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MANAGED-PRESSURE DRILLING; TECHNIQUES AND OPTIONS FOR IMPROVING OPERATIONAL SAFETY AND EFFICIENCY

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Abstract

In the most of the drilling operations a considerable amount of money is spent for drilling related problems; including stuck pipe, lost circulation, and excessive mud cost. In order to decrease the percentage of non-productive time (NPT) caused by these kind of problems, the aim is to control annular frictional pressure losses especially in the fields where pore pressure and fracture pressure gradient is too close which is called narrow drilling window. By solving these problems, drilling cost will fall, therefore enabling the industry to be able to drill wells that were previously uneconomical. Managed pressure drilling (MPD) is a new technology that enables a driller to more precisely control annular pressures in the wellbore to prevent these drilling related problems.

As the industry remains relatively unaware of the full spectrum of benefits, this paper involves the techniques used in Managed Pressure Drilling with an emphasis upon revealing several of its lesser known and therefore less appreciated applications.

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

1. Introduction

World energy demand is increasing continuously to meet the need of energy of the developing countries. Increase in the energy consumption rates forces the scientists and engineers to discover another ways of gathering energy or better ways to recover the sources that we have been already using for years. Most of the world's remaining prospects for hydrocarbon resources will be more challenging to drill than those enjoyed in the past [1].

Some industry professionals would say that 70% of the current hydrocarbon offshore resources are economically undrillable using conventional drilling methods. Managed Pressure Drilling (MPD) is a new technology that uses tools similar to those of underbalanced drilling to better control pressure variations while drilling a well. The aim of MPD is to improve the drillability of a well by alleviating drilling issues that can arise. MPD can improve economics for any well being drilled by reducing a rig's non-productive time (NPT). NPT is the time that a rig is not drilling [2].

Managed pressure drilling (MPD) is an adaptive drilling process to precisely control the annular pressure profile throughout the well [3]. MPD uses many tools to mitigate the risks and costs associated with drilling wells by managing the annular pressure profile. These techniques include controlling backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry in any combination [4].

The MPD subcommittee of IADC separates MPD into two categories -"reactive" (the well is designed for conventional drilling, but equipment is rigged up to quickly react to unexpected pressure changes) and "proactive" (equipment is rigged up to actively alter the annular pressure profile, potentially extending or eliminating casing points). The reactive option has been implemented on potential problem wells for years, but very few proactive applications were seen until recently, as the need for drilling alternatives increased [5].

2. The Need for Managed Pressure Drilling

22 percent of 7680 total drill days from spud date to date TD was reached, lost to trouble time [4]. More precise wellbore management can address a significant amount of the NPT. The need for MPD is clearly illustrated by current drilling statistics and problems that currently exist. Fig. 1 shows the results of a database search of NPT while drilling offshore gas wells.

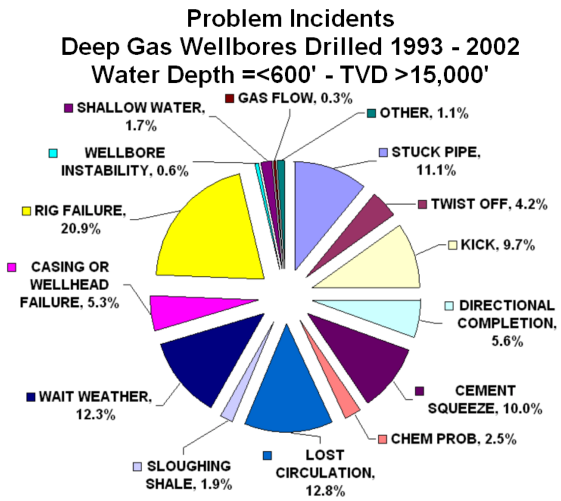

Fig. 1. Report of drilling downtime.TVD> 15,000 ft [6].

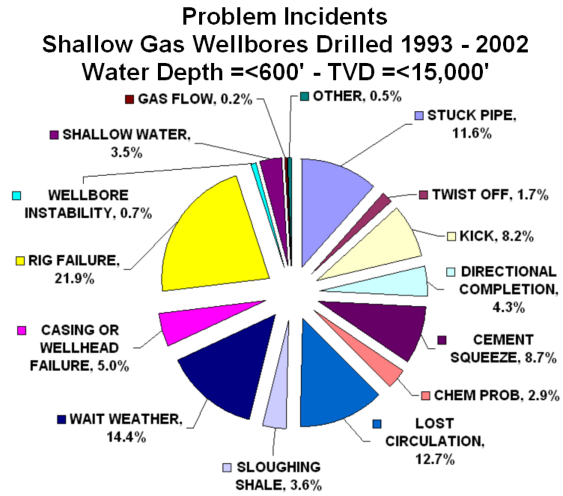

Fig. 2.Report of drilling downtime .TVD < 15,000 ft [6].

