caused from a washout in the drillstring. To verify the cause, the pump should be shut down and the flow from the well should be checked. If the flow continues, the well should be shut-in and checked for drillpipe pressure to determine whether an underbalanced condition exists [52].

5.3 Abnormal Pressure Indicators

5.3.1 Flowline Temperature

Using mud logging equipment, measuring the BHP directly has challenges. The heat generated from the formations, once they are penetrated, will be transferred to the drilling fluid. The purpose of using drilling fluid is to dissipate heat generated downhole while drilling.

One of the main issues is the rise in mud temperature at the beginning of each bit run. Steps should be taken to minimize bottom hole temperature by observing the hydraulic and mechanical properties created during drilling, determining torque and drag effects as a heat source and the comparison of data acquired during this process.

5.3.2 Chloride Content in Mud

Chloride comes from salt in the formation while drilling. The amount of chloride should be checked frequently. If changes in the chloride content are present, it could indicate drilling in a saline formation or water influx from the reservoirs.

5.3.3 Shale Density and Type

Shale density determination has often proved to be very effective in determining the degree of under compaction and consequent abnormal pore pressure in shale bodies. Shale density
determination can be of great value since it provides information on the compaction of the shale. Under normal conditions, shale density should increase with depth. Any sudden decrease in shale density (as porosity increases) may indicate that abnormal pressure does exist [53, 54].
6.0 KICK DETECTION AND MANAGEMENT TECHNOLOGIES

6.1 STANDARD KICK DETECTION MANAGEMENT

There are multiple systems used to measure real time flow data to identify early influx or losses and sound the alarms to notify the personnel on the rig. Some of the current kick detection systems include flow-in, flow-out, pit volume, surface data, drill pipe pressure, hook load and block position and are displayed on the data displays located in the drillers cabin. The displays enable the driller to view the captured data in real time, thus eliminating the time to do manual hand calculations. Sensors with the display units offer viewing time sensitive data while alarm parameters can be set for audible alerts. The rig data that is displayed in the driller's cabin can also be monitored onshore. Sensors are a critical element of monitoring drilling parameters to allow the driller to safely assess anomalies. The use of sensors allow the driller to make a split second decision to shut the well in by utilizing the information on the displays as well as communicating with the drill crew to perform basic intervention diagnostics to confirm the decision.

6.1.1 Mud Pit Sensors

The most current sensor technologies such as ultrasonic, radar, floatation, optical and pressure sensors can be used for specific applications. Any combination of mud pits can be assigned as being “active” by operating the pits selector switches. The sensor technologies will calculate the total volume of mud in the active pits and display it on an easy to read analog gauge. A second gauge continuously displays the gain or loss of mud from the active total making the drill crew aware of the prevailing well conditions.

6.1.2 Flow Out Sensor

The flow out sensor normally specified is of the paddle type. Flow in the flowline causes a rotation of the paddle and a corresponding rotation of a one turn potentiometer. Various paddle sizes are available to suit the different flowlines. Nonlinear and logarithmic calibrations in the computer allow accurate calibrations to be made for most installations over a wide range of flows.

6.1.3 Coriolis Meter

The Coriolis flow meter has been used in the industry for more than 15 years. Coriolis sensors (Figure 6-1) provide a measurement of mass, volume flow rate, density and temperature with
minimal loss in accuracy. This type of sensor consists of a manifold which splits the fluid flow in two, and directs it through each of the two flow tubes and back out the outlet side of the manifold (Figure 6-2). Some of the limitations of the Coriolis meter is it is effective only in a closed loop system and low flow rates. It is not very effective at high flow rates or when there is gumbo because the flow has to be bypassed.

Figure 6-1: Coriolis Sensor [59]

Figure 6-2: Coriolis Sensor connected to the return flow [81]
Currently the Coriolis sensor is restricted to be used onshore or on the offshore drilling rig to function properly. While the metering system is located topside, the gases that would incur a kick are reaching the rig. Development of the Coriolis to be used subsea to detect the influx of flow rate is needed as this would signal the driller of any influx at the seabed, thus allowing more time to change drilling operations to alleviate any well control procedures.

