University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: **Master Petroleum / Drilling**	Spring semester, 2011 **Open** / Restricted access
Writer: **Usman Zafar Iqbal**	…………………………………………… (Writer's signature)

Faculty Supervisor: **Kjell K. Fjelde** Institute Supervisor: **Gerhard Nygaard**

External supervisor(s):

Title of thesis:

MPD: Simulation and Control Systems

Credits (ECTS): **30**

Key words: **MPD Tools** **MPD Automation** **Rotating Control Device** **Choke Manifold** **Pipe connection simulation** **Constant BHP**	Pages: **72** + enclosure: **28** Stavanger, **15.06.2011** Date/year

Managed Pressure Drilling Simulation and Control Systems

Submitted by

Usman Zafar Iqbal

For

The Degree of Master of Science
In Drilling Engineering

SUMMARY

Managed Pressure Drilling (MPD) has solved many conventional drilling problems. It has given the access to the reservoirs where conventional drilling was facing difficulties. The tight pressure windows in depleted reservoirs, the kick scenarios, the loss circulation problems, the differentially stuck pipe problems and many other drilling relating problems has been solved by the means of Managed Pressure Drilling. Focus in this thesis has been to present the main idea behind the MPD concept and equipment involved. This has also been explained in the light of MPD vendors Halliburton and Weatherford.

MPD Automation is another important aspect which is expected to become more popular with time. The use of automatic top side choke to maintain the bottom hole pressure constant has helped the oil industry very efficiently. This provides more accurate pressure control of the well throughout the drilling. Before, it was difficult to operate the choke manually in order to keep the pressure constant especially during connections. But with the introduction of automatic control systems the risk of making errors has reduced to minimum. In this thesis, a pipe connection is simulated with the help of automatic operating of choke while keeping the bottom hole pressure constant. The AUSMV transient scheme has been used for this purpose along with PI-regulator. The simulation has been done with two different approaches, first with the adjustment of choke opening and secondly with the adjustment of choke pressure.

The results have shown the importance of the correct adjustment of the tuning parameters. It has been observed that choke opening regulation is sensitive to changes and can cause errors if proper tuning isn't done for parameters. On the other side choke differential pressure regulation has shown a great reliability in getting the desired results.

ACKNOWLEDGEMENTS

I would like to show my sincere gratitude to my supervisors Kjell K. Fjelde and Gerhard Nygaard for their continuous support and help. I am heartily thankful to Kjell K. Fjelde for his guidance, encouragement and patience in answering my questions from the initial to the final level.

I would like to thank Henrik Sveinall from Weatherford and Kjetil Knudsen from GeoBalance Halliburton for providing me with invaluable materials. I have benefited greatly from their help.

Last but not the least, I would like to thank my parents and friends for their prayers and support throughout the years.

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Nomenclature

MPD:	Managed Pressure Drilling
BHP:	Bottom Hole Pressure
RCD:	Rotating Control Device
UBD:	Underbalanced Drilling
NPT:	Non-Productive Time
ECD:	Equivalent Circulating Density
BOP:	Blow Out Preventer
CBHP:	Constant Bottom Hole Pressure
CCS:	Continuous Circulation System
DG:	Dual Gradient
PMCD:	Pressurized Mud Cap Drilling
DCIV:	Downhole Casing Isolation Valve
PRV:	Pressure Relief Valve
ROP:	Rate of Penetration
RPM:	Rotations per minute
MFC:	MicroFlux Control system
SD:	Secure Drilling
SPM:	Strokes per minute

1. Introduction

About one-half of remaining offshore reservoirs of hydrocarbons are undrillable with conventional tools and methods [16]. The drilling through narrow pressure windows will in many cases not be technical and economical viable with conventional overbalanced drilling. It is quite challenging and complex task to get rid of the drilling problems associated with depleted reservoirs by conventional drilling techniques. The drilling industry has been facing problems like slow ROP, loss circulation, stuck pipe, well instability and well control incidents [14, 17]. All these problems increases Non-Productive Time (NPT) and results into a great economic loss for the oil companies. All the drilling relating problems, mentioned above plus many more, can be addressed with a technology that offers more precise control of the wellbore pressure while drilling and that technology is known as Managed Pressure Drilling [16]. MPD has helped oil industry in achieving success in problem wells which are either impossible or uneconomical to drill with conventional drilling methods [14].

In this work, a special focus is given to MPD methods and tools. MPD techniques and procedures are also explained with reference to the MPD vendors (Halliburton & Weatherford). In many MPD systems, the bottom hole pressure is controlled by leading the flow through a return choke. This choke can be operated manually or automatically. In automatic regulation, flow models and appropriate regulation algorithms are needed. In this thesis, the automatic regulation of the choke with respect to bottom hole pressure is simulated during a pipe connection. This simulation of the pipe connection is performed by using regulation algorithm (PI controller) in the AUSMV scheme. The main objective in the simulation is to keep the bottom hole pressure constant during pipe connection.

1.1 Managed Pressure Drilling (MPD)

MPD is a drilling process used to control the annulus pressure throughout the wellbore. MPD gives a better control of down hole pressure and allows drilling in a zone where there is a small difference between pore pressure and fracturing pressure i.e. small operation pressure window. This wasn't possible with the conventional drilling method where mud weight is used to control the well pressure. The International Association of Drilling Contractors has defined MPD as [14]:

Managed Pressure Drilling is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the down hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. The intention of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.

