NTNU
Norwegian University of Science and Technology

Master thesis: Drilling engineering

Well control with Controlled Mud Pressure

Reviewing AGR's well control procedures for the CMP system, analyzing and comparing with conventional well-control procedures., possible impact of technology.

Morten Hansen
14.06.2011

Norges teknisk-naturvitenskapelige universitet
Studieprogram i Geofag og Petroleumsteknologi
Study Programme in Earth Sciences and Petroleum Engineering

Fakultet for ingeniørvitenskap og teknologi
Faculty of Engineering and Technology

Institutt for petroleumsteknologi og anvendt geofysikk
Department of Petroleum Engineering and Applied Geophysics

HOVEDOPPGAVE / DIPLOMA THESIS / MASTER OF SCIENCE THESIS

Kandidatens navn/The candidate's name:	**Morten Hansen**
Oppgavens tittel, norsk/Title of Thesis, Norwegian:	**Brønnkontroll med AGRs dual gradient system**
Oppgavens tittel, engelsk/Title of Thesis, English:	**Well control with Controlled Mud Pressure**

Utfyllende tekst/Extended text:

Background

AGR has proposed and patented and MPD system called Controlled Mud Pressure (CMP) with a cost reduction potential for deep water drilling. The mud return is taken out of the riser and pumped up to surface with a subsea mud pump. The riser is partly evacuated and the downhole pressure can be controlled by adjusting the mud level in the riser. Well control is one of the challenges with this new system, since conventional well control can not be applied.

Tasks:

1) Literature study: dual gradient systems in general and CMP in particular. Identify equipment and procedures\software needed. Discuss challenges and benefits.

2) Conventional well control for floaters: Discucc conventional well control for deep water drilling from floaters with subsea BOP.

3) Automatic well control with MPD: Discuss the automatic well control solutions offered by AtBalance and Secure Drilling

4) Well control with CMP: Define and discuss kick\loss detection, shut-in procedures and how to circulate out a kick. Discuss how to handle faults on the equipment during a kick.

5) Discuss well control with CMP compared to conventional well control and backpressure MPD.

Supervisor:	**John Morten Godhavn**
Studieretning/Area of specialization:	**Petroleum Engineering / Drilling Technology**
Fagområde/Combination of subject:	**Boring / Drilling**
Tidsrom/Time interval:	**January 17 – June 14, 2011**

John-Morten Godhavn

Summary

Dual Gradient Drilling (DGD) are a portfolio of drilling systems that in various ways pump returns from the well through a mud return line (MRL) from the seafloor, or somewhere between the seafloor and the rig floor. Two variations exist, with or without a marine riser. The system without riser is an open system which is intended for tophole sections where a blowout preventer (BOP) is not used. When depths are reached that require a BOP, a subsea BOP can be applied together with a riser. Both systems results in the augmentation of the fluid column by adding a lighter fluid gradient on top of the outtake to the MRL and subsea pump. In the event of an open system, this will be the seawater, with riser different blanket fluids can be used, like seawater, nitrogen or just a lighter mud component like base oil.

The controlled mud pressure (CMP) system is offered by AGR and applies a MRL together with a subsea pump to take returns from the wellhead to the rig. This system uses a riser, and can thus drill deeper than tophole applications and is intended to handle well control situations. Together with systems such as @Balance's dynamic annular pressure control (DAPC) system and Secure Drilling's microflux control (MFC) it represents the future of automated kick detection, control and handling. The two latter are offered as parts or supplements to mainly managed pressure drilling (MPD) systems. One of them also aims to increase safety by automation to all drilling systems on any rig.

The CMP technology can be seen as enabling and improving for drilling deepwater prospects, as well as through zones with either tight drilling windows or depleted pressures. The potential for automated well control can become a major increase in safety and improve the way kicks are handled. There are some challenges still to overcome, mainly the development of the anti u-tube valve, or other options to solve problems related to u-tubing, as well as looking into the issue of gas boiling in the circulation system.

Preface

This Master's Thesis has been completed at Norwegian University of Science and Technology (NTNU) in cooperation with Statoil and also AGR Drilling Services. During this work my supervisor has been John-Morten Godhavn, as a representative for both NTNU and Statoil. The work done for this report was outlined by Godhavn, and has been altered along the way to conclude in the following report. The thought behind the work has been to analyze the well control of a newly developed and promising drilling method. The aim was to analyze and simulate the different steps in the well control procedure, and see what differences the drilling method would require for implementation. Along the way the ambition was reduced to focus on the analysis, as the development of a simulation model was proving too challenging.

This work with this thesis would have been possible without the patience and guidance of my supervisor John-Morten Godhavn. I am also very grateful for Espen Hauge's help in my attempt to model the drilling system described herein. Furthermore I appreciate the opportunity to visit AGR's workshop and office in Bergen, as well as their help, through Nils Lennart Rolland and Kjell-Rune Toftevåg, and their willingness to support me with their information.

I would also like to thank Statoil for the opportunity to do this thesis work with them, and for supplying me with an office spot. During the report work, the online soruces such as OnePetro supplied by NTNU has been most valuable. I would also like to extend my appreciation to the open-source community of Zotero.org which supplies the reference tool that has been invaluable to this work.

I hereby declare that the work in this project is made independently and in accordance to the rules set down by "Examination regulations" at the Norwegian University of Science and Technology (NTNU), Trondheim.

Trondheim, June 14th 2011

Morten Hansen
Student

Table of Contents

List of tables

List of figures

1. Introduction

The aim of this thesis work has been to critically analyze the issue of well control using dual gradient (DGD) systems, specifically AGR's CMP system. In addition, the benefits and challenges other than well control have been reviewed and discussed.

Furthermore it was necessary to review conventional well control, and also look into automated well control systems offered for conventional drilling, and the potential they might have for the DGD systems.

The work is based on discussion and analysis of the provided information from AGR regarding their procedures for well control for their CMP system. Also Statoil's internal procedures and requirements for well control were used in the evaluation. These are proprietary resources that have not been added to appendices or reproduced in any other way than what is presented herein.

2. Dual gradient drilling

The aim with DGD is to allow the drilling of a well using heavy engineered mud, but still keeping the gradient within the drilling window. This can be especially hard to achieve with conventional methods when drilling through depleted zones, or in deep water areas.

This challenge can be met using a DGD system. The system uses two fluid columns, where one is lighter than the engineered mud and thence modifies the gradient of the well. This is generally done either by having no riser at all or to have the riser filled with a blanket fluid. The mud returns are taken through a diverter from the wellhead or somewhere on the riser. This is much like tophole drilling, just that the mud is in the hole and taken to surface through a pump and mudreturn line (MRL). The system this report focuses on has in addition to the mud return from subsea a riser. This allows for the interface between the mud and the lighter fluid to be adjusted within the riser.

The subsea wellhead diverts the mud to a subsea pump that brings the mud to surface through the MRL. The riser is then kept out of the circulation, and can be filled with a blanket fluid. This is typically water, base oil or an inert gas like nitrogen. Different technology suppliers generally keep a system of their own, and the blanket fluid typically separates them. For instance AGR's CMP system, which is the focus of this report, uses water while ORS put their trust in nitrogen.

The result is that the gradients of the well are shifted. Both the mud and the well pressures share the same overburden down to the mudline. This widens the drilling window as is illustrated in Figure 1. In the same way the gradient of the mud is also altered. Since the ratio between the light and heavy fluid will generally increase with depth, the gradient for the well fluid will be dipping towards a vertical line as plotted gradient against depth, as illustrated in Figure 2. This is the nature of the drilling method that gives the advantage of choosing to skip a casing section if the pressures are right.

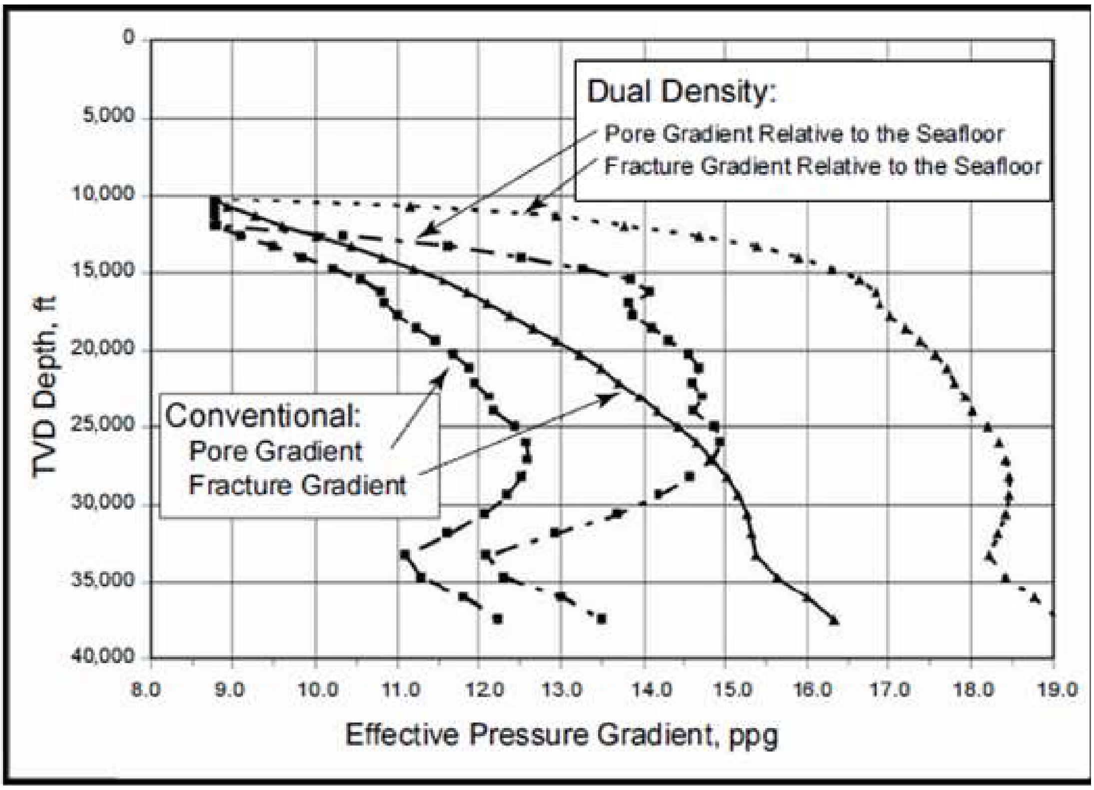


Figure 1: Difference between dual density gradients and conventional gradients (Rehm et al. 2008)

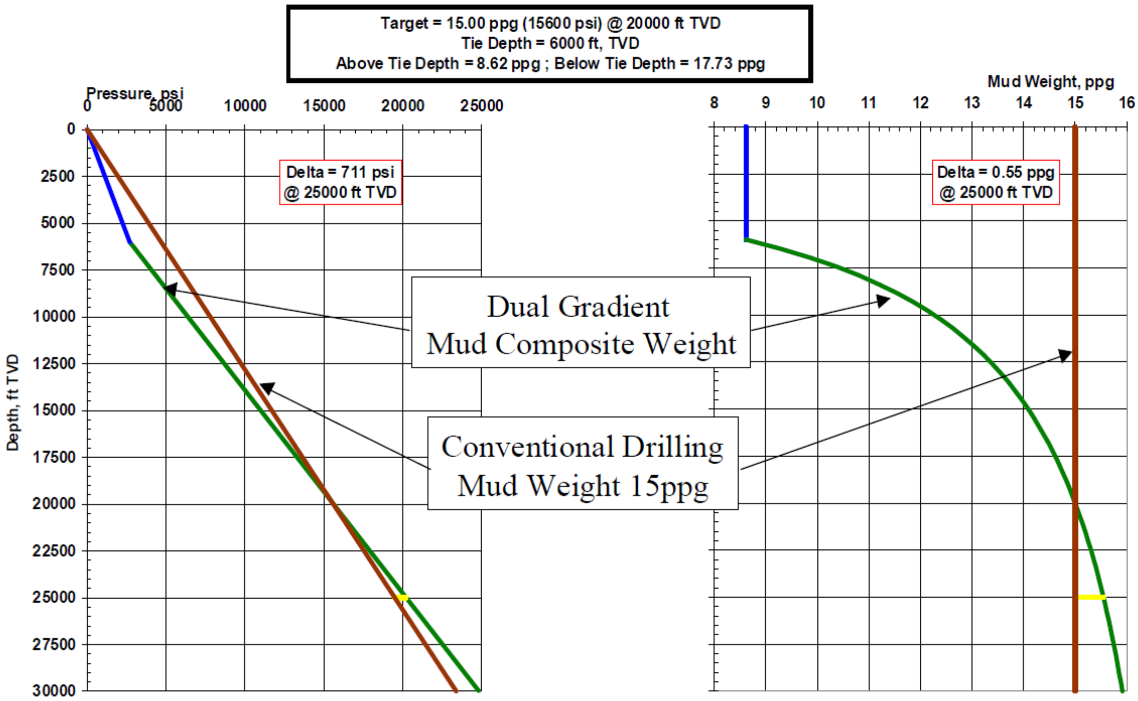


Figure 2: DGD pressures and gradients vs conventional (Forrest, Bailey, and Hannegan 2001)

2.1. Controlled mud pressure drilling system

CMP is AGR's system for DGD with a riser. In their portfolio of drilling systems, it aims to be a tool to improve drilling in the middle section, and together with EC-drill, the reservoir section. In addition it enables drilling of tight windows not drillable with conventional technologies. To date it has not been used on offshore wells, but the technology and method is promising. Although the system is quite like with the RMR system, drilling with CMP is all the more different in terms of applying the riser and the nature of the depths drilled, with the possibilities of well control situations

2.2. Equipment

Description	Dimension (m) [L x W x H]	Weight (Kg)
Riser Docking Arrangement	TBD	TBD
Subsea Pump Module (3-stage)	4.50 x 2.50 x 1.50	8500
Mud Return Hose	6" ID	12 /m
Hose Handling Platform	3.10 x 1.84 x 2.72	3500
Umbilical	TBD	TBD
Umbilical Winch (10-ton SWL)[1]	4.30 x 2.45 x 2.97	22000
CMP® Office/Tool Container	4.28 x 2.44 x 2.79	9000
CMP® Control Container	4.28 x 2.44 x 2.74	14000
Generator (Aggreko 1250 kW)	6.18 x 2.44 x 2.60	22000

Table 1: CMP Equipment Dimensions and Sizes

In Table 1 the equipment needed for operating AGR's CMP system is shown, with specified dimensions. Also in Figure 4 the system layout can be seen. The riser docking arrangement is yet to be described in detail, but will be a docking above the subsea wellhead and BOP and include the diverter for the subsea mud pump as well as the name states, a docking for the riser to surface. The module along with the connection to the pump module will also have to provide connection of choke lines to pump module, since the MRL and subsea mudpumps need access to the well annulus during a shut-in and well control situation.

2.2.1. Subsea pump module

The subsea pump module (SPM) is highly important and the module that sets the limits of the CMP operation. The pump's lifting capacity dictates at what sea depth the connection of the mud return line (MRL) will be, given a desired flow rate, or the other way around. The pumps are Discflo, same as AGR uses in the RMR system (Frøyen et al. 2006) pumps, which

[1] With platform and A-frame retracted, includes Umbilical on drum – Rated lifting capacity of winch frame.

are specially designed by AGR to allow pumping of mud with significant solids without jamming or destroying the pump disks. The pumps are made up in the module 3 together which one designated motor each.

2.2.2. Mud return line and handling platform

Another challenging piece of equipment is MRL and the handling platform. The length of the hose, the weight of the mud it is to carry, and also the fact that it will be suspended and flexible demands some expert engineering. The hose is supplied in 20 m lengths, and requires a ¼ turn to make up, and also features external tension cables to further support the weight of the massive MRL all the way to the SPM, see Figure 3. This hose is made of rubber, although suggestions by AGR might indicate an alternative steel MRL is being considered. The handling platform features a hang-off point where the lengths of MRL can be made up to the line already in the water.

Figure 3: MRL hose

2.2.3. Control unit and umbilical

Then it is the control and operating modules, which are typical two standard containers, holding the offices and control stations together with tools etc. The umbilical mentioned above is the communication line between the subsea modules and the control and operating modules, but also works as the lowering mechanism of the SPM, and is operated through the umbilical winch. Other equipment needed includes also the flow return line, which takes the mud return from the MRL to the rig mud system, through a manifold and also a Coriolis flow meter and automated choke setup. Both of these are used to handle a possible well control incident..