6.1.4 Pit Volume Sensors

The pit monitoring system uses a sensor to monitor individual pits. The computer system allows a total flexibility in defining the active and reserve pit systems. The configuration can be changed quickly through the keyboard. Alarms are computer controlled and can be set up for low and high levels on the active system, the reserve system, or on individual pits. The system can monitor up to sixteen pits. On trips, the gain tank and trip tanks are also assigned through the trip monitoring program for complete coverage of the pit system. On connections, the expected flow back gain encountered at various pump rates is entered. The system can correct for alarm if unexpected changes are seen during the connection.

The pit monitoring system is very robust and has been field proven for years as the simplest and most reliable of pit measurement in standard situations.

6.1.5 Drill/Stand Pipe Pressure

Measurement of pressure of the fluids inside the drill pipe is called the drill pipe or stand pipe pressure. The drill pipe pressure would remain constant when pumps are shut off. When the annulus fluid density is higher than the drill pipe fluid density, the drill pipe pressure would remain positive. This happens when the denser fluid in the annulus applies a u tube pressure on the drill pipe fluids.

When the pumps are turned on the drill pipe pressure will fluctuate depending on the relative fluid densities in the drill pipe and annulus. The change in drill pipe pressure can indicate washouts in the drill pipe, plugged bit nozzles, condition of the down hole motor (if used), etc. It is hard to interpret kicks looking at the drill pipe pressure due to multiple factors that can affect the pressure. So any sudden changes in drill pipe pressure should be investigated further.

The drill pipe pressure is measured in multiple ways. There is a pressure transducer placed in the drill pipe to measure drill pipe pressure. Pressure while drilling (PWD) tool placed in the bottom hole assembly (BHA) could be used to accurately measure the down hole pressure close to the drill bit.
6.1.6 Other Monitoring Systems

Pump Stroke counters are a mechanical sensor used on each mud pump to monitor the number of strokes and stroke rate which will help in calculating the volume and rate of fluid being pumped into the well bore.

Gas is detected from the sensor located on the shale shaker header box by detecting the increase in gas levels in the mud. The mud returning from the well is directed to the shale shaker where it is processed.

Video cameras are placed on multiple areas including the rig and flow lines for monitoring purposes. The flow line camera can be used to visually monitor flow rate to the pits.

All the collected data is displayed on customized screens (Figure 6-3) which consist of real time numerical data, historical trend lines and features like tables, charts and graphs.

![Figure 6-3: Live Data Presented on Screen][13]

All the monitoring systems have options to set and adjust visual and audible alarms for multiple data parameters such as pit gain, flow out and drill pipe pressure. The alarms could be set manually to activate whenever the incoming data crosses a preselected high and low thresholds and could also be shut off.

6.2 Measurement While Drilling

During circulation and drilling operations, Measurement While Drilling (MWD) systems can monitor mud properties, formation parameters and drillstring parameters. The system is widely used for drilling, but it also has applications for well control, including the following:
- Drilling-efficiency data, such as downhole weight on bit and torque, can be used to differentiate between rate of penetration changes caused by drag and those caused by formation strength.

- Monitoring bottomhole pressure, temperature, and flow with the MWD tool is not only useful for early kick detection, but can also be valuable during a well-control kill operation. Figure 6-4 shows the MWD screen display of the pressure pulses, data transmission and display of the various parameters.

![Figure 6-4: Measurement While Drilling (MWD) Screen [57]](image)

The MWD tool is used to monitor the acoustic properties of the annulus for early gas-influx detection. Pressure pulses generated by the MWD are recorded and compared at the standpipe and the top of the annulus. Full-scale testing has shown that the presence of free gas in the annulus is detected by amplitude attenuation and phase delay between the two signals. For water-based mud systems, this technique has demonstrated the capacity to consistently detect gas influxes within minutes before significant expansion occurs. Further development is currently under way to improve the system’s capability to detect gas influxes in oil-based mud.

The MWD tool offers kick-detection benefits if the response time is less than the time it takes to observe the surface indicators. This tool can provide early detection of kicks and potential influxes, as well as monitor the kick-killing process. Tool response time is a function of the complexity of the MWD tool and the mode of operation. The sequence of data transmission determines the update times of each type of measurement. Many MWD tools allow for
reprogramming of the update sequence while the tool is in the hole. This feature can enable the operator to increase the update frequency of critical information to meet the expected needs of the section being drilled. If the tool response time is longer than required for surface indicators to be observed, the MWD only serves as a confirmation source [57].