- MPD employs a collection of tools and techniques which may reduce the risks and costs linked with well operations that have limitations with respect to the down hole environment, by controlling the annular hydraulic profile [14].
- MPD deals with the control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction and hole geometry [14].
- MPD allows quick corrective actions against pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects [14].

1.2 Conventional drilling, Underbalanced drilling and MPD

Conventional Drilling is based on having an overbalanced pressure in the well during drilling. Overbalance is the condition where pressure exerted in a wellbore is higher than the pore pressure throughout the exposed formation. In such cases annular pressure is controlled by pump flow rates and mud density.

In static conditions, the relation between bottom hole pressure (P_{BH}) and hydrostatic pressure (P_{Hyd}) is given as [14]:

$$\mathbf{P_{Hyd} = P_{BH}}$$

Where as in dynamic condition, bottom hole pressure (P_{BH}) is equal to hydrostatic pressure (P_{Hyd}) plus annular friction pressure (P_{AF}) [14]:

$$\mathbf{P_{BH} = P_{Hyd} + P_{AF}}$$

In conventional drilling operations, problems like kick, stuck pipe, lost circulation etc are often associated with drilling operations. Such problems lead to Non-Productive Time (NPT) and many other hazards related to humans and environment. Well control monitoring in conventional drilling is often challenging as it is judged on the basis of flow rates. Inner bushings are pulled to check for flow and a tiny influx in this short time can lead to a disaster. Full control pressure monitoring can't be done until well is shut-in and behaves like a closed vessel.

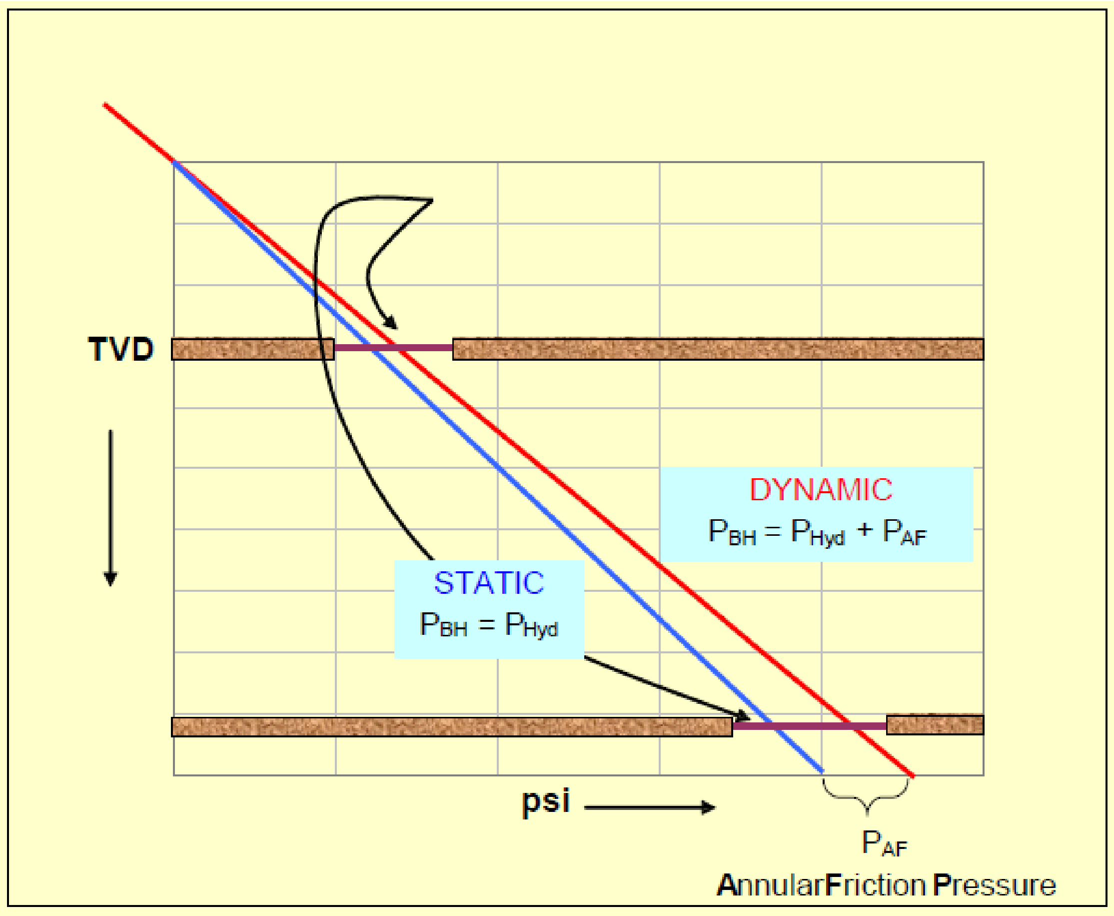

Fig 1: Static and Dynamic Pressure [14]

Underbalanced Drilling (UBD) is associated with making the pressure inside wellbore intentionally lower than the pore pressure [14]:

$$\mathbf{P_{Hyd} < P_{BH}}$$

The idea behind this is to enhance the productivity of reservoir by preventing mud from entering reservoir rock. The permeability of reservoir rock is not get reduced by this. When drilling through the reservoir section, influx from reservoir will be induced due to low wellbore pressure. Hence, a separator is needed to separate the returning mud from oil/gas. In addition to the separator, UBD also requires special mixing tanks because mud used in UBD is lighter than any conventional mud [4]. Mixture of water based mud with gas is often used in such operations.