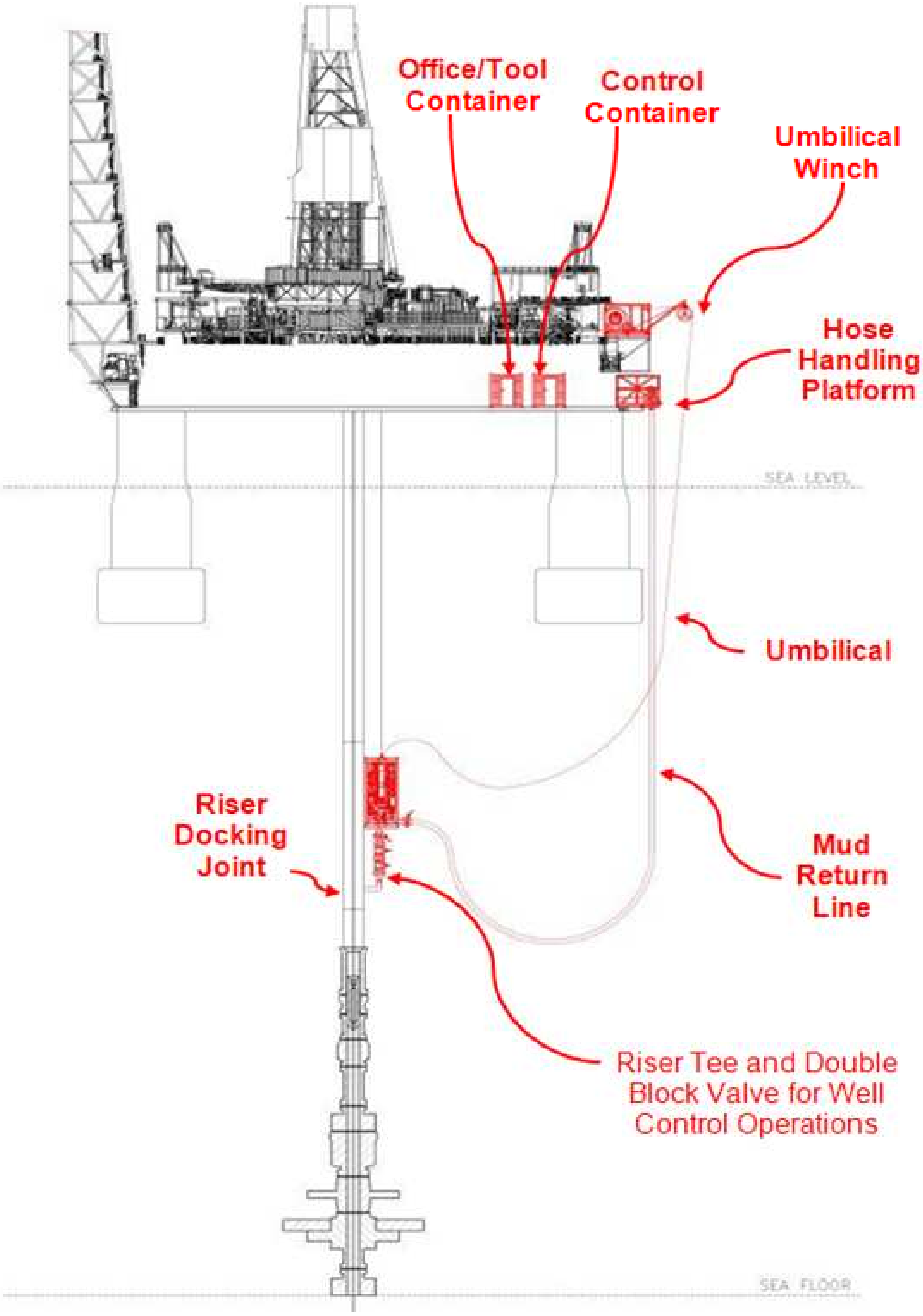


Figure 4: CMP system layout

2.2.4. Drillstring valve

The drillstring valve is designed to arrest the u-tube effect. The anti u-tube valve is essential in the procedures for well control with CMP. In some cases it is necessary for the usage of CMP throughout the well-control. In the case of no or a malfunctioning anti u-tube valve the procedures might be totally altered, or even conventional procedures have to be used. The valve was designed and built to hold the hydrostatic column of the whole drillstring.(Gonzalez and Smits 2002; Gonzalez 2001)

The valve will normally be adjusted for every section of the well, or when mud weight is changed. Thus it can be set to hold the hydrostatic column of the mud inside the drillstring to the depth and end of each section. The valve will then open at a set pressure, and allow flow through it. This complicates slightly hydraulic calculations, and also adds slightly to frictional pressure drops in the drillstring. However, the purpose to arrest the u-tube effect overcomes these slight downsides. Without it, the u-tube effect will cause the mud in the drillstring to freefall unless the rate is high enough, and thus increase the bottomhole pressure (BHP) and possibly fracture the well.

The valve is designed with springs that hold seals in place. See Figure 5 for the basic design of the valve, with the open position to the left and open to the right. The springs can be adjusted to the desired opening pressure, such that it fits to the mud and depth of each section. This adjustment can only be made while the valve is out of the hole though. Oskarsen (2001) did studies on the hydraulics of the valve, and also analyzed the location of the valve in the drillstring. He arguments that the hydraulics would require it to be as close to the mudline as possible to allow lower circulation rates to open it. Although this will still arrest the u-tube and work as intended, it would not allow for the use of any wireline should it be necessary. More importantly, it would hinder communication with the BHA whenever it is closed. That leads to the placement of the valve to be below the MWD tools so that communication with these tools will not be hindered.

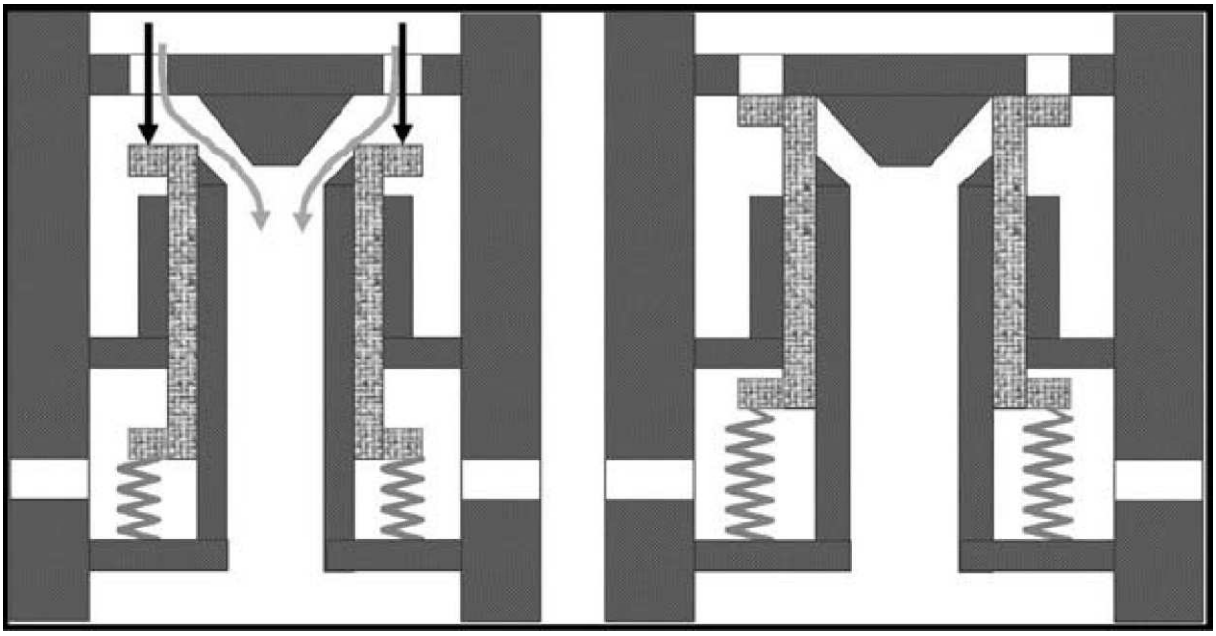


Figure 5: Anti u-tube valve, open position to the left and closed to the right (Rehm et al. 2008)

2.2.5. Coriolis flow meter

The Coriolis flow meter is an accurate flow meter that applies the Coriolis effect to measure flow. The Coriolis effect is shortly described the effect where a fluid flow in a rotating reference frame is deflected. The effect is generally experienced for example in a sink: When water drains in the sink, it will whirl in one direction on the northern hemisphere, and another in the southern hemisphere. This effect is caused by the earth's rotation, which is the rotating reference frame.

The Coriolis meter applies this in a looped setup, where the flow runs through a looped setup, and sensors register how much the flow changes the vibration of the tube. Figure 6 shows the setup of the meter. The physics of the Coriolis effect show that the acceleration caused by the flow is proportional to the mass flow. The meter can also be set to measure the density of the flow, and therefore accurately measure the volume flow as well as the mass flow. The meter is accurate to 0.2 percent (White 2008)

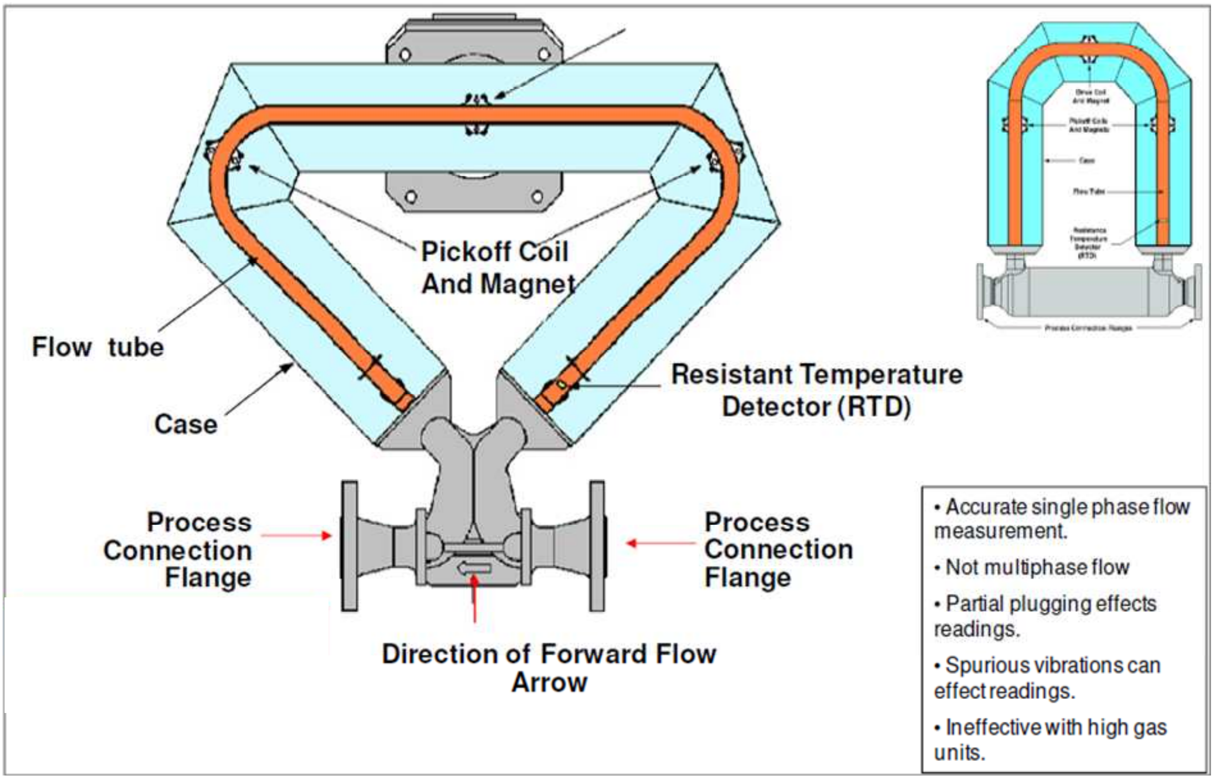


Figure 6: Coriolis meter(Reitsma 2010)

2.3. Possible benefits

The benefits from DGD are mainly economical, and possibly also safety-related. This however requires sound testing and analysis to state for a fact. However, it is not difficult to comprehend that using a riser filled with seawater may save significant amounts of mud, and may also require less storage capacity for mud on the rig, especially in long and deepwater wells. Even more mud may be saved by the fact that the probability of lost circulation is lessened, and if it should happen, the BHP can be very quickly adjusted. Compared to conventional drilling where new mud has to be weighted and circulated, an adjustment in subsea pump speed and flow may adjust the BHP much more efficiently and faster. The greatest pressure properties of the DGD system is illustrated very well in previously mentioned Figure 1 and Figure 2, showing how DGD gradients better adapt in narrow windows and in long wells, eliminating casing sections.

The similarities with RMR are many, even though they are quite different in some ways. Some of the benefits experienced with RMR on live wells can also apply to CMP. According to R. Stave et al. (2005) the benefits may also include: Improved well control, reduced numbers of casing and liner strings, reduced chances of loss of circulation. It is also interesting to note that with RMR Stave et al. also states that aside from the rig-up, the usage of the extra equipment doesn't require additional time compared to conventional use. It would be reasonable to think this would go for CMP as well, as the only other equipment affecting operations is the addition of the riser instead of the suction module.

When used on floaters, the CMP system can prove beneficial when the need to quickly disconnect arises. As the riser will only be filled with blanket fluid or seawater, disconnecting should not affect the pressure control of the well, since no fluid column is lost. The pump can quickly adjust the pressure to ensure the safety of the well before the BOP is closed and the disconnection is completed. There is then also limited spill, as the volume of the hose will be significantly smaller than the volume of the riser.

2.4. Challenges

According to AGR one of the challenges with the equipment has been the mud return line (MRL), making it both big enough to allow for flow, but small enough so it still is flexible and easy to use. The mud it carries makes up the biggest load on the hose, and the loads on the hose are significant, and this is the major challenge while trying to find the right size for it. Thus it has also been proposed to use steel pipes to increase the strength, but this would also mean the weight of the MRL will increase. However, for the current purposes the designed hose works fine, as the pumps restrict the possible water depth it can operate, and the hose is designed with this in mind. It has been mentioned that the limit is around 500m of water depth to the pump. This does not mean that the CMP system can't be utilized in deeper waters, just that the pump tie in to the riser will be in mid water. Then again, investigations should be done to look at how the distance between a deepwater BOP stack and the shallower pump module would affect well control and other operating challenges.

In case of equipment failure, the well will in many cases be returned to a conventional state. In most cases, this doesn't have to be critical. For instance if the mud pump fails, the returns can be taken through the riser as conventionally. That will result in the loss of the CMP advantages however, and in case the pressure profile of the well at that time requires CMP flexibility in the BHP, the equipment failure can result in loss of circulation and following problems.

The pump may be considered the piece of extra equipment compared to conventional drilling that increases the risk and possibility of equipment failures. The BOP is essentially the same, apart from the pump tie-in, the riser is the same and doesn't see the same pressures. The MRL and flow-return topside can essentially be viewed in the same manner as the rig mud handling system. However, there are still the tension problems that can be associated with the hose. On floaters the tension problems can be worse due to heave and rig movement in relevance to the wellhead.

Well-control with CMP will be reviewed in the following chapter 5.

3. Conventional well control

The general drilling method has remained the same for decades, and the same goes for well-control. The methods and procedures are well established, yet there remain two different methods of handling a kick. They are called the Driller's method and the Engineer's method (Wait & weight method) referring to the latter as more calculation intensive, hence the name. A brief description of these established well control procedures are included as a base-reference for the evaluation of the CMP well control procedures. As should be noted, no loss of safety should occur when implementing new technologies, therefore the CMP procedures should maintain even better well control than these conventional ones.Grace et al. (2003) lists the causes of kick in Table 2, and the indications of a kick in Table 3.

1. Mud weight less than formation pore pressure
2. Failure to keep the hole full while tripping
3. Swabbing while tripping
4. Lost circulation
5. Mud cut by gas, water, or oil"

Table 2: Causes for kick (Grace et al. 2003)

1. Sudden increase in drilling rate
2. Increase in fluid volume at the surface, which is commonly termed a pit level increase or an increase in flow rate
3. Change in pump pressure
4. Reduction in drillpipe weight
5. Gas, oil, or water-cut mud

Table 3: Kick warnings (Grace et al. 2003)

When a kick has been identified the normal shut-in procedure shown in Table 4, is used regardless of which circulation method is chosen (Driller's or Engineer's).

1. Drill no more than 3 feet of any drilling break.
2. Pick up off bottom, space out, and shut off the pump.
3. Check for flow.
4. If flow is observed, shut in the well by opening the choke line, closing the pipe rams, and closing the choke, pressure permitting.
5. Record the pit volume increase, drillpipe, pressure, and annulus pressure. Monitor and record the drillpipe and annular pressures at 15-minute intervals.
6. Close annular preventer; open pipe rams.
7. Prepare to displace the kick.

Table 4: Preparation for kick handling (Grace et al. 2003)

3.1.1. Driller's method

The Driller's method is the most widely used and the standard method to circulate a kick out of a well. Its main advantage is that it is simple and requires minimal calculations. In simplicity the Driller's method circulates the kick in one circulation, while the second circulation effectively kills the well. One circulation meaning pumping once the whole volume of the well, also referred to as bottoms up (BU). This is done to try to keep the bottomhole pressure stable and ideally constant. However, this procedure might be more time consuming, and applies a higher pressure to the well.