MPD can solve a large percentage of the problems the database lists, especially those that are caused by wellbore pressure deviating out of the pressure gradient window during drilling operations. Table 1 shows the NPT from Fig. 1 that could be reduced by using MPD [6].

Table 1. NPT downtime.TVD> 15,000 ft [6] Table 3. NPT downtime.TVD< 15,000 ft[6]

Lost circulation	12.8%	Lost Circulation	12.7%
Stuck Pipe	11.1%	Tuck Pipe	11.6%
Kick	9.7%	Kick	8.2%
Twist off	4.2%	Twist off	1.7%
Shallow Water/Gas Flow	2.0%	Shallow Water/Gas Flow	3.7%
Wellbore Instability	0.6%	Wellbore instability	0.7%
Total Downtime	40.4%	Total Downtime	38.6%

Numerous problems can occur if the wellbore pressure goes below the pore pressure gradient. At shallow depths, water or gas can flow into the wellbore. As noted above, a kick can occur. With a lower pressure in the wellbore, the hole can also become unstable and start to fall in on the drillpipe. This can lead to the pipe becoming stuck and could cause a twist off, which is breaking the pipe. The main problem when the pressure exceeds the fracture pressure-gradient is lost circulation, losing mud into the formation. Reservoir damage can also occur and the wellbore can become unstable. These problems account for more than 40% of drilling problems in the 10 years this study covers.

Table 2. NPT cost of 102 wells drilled with TVD > 15,000 ft [6].

Total Drill Days	NPT Time Days	NPT%	Dry Hole Cost/Foot	Cost/ft Due to NPT
7680	1703	22	444$	98$

Table 2 shows the economic impact that these hole problems have on drilling cost. These hole problems basically cost a company 98$ per foot drilled. If we can eliminate the problems with MPD, we could reduce hole costs by about 39$ per foot drilled. These figures assume that MPD will reduce the downtime by 40%. MPD will reduce these problems, although other events could still occur to prevent solving some of these problems. Even if we assume MPD could reduce that 40% to 20%, it could result in a savings of 19.50$ per foot, or an average savings of 293,000$ per well that is drilled to a depth of 15,000 ft.

Fig. 2 shows similar results for offshore wells that were drilled to less than 15,000 ft. Table 3 shows the NPT for these wells that could be reduced by using MPD.

Table 4 shows the economic impact of these problems. If MPD eliminated the 38% of drilling problems, the benefit could be 27$ per foot.

Table 4. NPT cost of 549 wells drilled. TVD < 15,000 ft [6].

Total Drill Days	NPT Time Days	NPT%	Dry Hole Cost/Foot	Cost/ft Due to NPT
17641	4264	24	291$	71$

If MPD only reduces these problems by half, the benefit of 13.50$ per foot would yield an average savings of 135,000$ per well that is drilled to a depth of 10,000 ft.

These statistics show that MPD can help reduce NPT for current drilling operations with associated excellent economic benefits. These economic benefits illustrate the need for MPD with current operations to help companies reduce their drilling costs.

3. Managed Pressure Drilling Techniques

There are four key variations of MPD. Occasionally, combinations of variations are practiced on the same challenging prospect. Combining several variations on the same prospect is expected to become more frequent as the technology becomes more status quo in the minds of drilling decision makers and as prospects become increasingly more difficult to drill [7]. The four key variations of MPD with sub-categories according to their application areas and different strengths they have are listed as below;

- Constant Bottom Hole Pressure (CBHP)
  - Friction Management Method
  - Continuous Circulation Method
- Mud Cap Drilling (MCD)
  - Pressurized Mud Cap Drilling (PMCD)
  - Controlled Mud Cap (CMC)
- Dual Gradient Drilling (DG)
  - Annulus Injection Method
  - Riserless Dual Gradient Method
- Return Flow Control (RFC) or HSE Method

4. Constant Bottom-Hole Pressure (CBHP)

Many drilling and wellbore stability related issues stem from the significant fluctuations in bottomhole pressure that are inherent to conventional drilling practices. Such pressure “spikes” are caused by stopping and starting of circulation for drillstring connections in jointed-pipe operations. Specifically, they result from a change in equivalent circulating density (ECD) or annulus friction pressure (AFP), which occurs when the pumps are turned on and off. The AFP additive to bottomhole pressure is present when circulating and absent when not circulating [8].