Pemex was challenged with heavy mud loss in the GoM while drilling at the Canterell field. With the sudden mud loss, the team employed MWD equipment and were initially sceptical of the transmitted data. The telemetry tool which was installed in the BHA maintained signal strength and delivered high quality real time data to the surface to assist in the guidance of the drilling plan thus saving valuable time and potential risks [70].

Telemetry is the conversion of a logging tool measurement to a signal suitable for transmission to the surface. Various systems exist including: positive mud pulse, annular venting mud pulse, electromagnetic and wired drill pipe and are offered by all of the major down hole service companies.

Mud pulse telemetry systems, the industry standard, use positive and annular venting mud-pulse telemetry with a high rate of transmission to generate real-time MWD/LWD logs on the surface. The mud pulse systems use valves to modulate the flow of drilling fluid in the bore of the drill string, generating pressure pulses that propagate up the column of fluid inside the drill string and then are detected by pressure transducers at the surface. It does have limitations with data intensive activities, such as seismic while drilling or taking downhole images. Also, mud pulse cannot transmit data during well-control problems or under balanced drilling with foam.

The electromagnetic MWD/LWD system transmits data via low-frequency electromagnetic waves that propagate through the earth and are detected by a grounded antenna at the surface. It provides higher data rates and greater reliability than traditional mud pulse systems. Electromagnetic telemetry is particularly applicable for drilling with air, foam or aerated muds that preclude the use of mud pulse.

Wired drill string systems, such systems as the NOV IntelliServ, Baker Hughes aXcelerate, offer bi-directional communication allowing commands to and from points on the drill string (e.g. BHA). This technology utilizes a cable running the length of and inside the wall of the drill pipe, ending at a ferritic lined groove at the pin/box (Figure 6-5). These systems typically do not need to be in contact; transmission is by way of induction across the gap between the pin and box ends. Wired drill string technology has been employed successfully on multiple projects. In the
Babbage Field (U.K.) the wired drill pipe enabled accurate steering of the drill string. Faster drilling was obtained and better placement of the well due to high-resolution images of the reservoir [71].

Figure 6-5: Representation of Wired Drill Pipe [57]
7.0 MANAGED PRESSURE DRILLING

7.1 INTRODUCTION

Managed Pressure Drilling (MPD) is defined by the International Association of Drilling Contractors (IADC) as “an adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore.” The objective of MPD is to assist drilling wells efficiently with minimal non-productive time with precise control of stabilizing bottom hole pressures. Monitoring control systems and mechanical equipment are used to dynamically adapt the annular pressure profile in the well [76].

7.2 MPD TERMINOLOGY

BHP (Drilling) – This is the actual pressure at the bottom of the well. It is best described by the formula: BHP = Static mud weight + ECD component + Effects + Applied Surface Backpressure (using MPD choke manifold and RCD)

BHP Variations – This describes the uncontrolled variation in BHP that will occur within the well. These variations are especially pronounced when the well is moved from dynamic to static condition or vice versa.

Drilling Window – This is defined in terms of the differential pressure between the pore pressure and the minimum fracture pressure (minimum fracture gradient). This is sometimes referred to as the “drilling margin” or “operating margin”.

Dynamic Condition – The condition in which the wellbore is being continuously circulated.

Dynamic Flow Check – The process during which backpressure is reduced on the well while continuing to circulate the well, and verifying that there is no net inflow (from the formation) or outflow (losses) from the well.

Equivalent Circulation Density (ECD) – The increase in BHP that results from the annular friction pressure created when well fluids are moved (circulated) along the wellbore.

ECD + Effects – Effects refer to temperature effects on mud weight and mud rheology that have a direct impact on downhole pressure. It also includes all additional effects on the Bottom Hole Pressure (BHP) that result from operations (e.g., rotation, torque, drilling, cuttings load, etc.). Although these effects exist in all wells, their magnitude becomes significant in HPHT drilling when large temperature variations occur and high mud weights are in use.
Gel Break – When heavy weight mud is allowed to remain static for any period of time, static gels are formed in the mud. Static gels are a required design feature of drilling mud to keep cuttings and other particles suspended during periods of no circulation. The combined effects of high temperatures and mud weights are such that the pressure required to break these gels, to initiate movement of the mud, can be considerable. A pressure surge occurs as the gels break and the mud begins to move. This pressure surge is applied directly to the exposed formations and can cause formation fracture. Operating procedures ordinarily compensate for the gel break strength and can eliminate their effects.

Original Pore Pressure – Pore pressure in reservoir prior to depletion. It is also referred as Initial Pore Pressure.