The Driller's method can be summarized in the following steps

1. Close in the well

   - Raise the top drive

   - Stop the pumps

   - Close preventer or pipe ram

   - Open choke line valve against closed choke

2. After sufficient time for the first pressure build up, pump slowly to open the float and read shut in drillpipe pressure (SIDPP)

3. Circulate with predetermined kill rate, when keeping choke-pressure constant. Read standpipe pressure and calculate.

4. Circulate out the influx at a predetermined pump rate and control the choke to keep the standpipe pressure constant. Make sure that all influx is circulated out of the well before proceeding to the next step.

5. Displace the existing mud using a predetermined pump rate and a new mud weighted to balance the formation pressure, thus killing the well.

6. Control the choke to give constant standpipe pressure while circulating the new mud up the annulus.

The Driller's method can also be summarized in a killsheet as prepared by IADC, please see Appendix C.

3.1.2. Engineer's method

The Engineer's method, also referred to as the wait and weight method, is a more calculation intensive method than the driller's method. It only applies one BU to both kill the well and circulate the influx out. This is done by waiting for the weighting of kill mud, and circulating the influx using the kill mud.

The Engineer's method can be summarized in the following steps:

1. Close in the well
    - Raise top drive
    - Stop pumps
    - Close preventer or pipe ram
    - Open choke line valve against closed choke
2. After sufficient time for the first pressure build up
    - Read shut in annulus pressure (SICP). Pump slowly to open the float and read shut in drillpipe pressure (SIDPP)
    - Determine surface volume gain
    - Determine the new mud weight for killing the well, SGkill. Use the true vertical depth (TVD) of the bit in a deviated well.
    - Determine preparations for killing, watch drillpipe pressure (SIDPP) and casing pressure (SICP) for a second pressure build-up, resulting from gas percolating up the annulus. If necessary, bleed off mud from the annulus until drillpipe pressure reverts to the original shut in drillpipe pressure (SIDPP).
3. Start killing with the new mud weight as soon as possible in the following way:
    - Open choke and start the pumps at a pre-selected reduced killing speed

- Regulate the choke opening to the initial choke pressure (SICP). Read the corresponding drillpipe pressure which will be initial circulating pressure (ICP).
- Find friction loss in system= ICP – SIDPP
- Determine the surface to bit pump strokes and travel time (t1) and bit to surface pump strokes and travel time (t2)
- Calculate either the new friction loss(Pc2) from the previous (Pc1) using Eq 3.1 or the final circulating pressure(FCP) from the pressure at slow circulating rate(SCR) using Eq.3.2. SGkill is the kill mud weight and SG1 the original mud weight

$$p_{c2} = p_{c1} \cdot \frac{SG_{kill}}{SG_1} \tag{3.1}$$

$$FCP = SCR \cdot \frac{SG_{kill}}{SG_1} \tag{3.2}$$

- Regulate the choke opening during t1 in such way that ICP drops gradually to FCP while maintaining the same pump speed.
- At the end of the interval t1 when the new heavy mud (SGkill) has reached the bit, continue to circulate the influx out of the hole. Maintain pump strokes constant and regulate the choke opening in such a way that the FCP is the observed standpipe pressure.

The Engineer's method can also be summarized in a killsheets as prepared by IADC, please see appendices A and B.

4. Automated well control

There are suppliers that have developed systems to handle kick detection and controlling the handling of the kick. These systems can be applied to both MPD and conventional drilling, although the application will most likely be with MPD systems, where there already are lot of the systems and equipments used in place.

With the general development of technology, automation is also coming to the drilling rig. With more advanced flow and pressure meters, the potential for more accurate handling of well control is apparent. In the first instance it is the detection of kick that is being upgraded, with hydraulic models monitoring the measurements from flow meters, pressure transducers and rig pumps. In some cases measurements from MWD tools and especially pressure while drilling (PWD) data further improve the potential for well control helped by automated systems.

There are two main competitors in this field. @Balance offers Schlumberger's project Dynamic annular pressure control (DAPC), and Secure Drilling is a part of Weatherford. Both are offered as enhancements to conventional drilling, but are for the most part applied as integrated parts of various MPD systems. The knowledge of the systems is limited to published materials, so now thorough procedures can be reviewed, only the general concepts of the technologies.

4.1. Backpressure MPD system

Since both the automated well control systems reviewed are developed on the basis of a backpressure MPD system, here follows a short description of the basics of drilling with a backpressure system.

By drilling underbalanced, but by adding a backpressure, the resulting ECD is in balance. While making connections, the driller can maintain the bottomhole pressure by applying a backpressure and sealing the wellbore with a continuous circulation device, like a continuous circulation coupler (CCS) or a rotating circulation device (RCD). The backpressure is added in either one of the two methods:

- Can be achieved in an open system by using a continuous circulation method

- Can be achieved in a closed system by using a backpressure setup

The system seals off the wellhead and applies a surface backpressure by restricting the return flow through a choke. Thus the backpressure can replace the loss of pressure when the rig pumps are turned off, and causing the loss of frictional pressure. This backpressure can be applied both when drilling, and during connections.

This gives us more control of both static and dynamic pressure, and although it might not always be possible or necessary to make them equal, it enables us to better control the pressure within a pressure range defined by downhole conditions.

The control of this system can also be achieved by an additional pump at the backpressure line, increasing control, magnitude and precision of the applied backpressure. The system can also be run automatically through a control system which applies a hydraulic model, downhole pressure data from pressure while drilling (PWD) tools, and may also include flowmeters to enhance kick detection.

By using a back-pressure pump, the system can exercise an even faster response to pressure changes in the well. In many cases, a choke system will not be fast enough if something dramatic happens to the BHP like a pump failure or a human error. Also, a choke can only trap the pressure that is left in the well when it finally is able to close. The back-pressure pump can respond quicker, and can apply more pressure than a flow restriction can. The precision of back-pressure from a pump is also greater at lower flowrates compared to choke.

4.2. @Balance

The systems provided by Schlumberger are offered through @Balance, and includes several systems related to MPD and UBO drilling. The system for kick detection and pressure control is referred to as Dynamic Annular Pressure Control (DAPC).

The DAPC is a system designed as a part of a backpressure MPD system. This system applies a backpressure pump to keep BHP constant when not circulating, most typically during a connection. The system also involves an automated choke, and the control system. An illustration showing the setup of the system can be seen in Figure 7. The kick detection has been done in various ways. Fredericks et al. (2008) applies a Coriolis flow meter, while later

Reitsma (2010) arguments that the system can detect kicks better by applying a model that looks at trending data for annular discharge pressure and standpipe pressure.

In the full scale test described by Fredericks et al. the system is a part of several other drilling system providers. The DAPC is handling kick detection and control, and analyzing the hydraulics. In this case wired drillpipe and real time PWD measurements were used to calibrate the hydraulic model while drilling ahead. This case thus applies several high end technologies to further the well control, as it was described a prerequisite for the project which Fredericks et al. is referring to.

The system is applied in this instance to one of the more widely used MPD methods, as backpressure control is a highly effective way to control BHP without adding or modifying too much equipment. The system should therefore be thoroughly tested and be well developed. By looking at the work done by Reitsma (2011) it could be indicated that the system is being developed further, or that the kick detection with Coriolis meter isn't working optimally. However, this shows that the system has been successfully tested and is still in development. Further full scale test results should be published to prove the value of the system

4.3. System value

As it is offered as a system that can be implemented to other drilling systems together with other suppliers, this could prove a promising system. However, such combinations could also present major challenges when the interfaces of different systems don't always work well together. The tests done by Fredericks et al. seemed positive, but other full scale test results hasn't been published since, so it can't be made for fact that the system is fully operational. This could be because the focus of the project is on the system handling the hydraulics, and that to apply it to drilling it needs to be combined with an advanced MPD system. Thus there might be the challenges of competing companies and other management related problems. Then again, the core of such a system is a hydraulics model and programmed controllers for chokes and pumps. Those aren't proprietary and very high end developments, and it might be that suppliers of MPD systems can well enough develop their own systems for this.

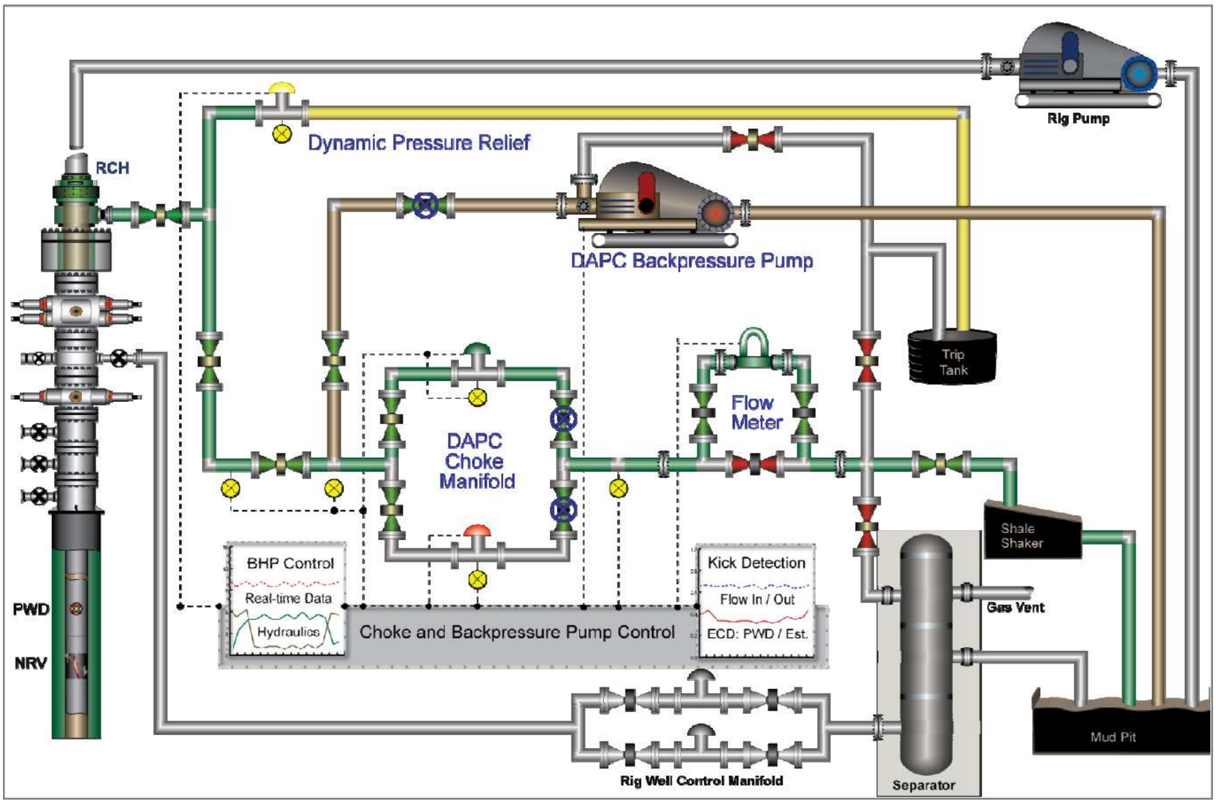


Figure 7: DAPC system setup (Reitsma 2010)

Should @Balance supply the whole MPD drilling package however, the experience with the system in operation, and a well built model with a lot of data available for calibration could prove to be a great advantage.

4.4. Micro-Flux Control

Micro-Flux Control (MFC) is Weatherford's system for pressure control, developed by Secure Drilling. The system aims to supply increased safety and reduce risk of kicks with all drilling systems on all rigs, according to (H. Santos, Reid, and Lage 2004).

The system is also a backpressure MPD system that applies rigid pressure control to a closed-loop drilling fluid system. As with the above mentioned @Balance DAPC system, this is based on the MPD backpressure system, but may be applied to other drilling systems as well. Through controlling a backpressure pump and an automated choke, together with a RCD completing the closed circulation system, the system setup is shown in Figure 8. Similar systems are offered by several others, but the thing separating the MFC system is that it applies such strict control on the flow measurements and well control that it can handle pressure tests while drilling ahead (H. Santos, Reid, and Lage 2004).

These pressure tests will be used to calibrate the pressure control of the well as drilling progresses. Whereas the DAPC of @Balance will calibrate its hydraulic model real time with hydraulic and PWD data from the well, the MFC system will measure fracture and pore pressure as it drills ahead. Since the system is closed and the sensitivity of the flow measurements are so good, the risk of what is referred to as “micro influxes” or “micro out fluxes” by the authors, it can take leak-off and inflow tests as it drills ahead. However, (Helio Santos, Leuchtenberg, and Shayegi 2003a; 2003b) don’t state what method is used to ensure such accurate flow measurements. However, from the schematic in Figure 8, it may be glanced that item 2 looks very much like a Coriolis flow meter. Item 1 would be the RCD, and item 3 reflects that the control system is the important third part of the system.

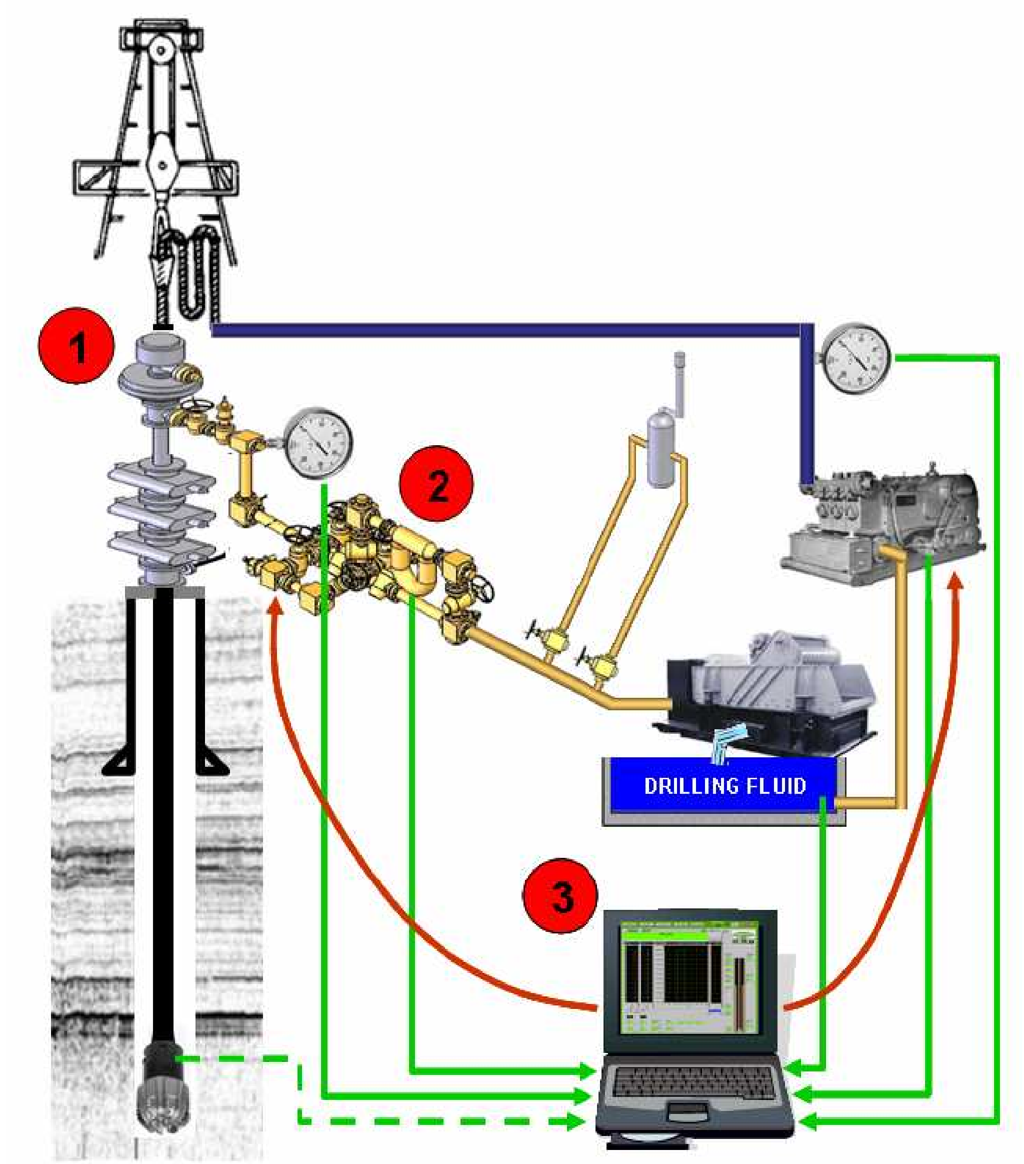


Figure 8:MFC system setup (Santos et al. 2007)

5. Analysis of CMP well control procedures

The well control procedures for CMP has been put down by AGR in a slideshow depicting the well and the fluid system for several steps throughout the process of handling the kick, as well as an official procedure plan for the incident. Both of these have been used in the following analysis of well control with CMP compared to conventional well control. Figure 9 shows the setup of the subsea BOP stack used for CMP drilling, and is essential in this analysis. The well control procedure steps as shown requires a working anti-U-tube valve in the drillstring. See chapter 5.2 for alternative procedure for drillstrings with nonexistent or malfunctioning anti-U-tube valve.