CBHP is the term generally used to describe actions taken to correct or reduce the effect of circulating friction loss or equivalent circulating density (ECD) in an effort to stay within the limits imposed by the pore pressure and fracture pressure. In order to reduce the effect of AFP or ECD, the need for backpressure (BP) is to be understood [9]. When drilling ahead, surface annulus pressure is near zero. During shut-in for jointed pipe connections, a few hundred psi backpressure is required. Using of backpressure shows the industry the capability to use a less dense mud [10].

MPD replaces the pressure exerted by static mud weight with dynamic friction pressure to maintain control of the well without losing returns. The objective of the technique is to maintain wellbore pressure between the pore pressure of the highest pressured formation and the fracture pressure of the weakest. This is usually done by drilling with a mud weight whose hydrostatic gradient is less than what is required to balance the highest pore pressure, with the difference made up using dynamic friction while circulating. That sounds quite simple but has been made extremely complicated [11].

The first issue that must be addressed is how to go from static balance to dynamic (circulating) balance without either losing returns or taking a kick. This can be done by gradually reducing pump speed while simultaneously closing a surface choke to increase surface annular pressure until the rig pumps are completely stopped and surface pressure on the annulus is such that the formation "sees" the exact same pressure it saw from ECD while circulating. It has to be taken into consideration that the bottomhole pressure is constant at only one point in the annulus [11].

The rig up for a CBHP set-up is shown in Fig. 3 [12].

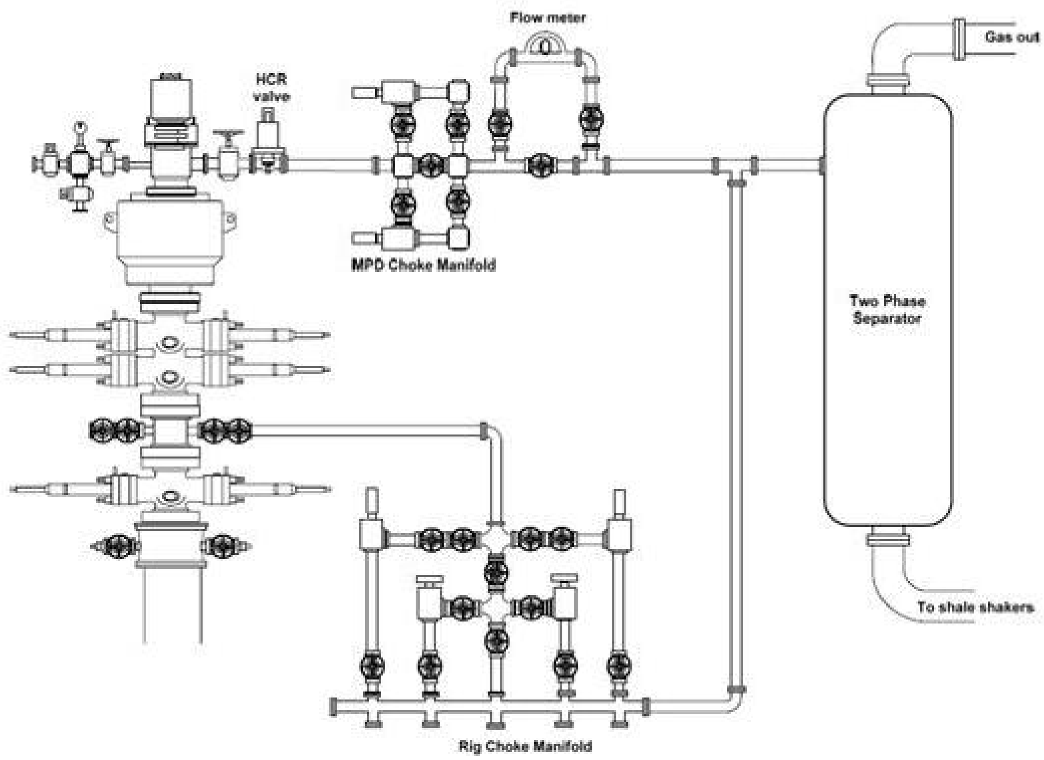

Fig. 3. Rig up for CBHP applications. [12]

5. Friction Management

Friction management techniques are used in HPHT or in Extended Reach wells, where the annular pressure is maintained to keep the bottomhole pressure as constant as possible. Hannegan explained that in HPHT wells, this is done by maintaining some kind of annular circulation through the use of a concentric casing string. In ERD wells, the annular pressure loss often needs to be reduced to achieve the required length and reach of the well. This can now be achieved through the use of an annular pump. The pump is placed in the cased section of the well and pumps annular fluid back to surface thus reducing the annular friction pressures. These friction management techniques are considered part of the CBHP variation [12].