Pore Pressure – The actual pore pressure of the formation being drilled, considering any depletion. Values can be determined by stethoscope (pressure probe inserted onto formation), Pressure Volume Temperature (PVT), standard methods of determining pore pressure, etc.

Prognosed Pore Pressure – The pore pressure forecasted the reservoir simulation bases the most likely pore pressure on produced volume and reservoir model.

Static Condition – The condition in which circulation is stopped (e.g. during a conventional connection, trip or during well control when the BOP is closed and there is no increase of pressure from an influx or drilling fluid losses to the formation).

Static Flow Check – The process during which circulation in the well is stopped, removing the ECD component, and verifying that there is no net inflow or outflow from the well.

Static Mud Weight – The actual mud weight in use, sometimes this is called ESD or Equivalent Static Density. Although this weight does vary with the wells temperature profile, for simplicity this can be assumed to be lowest average mud weight in the well during any operations. It is measured in Specific Gravity (SG).

Trip Margin (TM) – Trip Margin is an addition to the BHP above the pore pressure as a safety margin. Its only function is to compensate for swab pressure while the drill pipe is being lifted from the well either by pulling out or by heave. This addition can be additional static mud weight for conventional or additional backpressure for MPD.

MPD Automated Choke Manifold – A set of high-pressure valves and associated piping that includes two automated chokes, arranged such that one automatic choke may be isolated and taken out of service for repair and refurbishment while well flow is directed through the other
one. It also includes a pressure gauge upstream and a Coriolis flow meter on the manifold. Both chokes are automated and hydraulically controlled by a Pro Logic Control (PLC) system using real-time control system software, surface pressure, temperature and flow rate data and the MWD BHP to maintain tight control over the BHP. The chokes are designed for continuous use while using MPD with cuttings and mud returns.

**Mud Gas Separator** - MGS device that removes air or gases from drilling liquids. This works by increasing the surface area available to the mud so that bubbles escape (through the use of various cascading baffle plates). Gas is routed away from the rig up to the top of the derrick via the vent line on an offshore installation, or to a flare pit on a land rig.

**Rotating Control Device (RCD)** - A rotating sealing element / diverter (Figure 7-1) which allows drill pipe to enter and exit the wellbore whilst maintaining pressure in the annulus, also allows rotation of the drill pipe whilst containing annulus pressure. The sealing elements rotate with the drill string, as they are mounted in a bearing assembly. They divert flow from the well to the MPD system via a flow spool under the RCD.

![Figure 7-1: Rotating Control Device][61]

### 7.3 Types of MPD

#### 7.3.1 Pressurized Mud Cap Drilling (PMCD)

Pressurized mud cap drilling, as defined by the IADC, is a variation of MPD whereby drilling proceeds with no returns to surface and an annulus fluid column, assisted by surface pressure (made possible with the use of a rotating control device), is maintained above a formation...
capable of accepting fluid and cuttings. A sacrificial fluid with cuttings is accepted to the lost circulation zone. It is useful for cases of severe lost circulation that preclude the use of conventional wellbore construction techniques. PMCD turns the tables of negative conventional drilling to positive by increasing rate of penetration and non-productive time while reducing mud costs. Well control is also increased by utilizing this MWD method.

7.3.2 Constant Bottom Hole Pressure (CBHP)

Constant Bottom Hole Pressure (Figure 7-2) is useful that in conventional or open to the-atmosphere drilling, BHP or annular pressure is determined mainly by two factors: the hydrostatic pressure of the drilling mud and the friction pressure generated when the pumps are operating [46].

![Figure 7-2: Constant Bottom Hole Pressure Method](image)

7.3.3 Dual Gradient Drilling

IADC currently defines dual gradient as the “creation of multiple pressure gradients within select sections of the annulus to manage the annular pressure profile. Methods include use of pumps, fluids of varying densities, or combination of these”.

7.3.4 Automated MPD

Adding automation to a closed-loop circulating system improves information and management capabilities that contribute to greater safety and efficiency in drilling operations. This type of system requires a RCD, automated drilling chokes, mass flowmeter and an intelligent control unit.
Human intervention is still required in determining the final decision when a kick is detected, to shut in the well. In primary use, the MPD control apparatus functions effectively as a first responder type control and data acquisition system [14]. Figure 7-3 and Figure 7-4 show the automated MPD Skid Unit which includes the Choke Manifold, Coriolis Meter, and Separator to handle influx of gases [64].