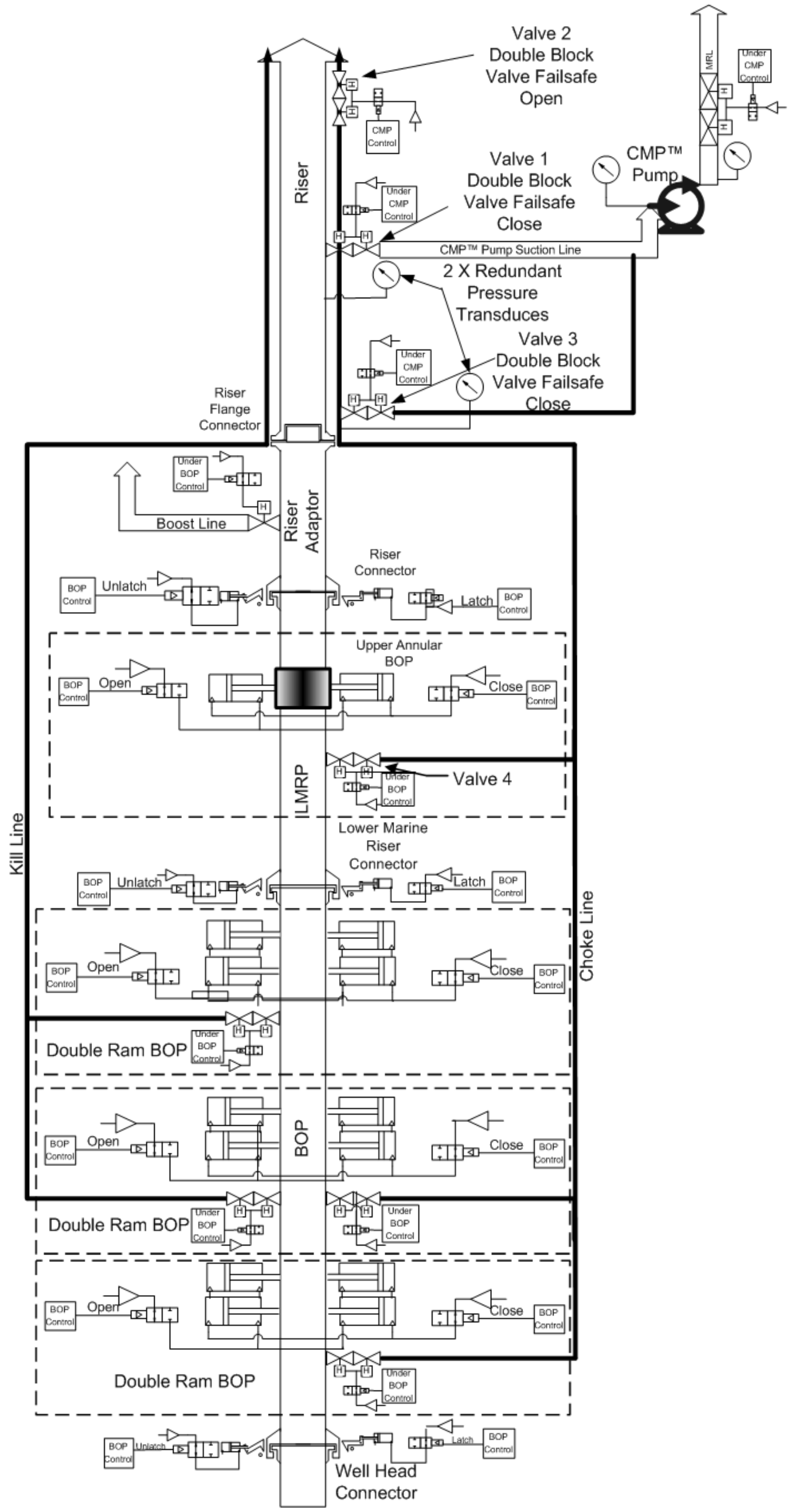


Figure 9: BOP stack sketch

5.1. Normal Procedure

The procedure denoted as normal procedure is the well control procedure for a drillstring with a working anti u-tube valve. For contingency or alternative procedure, it is referred to the following chapter 5.2. The numberings below each step headline are referring to the numbered steps in the slideshow (SS) showing the steps, and the procedure document (D) both provided by AGR.

Step 1: Detection

(SS: 1-5, D1)

Detection of the kick is the first step in any well-control procedure, and for conventional drilling it is mentioned above that pit gain and monitoring the trip tank is the main indication of a kick. For CMP the pit gain comes in addition to some more advanced indicators. The CMP pumps will show an increase in speed\power usage to compensate for the influx. If the pump is set to keep a constant suction pressure, this will result in the speed of the pump to increase. If the pump is set to keep a constant speed, the pressures will increase indicated by the pressure transducers. Furthermore there will be a Coriolis flow meter on the mud return manifold topside that will further help identify an increase in flow return. The principle the meter is based upon indicates a flow increase much more precisely than a pit gain may. Thus, influx volumes down to half a barrel may be identified.

Comment

It seems that the detection of the kick is more rapid with CMP, having both the flowmeter and pump indicating an increased flow in addition to the traditional pit gain. However, the sensitivity of half a barrel may seem unnecessary, as I assume there will never be such a stable flow return that once there is a deviation of half a barrel, we can assume it's a kick. Care should be taken not to too quickly flag a change in flow returns as a kick. Furthermore, with the u-tube phenomenon, even with an anti-u-tube valve, there may come air into the drillstring. This is a result of the mud freefalling, and this will happen even with the arrestor valve, below it. Then small bubbles of air come into the well, and passing the subsea pump they will cause it to operate abnormal and potentially be flagged as a kick. These problems will need to be mitigated with sound procedures and limits, to avoid unnecessary warnings. This is not mentioned in the procedures, either in the document or the presentation, but it *should be implemented in the operating software. However, a written procedure should be prepared, so that this can be manually monitored and verified for contingency.*

Step 2: Shut-in

(SS 6-7, D 2-7)

Stop drilling and space out drillpipe, prepare to shut in well, stop rig pumps, stop CMP pumps. It is important that the rig pumps are stopped before the CMP pump so that the mud level doesn't start to travel up the riser. The valve on the MRL should close automatically to prevent u-tubing into the riser. The BOP and CMP pressures should be monitored to verify kick, and try to estimate the magnitude. Then the annular preventer is closed

Comment

The shut in of the well following these steps is known as a soft shut in, done to mitigate u-tubing problems. This differs from normal shut-in procedures where hard shut ins, with annular preventer being closed before pumps are shut off are normal on the Norwegian continental shelf (NCS).

Step 3: Stabilize and monitor well

(SS 8-9, D 8-9)

The well is monitored and stabilized, as with any well control method. The kill calculations are done and a kill schedule is made.

Comment

This step is the same as with any well control procedure, although the calculations needed are different since the system is different.

Step 4: Close isolation valves

(SS 10A, D 10)

A number of isolation valves are closed to prepare the system for handling the influx. Referring to Figure 9, Valve 1 is closed and isolates the main suction line from the subsea pump. Valve 2 is also closed, isolating the choke-line and redirecting it into the mud pump.

Comment

With Valve 1 closed the riser is isolated and the choke is lined up and ready to be handled through the CMP system. This is only a number of steps where valves are used to divert the flow from the riser to the CMP and MRL system. It is worth to note that for every valve used, there is an increased chance of failure. The valves are failsafe closed, so the contingency is that should any of the valves fail, it is still possible to handle the kick conventionally through the riser.

Step 5: Open choke line to CMP

(SS 10B, D 10)

Again referring to Figure 9, Valve 3 is to be opened and Valve 4 closed. Now the BOP is controlling the choke line valve (Valve 4), and the CMP is controlling the isolation valve (Valve 4).

Comment

The CMP now can actively start handling the kick through the choke line and subsea pump. Both the subsea pump and the isolation valve mentioned may help control the pressure and flow from the well. This is also where the well control now will be different from conventional control, as the flow out of the well is controlled by both a choke line valve at the subsea head, as well as the subsea pump. The equipment handling the kick here now will be bigger, as a MRL is much larger than the choke line, and the pump also is a difference.

Step 6: Obtain pressure readings and start rig pumps

(SS 11-15, D 11-15)

This assumes a working anti U-tube valve as described is part of the bottomhole assembly (BHA). The rig pumps will be started slowly to obtain the pressure required for opening the anti u-tube valve.

The rig pumps are started at slow rates and slowly increased, to monitor standpipe pressure (SISPP) while building up pressure to open anti u-tube valve. The valve is predesigned to open at a pressure specific for the section currently being drilled. The opening pressure of the valve should also have been fingerprinted throughout the section. Thus, when the valve opens, that's the maximum SISPP. Now the kick pressure can be calculated using eq 5.1 and pumps are shut off again. Here p_{kick} is the kick pressure, and p_{open} is the opening pressure of the anti u-tube valve.

$$p_{kick} = SISSP - p_{open} \tag{5.1}$$

Comment

This step is done to obtain the kick pressure, and thus allowing the correction of the suction pressure as in the next step. Doing this isn't out of the ordinary; it would have had to be done in conventional operations as well if there was a float valve in the drillstring. The fingerprinting is also done in conventional operations, so in general this step shouldn't be out of the ordinary.

Step 7: Adjust suction pressure and decide circulation method

(SS 16, 17, D 16-18)

The kick pressure calculated in the previous step is added to the pump suction pressure, in addition to a safety margin typical of 50 psi, but this may be adjusted to fracture pressure. This suction pressure should now help keep the kill rate throughout the well. Using eq. 5.2 we can now calculate the new set suction pressure. Here p_{set} is the new set suction pressure, while $p_{set,pre-kick}$ is the original set suction pressure, and p_{safety} is the safety margin that applies to the well.

$$p_{set} = p_{set,pre-kick} + p_{kick} + p_{safety} \tag{5.2}$$

Comment

The suction pressure set this way ensures a uniform flow throughout the well. The difference from conventional method here is that the kill rate needs to be controlled in "both" ends of the well, so as not to cause the well to build up fluid and pressure, or lower it. However it is not mentioned here, it is assumed that all the same, care should be taken to set the suction pressure based on PVT analysis as well. The pump will not work effectively should it pump gas, so the suction pressure should ensure that no gas boils out prior to passing the pump. This is of course dependant on the well. Furthermore it is a lower limit to the maximum possible pressure the CMP system can handle compared to a conventional system handling a *kick. Furthermore the pressure limits of the CMP equipment must be considered. Should the casing pressure exceed the operating limits of the CMP equipment, the kick will have to be either circulated conventionally through the choke line, or be bullheaded.*

Step 8: Start CMP pump

(SS 18-20, D 19-20)

The CMP pump is restarted with the new suction pressure set in the previous step. This should be close to the casing pressure. Valve 4 is opened and the CMP pump now communicates with the well below the annular preventer through the choke line. The set pressure is only a starting point, and pump control should be switched to set speed.

Comment

This is where the CMP actively start handling the kick, with the flow from the well now going around the preventer through the chokeline to the CMP mud pump. It is interesting to not that the CMP pump should be switched to set speed after the pressure has equalized to the set suction pressure from step 7. This will allow the pressure just below the BOP to vary, while the flow from the well is steady.

Step 9: Start rig pumps and switch flow return

(SS 21, D21-24)

The rig pumps are started and brought up to kill rate. Flow return switched from Coriolis meter to choke and degasser line. Before switch, check that CMP flow return equals flow rate from mud pumps.

Comment

Now the CMP pump will start automatically, as the pressure builds up after the rig pumps are started. The monitoring of the CMP pump will be important here, to ensure that outflow equals inflow to prevent pressure build up. This should take care of itself if the suction pressure is set correctly. That will enable a switch to constant speed for the pump, so that the flow rate becomes stable. This will be the most effective way to ensure a constant rate, as the control of the pump doesn't allow a set flow rate without doing some intermediate calculations.

Step 10: Record pump speed and rates, switch CMP pump control to fixed speed

(SS 22-23, D 22-23)

Monitor the flow of the well and record pump info such as speed and rates, keep outflow=inflow. When the flow is balanced, operate CMP at fixed speed.

Comment

This should be one of the advantages of CMP, where the flow is very well controlled, since the CMP pump is actively controlling the outflow, and the Coriolis meter as mentioned provides better flow reading than conventional methods. The control of the CMP pump, both when reaching the flow balance, but also at fixed speed should be simple with the operating software of CMP. However, it is important that if this is to be automated, it should still show info so that this can be manually monitored all the time.

The document doesn't specifically tell to monitor pump speed and rates after the CMP control is switched to constant speed. However, it does mention to set the automated choke to keep the standpipe pressure constant, so that also the BHP remains constant. This is now where the complexity of the pressure situation in the well starts to show itself. Considering rig pumps are held at the kill rate, there is still the control of the CMP pump and topside choke valve that needs to be coordinated to control the pressure. The topside choke will control the BHP. However, there are now a number of points of interest regarding pressure, that all will be adjusted simultaneously: suction and outlet pressure of pump, BHP and the point of boiling for the gas if applicable. Should the control system be inexact or malfcuntioning, the satisfactory control of all of these points of interest could prove difficult.

Step 11: Maintaining constant standpipe pressure

(SS 24-26)

Flow on return manifold is switched to topside choke and degasser. The choke is automated and the set point should be adjusted to keep the standpipe pressure constant.

Comment

This is another operation that can be automated, and if the equipment works the control of the circulating kick is increased. If choke topside should fail, there is no barrier against possible boiling of gas in MRL, still the same as with conventional. If automated, need the possibility of quickly manually controlling it. This may require extra thought on how to place the extra equipment of CMP such as the manifold and its choke.

Step 12: Circulate the kick out, monitor well

(SS 27,28)

While continuing to circulate the kick out of the well, keep monitoring the situation and pumps, as well as standpipe and casing pressures. If some values seem unnatural, shut down pumps and close the automated choke and diagnose the situation. When the kick eventually boils out of solution, the pressure increase will cause the choke to close to keep pressures constant.

Comment

The automated choke should in this phase of the operations control the well automatically, helped by the operating system. This is the phase where the CMP automated system really can come to its benefit, where the control while gas is boiling is good, as long as the operating system and its models can handle it. As mentioned above, there will be an issue here of trying to keep the kick from boiling before reaching the pump.

Step 13: Confirm kick has been circulated out of well

(SS 30, D30)

By inspection of the return flow and pit volumes, it should be agreed that the kick is out of the well. Now the BOP stack has to be flushed and the pressure across the annular preventer needs to be equalized.

Comment

Standard procedure

Step 14: Flush BOP stack and circulate out flushed gas

Use BOP control to open BOP valve and flush and circulate out CMP pump and MRL

Comment

Standard procedure

Step 15: Determine kick pressure for killing the well

(SS 33-36, D33-36)

Using the pressure transducer connected to the riser, the pressure difference over the annular preventer can be determined. Thus the procedure to equalize the pressure can be begun after mud return line and CMP pump are shut off. There are 2 methods to restore the pressure across the preventer. They are described as Method A and Method B

Comment

This is when CMP might be a bit more complex than conventional drilling, as there are more pressures to evaluate and a little more to calculate. Differential pressure over the annular preventer will be the pressure difference between riser pressure and casing shut in pressure

Method A

This method is much the same as the second step in the conventional Driller's method. Heavy mud is used to displace the well below the annular preventer to kill the well and equalize presser across BOP.

Step 1: Adjust mud

(SS 39,40, D 39, 40)

Looking at the suction pressure used, the delta pressure from this to the ambient water pressure at the pump depth will be the increased well pressure, which the mud weight should apply. Then the mud should be prepared to add this pressure to the well

Step 2: Circulate

(SS 41)

The heavier mud is pumped into the well, and CMP suction pressure should be reduced as the well pressure increases. When the well is filled with the new, heavy mud, the pressure across the BOP should be equalized. Should the riser be filled with other blanket fluid, this should be adjusted for when determining the target suction pressure.

Comment

This is really just a change in the mud, but the calculations are a bit different from conventional operations. Furthermore, the CMP system requires the suction pressure to be adjusted at the same time, but the operating software should take care of this easily. However, this requires the pressure transducer to be working, unless the well should fracture and loss of circulation occur.

Method B

This method is quite simple. The riser is filled through a boost line with mud until the column above the BOP equalizes the pressure across it.

Comment

This is an easy way to equalize the pressure, but has a few shortcomings. The riser needs to be long/deep enough so that a proper mud column can be placed on top of the BOP.

Furthermore this goes against the CMP basics, with filling the riser, thus there might not be enough mud on the rig to do this, or possibly the boost line might not work properly.

5.2. Contingency procedure

With no or malfunctioning procedure, the normal procedure cannot be used, thus this contingency procedure to handle u-tubing has to be used. This procedure is only presented in the procedure document, not the slideshow.

Step 1, Fingerprinting

(1)

Fingerprint the pump rates needed to keep 50 psi (3.4bar) on the standpipe. This is done to keep the standpipe pressure above zero in the case of a well control situation, so that standpipe pressure can be used to adjust choke pressure

Comment

This is keeping the mud from freefalling and creating vacuums in the drillpipe and thence removing the standpipe pressure transducer and pump pressure communication with the well. This might be a challenge though. From some simple calculations shown below it can be anticipated that keeping the mud from freefalling might be a challenge. The fingerprinting is also important with a functioning anti u-tube valve, to know the slow circulation rates and frictional pressure losses. However, without the valve it is more so important to ensure that the string is always filled up to the standpipe.