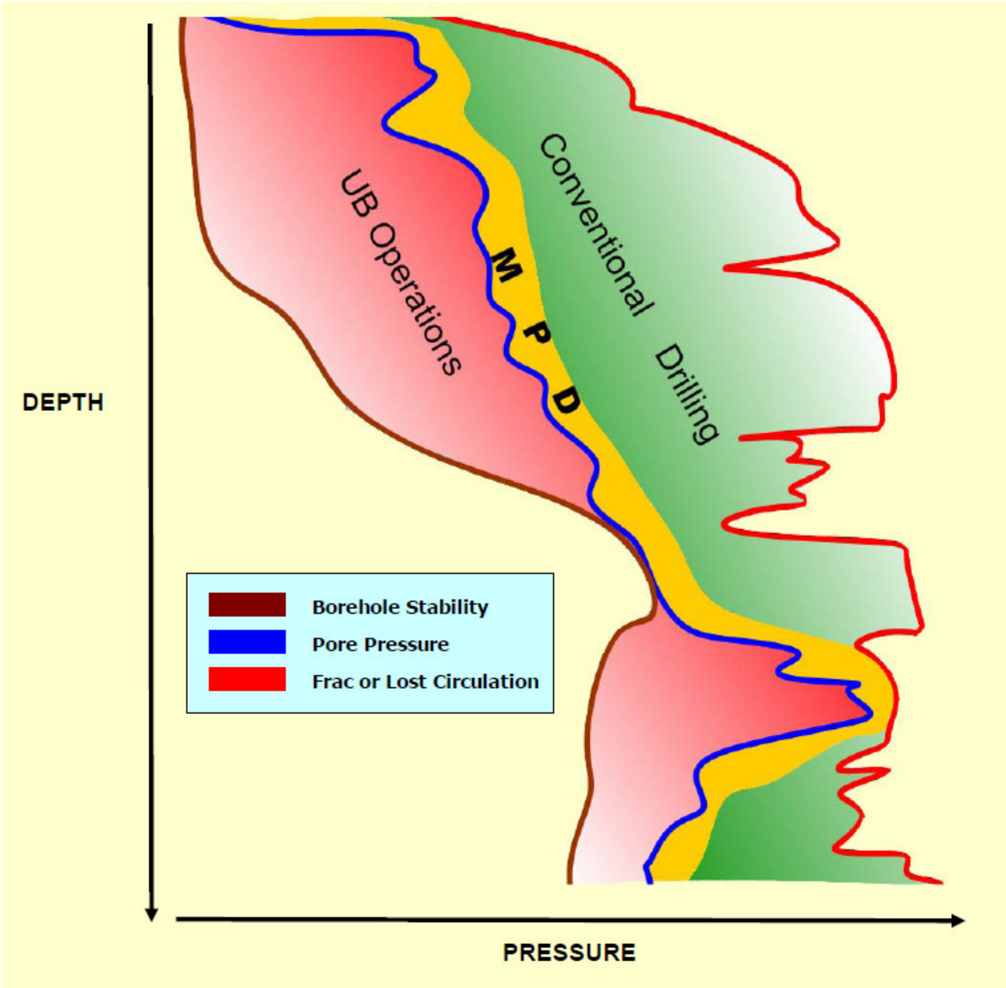

Fig 2: Example of Drilling Windows [14]

In **Managed Pressure Drilling** the intention is to drill close to the pore pressure. Here, continuous influx of formation fluids is avoided as compared to UBD. Many undrillable reservoirs have been reached with the help of MPD. The deepwater wells which were unreachable with respect to conventional drilling due to small pressure operating window (difference between pore pressure and fracture pressure) is now reachable with MPD. As MPD can be operated close to pore pressure, this gives it an advantage over conventional drilling in tight pressure conditions. In MPD, annulus is closed by a Rotating Control Device (RCD) and a choke manifold system is used to control the pressure in annulus. By varying the choke settings Bottom Hole Pressure (BHP) can be obtained to a desired value. In dynamic conditions BHP is given as [15]:

BHP = Mud weight + Back pressure + ECD

And in static conditions, it is given as [21]:

BHP = Mud weight + Back pressure

The backpressure pump provides a flow during connections and compensates the pressure which gets reduced due to the turning off of the mud pumps. In this way a stable BHP can be achieved during connections. The working principle of MPD is given in the figure below.