Figure 7-3: Automated MPD Skid Unit [64]
**Figure 7-4: Configuration of Automated Closed-Loop System Using a RCD [28]**

A configuration using just the RCD and analysis capabilities is the most basic application of the control technology. The move to MPD operations, either manual or automatic, comes with the decision to begin actively managing wellbore pressure using surface backpressure.

The change from manual MPD to automated MPD is a matter of enhanced precision and timely counteraction to address unplanned events. Manual MPD operations involve reading data and interpreting it and then reacting manually. In the automated mode, the system uses its own internal algorithms to identify what is occurring in the wellbore and apply an automatic response.

When operated manually, MPD systems require coordination between individuals, including the driller, a choke operator, data-acquisition personnel, and a data-interpretation specialist. Incoming data first require attention and recognition that something is occurring before an action is taken which requires time.

While the automated system drives itself, the MPD operations nevertheless require on site monitoring and input. Oversight is critical because of uncertainties that come with drilling a well. If the process could be precisely described in advance, as in a factory, it could be programmed into the system (Figure 7-5).
7.4 Case History

Below are some case histories of projects where MPD technology has been used successfully.

Case History #1

Petronas implemented automated MPD offshore Myanmar in 2008 using the first closed loop, multiservice control system. As there was not an MPD system available to suit their project requirements, Petronas decided to mesh technologies from different companies to safely drill their wells. The final result integrated the use of automated pressure control, automated kick control, micro kick detection and bottom hole pressure and delivered it in real time. This included the use of the following items: managed pressure drilling, pressure while drilling, wired drill string, Coriolis flow meter and systematic drilling [78].

Case History #2

Statoil initiated a planning process to use MPD by employing a special team to conduct rig surveys, determine the placement of equipment, understand the wellbore dynamics and develop MPD procedures and guidelines for conventional HP/HT use of MPD. The findings led to the following modifications inclusion of a Rotating Control Device (RCD), MPD manifold unit,
intelligent control unit, Coriolis flow meters, automated chokes and MPD sensors in the flowline and mudpit areas.

Before the well was drilled, systems testing, fingerprinting, pressure testing were completed to familiarize the rig crew with the new procedures. The system was also used in the plug and abandon phase of the well. Some of the operational and economic advantages realized were a reduction in drilling days which led to substantial savings through accurate detection of influxes and monitoring of pressures [50].

**Miscellaneous**

Figure 7-6 shows the case history of different types of MPD which have been implemented on some of the Transocean rigs world-wide [82].