5.2.1. Freefalling rate

The phenomenon known as freefalling is when the mud inside the pipe will flow faster than the pumps can keep up. In general the weight of the mud is greater than the friction force, and the resulting flow rate is greater than the pump rate. Some vacuum mechanics might be affecting this as well, but with some simple calculations the matter has been illustrated.

The API have declared formulas to be used for the calculation of frictional pressure losses, for either drillpipe or annulus, and for the properties of the mud, either the Newtonian, Bingham-Plastic or the Power-law method. (Bourgoyne 1986, 2:155) For these calculations a lot of assumptions were made to simplify, and focus on the result; that high flow rates will be needed to prevent freefalling. From the formulas declared by API and given by Bourgoyne, the formulas for turbulent flow with Bingham-Plastic fluid were chosen. A vertical well, as a simple case that induces the largest freefall rates was chosen.

$$\Delta p_{tot} = \Delta p_{gravity} + \Delta p_{friction} \tag{5.3}$$

$$\Delta p_{friction} = \frac{\rho^{0.75} \cdot \bar{v}^{1.75} \cdot \mu_p^{0.25}}{1800 \cdot d^{1.25}} \cdot \Delta L \tag{5.4}$$

$$\Delta p_{tot} = BHP - p_{surf} \tag{5.5}$$

$$\Delta p_{gravity} = \rho \cdot g \cdot D \tag{5.6}$$

$$\Delta p_{gravity} = 0.052 \cdot \rho \cdot D \tag{5.7}$$

Now since eq. 5.4 involves a constant and the API formulas uses field units, we can rewrite eq 5.6 to 5.7

By inserting eq 5.4, 5.5 and 5.7 into 5.3, and order it to express the mean velocity, we get eq 5.8

$$\bar{v} = \sqrt[1.75]{\frac{(BHP - 0.052 \cdot \rho \cdot D) \cdot 1800 \cdot d^{1.25}}{\rho^{0.75} \cdot \mu_p^{0.25} \cdot \Delta L}} \tag{5.8}$$

Now since the eq xxx involves a constant and the API formulas uses field units, we can

Surface pressure	50	psi	3	bar
BHP	5000	psi	345	bar
Length	7000	ft	2134	m

Table 5: Calculation parameters

The pressures and well depth was chosen randomly, as emphasis is put on mud and pipe variations and their effect on the freefall rate.

To illustrate the variation in freefall rates with mud, the freefall rate was plotted against the mud weight, with a given pipe ID and mud rheology. For pipe with 1.75" id, the freefall rate is plotted in **Feil! Fant ikke referansekilden.** with one graph for mud with plastic viscosity of 25 and 40 cp, and the same in **Feil! Fant ikke referansekilden.** when the pipe id is 3.75".

From Figure 10 it is apparent that there is a difference in the rate to keep up with freefalling from the two fluid viscosities. What the graph doesn't show is the domain between 25 and 40 cp for mud with the same weight. However, it is clear that the rheology can affect the freefall rate as much as the mud weight. At the same time, rheology has a direct impact on the freefall rate, while the effect mud weight has can be more or less depending on BHP and surface pressure. The rheology effect will also be affected by depth, as the friction will increase with the length of the string. However, the graph shows that in general, for the same mud weight, the higher the viscosity the lower the freefall rate. The effect is here about 350 LPM (liters per minute) between 25 and 40 cp. The outer points of weight, with 1.20 and 2.20 is roughly 400 LPM.

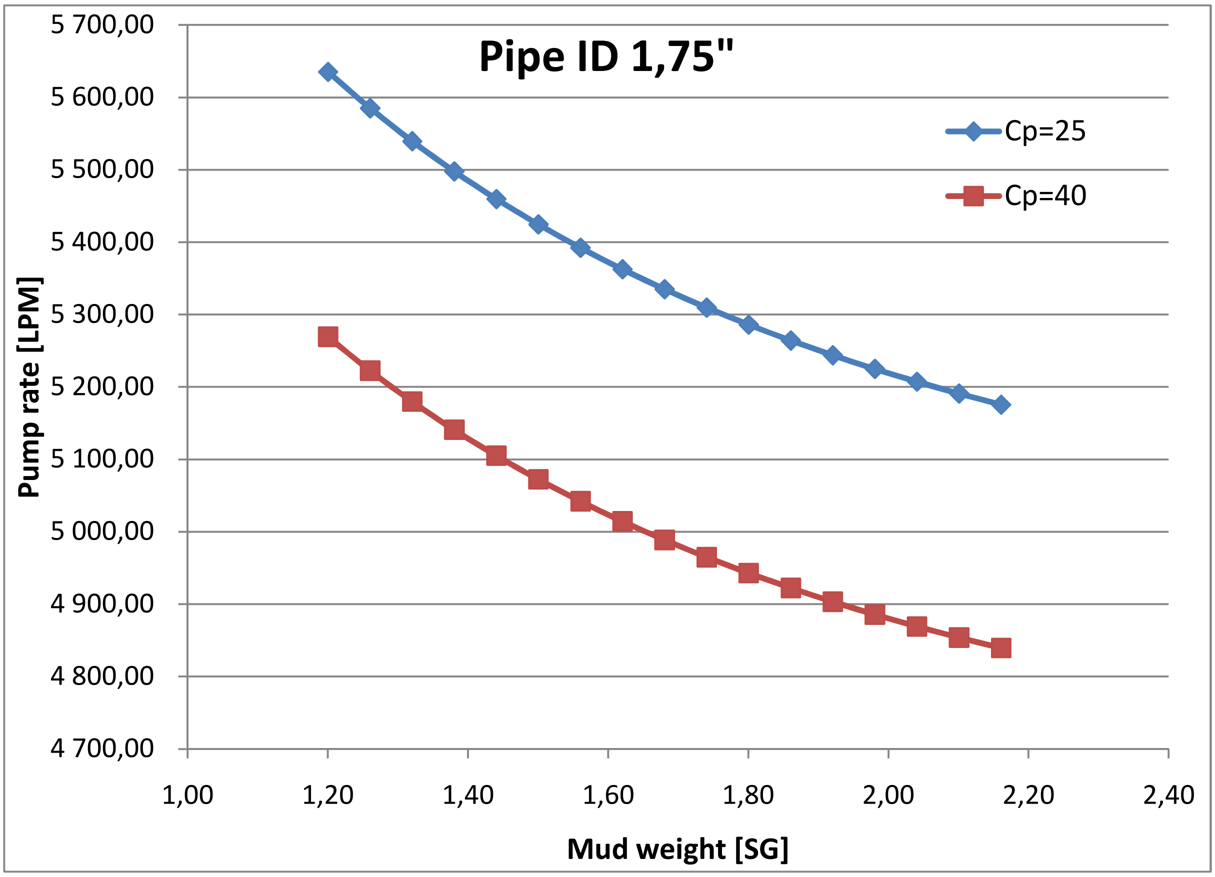


Figure 10 Freefall rate vs. mud weight, pipe ID 1.75"

Looking at Figure 11**Feil! Fant ikke referansekilden.** it is apparent that the rates are much higher with pipe ID 3.75” than with 1.75”. These pipe sizes are not meant to refer to specific drillpipes, just used to illustrate the effect pipe ID has on the freefall rate. The freefall rate is here over 40 000 lpm for some mud weights. This might show that the calculations are simplified just a bit too much, and that more thorough analysis should be done. On the other hand, it is beyond doubt that the rate to keep up with freefalling mud will be high. Drillpipes with ID around 1.75” is 2” OD, a size that is rarely used on the NCS. With this pipe size requiring around 4000 LPM in these calculations, there is reason to believe that for normal used pipes with ODs from 5” to 6 5/8” will have significant flow rate requirements if freefalling is to be avoided.

Again, these are simple calculations, with quite arbitrary picked parameters, to show the magnitude of flow rates needed, as well as the impact mud weight, rheology and pipe size has on the freefall rate. More thorough simulations with complete well set up, as well as flow up the annulus should be looked into to further determine the severity of the freefall rate problem.

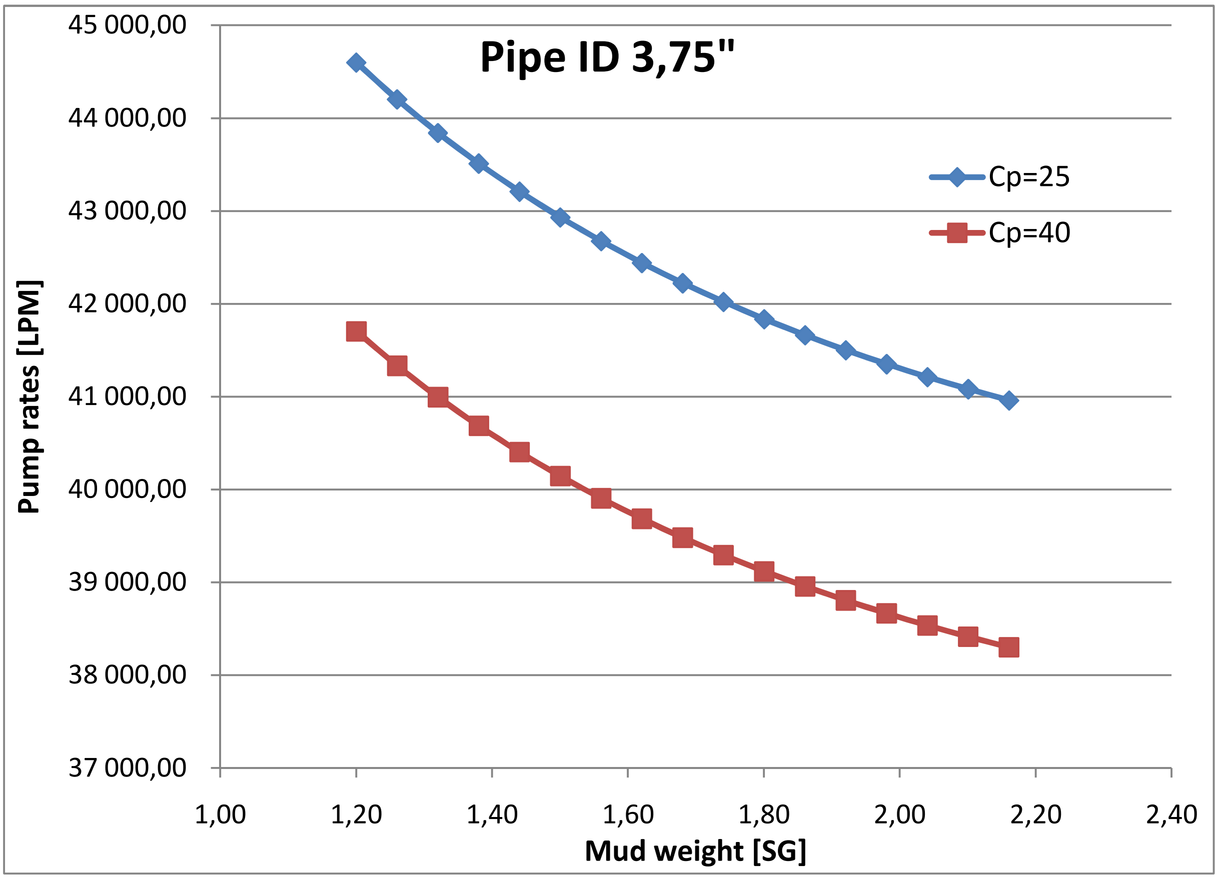


Figure 11: Freefall rate vs. mud weight, pipe ID 3.75”

Step 2: Detect influx

(2)

Indications of a kick are generally an increase in pump speed, or an indication from the Coriolis flow meter. Both separately and especially combined these indicators can early indicate kicks of rather small sizes

Comment

This is done in the same way with or without the anti u-tube valve.

Step 3: Shut-in

(3-6)

The drillpipe is spaced out, choke line to BOP is opened, Valve 4 in Figure 9. Then the valve to the CMP suction line is closed, Valve 1 in Figure 9. Now the well is prepared to be shut in, and annular preventer is closed.

Comment

The difference here is that a hard shut in is done, as the pumps aren't shut down prior to shut in. It says under step 4 in the document that: "The in-line choke valve (valve 2) and the choke line to CMP pump valve (valve 3) are pre set when setting up for dual gradient drilling". What this means exactly is not fully understood, the procedures for a working anti u-tube valve doesn't express it in this way, merely telling which position the valves should be in. It should say so in these procedures as well, so that the two different procedures don't have to be mixed up in a well control situation. By glancing at the next few steps, noting that there isn't said anything about these two valves, it is assumed that: Valve 2 (Figure 9) should be closed to isolate rig choke line, and Valve 3 (Figure 9) should be opened to direct flow from below the annular preventer and choke line to the CMP pump and MRL.

Step 4: Adjust pumps

(7-9)

The rig pumps should be slowed to kill rate, which is the fingerprinted rate that keeps 50 psi (3.4 bar) on the standpipe. CMP pump suction pressure is increased to outflow matches inflow, then 50 psi safety margin is added. The safety margin is well specific and may be adjusted.

Comment

The pumps are synchronized to ensure the kill rate is uniform throughout the well. Whereas the setup with anti u-tube valve demanded calculations to adjust the pump, this is based on fingerprinting and adjusting the pumps to match. This can be easily done manually if the automated system should fail. However, this is typically much like conventional well control, and doesn't offer any improvement to well control. The safety margin is the same as for normal procedures and may be adjusted to well specific conditions such as safety towards fracture pressure etc.

Step 5: Prepare to circulate

(10-13)

Kill calculations and decision on how to circulate the kill is done while the well is stable and pumps are at kill rates. Use well control model to prepare kick circulation and do necessary calculations. Decide based on the well control model if it is safe to bring the kick up to surface through the CMP pump and MRL. Flow returns on the manifold is switched to the degasser line rather than the Coriolis flow meter line. Automated choke control to keep standpipe pressure and BHP constant. The CMP pump control is set to keep fixed speed, thus keeping the kill rate regardless of well pressures. Now pressure control is by the automated choke only

Comment

The procedure only says to use the well control model. Steps to do the calculations manually are missing, and should be included for safety control and contingency should anything about the automated system fail. Interesting to note that a comment about the decision to circulate through CMP pump and MRL or not is made here. No such comment is made in the normal procedures. In general the pressure control is better without the u-tube effect, but the boiling of gas in the CMP pump and MRL is also a problem with the anti u-tube valve. Awareness of this matter could with safety in mind be expressed in both procedures. Flow is switched as with normal procedures. Automated choke control on the manifold the same as for normal procedures. As for the normal procedures, CMP pump is operated at fixed speed, giving control of the pressures to the automated choke. This result in a system generally simple and similar to conventional drilling should manual control be necessary; adjustment of the choke.

Step 6: Circulate out kick

(14-16)

The CMP suction pressure will indicate changes in the standpipe pressure and BHP, and will allow for choke adjustment, given that CMP pump is operating at fixed speed. While monitoring flow, continue till kick is out of the well

Comment

As with the normal procedures, the kick is circulated out with choke keeping the pressures stable, and pumps keeping the kill rate. Missing again some thoughts and procedures to handle the boiling of gas, by adjusting pressures and keeping the gas from boiling prior to reaching the MRL.

Step 7: Confirm kick is out of the well

(16-17)

Confirm the well fingerprint to pre kick fingerprint

Comment

Should also include the comments from the normal procedure, where inspection of pits and pit level as well as conferring with the whole crew to agree that kick is out of the well. Otherwise the same as normal and conventional procedures.

Step 8: Flush BOP stack and circulate out trapped gas

(18-19)

There may be trapped gas below annular preventer, flush and circulate out

Comment

Standard procedure.

Step 9: Flow check and decide on method to balance pressure across BOP

(20-22)

The well is flow checked after CMP pump control has been switched back to suction pressure control. Mud pumps are kept at pre kick kill rate, return flow should be on Coriolis line. As with the normal procedures there are two methods to restore pressure across the annular preventer.

Comment

In this step a flow check is performed to ensure a stable well, but the procedure doesn't say specifically to switch return flow on choke manifold, just to measure with Coriolis meter. Also *it should be noted that if the 50 psi wasn't held at the standpipe, there might be air in the drillstring, and this together with the possibility of u-tubing could result in a unsuccessful flow check. Choosing method to restore pressure is the same as with normal procedures.*

Method A

This method is similar to Driller's method, as it uses heavier mud to keep the BHP constant, while lowering the shut in casing pressure so that the pressure across the annular preventer is equalized

Step A1: Set new mud weight and prepare new mud

(24-25)

The difference in pump suction pressure to ambient seawater pressure is the additional pressure needed by the new mud weight. Calculate and prepare with safety margin.

Comment

Standard calculations and mud weight adjustment.

Step A2: Prepare CMP pump schedule

(26)

As the new heavier mud replaces old mud, suction pressure should be gradually decreased, calculate and make schedule

Comment

Standard pump schedule, however u-tubing could affect the pressure here, so a safety margin on the suction pressure could with benefit be added to compensate for this. However, calculations shown above under freefalling may indicate that to eliminate u-tubing by pumping may be hard, but the effect may be mitigated.