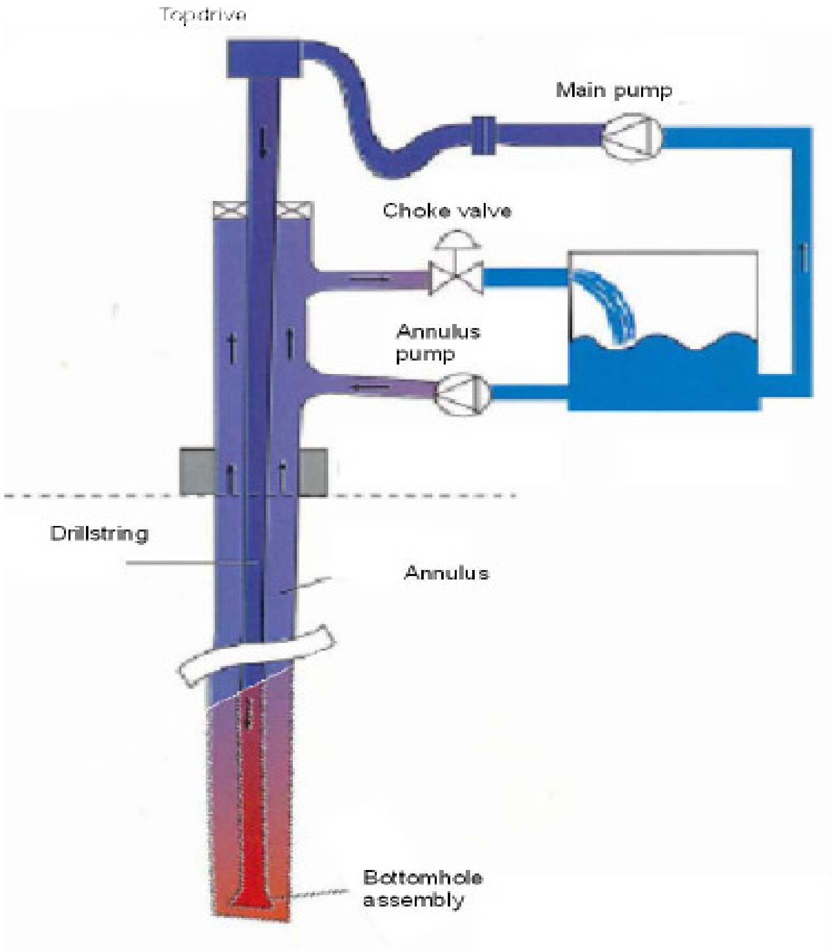

Fig 3: Schematic layout of MPD system [8]

MPD makes it possible to drill with lighter mud than in a conventional drilling one because of choke control system [4]. It helps to add back pressure as a compensation of the reduced well pressure due to the lighter mud. MPD has been proved as an important concept in reducing drilling problems like lost circulation, stuck pipe, wellbore instability and well control incidents.

2. MPD Technology

In this section a brief description about MPD approaches is going to be explained along with the MPD techniques. The four key techniques which are going to be explained are: Constant Bottom Hole Pressure (CBHP), Continuous Circulation System (CCS), Dual Gradient (DG) and Pressurized Mud Cap Drilling (PMCD). Then in the end of this section, well barrier requirements are going to be addressed both for the conventional and MPD operations.

2.1 Approaches

1. ***Reactive MPD***
   It uses MPD methods/equipments to reduce the effect of drilling problems after they arise. The well is basically based on conventional drilling methods and MPD procedures will be applied only in case of unplanned events that may occur [14].
2. ***Proactive MPD***
   In this the well is designed according to MPD procedures. All the MPD equipments/methods are employed in order to have control of annular pressure profile and to deal with unplanned events [14].

2.2 MPD Techniques

The most common MPD techniques are given below:

2.2.1 Constant Bottom Hole Pressure (CBHP)

This method is used in tight operating pressure windows. The difference between fracture and pore pressure is very narrow and BHP must be controlled in such a way that pressure is kept within narrow window. A back pressure pump and choke is used to keep the bottom hole pressure constant by providing the surface pressure. During connection, pumps are stopped and there is no circulation present. In this condition bottom hole circulating pressure get reduced due to loss of Equivalent Circulating Density (ECD). So with the help of this technique, pressure loss can be compensated by adding surface pressure. After finishing the connection, pumps are started again and circulation resumed. Now the ECD comes back into account by the reducing of surface pressure. This keeps the BHP constant [5].