6. Continuous Circulation System

The continuous circulation system (CCS) is a new technology that enables a driller to make connections without stopping fluid circulation. A CCS enables a driller to maintain a constant ECD when making connections [13].

The method is used on wells where the annular friction pressure needs to be constant and/or to prevent cuttings settling in extended reach horizontal sections of the wellbore [12].

Fig. 4 shows a coupler, the device that enables the continuous circulation of the fluid. The drillstring passes through this device, and during the connection process it provides a seal around the drillstring. The coupler can be divided into an upper and lower section. A sealing device can separate the two sections [13].

The continuous circulation system is useful in preventing pressure spikes when making connections, thus reducing wellbore problems. Benefits of using the CCS include [14]

- Reducing nonrotation time by eliminating the need to circulate the cuttings out of the bottom hole assembly.

- Reducing the possibility of a stuck drillstring by keeping the cuttings from dropping to the bottom.
- Constant ECD can be maintained.

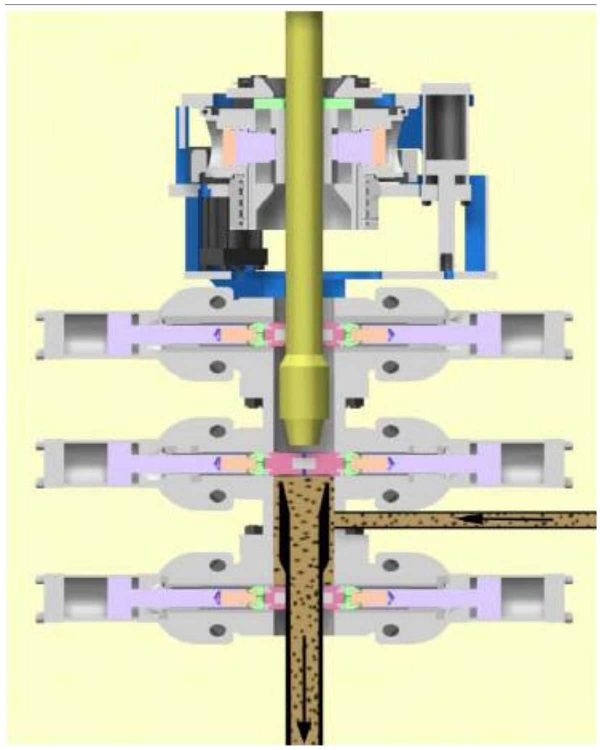

Fig. 4. Coupler device used in the continuous circulation system [13]

7. Pressurized Mud Cap Drilling

The pressurized mud cap drilling technique (PMCD) is used when dealing with reservoirs that could result in a severe loss of circulation. Depleted reservoirs, which have lower reservoir pressures because of the production from other wells, often have circulation loss. If the reservoir pressure is significantly lower than the wellbore pressure necessary to drill the well, the lost circulation can be severe. As the mud is lost into the depleted zone, the hydrostatic pressure of the wellbore decreases to balance the reservoir pressure at the depleted zone. At this point, the wellbore pressure is below the reservoir pressure of a zone that is not as deep as the loss zone. This causes gas to begin to flow into the wellbore. One way to keep such a well under control is to fill up the well at a rate that exceeds the gas percolation rate. The PMCD method uses a heavier mud pumped down the annulus to keep the gas influx from reaching the rig floor [15].

Fig. 5 shows the pressure profile of the pressurized mud cap method. A lighter mud is used to drill the depleted section and the heavier mud forces the fluid into the loss zone. Drilling continues and all the lighter mud and any influx is forced into the depleted zone. This method keeps the well under control even though all returns go to the depleted zone [16].

The advantage of the PMCD method is that it can keep the well under control even while suffering severe losses to the formation. The rig is still protected by two barriers, the BOPs and the mud cap. Using a lighter drilling fluid also increases the rate of penetration (ROP) (The lighter drilling fluid improves ROP because of increased hydraulic horsepower and less chip hold down) and the lighter mud costs less than the mud that would be lost in conventional drilling. Also another advantage with a lighter fluid is that drilling is underbalanced, resulting in less damage to the reservoir [16].

For PMCD operations, a flow spool must be installed below the RCD to allow fluid to be pumped into the annulus. The rig up for this set up is shown in Fig. 6. The manifold on the left hand side of the RCD is the bleed off manifold that is used to be able to keep the well full from the trip tank. It also allows any pressure to bled off from the stack should this be required when changing RCD packers [12].