Step A3: Displace mud and check well

(27-29)

Displace mud, and when suction pressure equals or is close to ambient seawater (or blanket fluid) pressure in the riser, the mud has been properly displaced. Flow check well by stopping rig pumps and let well u-tube, check for flow from well.

Comment

New mud should provide desired BHP without the casing pressure, so suction pressure should be close to ambient pressure. When the flow check is done, the mud is allowed to u-tube. This will not increase BHP as the pump is set to operate on suction pressure. However, this may be a very critical point if the flow check should fail. If there still should be gas in the well, or a new influx occurs for any reason, the standpipe doesn't have communication with the mud in the drillstring. Thus the handling of a possible well control at this point may be complicated, as the standpipe pressure can't help determine the BHP.

Step A4: Additional check

(30-33)

Perform additional check to ensure that well is dead: stop CMP pump and monitor casing\suction pressure, should there be a kick in the well, these will increase. If well is not dead, recalculate and start procedure anew with new heavier mud.

Comment

Additional check to ensure well is dead. Since u-tubing already occurred with the previous check it is safe to turn off CMP pump without risking an increase in BHP.

Resume operations if flow check ok.

Method B

As with the normal procedures, this method applies pressure on top of the annular preventer to balance the pressure again.

Step B1: Calculate mud weight and prepare

(35-36)

Using the suction pressure again, calculate the required pressure supplied by mud and add safety margin. With the new mud on top of the annular preventer, no casing pressure should be needed when annular preventer is opened

Comment

Standard procedure calculating the mud weight from a given pressure requirement. The procedure doesn't say anything about balancing the mud weight against the volume (height) of the mud column in the riser. As it will be hydrostatic pressure, a lower weight can be chosen of the volume is greater, and vice versa.

Step B2: Use boost line to fill riser with mud

(37)

Fill the riser with mud to the required height to balance pressure and check pressures above and below preventer.

Comment

The procedures states that mud should be pumped to the required height in the riser. This should be corrected to clarify that the required volume should be pumped. The pressures are checked with pressure transducers in the riser and in the CMP suction line

Step B3: Open annular preventer and set valves to correct position and flow check

(38-42)

Annular preventer and CMP suction line valve (Valve 1, Figure 9) is opened, while BOP choke line valve (Valve 4, Figure 9) is closed. Now flow check well and check against fingerprinting

Comment

Here the u-tubing isn't mentioned, but it should. Depending on the weight and volume of the mud pumped into the riser in step B2, there could still be some u-tubing occurring during the flow check. The procedure steps from Method A flow check might be put to good use here.

Resume operations if flow check is ok

6. Discussion

6.1. The CMP technology

As discussed in chapter 2.3 and 2.4 there are both advantages and challenges in using the DGD technology.

The major advantage of the technology is the effect the removal of mud in the riser has on the BHP, and the possibility to easily regulate it with the CMP subsea pump. The fluid column is greatly changed by the fact that the pressure in the riser in general doesn't affect the BHP since it is equal to normal water pressure. The CMP pump can easily regulate the BHP by adjusting the fluid column above the inlet to the suction line. Thus the drilling window has been opened, since the gradients can be calculated from the mudline, and also the response time for adjusting the BHP has been greatly improved.

This leads to making DGD and the CMP system a technology to enable the drilling of projects with very tight drilling windows, and also improves drilling in normal operations. The improvement is mainly from increasing the efficiency of drilling. With pressure control that good, the BHP can be adjusted without weighting and circulating in new mud, so that lost circulation and differential sticking should be very much less likely. This leads to less nonproductive drilling time caused by these two incidents. Thus the system can prove to be highly economical, and thus again another enabling aspect.

However, there are some obstacles to overcome for the technology to be widely accepted. One of which may be that the system as it is designed, is highly dependent on the anti u-tube valve. For the safe operation during shut-in or low pump rates, u-tubing will have to be mitigated. The proposed anti u-tube valve is a means to meet this problem, but has yet to be tested successfully in the field, according to Godhavn. He also proposes that a continuous circulation device may help solve the problems related to u-tubing. U-tubing could, under normal drilling operations affect the BHP, depending on what operation mode the CMP pump is in. Should it be in constant suction pressure, it shouldn't affect the BHP for too long till the pump will adjust. Should it be in constant speed (constant flow) the BHP will increase until u-tubing equalizes between the drillstring and annulus, or till it is stopped. Furthermore, the u-tubing will result in air bubbles in the circulation system, which might trigger the kick detection alarms, and they could also reduce the service time of the pump.

Therefore, either the u-tube valve has to be developed satisfactory, or other options to prevent the u-tube effect should be considered.

The CMP system is a developed RMR system, as it is connected to the subsea BOP stack by a riser, while the RMR is an open system. The added riser allows for drilling through hydrocarbon bearing zones, as well control now is possible. The RMR system is designed for tophole sections where well control is no issue. This results in that the mud return equipment is not designed to handle well control, and it is to be anticipated that an attempt to apply the same mud return equipment will be used for CMP purposes as well. Thus it is not rated for the high pressures well control equipment normally is. For instance AGR informs that the MRL is rated for operation on 35 bar. This is much less than a BOP is required to handle. Testing and verification of the system's ability to handle the pressures associated with well control situations should be done. Furthermore it is worth to notice that the MRL is a AGR design and is a rubber hose which features a ¼ turn connections. The hose's ability to potentially handle the gas coming out of solution can become a serious issue.

Lastly, as with all new technologies, CMP will face a challenge in being implemented as a new and different method to drill. CMP will not only be different in the way drilling is done, it will also greatly affect the safety aspects of the drilling process. Although the system should add to the safety of drilling for hydrocarbons, there is always great skepticism to safety-changing technologies. This is both a good thing, and a demanding aspect. The rig crews will have to develop new routines in well control, and train all over again on a new system. As well control training is one of the prime training objectives of any drilling crew, it will be even a greater challenge to train them in a new and different matter, and all the while keeping confidence. This stresses the point of having very secure test results, just as sound theoretical background, before the system is put to use in the field.

6.2. Automated well control

The information about the automated well control systems have been limited to whatever is published material, and thus the information has also been very biased.

The two systems reviewed are both based on MPD drilling in their development. Although the aim for the MFC system was stated to be for all drilling systems on any rig. Thus the real technology here lies in the control system, which is the core of any automated operation. Using a hydraulics model, together with interfaces for the available data, and taking default inputs, the system will fully or partly automate some of the operations in a drilling system. @Balance offers the DAPC system together with Schlumberger's portfolio of drilling services, while the MFC system is offered as a part of Weatherford's drilling tools. That makes them two competing systems offered by the two of the major service providers. Yet, they are surprisingly similar, that they both offer the control system as the main service, and rely heavily on the accurate flow measurements of the Coriolis meter. Although recent a publication by VP of @Balance, Reitsma (2011) may indicate that soon, the means of measuring flow may distinguish them from each other.

Other than that, it is hard to see what these systems contribute to drilling with. The published material does argument that both systems have handled pressure control well, and also handled (Roes et al. 2006; Fredericks et al. 2008; Helio Mauricio Santos et al. 2007). Then again this is working together with other suppliers and MPD systems. As the CMP system herein analyzed has its own control system and procedures for well control, it is hard to see the applicability of these systems as standalone control-systems. An indication of this might be that both systems are offered through service providers that also offers drilling systems. However, the aim of the MFC system is an admiring one; to be applied to any drilling system on any rig. That clear aim the @Balance's DAPC system lacks. So the MFC might add increased pressure control and add to the safety of conventional drilling. As the advanced drilling system will be more applied, it would be beneficial to still drill conventionally, but benefit from the increased safety of the more advanced systems, without the full cost. This is a market that probably could prove successful as there are still marginal fields that will have to be drilled with less costly conventional technologies, but still satisfying increased demands for safety.

It remains to be seen if automated systems can be applied in this way, rather than being bought by the big service providers. Because there is no doubt that any company that provides MPD and DGD systems, will need a good controlling system. And with the broad testing experience and database of such systems already tested, they may prove tempting for such companies.

6.3. CMP well control

The steps for the CMP well control procedure have all been analyzed and reviewed in Chapter 5. The discussion here will wrap up the general concerns of the procedure, and for thought on each specific step, it is referred to the mentioned chapter.

CMP is an development of the RMR system which has been tested and prepared for field tests. AGR currently have contracts to use the RMR system both in the Gulf of Mexico and in Australia for deep water drilling. As earlier mentioned, what separates the two systems is that the CMP system applies a riser and a BOP to allow for drilling in hydrocarbon bearing geologies. Thus the systems feature to handle a well control situation hasn't been tested, as the CMP system is based on RMR, but not yet tested to full scale.

The RMR system is not designed for handling and circulating a kick, and the equipment doesn't have the pressure rating normal for well control handling equipment. As mentioned the MRL hose is rated to a 35 bar pressure. This could prove problematic when there is a chance of the influx of a kick to come out of solution in or before the riser. Generally, the boiling point of gas in an oil based mud can be expected around 35 bar. This issue, and the general issue of gas boiling is missing in the information provided by AGR. The issue of gas coming out of solution will affect the pressures of the situation, and also the CMP pump will become useless when filled with gas.

The procedure analyzed doesn't either have any means of handling gas boiling. It seems like the system was designed to handle a kick without addressing the matter. It will be able to control the pressures, with good system control of pump rates and pressure applied by the choke, but it will lack control of the point of boiling. This will generally prove problematic for the operation of the pump, and possibly the integrity of the mentioned MRL hose.

Having both the CMP pump and the automated choke available as means of controlling pressures in the circulation could prove for the control of also this problem. If the hose was rated for handling the gas, the pump could modify the pressure in the annulus, without bringing the BHP out of the drilling window, so that the boiling point is not reached before the MRL hose. Then the choke could control the pressure loss in the MRL hose, and thus the effect of boiling. If the pressures are right, it could also help hold the boiling point down until the manifold and degasser is reached.

These are matters that could further strengthen the well control aspect of the CMP system. However, simulations and tests should be done, to see if this is possible to achieve.

The procedure steps provided by AGR seem very well thought through, beside the fact that they ignore the gas boiling problem.

The procedures are put for two system setups, with and without the anti u-tube valve. The normal procedure being with the valve, and the contingency procedure for drillstrings without the valve.

The normal procedure is in general similar to the driller's method, in the way that the kick is being circulated out of the well before the mud weight is adjusted. However, the BHP will at once be adjusted to be over the kick pressure, and another kick shouldn't happen. It is circulated out with the rig pumps and CMP pump set to keep the kill rate uniform through the well, and the automated choke to control the BHP as the kick progresses. When the kick is out of the well, there are two options for the equalizing of the pressure across the BOP, either to circulate in heavier mud, or add more mud on top of the BOP through a boost line to the riser. The latter in general allows for any mud to be used, as long as the height of the column and the mud weight applies the necessary pressure, while still ensuring it is compatible with the original mud.

Should all the equipment work, the procedures are well functioning. They shouldn't appear as too different for the crew, as the general flow of actions is the same as with conventional well control. However, an important thing to point out is that it is suggested that a soft shut in procedure is applied, though that shouldn't be unknown to the crews, despite not being the standard procedure. Also they do explain the calculations needed, and should help the crew to keep up with and follow the automated system. This requires the control system to also display the data used for the automated control, so that manual follow-up is possible. Should the system fail however, it may become difficult to manually control the system in a way that yields the same control over BHP and flow as the automated system would. This might be a reason for keeping the CMP pump on constant speed\flow, so that the focus in the event of system failure would be to control the choke, as with conventional well control.

Then again, a specific procedure for how to control the well should the control system somehow malfunction is not provided. The procedures clearly state that should a problem occur, the rig pumps should be stopped to avoid fracturing the well, and then ensure the BHA is pulled up into the last casing, so equipment can safely be repaired. Since CMP is a new system without field tests, it is reasonable to believe that possible problems will have to be met and solved, for the gaining of experience as a base for procedures. However, two contingency plans should be made beforehand without the need for field experiences: A procedure on how to control the well conventionally through the rig choke line, in the event of failure on CMP pump, MRL or the CMP choke manifold, and a procedure on how to control the well manually, in the event of failure on the CMP control system. The control of the well could be complex, with pump, choke, and possibly point of gas boiling to control. This requires strict and clear procedures to maintain the safety of personnel and equipment. This could be a point where CMP well control could prove to be more complex than conventional well control, and if gas is in the MRL, conventional well control is no longer an option. Thus the operation might be less safe and controlled than conventional control. That would be a major setback and obstacle for the implementation for CMP drilling. It is not likely that technologies that in the worst case could cause a lessened safety would be broadly applied, or even permitted in most areas.

7. Conclusions

From the analysis it can be concluded that there are both benefits and challenges in implementing CMP, both regarding the method itself, but most importantly the well control of the system.

- The procedures lack some key points
  - What to do in the event of control system failure?
  - How to manually calculate and monitor control system?
- Both the procedures and the available material fail to address the important problem of gas boiling
- The method for safe well control will heavily rely on the u-tube valve. Without it, the well control will still be possible, but not safer than conventional well control
- The mud return equipment, hose and pump, need to be proven to be able to handle the possible pressures of a well control situation, as well as gas.
- The CMP system has the potential to become both an enabling and improving technology. If the well control issues pointed to herein, it will also increase the safety of drilling.
- In the implementation the CMP system, well control will be the major obstacle
- Training personnel and gaining their trust and confidence with the system have to be prioritized.
- @Balance's DAPC control system is a promising candidate for increase well control, but should be coupled with a MPD system for successful implementation
- Secure Drilling's MFC system has an ambition and prospect of becoming an industry standard that improves safety without the need of great modifications
- DAPC could have the same opportunity, but lacks the ambition and goal which could prove MFC successful.

7.1. Further work

This work has been done purely analytical, and further work should be carried out to evaluate the well control procedures for CMP, as well as the potential for the automated well control systems MFC and DAPC

- Simulate and model the well control procedures of CMP
- Specially look into the issue with gas boiling, do simulations to prove if it will be a problem or not, and decide how the system should handle it.
- Lab tests of the well control abilities of the CMP should follow the simulations, to look for possible caveats in the procedures.
- Field tests of the CMP technology, and the well control abilities
- Follow up from the RMR operations to look for improvements that can be made to the equipment
- Consider options to the anti u-tube valve if it cannot be made to work correctly

8. Nomenclature

BHA: bottomhole assembly;26

BHP: bottomhole pressure;7

9.

BOP: Blowout preventer;III

BU: bottoms up;13

CCS: Continuous circulation coupler;17

CMP: Controlled mud pressure;III

DAPC: Dynamic annular pressure control;III

DGD: Dual gradient drilling;III

FCP: Final circulating pressure;16

ICP: Iinitial circulating pressure;16

LPM: litres per minute;36

MFC: Microflux control;III

MPD: Managed pressure drilling;III

MRL: Mud return line;III

NCS: Norwegian continental shelf;25

$p\_(set, pre - kick)$: Original set suction pressure;27

p_kick: Kick pressure;27

p_open: Opening pressure of anti u-tube valve;27

p_safety: Safety margin;27

p_set: Set suction pressure;27

Pc1: Ffriction loss, original mud;16

Pc2: Friction loss, kill mud;16

PWD: Pressure while drilling;17

RCD: Rotating circulation device;17

SCR: Pressure loss at slow circulation rate;16

SG1: Original mud weight;16

SGkill: kill mud weight;16

SICP: Shut in casing pressure;15

SIDPP: Shut in drillpipe pressure;14

SPM: subsea pump module;4

t1: Surface to bit travel time;16

t2: Bit to surface travel time;16

TVD: True vertical depth;15

10. References

Personal communication with John-Morten Godhavn, Nils Lennart Rolland and Kjell-Rune Toftevåg.

AGR procedure documentation, in procedure document and slideshow.

Bourgoyne, Adam T. 1986. *Applied drilling engineering*. Vol. 2. SPE textbook series. Richardson, TX: Society of Petroleum Engineers.

Forrest, Neil, Tom Bailey, and Don Hannegan. 2001. Subsea Equipment for Deep Water Drilling Using Dual Gradient Mud System. In *SPE/IADC Drilling Conference*. Amsterdam, Netherlands. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=00067707&societyCode=SPE.

Fredericks, Paul Douglas, Don Reitsma, Tom Runggai, James Neil Hudson, Ralf Zaeper, Oliver Backhaus, and Maximo Hernandez. 2008. Successful Implementation of First Closed Loop, Multiservice Control System for Automated Pressure Management in a Shallow Gas Well Offshore Myanmar. In *IADC/SPE Drilling Conference*. Orlando, Florida, USA. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=SPE-112651-MS&societyCode=SPE.

Frøyen, Johnny, Nils Lennart Rolland, Rolv Rommetveit, Roger Stave, and Hitesh Jaising. 2006. Riserless Mud Recovery (RMR) System evaluation for top hole drilling with Shallow Gas. In *SPE Russian Oil and Gas Technical Conference and Exhibition*. Moscow, Russia: Society of Petroleum Engineers. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=SPE-102579-MS&societyCode=SPE.