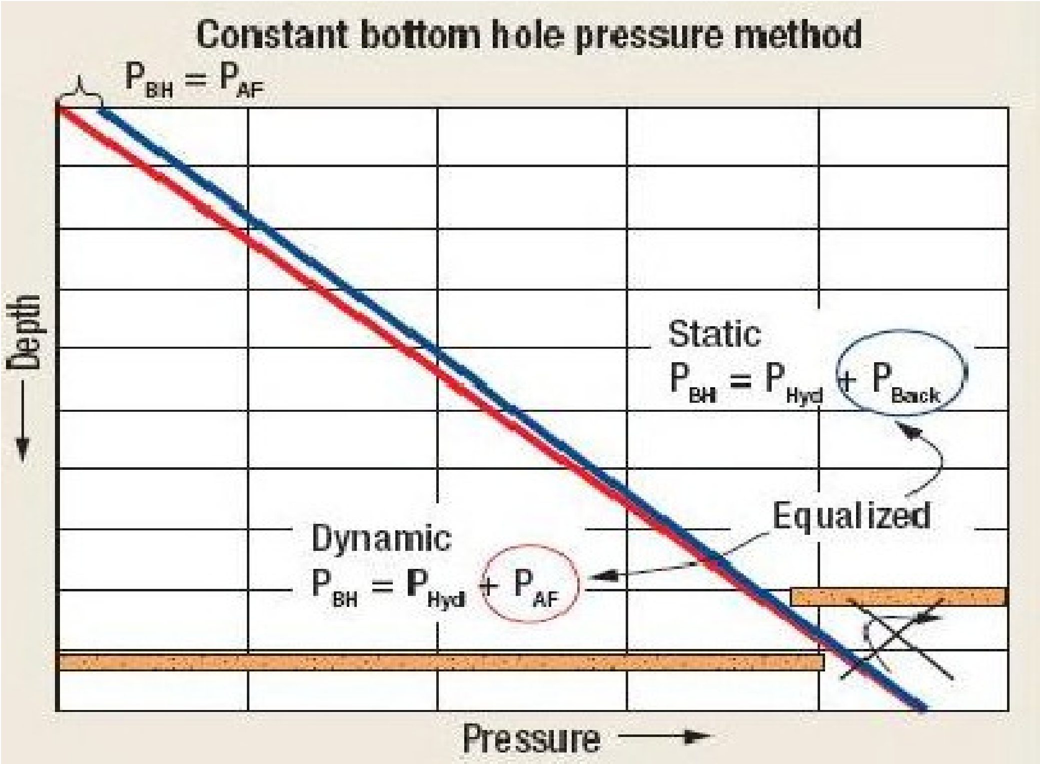

Fig 4: Imposes Backpressure to equalize Annular Friction Pressure [21]

2.2.2 Continuous Circulation System (CCS)

This is used on wells where the annular friction pressure needs to be constant and to prevent cuttings settling in extended reach horizontal sections. In this technique circulation is not stopped during connections. This makes it possible to keep the ECD constant during connections. Continuous circulation solves many problems that can occur during stop pumping/circulation during connections. By keeping the ECD constant, it helps efficiently in long horizontal sections where removal of cuttings is difficult. In such sections cuttings can be settled down when circulation is stopped during connections. A special circulating BOP and continuous circulating subs make it possible to have an uninterrupted circulation [5].

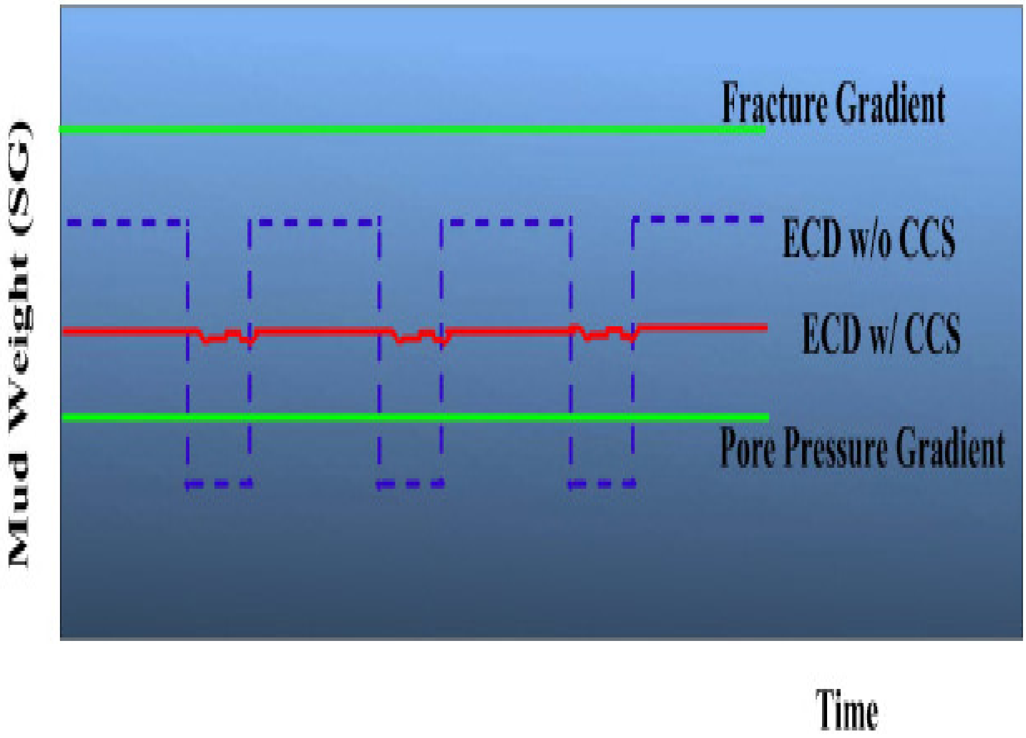

Fig 5: Shows stable ECD with CCS [23]

2.2.3 Dual Gradient technique (DG)

This is best known in deepwater applications. As it is clear from its name, it comprises of double density gradients. It is primarily used in offshore applications where water is a significant portion of the overburden [21]. This liquid overburden is less than the formation overburden. In conventional drilling deepwater applications, normally there is a requirement of multiple casing strings because of weak formation strength. This helps in preventing loss of circulation at shallow depths, using single density drilling fluid.

The main concept in this technique is to displace the upper part of well by lighter fluid and lower part contains heavier fluid. The two different density fluids will produce an overall hydrostatic pressure in the well which avoids exceeding the fracture gradient and breaking down the formation [21].