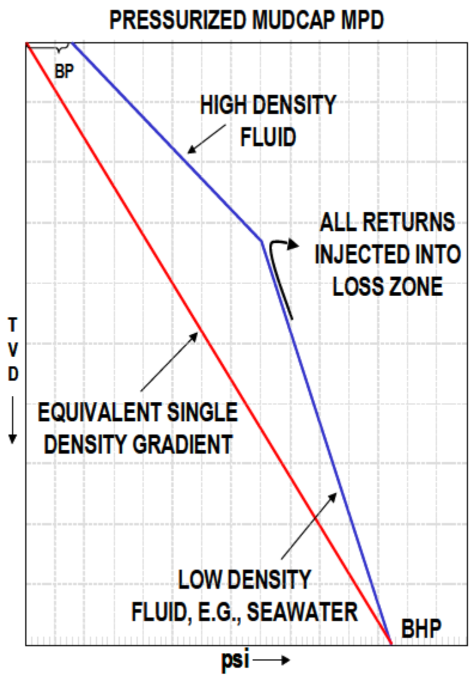

Fig. 5. Pressure-gradient profile for pressurized mud cap drilling method [16]

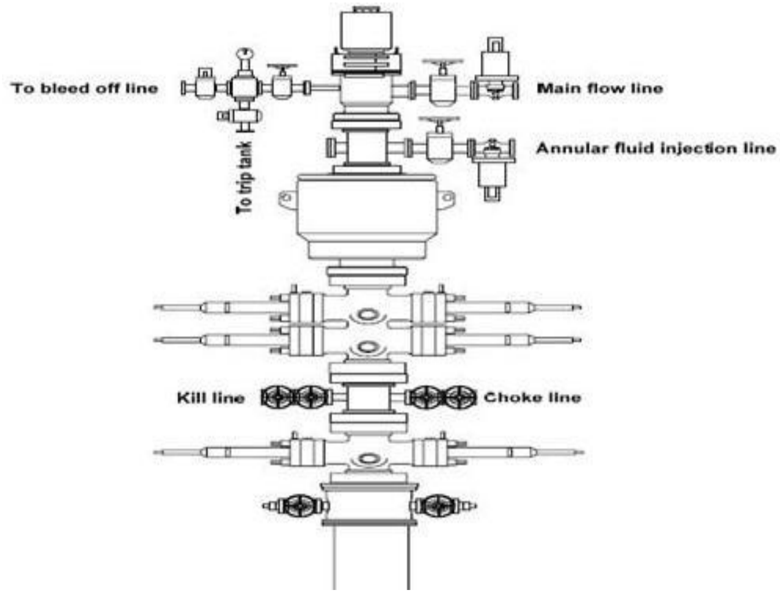

Fig. 6. Rig up for Pressurized Mud Cap Drilling Operations [12]

8. Controlled Mud Cap System

A newer drilling concept is the controlled mud cap system (CMC). This system is similar to the pressurized mud-cap system, except that the level of the mud cap is adjusted by a mud pump to better manage the bottom hole pressure. Fig. 7 shows a basic setup of this system for a well being drilled in deepwater. A subsea mudlift-pump is connected to the riser by a riser-outlet joint. The outlet joint has high-pressure valves that enable it to isolate the pump system from the riser. The pump is connected to the mud pits by a return and a fill line. This allows the pump to increase or decrease the amount of mud in the riser. To determine the level of the mud in the riser, pressure sensors are located throughout the riser. The drilling riser is filled with air above the mud cap [17]. The basic concept of this system is to compensate for ECD and thus manage the BHP.

This system also is unique in that it can be operated as either an open or closed system. The first advantage to an open system is that it needs no continuous closure elements to trap pressure in the well. This comes in handy when considerable rig movement can affect the downhole pressure control. This effect can occur when slips are set to make a pipe connection. With the CMC system, the downhole pressure regime will generally be the same as in conventional drilling except the mud weight may be higher and part of the drilling riser may be filled with gas. The second advantage with an open system is that a positive riser margin can be designed to be included in this system. With this system the hydrostatic pressure in the riser at sea level can be designed to equal or be less than seawater pressure. This means a positive riser margin can be added with no overbalance in the well. This positive riser margin means that if the riser was to disconnect, the BHP would increase thus improving well control. The third advantage is the CMC system's ability to handle hydrocarbons. The system operates as an open system until one of the rams of the surface BOP is closed. Since this system acts as an open system with gas pressure close to ambient, the drilling riser effectively becomes the hydrocarbon separator. The gas is separated in the riser and the liquids are transported through the pump system up to the rig. Being able to regulate the mud level while this happens enables fast and accurate changes to the BHP [17].