Gonzalez, Romulo. 2001. Deepwater drill string shut-off valve system and method for controlling mud circulation. July 24. http://patft.uspto.gov/netacgi/nph-Parser?Sect1=PTO1&Sect2=HITOFF&d=PALL&p=1&u=%2Fnetahtml%2FPTO%2Fsrchnum.htm&r=1&f=G&l=50&s1=6263981.PN.&OS=PN/6263981&RS=PN/6263981.

Gonzalez, Romulo, and Frans Sippo Wiegand Smits. 2002. Deepwater drill string shut-off. June 11. http://patft.uspto.gov/netacgi/nph-Parser?Sect1=PTO1&Sect2=HITOFF&d=PALL&p=1&u=%2Fnetahtml%2FPTO%2Fsrchnum.htm&r=1&f=G&l=50&s1=6401823.PN.&OS=PN/6401823&RS=PN/6401823.

Grace, Robert D., Bob Cudd, Richard S. Carden, and Jerald L. Shursen. 2003. *Blowout and Well Control Handbook*. Gulf Professional Publishing.

Oskarsen, R.T. 2001. Toolkit and Drillstring Valve for Subsea Mudlift Drilling. College Station, Texas: Texas A&M U.

Rehm, Bill, Jerome Schubert, Arash Haghshenas, Amir Saman Paknejad, and Jim Hughes. 2008. *Managed Pressure Drilling*. Gulf Publishing Company.

Reitsma, Don. 2010. A simplified and highly effective method to identify influx and losses during Managed Pressure Drilling without the use of a Coriolis flow meter. In *SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition*. Kuala Lumpur, Malaysia: SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=SPE-130312-MS&societyCode=SPE.

Reitsma, Don. 2011. Development of an Automated System for the Rapid Detection of Drilling Anomalies using Standpipe and Discharge Pressure. In *SPE/IADC Drilling Conference and Exhibition*. Amsterdam, The Netherlands. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=SPE-140255-MS&societyCode=SPE.

Roes, Vincent C., Don Reitsma, Larry Smith, John McCaskill, and Fred Hefren. 2006. First Deepwater Application of Dynamic Annular Pressure Control Succeeds. In *IADC/SPE Drilling Conference*. Miami, Florida, USA. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=SPE-98077-MS&societyCode=SPE.

Santos, H., P. Reid, and A. Lage. 2004. Opening New Exploration Frontiers With The Micro-Flux Control Method For Well Design. In . http://www.onepetro.org/mslib/app/Preview.do?paperNumber=OTC-16622-MS&societyCode=OTC.

Santos, Helio Mauricio, Erdem Catak, Joseph Irvin Kinder, and Paul Sonnemann. 2007. Kick Detection and Control in Oil-based Mud: Real Well Test Results Using Micro-Flux Control Equipment. In *SPE/IADC Drilling Conference*. Amsterdam, The Netherlands. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=SPE-105454-MS&societyCode=SPE.

Santos, Helio, Christian Leuchtenberg, and Sara Shayegi. 2003a. Micro-Flux Control: The Next Generation in Drilling Process for Ultra-deepwater. In . http://www.onepetro.org/mslib/app/Preview.do?paperNumber=OTC-15062-MS&societyCode=OTC.

Santos, Helio, Christian Leuchtenberg, and Sara Shayegi. 2003b. Micro-Flux Control: The Next Generation in Drilling Process. In *SPE Latin American and Caribbean Petroleum Engineering Conference*. Port-of-Spain, Trinidad and Tobago. http://www.onepetro.org/mslib/app/Preview.do?paperNumber=00081183&societyCode=SPE.

White, Frank M. 2008. *Fluid mechanics*. Boston: McGraw-Hill.

11. Appendix

Appendix A: Worksheet Wait and weight, surface BOP

IADC WellCAP Well Control Worksheet
Surface Stack - Wait and Weight Method

Well Name: ______________________ Completed By: ______________________ Date: _____ / _____ / _____

PRE-RECORDED INFORMATION

TRUE PUMP OUTPUT: ________ (Bbls/Stk @ 100%) **X** ________ (% Efficiency) **=** ________ (TPO (Bbls/ Stk))

Surface Line: ________ (Bbls) (Surface Line Capacity) ÷ ________ (True Pump Output (Bbls/Stk)) = ________ (Strokes to Pump)

DRILL STRING CAPACITY:

Drill Pipe #1: ____ Size (in.) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) **=** ____ DP Bbls

Drill Pipe #2: ____ Size (in.) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) **=** ____ DP Bbls

HWDP: ____ Size (in.) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) **=** ____ HWDP Bbls

Drill Collars #1: ____ Size (in.) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) **=** ____ DC Bbls

Drill Collars #2: ____ Size (in.) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) **=** ____ DC Bbls

________ Total Drill String Capacity (Bbls)

STROKES FROM SURFACE TO BIT:

________ (Total Drill String Capacity (Bbls)) ÷ ________ (True Pump Output (Bbls/Stk)) = ________ (Strokes, Surface to Bit)

ANNULAR CAPACITY:

Between CSG and DP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between Liner #1 and DP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between Liner #2 and DP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between OH and DP/HWDP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between OH and DC: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

STROKES FROM BIT TO SHOE:

________ (Open Hole Annular Vol. (Bbls)) ÷ ________ (True Pump Output (Bbls/Stk)) = ________ (Strokes, Bit to Shoe)

STROKES FROM BIT TO SURFACE:

________ (Total Annular Volume (Bbls)) ÷ ________ (True Pump Output (Bbls/Stk)) = ________ (Strokes, Bit to Surface)

TOTAL STROKES FROM SURFACE TO SURFACE:

________ (Strokes, Surface to Bit) + ________ (Strokes, Bit to Surface) = ________ (Strokes, Surface to Surface)

CURRENT WELL DATA

PRESENT MUD WEIGHT: ________ ppg

SLOW CIRCULATION RATE (SCR):

SCR taken @ ____________ (ft)

	Stks/min	Pressure(psi)	Bbl/min	Pressure(psi)
Pump #1				
Pump #2				
Pump #3				

CASING DATA:

CASING ____ size , ____ ID , ____ weight

SHOE DEPTH @ MD / TVD ________ / ________ ft

SHOE TEST DATA:

Depth #1 ________ (psi) @ Test MW of ________ (ppg)

Depth #2 ________ (psi) @ Test MW of ________ (ppg)

Depth #3 ________ (psi) @ Test MW of ________ (ppg)

LINER #1 ____ size , ____ ID , ____ weight

LINER #2 ____ size , ____ ID , ____ weight

LINER #1 TOP DEPTH ________ ft

LINER #2 TOP DEPTH ________ ft

LINER #1 SHOE DEPTH ________ ft

LINER #2 SHOE DEPTH ________ ft

TVD CASING or LINER ________ ft

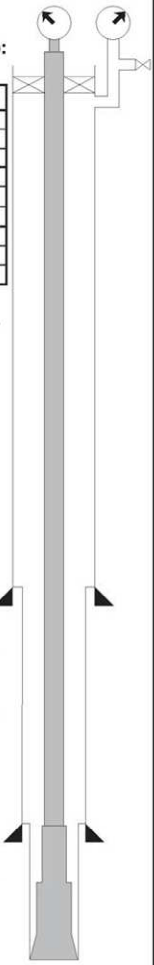
HOLE DATA:

TOTAL DEPTH (MD) ________ ft

TOTAL DEPTH (TVD) ________ ft

BIT DEPTH @ MD / TVD ________ / ________ ft

BIT SIZE ________ inches



MAXIMUM ALLOWABLE ANNULUS SURFACE PRESSURE (MAASP)

(________ (Max. MW from Shoe Test (ppg)) - ________ (Present Mud Weight (ppg))) **X** 0.052 **X** ________ (True Vertical Depth Shoe (ft)) **=** ________ psi MAASP

MAXIMUM ALLOWABLE ANNULUS SURFACE PRESSURE (MAASP) **WITH KILL MUD**

(________ (Max. MW from Shoe Test (ppg)) - ________ (Kill Mud Weight (ppg))) **X** 0.052 **X** ________ (True Vertical Depth Shoe (ft)) **=** ________ psi MAASP WITH KILL MUD

Field Units
(psi, ft, ppg)

Rev 06/12/06
Page 1

KICK DATA

SIDPP: __________ psi SICP: __________ psi PIT GAIN: __________ Bbls Time of Incident: ____ : ____

CALCULATIONS

KILL MUD WEIGHT (KMW)

(__________ ÷ 0.052 ÷ __________) + __________ = __________ ppg KILL MUD WEIGHT

SIDPP (psi) True Vertical Depth (ft) Present Mud Weight (ppg)

INITIAL CIRCULATING PRESSURE (ICP)

__________ + __________ = __________ psi INITIAL CIRCULATING PRESSURE

SIDPP (psi) Pump Pressure (psi) @ SCR of ______SPM

FINAL CIRCULATING PRESSURE (FCP)

__________ X __________ ÷ __________ = __________ psi FINAL CIRCULATING PRESSURE

Pump Pressure (psi) @ SCR of ______SPM Kill Mud Weight (ppg) Present Mud Weight (ppg)

PRESSURE CHART

Stroke or Volume	Theoretical Drill Pipe Pressure	Actual Drill Pipe Pressure	Actual Casing Pressure	Actual Pit Volume Deviation
SURFACE 0	ICP			
BIT	FCP			

__________ ÷ 10 = __________ __________ - __________ ÷ 10 = __________

Strokes Surface to Bit Strokes per Step Initial Circulation Pressure Final Circulation Pressure PSI per Step

BIT	FCP			
SURFACE				

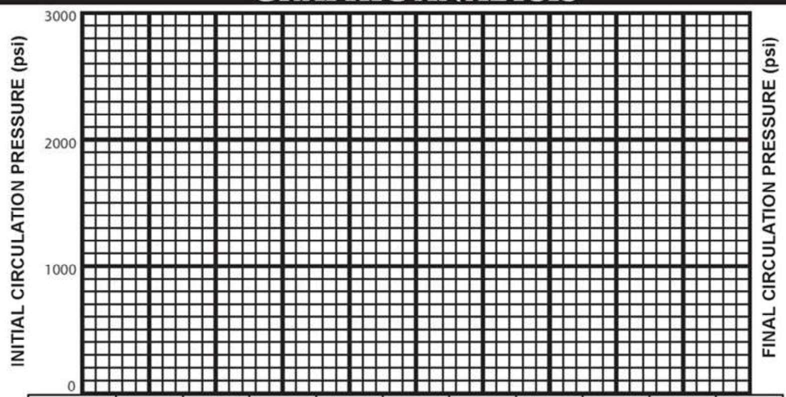
__________ ÷ 10 = __________

Strokes Bit to Surface Strokes per Step

Field Units
(psi, ft, ppg)

Rev 06/12/06
Page 2

GRAPHIC ANALYSIS



Stroke										
Pressure										
Time										

FORMULAS

1. Pressure Gradient (psi/ft) = Mud Weight (ppg) x 0.052

2. Hydrostatic Pressure (psi) = Mud Weight (ppg) x 0.052 x Depth (ft, TVD)

3. Capacity (bbls/ft) = Inside Diameter^2 (in.) ÷ 1029.4

4. Annular Capacity(bbls/ft) = (Inside Diameter of Casing^2 (in.) or Hole Diameter^2 (in.) - Outside Diameter of Pipe^2 (in.)) ÷ 1029.4

5. Pipe Displacement (bbls/ft) = (Outside Diameter of pipe^2 (in.) - Inside Diameter of pipe^2 (in.)) ÷ 1029.4

6. Maximum Allowable Mud Weight (ppg) = $\frac{\text{Surface LOT Pressure (psi)}}{\text{Shoe Depth (ft, TVD) x 0.052}}$ + LOT Mud Weight (ppg)

7. MAASP (psi) = [Maximum Allowable Mud Weight (ppg) - Present Mud Weight (ppg)] x 0.052 x Shoe TVD (ft)

8. Pressure Drop per Foot Tripping Dry Pipe (psi/ft) = $\frac{\text{Drilling Mud Weight (ppg) x 0.052 x Metal Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft) - Metal Displacement (bbl/ft)}}$

9. Pressure Drop per Foot Tripping Wet Pipe (psi/ft) = $\frac{\text{Drilling Mud Weight (ppg) x 0.052 x Closed End Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft) - Closed End Displacement (bbl/ft)}}$

10. Formation Pressure (psi) = Hydrostatic Pressure Mud in Hole (psi) + SIDPP (psi)

11. EMW (ppg) @ Shoe = (SICP (psi) ÷ 0.052 ÷ Shoe Depth (ft, TVD)) + Present Mud Weight (ppg)

12. Sacks (100 lb) of Barite Needed to Weight-Up Mud = $\frac{\text{Bbls of Mud in System x 14.9 x (KMW - OMW)}}{\text{(35.4 - KMW)}}$

NOTE: This formula assumes that the average density of Barite is 35.4 ppg and the average number of sacks (100lb) per barrel is 14.9.

13. Volume Increase from Adding Barite (bbls) = Number of Sacks (100 lb) added ÷ 14.9

14. Equivalent Mud Weight (ppg) @ ________ depth (ft) = $\frac{\text{Pressure (psi)}}{\text{Depth (ft, TVD) x 0.052}}$

15. Estimated New Pump Pressure at New Pump Rate (psi) = Old Pump Pressure (psi) x $\left[\frac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right]^2$

16. Estimated New Pump Pressure with New Mud Weight (psi) = Old Pump Pressure (psi) x $\frac{\text{New Mud Weight (ppg)}}{\text{Old Mud Weight (ppg)}}$

Appendix B: Worksheet Wait and weight, subsea BOP

IADC WellCAP Well Control Worksheet
Subsea Stack - Wait and Weight Method

Well Name: ______________ Completed By: ______________ Date: ____ / ____ / ____

PRE-RECORDED INFORMATION

TRUE PUMP OUTPUT: ________ Bbls/Stk @ 100% **X** ________ % Efficiency **=** ________ TPO (Bbls/Stk)

Surface : Line ________(Bbls) Surface Line Capacity ÷ ________ True Pump Output (Bbls/Stk) = ________ Strokes to Pump

DRILL STRING CAPACITY:

	Size (in)	Weight (lb/ft)	Bbls/ft		Length (ft)			
Drill Pipe #1:	____	____	____	X	____	=	____ DP	Bbls
Drill Pipe #2:	____	____	____	X	____	=	____ DP	Bbls
HWDP :	____	____	____	X	____	=	____ HWDP	Bbls
Drill Collars #1:	____	____	____	X	____	=	____ DC	Bbls
Drill Collars #2:	____	____	____	X	____	=	____ DC	Bbls

________ Total Drill String Capacity (Bbls)

STROKES FROM SURFACE TO BIT:

________ Total Drill String Capacity (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes, Surface to Bit

ANNULAR CAPACITY

Between CSG and DP:	____ Bbls/ft	X	____ ft	=	____	Bbls
Between Liner #1 and DP:	____ Bbls/ft	X	____ ft	=	____	Bbls
Between Liner #2 and DP:	____ Bbls/ft	X	____ ft	=	____	Bbls
Between OH and DP/HWDP:	____ Bbls/ft	X	____ ft	=	____	Bbls
Between OH and DC:	____ Bbls/ft	X	____ ft	=	____	Bbls
Choke line capacity:	____ Bbls/ft	X	____ ft	=	____	Bbls

STROKES FROM BIT TO SHOE:

________ Open Hole Annular Vol. (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes, Bit to Shoe

STROKES FROM BIT TO SURFACE:

________ Total Annular Volume (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes, Bit to Surface

ANNULAR VOL. BETWEEN DRILL PIPE & RISER:

(________ Riser ID² − ________ Drill Pipe OD²) ÷ 1029.4 = ________ Capacity Drill Pipe/Riser (Bbls/ft)

________ Capacity Drill Pipe/Riser (Bbls/ft) x ________ Riser Length ft = ________ Volume between Drill Pipe & Riser (Bbls)

STROKES TO DISPLACE RISER:

________ Volume between Drill Pipe & Riser (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes

CURRENT WELL DATA

PRESENT MUD WEIGHT: ________ ppg

SLOW CIRCULATION RATE (SCR):

SCR taken @ ________ (ft)

	Stks/min	Pressure(psi)	Bbl/min	Pressure(psi)
Pump #1				
Pump #1				
Pump #1				
Pump #2				
Pump #2				
Pump #2				
Pump #3				
Pump #3				
Pump #3				

CASING DATA:

CASING ____ size, ____ ID, ____ weight

SHOE DEPTH @ MD / TVD ____ / ____ ft

SHOE TEST DATA:

Depth #1 ____ (psi) @ Test MW of ____ (ppg)

Depth #2 ____ (psi) @ Test MW of ____ (ppg)

Depth #3 ____ (psi) @ Test MW of ____ (ppg)