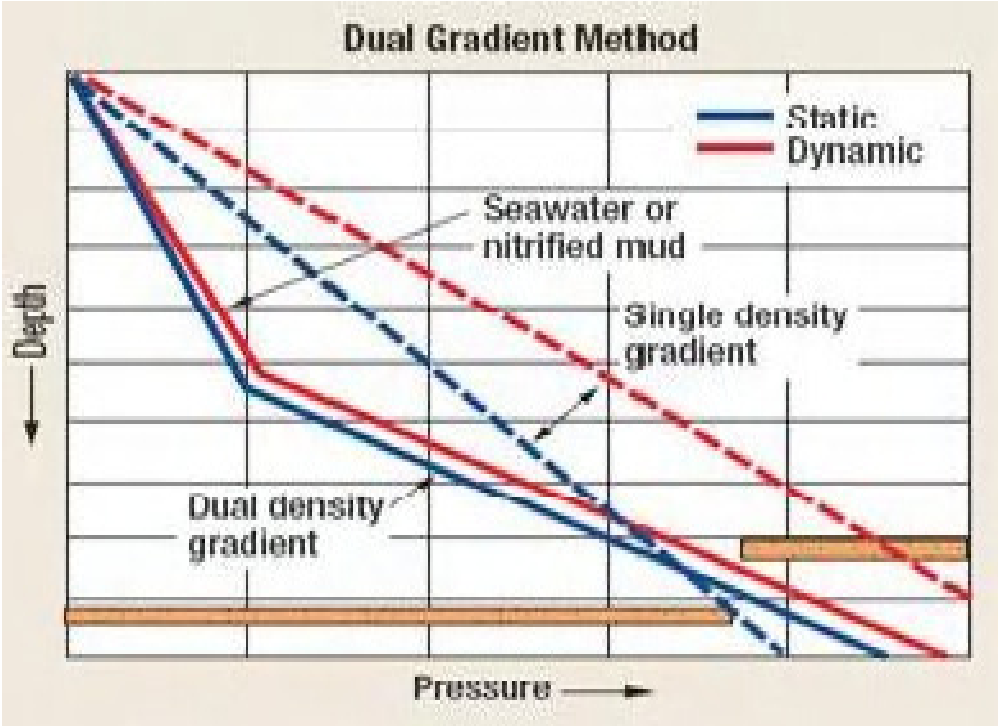

Fig 6: DG Pressure Profile [21]

2.2.4 Pressurized Mud Cap Drilling (PMCD)

This technique is used in depleted reservoirs where loss of circulation is very large. It deals with total loss returns i.e. drilling is carried out safely by having no returns on surface and with a full annular fluid column maintained above a formation that is taking drilling fluid and cuttings [23].

Pressurized mud cap drilling addresses lost circulation issues but by using two drilling fluids [21]. A heavy, viscous mud is pumped down the backside in the annular space to some height. This mud cap serves as an annular barrier, while the driller uses a lighter and less damaging fluid to drill into the weak zone [21].

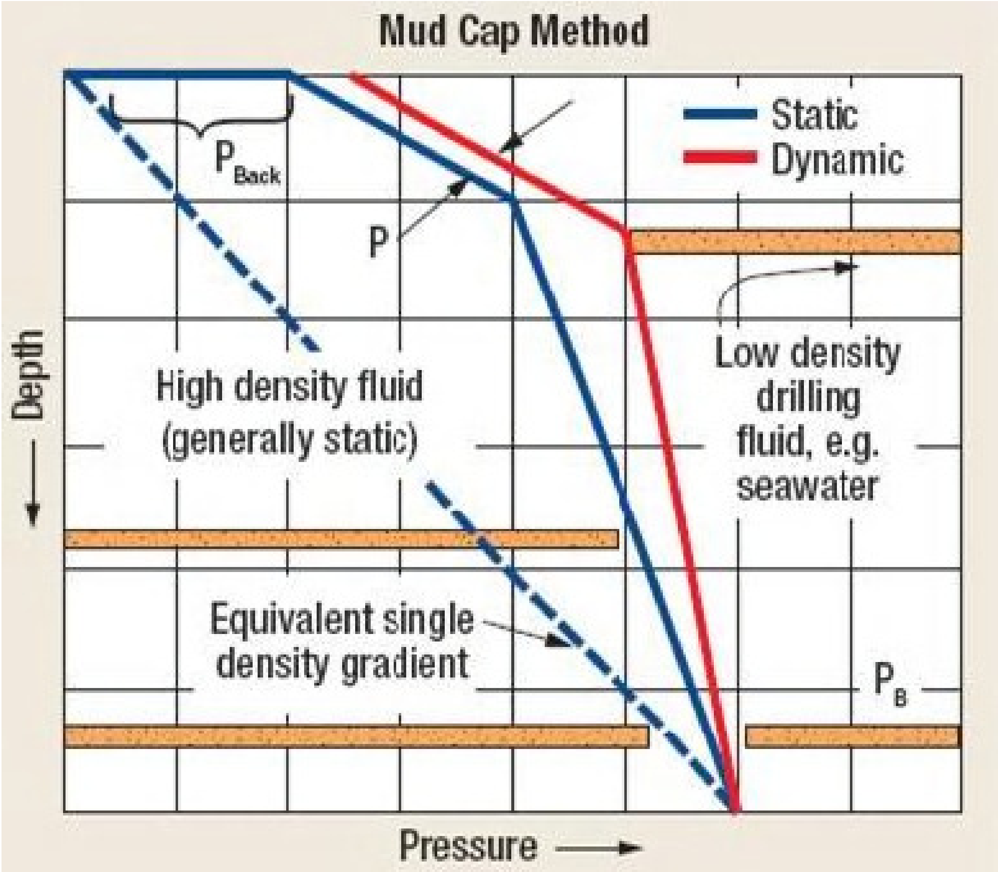

Fig 7: PMCD Method [21]

The lightweight scavenger fluid will be pumped down the drill pipe. After circulating around the bit, the fluid and cuttings will be injected into a weak zone. The heavy viscous mud will be remained as a mud cap in the annulus above the weak zone [21]. An optional backpressure can be applied to maintain the annular pressure control.