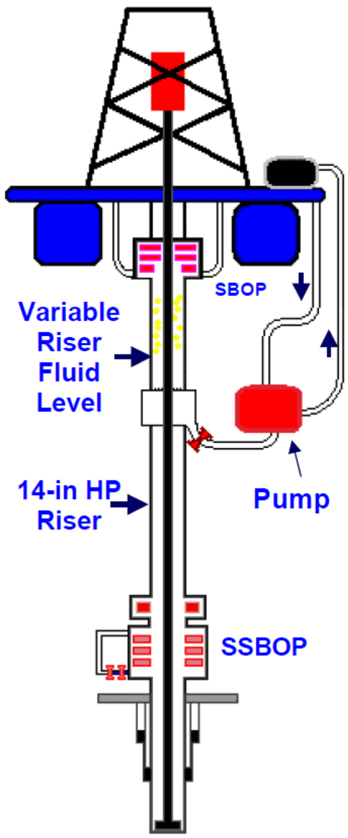

Fig. 7.Controlled mud cap setup [9]

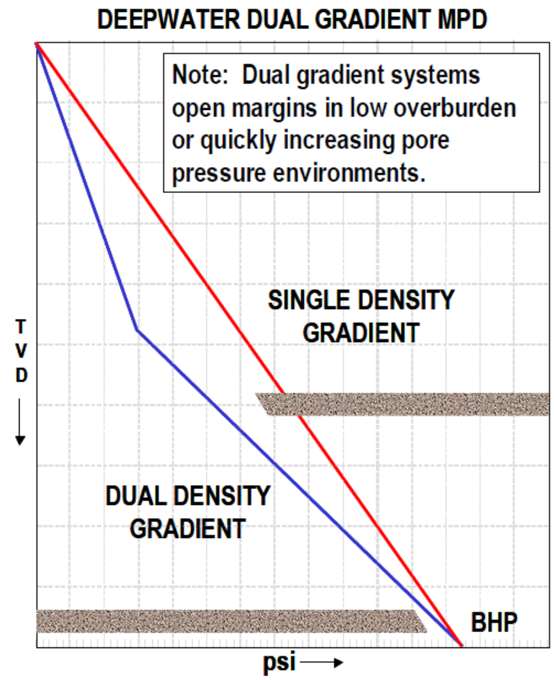

Fig. 8. Dual-gradient drilling pressure gradient profile [16]

If a well control problem arises, the system is designed to adjust to compensate for the change. The subsea BOP would be closed. The mud level in the riser would be increased to compensate for the fact that the pumps are shut down and brought even higher to stop the influx or increase till it brings the pressure close to the maximum allowable annulus shut-in pressure. The RCD at the surface would be closed, but the choke line would be open to minimize the pressure in the gas phase in the riser. The gas that remains in the riser can be bled off to the atmosphere via the choke manifold. This procedure could be performed in a very short time frame [17].

The main challenge with this system is to compensate for the hydrostatic pressure that is caused by the standing column of mud in the drill pipe. Having a full column of mud with the subsea BOP closed would cause the BHP to become higher than the fracture pressure. This is due to the system using a higher mud weight than is used in conventional drilling. A u-tube effect occurs where the mud in the drill pipe flows into the annulus until the pressure equalizes between the annulus and the drill pipe. One way to neutralize this effect is to have a pressure differential valve in the drill string. The valve would be open at a predetermined pressure and compensate for the static imbalance between the drill pipe and the annulus. The valve would be closed if the pressure in the annulus is lower than the pressure in the drill pipe. This blocks the annulus from being affected by the standing column of mud when the subsea BOP is closed.

This method has many advantages. A driller is able to control downhole pressure almost instantaneously by adjusting the height of mud in the riser. Hydrocarbon influxes can be controlled and circulated out with ease. This system also can act as either a closed or open system, depending on what is needed [17].

9. Dual-Gradient Drilling Method

Dual-Gradient drilling refers to drilling with two different fluid-density gradients. Fig. 8 shows the dual-gradient pressure profile. In this case, using a single density fluid for this wellbore will cause the wellbore pressure to exceed the formation pressure and result in lost circulation. With dual-gradient drilling, a lighter fluid is used in the upper portion of a wellbore and a heavier fluid at the lower portion. This enables the pressure to remain in the pressure window between the pore pressure and fracture pressure [16].