LINER #1 ____ size, ____ ID, ____ weight

LINER #2 ____ size, ____ ID, ____ weight

LINER #1 TOP DEPTH ____ ft

LINER #2 TOP DEPTH ____ ft

LINER #1 SHOE DEPTH ____ ft

LINER #2 SHOE DEPTH ____ ft

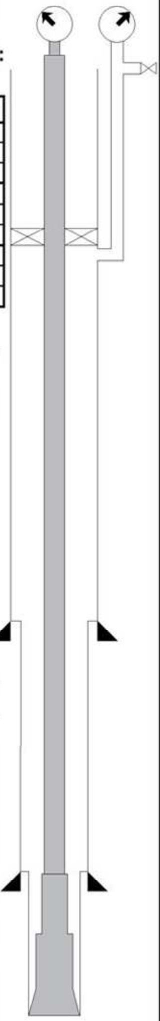
TVD CASING or LINER ____ ft

HOLE DATA:

TOTAL DEPTH (MD) ____ ft

TOTAL DEPTH (TVD) ____ ft

BIT DEPTH @ MD / TVD ____ / ____ ft



BIT SIZE ____ inches

KICK DATA

SIDPP: ________ **psi** **SICP:** ________ **psi** **PIT GAIN:** ________ **Bbls** **Time of Incident:** ____ : ____

Revision 2

Field Units (psi, ft, ppg)

Revised January 8, 2009

Page 1

CALCULATIONS

KILL MUD WEIGHT (KMW)

(________ ÷ 0.052 ÷ ________) + ________ = ________ ppg KILL MUD WEIGHT

SIDPP (psi) · True Vertical Depth (ft) · Present Mud Weight (ppg)

INITIAL CIRCULATING PRESSURE (ICP)

________ + ________ = ________ psi INITIAL CIRCULATING PRESSURE

SIDPP (psi) · Pump Pressure (psi) @ SCR of ______SPM

FINAL CIRCULATING PRESSURE (FCP)

________ x ________ ÷ ________ = ________ psi FINAL CIRCULATING PRESSURE

Pump Pressure (psi) @ SCR of ______SPM · Kill Mud Weight (ppg) · Present Mud Weight (ppg)

MAXIMUM ALLOWABLE MUD DENSITY (ppg)

(________ ÷ 0.052 ÷ ________) + ________ = ________ ppg MAX. ALLOWABLE MUD DENSITY

Surface LOT Pressure (psi) · Shoe Depth (ft,TUD) · LOT Mud Density (ppg)

MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE (MAASP) (psi)

(________ - ________) x 0.052 x ________ = ________ psi MAX. ALLOWABLE ANNULAR SURFACE PRESSURE

Max. Allowable Mud Density (ppg) · Present Mud Density (ppg) · Shoe Depth (ft,TUD)

SELECTED KILL PUMP DATA

	Kill Rate Speed (STKS/MIN)	Pump Output (BBLS/STK)	Circ. Rate (BBLS/MIN)	Slow Pump Pressure (Circ. Down DP & Up Riser)	Circ. Pres thru Choke Line (PSI)	Circ. Pres thru Choke & Kill Line (PSI)	CLFP Choke Line (PSI)	CLFP Choke & Kill Line (PSI)
PUMP No. 1								
PUMP No. 2								
PUMP No. 3								

PRESSURE CHART

Stroke or Volume	Theoretical Drill Pipe Pressure	Actual Drill Pipe Pressure	Actual Casing Pressure	Actual Pit Volume Deviation
SURFACE 0	ICP			
BIT	FCP			

________ ÷ 10 = ________ · ________ - ________ ÷ 10 = ________

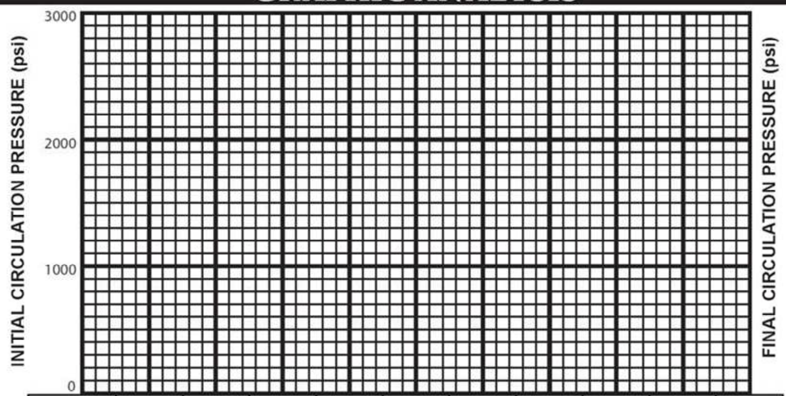
Strokes Surface to Bit · Strokes per Step · Initial Circulation Pressure · Final Circulation Pressure · PSI per Step

BIT	FCP			
SURFACE				

________ ÷ 10 = ________

Strokes Bit to Surface · Strokes per Step

GRAPHIC ANALYSIS



Stroke										
Pressure										
Time										

FORMULAS

1. Pressure Gradient (psi/ft) = Mud Weight (ppg) x 0.052

2. Hydrostatic Pressure (psi) = Mud Weight (ppg) x 0.052 x Depth (ft, TVD)

3. Capacity (bbls/ft) = Inside Diameter^2 (in.) ÷ 1029.4

4. Annular Capacity(bbls/ft) = (Inside Diameter of Casing^2 (in.) or Hole Diameter^2 (in.) - Outside Diameter of Pipe^2 (in.)) ÷ 1029.4

5. Pipe Displacement (bbls/ft) = (Outside Diameter of pipe^2 (in.) - Inside Diameter of pipe^2 (in.)) ÷ 1029.4

6. Maximum Allowable Mud Weight (ppg) = $\dfrac{\text{Surface LOT Pressure (psi)}}{\text{Shoe Depth (ft, TVD)} \times 0.052}$ + LOT Mud Weight (ppg)

7. MAASP (psi) = [Maximum Allowable Mud Weight (ppg) - Present Mud Weight (ppg)] x 0.052 x Shoe TVD (ft)

8. Pressure Drop per Foot Tripping Dry Pipe (psi/ft) = $\dfrac{\text{Drilling Mud Weight (ppg)} \times 0.052 \times \text{Metal Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft)} - \text{Metal Displacement (bbl/ft)}}$

9. Pressure Drop per Foot Tripping Wet Pipe (psi/ft) = $\dfrac{\text{Drilling Mud Weight (ppg)} \times 0.052 \times \text{Closed End Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft)} - \text{Closed End Displacement (bbl/ft)}}$

10. Formation Pressure (psi) = Hydrostatic Pressure Mud in Hole (psi) + SIDPP (psi)

11. EMW (ppg) @ Shoe = (SICP (psi) ÷ 0.052 ÷ Shoe Depth (ft, TVD)) + Present Mud Weight (ppg)

12. Sacks (100 lb) of Barite Needed to Weight-Up Mud = $\dfrac{\text{Bbls of Mud in System} \times 14.9 \times (\text{KMW} - \text{OMW})}{(35.4 - \text{KMW})}$

NOTE: This formula assumes that the average density of Barite is 35.4 ppg and the average number of sacks (100lb) per barrel is 14.9.

13. Volume Increase from Adding Barite (bbls) = Number of Sacks (100 lb) added ÷ 14.9

14. Equivalent Mud Weight (ppg) @ __________ depth (ft) = $\left[\dfrac{\text{Pressure (psi)}}{\text{Depth (ft, TVD)} \times 0.052}\right]$ + Current Mud Weight (ppg)

15. Estimated New Pump Pressure at New Pump Rate (psi) = Old Pump Pressure (psi) x $\left[\dfrac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right]^2$

16. Estimated New Pump Pressure with New Mud Weight (psi) = Old Pump Pressure (psi) x $\dfrac{\text{New Mud Weight (ppg)}}{\text{Old Mud Weight (ppg)}}$

Appendix C: Driller's method

IADC Driller's Method Worksheet

Well Name: ______________________ Completed By: ______________________ Date: _____ / _____ / _____

KICK DATA

SIDPP: __________ **bar** **SICP:** __________ **bar**

PIT GAIN: __________ **Liters** **Time of Incident:** ____ : ____

PROCEDURE

First Circulation to clear influx from well:

1. Bring pump(s) up to slow circulation rate and attempting to hold casing pressure constant by manipulating or adjusting the choke. The slow circulation rate will normally be 50% of the rate used in drilling operations.
2. Read and record Initial Circulating Pressure on Drill Pipe. This pressure should equal the SIDPP plus the slow circulation rate pressure.

   Recorded ICP __________ bar @ rate __________ spm
3. Maintain pump rate and drill pipe pressure constant until influx is circulated out of well.
4. Shut down pump(s) while holding casing pressure constant closing the choke as required. The trapped SIDPP will represent formation pressure.
5. With the pumps off and choke closed, the casing pressure and drill pipe pressures should be equal. If not, continue to circulate out the influx.
6. Record the new shut in casing pressure.

   SICP __________ bar
7. Calculate Kill Mud Weight.

   KMW = __________ kg/l
8. Increase surface mud system to required KMW density.

Second Circulation to balance well:

1. Bring bump(s) up to slow circulation rate and open choke as required while holding new casing pressure contant.
2. Adjust the choke to hold the new casing pressure constant until the drill pipe is full of kill mud of the required density.
3. After drill pipe is full of kill mud, record drill pipe pressure.

   __________ bar
4. Hold pipe rate constant and drill pipe pressure by adjusting the choke until the annulus is filled with kill mud.
5. When kill mud reaches the surface, choke pressure, if any, is bled off.
6. Stop circulating and check for flow.

CURRENT WELL DATA

PRESENT MUD WEIGHT: ______ kg/l

SLOW CIRCULATION RATE (SCR):

SCR taken @ ____________ (m)

	Stks/min	Pressure(bar)	Liter/min	Pressure(bar)
Pump #1				
Pump #2				
Pump #3				

TOTAL DEPTH (MD) ______ m

TOTAL DEPTH (TVD) ______ m

CASING DATA:

CASING ______ (size), ______ (ID), ______ (weight)

CASING SHOE DEPTH ______ m

SHOE TEST DATA:

Depth #1 ______ (bar) @ Test MW of ______ (kg/l)

Depth #2 ______ (bar) @ Test MW of ______ (kg/l)

Depth #3 ______ (bar) @ Test MW of ______ (kg/l)

LINER #1 ______ (size), ______ (ID), ______ (weight)

LINER #2 ______ (size), ______ (ID), ______ (weight)

LINER #1 TOP DEPTH ______ m

LINER #2 TOP DEPTH ______ m

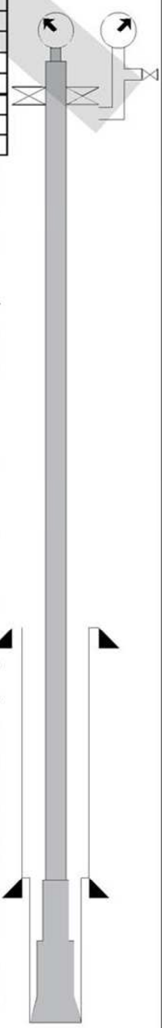
LINER #1 SHOE DEPTH ______ m

LINER #2 SHOE DEPTH ______ m

TVD CASING or LINER ______ m

HOLE DATA:

BIT SIZE ______ inches



Metric Units (bar, Liters, kg/l)

042508
Page 1

CALCULATIONS

KILL MUD WEIGHT (KMW)

(____________ ÷ 10.2 ÷ ____________) + ____________ = ________ kg/l KILL MUD WEIGHT

SIDPP (bar) / True Vertical Depth (m) / Present Mud Weight (kg/l)

INITIAL CIRCULATING PRESSURE (ICP)

____________ + ____________ = ________ bar INITIAL CIRCULATING PRESSURE

SIDPP (bar) / Pump Pressure (bar) @ SCR of ______SPM

TRUE PUMP OUTPUT:

________ X ________ = ________

Liters/Stk @ 100% / % Efficiency / TPO (Liters/Stk)

DRILL STRING CAPACITY:

	Size (mm)	Weight (kg/m)	Liters/m		Length (m)			
Drill #1: Pipe	____	____	____	X	____	=	____ DP	Liters
Drill #2: Pipe	____	____	____	X	____	=	____ DP	Liters
HWDP:	____	____	____	X	____	=	____ HWDP	Liters
Drill #1: Collars	____	____	____	X	____	=	____ DC	Liters
Drill #2: Collars	____	____	____	X	____	=	____ DC	Liters
Surface: Line	____	____	____	X	____	=	____ SL	Liters

________ Total Drill String Capacity (Liters)

STROKES, SURFACE TO BIT:

________ ÷ ________ = ________

Total Drill String Capacity (Liters) / True Pump Output (Liters/Stk) / Strokes, Surface to Bit

ANNULAR CAPACITY (Between):

CSG and DP:	____ Liters/m	X	____ m	=	____	Liters
Liner #1 and DP:	____ Liters/m	X	____ m	=	____	Liters
Liner #2 and DP:	____ Liters/m	X	____ m	=	____	Liters
OH and DP/HWDP:	____ Liters/m	X	____ m	=	____	Liters
OH and DC:	____ Liters/m	X	____ m	=	____	Liters

STROKES, BIT TO SHOE:

________ ÷ ________ = ________

Open Hole Annular Volume (Liters) / True Pump Output (Liters/Stk) / Strokes, Bit to Shoe

STROKES, BIT TO SURFACE:

________ ÷ ________ = ________

Total Annular Volume (Bbls) / True Pump Output (Liters/Stk) / Strokes, Bit to Surface

TOTAL STROKES, SURFACE TO SURFACE:

________ + ________ = ________

Strokes, Surface to Bit / Strokes, Bit to Surface / Strokes, Surface to Surface

MAXIMUM ALLOWABLE ANNULUS SURFACE PRESSURE (MAASP)

(____________ - ____________) X 10.2 X ____________ = ________ bar MAASP

Max. MW from Shoe Test (kg/l) / Present Mud Weight (kg/l) / True Vertical Depth Shoe (m)

MAXIMUM ALLOWABLE ANNULUS SURFACE PRESSURE (MAASP) WITH KILL MUD

(____________ - ____________) X 10.2 X ____________ = ________ bar MAASP WITH KILL MUD

Max. MW from Shoe Test (kg/l) / Kill Mud Weight (kg/l) / True Vertical Depth Shoe (m)

COMMENTS

Metric Units
(bar, Liter, kg/l)

FORMULAS

1. Pressure Gradient (bar/m) = Mud Weight (kg/l) x 10.2

2. Hydrostatic Pressure (bar) = Mud Weight (kg/l) x 10.2 x Depth (m, TVD)

3. Capacity (l/m) = Inside Diameter^2 (mm) ÷ 1273

4. Annular Capacity(l/m) = (Inside Diameter of Casing^2 (mm) or Hole Diameter^2(mm) - Outside Diameter of Pipe^2 (mm)) ÷ 1273

5. Pipe Displacement (l/m) = (Outside Diameter of pipe^2 (mm) - Inside Diameter of pipe^2 (mm)) ÷ 1273

6. Maximum Allowable Mud Weight (kg/l) = $\dfrac{\text{Surface LOT Pressure (bar)}}{\text{Shoe Depth (m, TVD)} \times 10.2}$ + LOT Mud Weight (kg/l)

7. MAASP (bar) = [Maximum Allowable Mud Weight (kg/l) - Present Mud Weight (kg/l)] x 10.2 x Shoe TVD (m)

8. Pressure Drop per Foot Tripping Dry Pipe (bar/m) = $\dfrac{\text{Drilling Mud Weight (kg/l)} \times 10.2 \times \text{Metal Displacement (l/m)}}{\text{Casing Capacity (l/m)} - \text{Metal Displacement (l/m)}}$

9. Pressure Drop per Foot Tripping Wet Pipe (bar/m) = $\dfrac{\text{Drilling Mud Weight (kg/l)} \times 10.2 \times \text{Closed End Displacement (l/m)}}{\text{Casing Capacity (l/m)} - \text{Closed End Displacement (l/m)}}$

10. Formation Pressure (bar) = Hydrostatic Pressure Mud in Hole (bar) + SIDPP (bar)

11. EMW (kg/l) @ Shoe = (SICP (bar) ÷ 10.2 ÷ Shoe Depth (m, TVD)) + Present Mud Weight (kg/l)

12. Kg of Barite Needed to Weight-Up Mud = $\dfrac{\text{Liters of Mud in System} \times 4.25 \times (\text{KMW} - \text{OMW})}{(4.25 - \text{KMW})}$

13. Volume Increase from Adding Barite (l) = $\dfrac{\text{Kg of Barite Needed to Weight-Up Mud}}{4.25}$

14. Equivalent Mud Weight (kg/l) @ __________ depth (m) = $\dfrac{\text{Pressure (bar)}}{\text{Depth (m, TVD)} \times 10.2}$

15. Estimated New Pump Pressure at New Pump Rate (bar) = Old Pump Pressure (bar) x $\left[\dfrac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right]^2$

16. Estimated New Pump Pressure with New Mud Weight (bar) = Old Pump Pressure (bar) x $\dfrac{\text{New Mud Weight (kg/l)}}{\text{Old Mud Weight (kg/l)}}$

COMMENTS