2.3 MPD and Conventional Barriers

According to NORSOK STANDARD [24] well barrier is defined as:

Well barriers are envelopes of one or several dependent well barrier elements preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface

A well barrier limits the accidents caused by failures or hazards by stopping them to develop further. In MPD operations barriers are important on the same scale as in conventional drilling. The maintenance and proper functionality of the barriers is of high priority for a successful MPD operation. The primary and secondary barrier elements for conventional drilling operation and MPD are given below [24]:

2.3.1 Conventional Drilling Barriers

The conventional drilling barrier elements are given as [24]:

Primary Barrier Elements:

- Fluid Column

Secondary Barrier Elements:

- Casing Cement
- Casing
- Wellhead
- High Pressure Riser
- Drilling BOP

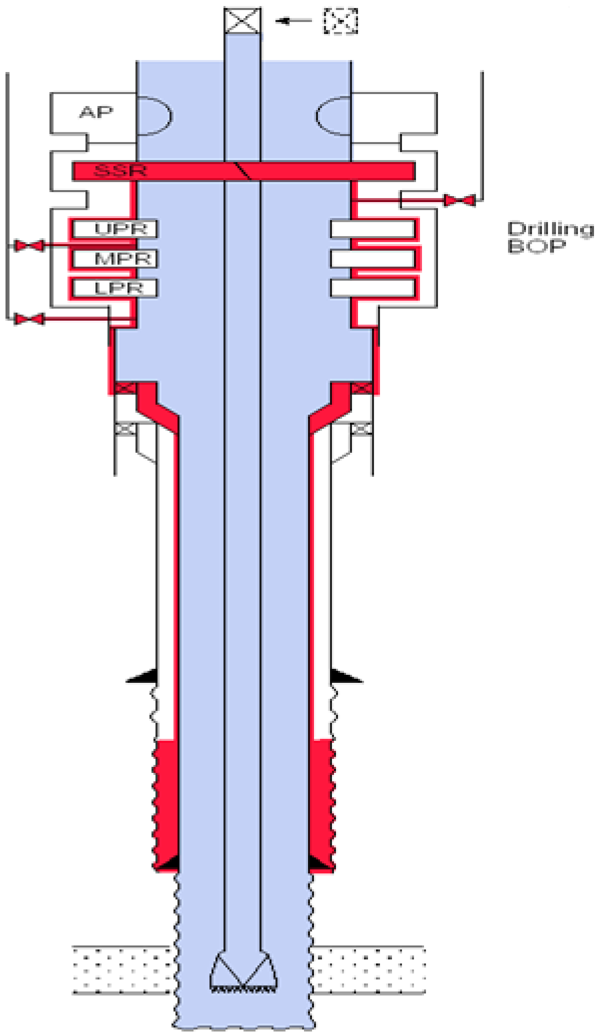

Fig 8: Drilling, Coring and Tripping with shearable drill string [24]

2.3.2 MPD Barriers

The Managed Pressure Drilling barrier elements are given below [24]:

Primary Barrier Elements:

- Fluid Column
- Rotating Control Device (RCD)
- Choke System
- Drill String
- Drilling BOP
- Casing Cement
- Casing
- High Pressure Riser
- Non Return Valves
- Wellhead

Secondary Barrier Elements:

- High pressure Riser
- Drilling BOP
- Casing Cement
- Casing
- Wellhead

The Rotating Control Device is an important barrier element in MPD operations. It must be installed above the drilling BOP. It should have a capability to seal the certain wellhead circulating pressure against the rotating string and also have to contain the certain shut-in wellhead pressure against the static string.