To achieve a dual gradient, a less-dense fluid such as air, inert gas, or light liquid is injected at a certain point in the wellbore. Introducing this less dense fluid at this point would decrease the density of the fluid from that point up to the surface [16]. This technique is helpful as a means of adjusting the effective bottomhole pressure without having to change base fluid density and with fewer interruptions to drilling ahead, usually to avoid lost circulation in a thief zone or to minimize differential sticking of the drillstring. (Injecting Less Dense Media Method) [10].

Another technique is used for offshore environments. A small diameter return line is run from the seafloor to circulate the drilling fluid and cuttings. The marine riser is kept full of seawater. A subsea pump is used to lift the drill cuttings and the drill fluid from the wellbore annulus up to the rig floor. By using seawater in the marine riser, a more dense mud is used in the wellbore to achieve the bottomhole pressure required. (Subsea Mudlift Drilling (SMD))

The purpose of dual-gradient drilling is to prevent a large overbalance and prevent exceeding the fracture gradient. Dual-gradient drilling allows the operator to manipulate the pressure profile to prevent exceeding the fracture pressure at a point but still to remain above the pore pressure. It is basically being able to take a tight pressure gradient window and design a drilling plan to manipulate the pressure curve to fit into the window. Dual-gradient drilling can also be achieved in deep water without a riser when first starting a subsea drilling location. A subsea RCD and remote operating vehicle are used. The ROV is able to adjust backpressure at the mudline by adjusting the choke. If the ROV closes the subsea choke, the BHP increases. This results in drilling with a slight overbalance as if a marine riser filled with drilling fluid were present. The advantage of being able to drill with a slight overbalance is that it helps to prevent shallow gas or water flow. The seawater is used as the drilling fluid so the drilling fluid and cuttings can be left on the sea floor. Fig. 9 shows the pressure profile for this example and how adding the backpressure at the seafloor causes the pressure profile to equal that which would be achieved by having a single gradient.

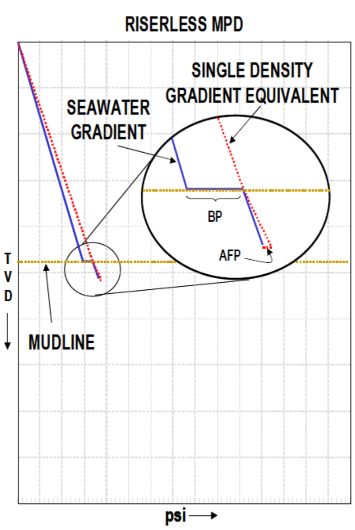

Fig. 9.Pressure profile for drilling dual gradient without a riser [16]

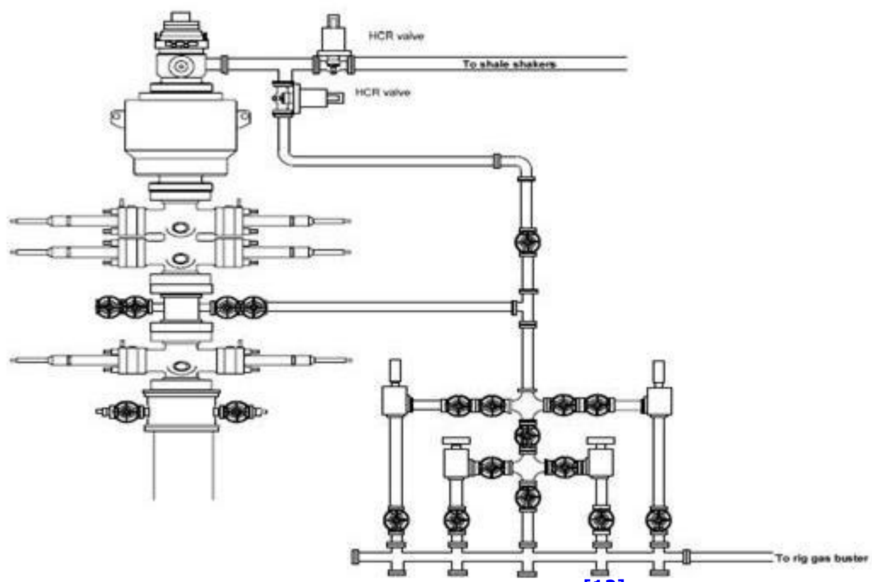

Fig. 10. MPD rig up for Return Flow Control [12]

As far as well control with dual-gradient drilling is concerned, the detection criteria of a kick are very similar to conventional drilling. With dual-gradient drilling, pressure gauges installed on the rig floor are more sensitive to changes than the gauges used in conventional drilling. A decrease in circulating pressure caused by an increase in flow will be more easily seen. If a kick occurs, the annular flow rate of the drilling fluid will increase by an amount equal to the influx rate. If the subsea pump were set to operate at a constant inlet pressure, the subsea pump rate would increase. This increase would be seen on the computers at the rig floor and would give a good indication of a kick. The procedures used to circulate the kick out are very similar to the ones used in conventional drilling [18].