<table>
<thead>
<tr>
<th>Rig Name</th>
<th>Rig Type</th>
<th>Location</th>
<th>Customer</th>
<th>Year</th>
<th>Application</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trident 8</td>
<td>Jack Up</td>
<td>Cabinda</td>
<td>Gulf</td>
<td>2003</td>
<td>PMCD</td>
<td>Completed</td>
</tr>
<tr>
<td>Sedco 601</td>
<td>Semi Sub</td>
<td>Indonesia</td>
<td>Santos</td>
<td>2004</td>
<td>PMCD w/ Surface BOP</td>
<td>Completed</td>
</tr>
<tr>
<td>Sedco 601</td>
<td>Semi Sub</td>
<td>Indonesia</td>
<td>Santos</td>
<td>2005-2006</td>
<td>PMCD w/ Risercap™</td>
<td>Completed</td>
</tr>
<tr>
<td>Roger W. Mowell</td>
<td>Jack Up</td>
<td>Malaysia</td>
<td>Talisman</td>
<td>2006-2007</td>
<td>CBHP</td>
<td>Completed</td>
</tr>
<tr>
<td>Constellation II</td>
<td>Jack Up</td>
<td>Egypt</td>
<td>BP</td>
<td>2007</td>
<td>CBHP, HPHT</td>
<td>Completed</td>
</tr>
<tr>
<td>High Island VII</td>
<td>Jack Up</td>
<td>Gabon</td>
<td>Total</td>
<td>2007</td>
<td>CBHP, HPHT</td>
<td>Completed</td>
</tr>
<tr>
<td>Deepwater Frontier</td>
<td>DP DrillShip</td>
<td>India</td>
<td>Reliance</td>
<td>2007</td>
<td>CBHP, Concentric Riser</td>
<td>Completed</td>
</tr>
<tr>
<td>Actinia</td>
<td>Semi Sub</td>
<td>Libya</td>
<td>ENI</td>
<td>2008-2009</td>
<td>ECD, HPHT, Reconfigurable Riser</td>
<td>Completed</td>
</tr>
<tr>
<td>Arctic III</td>
<td>Semi Sub</td>
<td>Indonesia</td>
<td>Pearl</td>
<td>2010</td>
<td>UBD (Low Head Drilling)</td>
<td>Completed</td>
</tr>
<tr>
<td>Harvey H. Ward</td>
<td>Jack Up</td>
<td>Malaysia</td>
<td>Talisman</td>
<td>2009</td>
<td>CBHP</td>
<td>Completed</td>
</tr>
<tr>
<td>Shell Explorer</td>
<td>Jack Up</td>
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<td>Talisman</td>
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<td>CBHP</td>
<td>Completed</td>
</tr>
<tr>
<td>Trident IX</td>
<td>Jack Up</td>
<td>Indonesia</td>
<td>Pearl</td>
<td>2010</td>
<td>UBD (Low Head Drilling)</td>
<td>Completed</td>
</tr>
<tr>
<td>Sedco 601</td>
<td>Semi Sub</td>
<td>Indonesia</td>
<td>Petronas</td>
<td>2010</td>
<td>CBHP</td>
<td>Completed</td>
</tr>
<tr>
<td>GSF Explorer</td>
<td>DP DrillShip</td>
<td>Indonesia</td>
<td>MSEC</td>
<td>2010-2011</td>
<td>CBHP, PMCD, Riser Degasing</td>
<td>Completed</td>
</tr>
<tr>
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<td>Semi Sub</td>
<td>Nigeria</td>
<td>Addax</td>
<td>2011-2012</td>
<td>CBHP, HPHT</td>
<td>Completed</td>
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<tr>
<td>Actinia</td>
<td>Semi Sub</td>
<td>Malaysia</td>
<td>Petronas</td>
<td>2011-2012</td>
<td>PMCD w/Risercap™</td>
<td>Completed</td>
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<tr>
<td>Marianas</td>
<td>Semi Sub</td>
<td>Ghana</td>
<td>ENI</td>
<td>2012</td>
<td>CBHP, HP</td>
<td>Completed</td>
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<tr>
<td>HH Ward</td>
<td>Jack Up</td>
<td>Indonesia</td>
<td>Pertamina</td>
<td>2012</td>
<td>PMCD</td>
<td>Ongoing</td>
</tr>
</tbody>
</table>

**Figure 7-6: Case history of rigs using MPD [82]**

### 7.5 IADC MPD Technology Selection Tool

As per IADC the “IADC MPD Selection Tool is a selection guide (Figure 7-7) for users unfamiliar with MPD techniques and their relative capabilities and limitations. By selecting the appropriate
well data and objectives, this selection guide will give the user a ranking of potential technologies." There are four sections which include:

- Introduction, which explains the function of the program as well as procedures.
- MPD technology which describes basic principles of the different technology which are available.
- Well data and the overall objectives are entered and the results will show numerical ratings and techniques of the available technologies which can be used. This tool is used to assist in learning and is not designed to replace any regulatory rules or regulations [41].

Figure 7-7: IADC MPD Selection Tool – Well Description Input and Output Screen [41]

### 7.6 Recommendations in Training on MPD

Presently drilling operations are currently practicing reactive MPD. Moving from conventional drilling to proactive MPD is a step change. The step change level is comparable to the change from cable tool to rotary drilling. Proactive MPD would require specialized well engineering design and planning. Rig personnel may need additional assistance to increase their well control training to better understand the process [63]. Learning how to use the tools of MPD safely is imminent.
Managed pressure drilling will change from well to well which will require careful evaluation of the current equipment specifications and processes. After the well is engineered it is suggested to develop/revise a MPD process and personnel training. This process may change on each well and guidelines established to ensure personnel are aware of what changes are in effect and why to fully understand consequences of the possible outcome if there is any deviation.

Training should include:

- Review of MPD operations and procedures
- When to utilize different MPD procedures in various scenarios
- Use of MPD equipment/control systems
- Familiarization with the different pump rates, mud weights and choke and how they affect the MPD process during a detected influx
- Operational challenges using conventional well control methods vs. a MPD process
- Understanding what the MPD equipment capabilities are and the functions it performs
- MPD process design and placement of MPD equipment

### 7.6.1 Personnel Competencies

To adequately prepare rig personnel for possible well control situations the following actions could be taken into consideration prior to drilling:

- Training and well plan review for knowledge.
- Awareness of potential hazards that may be encountered when drilling needs to be communicated to all personnel.
- Ensure rig crew is competent of their stations, the job they carry. Competency must meet current industry requirements for well control situations.
- Regularly scheduled BOP and stripdrills to be held to ensure correct actions are taken.
- Loss and kick detection drills to be practiced until the response times and actions are satisfactory.
- Drillers need to be certain of the need of awareness regarding kicks and or losses.
- The driller needs to stop drilling to ascertain if a depleted zone was run into at the moment of a drilling break (or high torque).
• At the first sign of mud losses, the driller will stop drilling to gauge extent of losses. Keeping
  the hole full at all times. If the loss rate is more than the capacity of rig to make new mud
  the driller will stop circulating, pulling out of hole (POOH) to shoe and immediately fill the
  annulus with water. Prepare Lost Circulation Pills (LCM) pills to cure losses [3].
8.0 DUAL GRADIENT DRILLING (DGD)

8.1 INTRODUCTION

DGD is a type of MPD system and is a collection of techniques and varied equipment utilized to create the dual gradient pressure profile. These DGD technologies are applicable offshore to either floater mobile offshore drilling unit (MODU), jack-up MODU or fixed platform facility application.

8.2 NEED FOR DGD

DGD is not a new idea and some of the reasons for the need for DGD were driven due to rig limitations in the 1950's and 1960's and also driven by drilling problems in the past two decades. Current reasons to use DGD are due to narrow margins between pore and fracture pressures in which could lead to:

- Well control events
- Ballooning (losses/gains)
- Excessive mud circulation time
- Remedial cement jobs

In the GoM deepwater, estimated costs of non-productive time (NPT) due to the above problems are 20% - 30% of total NPT [47]. Some wells never reach targets due to high development costs and the potential loss of leases. There is also a need for better management of wellbore pressures.

8.3 DGD CATEGORIES

The two main broad DGD categories are:

- Top Hole drilling - Riserless
- Post-BOP drilling

**Top Hole Drilling** - The two DGD methods to drill top-hole sections in offshore wells are Pump and Dump and Riserless Mud Returns (RMR). In the Pump and Dump system, the mud returns are dumped on the seafloor when the top-hole section is been drilled [66]. RMR is an enabling technology and is an alternative to Pump and Dump. Top Hole Drilling is not the focus of this report as there is no BOP involved.
**Post-BOP Drilling** - Once the BOP is placed on the subsea well head and drilling is continued it is considered as Post-BOP drilling.

Below are the four different types of Post-BOP DGD systems (highlighted using an arrow) which are active right now (Figure 8-1):

- Subsea Mud Lift Drilling
- Controlled Mud Pressure (CMP)
- Continuous Annular Pressure Management (CAPM)
- Low Riser Return System (LRRS)

![Figure 8-1: Four Different Types of Post-BOP DGD Systems](image)

Some of the active Post-BOP DGD systems are:

### 8.3.1 Dual Gradient - Utilizing a Subsea Pump

Two fluids of different density are used to achieve a desired pressure gradient with heavy mud in the wellbore up to the mud line and a lighter fluid (typically seawater density) in the riser. A Subsea Mud Lift Pump (MLP) which is seawater driven is located above the BOP/LMRP. The
mud is removed from the well and pumps it to the surface through a line attached to the drilling riser. The riser is filled with a seawater-density fluid, or the mud/riser fluid interface can be maintained at any depth.

Subsea Rotating Device (also called the Rotating Control Head) is placed above the MLP and is a mechanical barrier between the wellbore and the riser. A Solids Processing Unit (SPU) is located above the MLP and its main function is to ensure that all solids are ground into small pieces so that they can be pumped through the choke and kill line without plugging.

Changes in pump speed can be used to detect kicks or losses early, thus limiting their size. The high resolution positive displacement pump can be used to detect very low rate kicks. The BOP will be closed during kicks, and all kicks encountered will be circulated up the choke/kill lines. The pump is designed to safely circulate out kicks of virtually any size, including gas kicks. The system can be used in water depths up to 10,000 ft. currently. Chevron estimates to implement this equipment in the GoM in 2013 (Figure 8-2, Figure 8-3).