10. Return Flow Control (RFC) / HSE Method

Because we are tooling up to securely and more efficiently react to any downhole surprises, RFC can be regarded as a crucial part of the MPD definition in spite of the fact that technique does not control any annular pressure. In Hannegans's point of view, annulus returns diverts away from the rig floor, to prevent any gas, including and especially H_2S from spilling onto the rig floor. It is used as a safety measure. If an influx is taken whilst drilling the well, or trip gas or connection gas spills onto the rig floor, the flow line to the shakers is closed and flow is immediately diverted to the rig choke manifold, where the influx is safely controlled and circulated out of the hole. The use of the rotating control device (RCD) avoids the need for the closing of the BOP minimizes the potential for hydrocarbon release onto the drill floor, and it allows pipe movement whilst circulating out an influx or dealing with gas cut mud [12].

For RFC operations, two hydraulic valves, a conventional flow line to the shakers and a flow line to the rig choke manifold are installed. This allows any influx to be handled by the rig choke manifold and in normal operations the conventional flow line is used to circulate fluids.

The objective is to drill with a closed annulus return system for HSE reasons only. For example, a conventional production platform drilling operation with an open-to-atmosphere system may allow explosive vapors to escape from drilled cuttings and trigger atmospheric monitors and/or automatically shut down production elsewhere on the platform. Other applications of this variation include toxicological ramifications of drilling with fluids emitting harmful vapours onto the rig floor, as a precaution wherever there is a risk of a shallow-gas hazards, and when drilling in populated areas. Typically only an RCD is added to the drilling operation to accomplish this variation [12].

11. Conclusion

Managed pressure drilling is a new technology which has capability of mitigating drilling hazards, improving drilling performance and increasing production rates. It will increase reserves by enabling drilling of areas that were previously economically undrillable.

Since MPD uses tools that are similar to that are being used for underbalanced drilling, the transition for companies to begin using MPD is smoother.

The continuous circulation system prevents pressure spikes that can occur when turning pumps on or off for making connections. This method could be useful in situation where a well can remain in the pressure margins with a specific mud weight in the drilling plan but pressure spikes while making connections could cause the pressure to deviate out of margins.

Pressurized Mud Cap Drilling method could help with wells that have severe circulation loss (e.g. drilling in depleted formations). This method improves the economics of drilling with severe lost circulation by using a drilling fluid that is less dense and inexpensive and can be lost to the formation. A heavier mud above the point of lost circulation provides the pressure necessary to force mud into the depleted formation. It also allows a driller to keep control of a well even if suffering severe losses.

Controlled mud cap drilling is ideal for areas in which a driller is not sure about the exact pressure gradients. This method allows the driller to adjust the pressure by changing the mud level in the riser and keep the well within margins.

Dual-Gradient Drilling uses two different drilling fluids during drilling to create a pressure profile that has two gradients. This is good for situations in offshore drilling where using one fluid throughout the wellbore would cause the pressure to exceed the fracture gradient.

HSE MPD utilizes the benefits of a closed, pressurized mud returns system; it is typically applied when dangerous conditions threaten to halt the drilling or subsequent production of a well.

MPD technology challenges the traditional drilling practice of weighting a mud system while drilling through formations that are overpressured. The technology is an advanced drilling optimization process that applies an advanced well control methodology and specialized equipment to enhance drilling economics and reduce drilling cost uncertainty.

The strengths of each method should be understood clearly since MPD is application specific.

Nomenclature

AFP	Annulus Friction Pressure	IADC	International Association of Drilling Contractors
BHP	Bottom Hole Pressure	MCD	Mud Cap Drilling
BOP	Blow Out Preventer	MPD	Managed Pressure Drilling
CBHP	Constant Bottom Hole Pressure	NPT	Non Productive Time
CCS	Continuous Circulation System	PMCD	Pressurized Mud Cap Drilling
CMC	Controlled Mud Cap	RCD	Rotating Control Device
DG	Dual Gradient	RFC	Return Flow Control
ECD	Equivalent Circulating Density	ROP	Rate of Penetration
ERD	Extended Reach Drilling	ROV	Remote Operating Vehicle
HPHT	High Pressure High Temperature		

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