This system's equipment has been classified and certified by ABS and DNV [11].

![Figure 8-2: DGD System [65]](image_url)
8.3.2 Controlled Riser Mud Level

Controlled Riser Mud Level systems use a modified riser joint and a subsea pump to return cuttings and mud back to the drilling vessel. This system uses either an inert gas mixture or light mud in the upper part of the riser over a column of heavier mud. The bottom hole pressure is controlled by adjusting the riser mud level through regulation of the return pump rate. The BHP can be adjusted for both dynamic conditions (ECD effects), and static conditions (trip/connection margins). The changes in the return pump rate/power or the riser fluid level can be used to detect influxes or losses early, thus limiting their size. AGR's EC Drill and EC Drill + is one type of Controlled Riser Mud Level systems and can be effectively used in water depths over 1,000’ with subsea pump placement from 500 ft. to 3,000 ft. (Figure 8-4). Three deepwater wells have been drilled so far using EC Drill.
AGR's EC Drill and EC Drill + has been classified/certified per DNV-OS-E101 Drilling facility and peer reviewed as per DNV-RP-A203 qualification of new technology [11].

![Figure 8-4: AGR's EC-Drill System [47]](image)

8.3.3 Continuous Annular Pressure Management (CAPM)

The CAPM system from Transocean works by pumping a light drilling fluid through the annulus formed between the drilling riser and an inner riser such as a 16” casing or using dedicated booster lines. The light drilling fluid mixes with the return mud from the wellbore and creates a lighter density mud in the drilling riser. The mud is then processed through centrifuges to separate into the light dilution fluid and the heavier drilling fluid. An RCD is run at the top of the Riser with the resultant closed loop system enabling early detection of kicks and losses, thus limiting their size.

The CAPM has been installed on the Discoverer Enterprise in July 2009 and is ready for use on Transocean Enterprise class rigs or other rigs with some modification (Figure 8-5). The estimated date for deployment is scheduled for 2014 [11].

This system’s equipment has been classified and certified by DNV Design Verification Report (DVR). Installation will require review dependent on MODU (ABS / DNV) [11].
8.3.4 Low Riser Return System (LRRS)

In the Low Riser Return System (LRRS) from Ocean Riser Systems (now part of AGR), the pump is suspended from the rig to a certain depth in the sea (Figure 8-6). The LRRS consist of partially filled riser with a single mud gradient. The riser is evacuated and flushed with nitrogen, and the gas/liquid interface in the riser is managed. The mud is returned via a subsea mud pump. The control system monitors and adjusts the fluid level and controls the pump such that the bottom hole pressure can be changed in minutes instead of hours [47].
8.4 **DGD Pros and Cons**

There are many benefits of using DGD systems. Safer wells due to:

- Improved process monitoring during drilling operations
- In some cases, ability to implement Riser Degas and Managed Pressure Drilling
- Improved Riser Margin and Kick Tolerance

Reduction in Non-Productive Time (NPT) due to:

- Improved wellbore pressure management
- Reduced or eliminated mud losses
- Simplified well design
- Possibly fewer casing strings
• Can reach deeper targets / drill “unreachable” wells

Development Drilling
• Improved drilling efficiency and well productivity
• Greater production NPV and lower upfront capital expenditure (Capex)
• Some of the limitations of using DGD systems are:
  • Additional cost due to customized equipment
  • Specialized crew training

8.5 QUALIFICATION OF DGD

The DGD systems have to be qualified dependent on the configuration of the DGD system, the drilling equipment and the particular well conditions. Changing any of these above conditions would trigger a reassessment of the qualification. The qualification of these systems would be required to provide documented evidence that the system will operate safely.

Some of the relevant design standards for DGD on floating drilling rigs with DNV Class are [67]:
• DNV OS E 101 “Drilling Plant”
• DNV OS A 101 “Safety Principles and Arrangements”
• DNV OS D 202 “Automation, Safety, and Telecommunication Systems”

Some of the initiatives on going to produce more specific guidelines for designing DGD systems are:
• The IADC Underbalanced Operations & Managed Pressure Drilling Committee has drafted an API Recommended Practice for managed pressure drilling, “Constant Bottom Hole Pressure using Applied Surface Back Pressure (Category 2 MPD) with Single Phase Fluid”
• Revised version of NORSOK D-010
• DNV revision of DNV-OS-E101
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