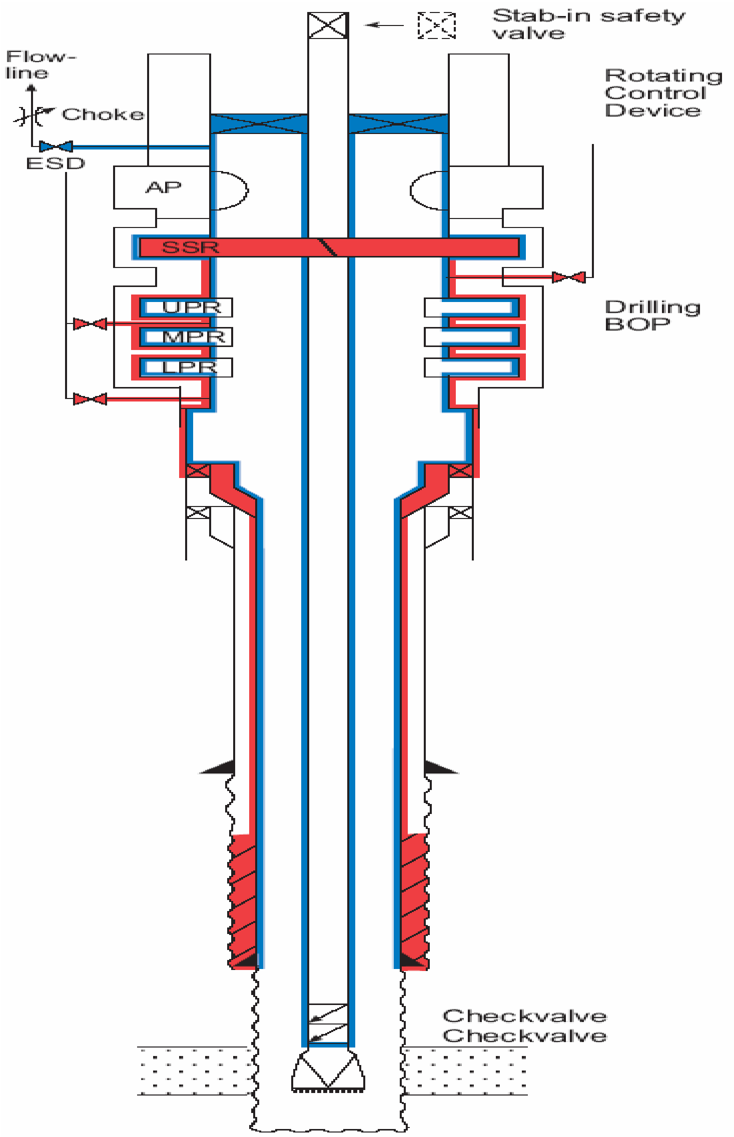

Fig 9: Drilling and Tripping of work string in UB fluid [24]

MPD primary barrier elements include all the secondary barrier elements of conventional drilling operation in addition to the fluid column. The main difference seen in barrier elements is in MPD i.e. Rotating Control Device, choke system and non-return valves. These are the additional equipment required for MPD operations.

3. MPD Tools

In this section, a detailed description about MPD equipment is going to be addressed. The main tools which enable the MPD operations are going to be discussed in this section:

- Rotating Control Device
- Choke manifold
- Downhole Casing Isolation Valve
- ECD reduction tool
- Continuous circulating system

3.1 Rotating Control Device (RCD)

RCD is an important tool in MPD operations. It is installed on the top of the standard BOP on production rigs which are anchored permanently to the sea bottom and in mobile rigs RCD is placed on the top of the riser [4]. RCD allows the rotation of the drill string and drilling by keeping the top of annulus sealed. This seal assembly enables the mud returns closed and pressurized. RCD diverts this mud return from annulus to the choke manifold. RCD is a supplemental safety device which is very effective and reactive towards stopping the incidentally escaping of hydrocarbons from wellbore [23].

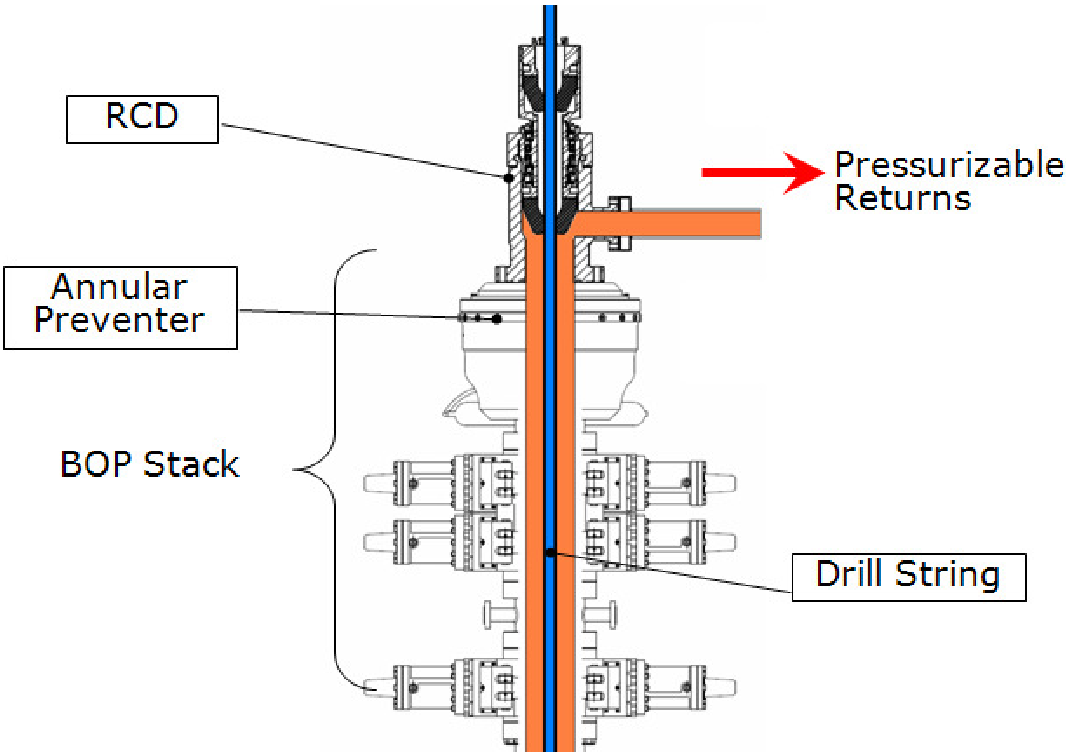

Fig 10: RCD Installation on top of BOP [23]

Placing of RCD at the top of BOP stack gives more range and flexibility. The design and size of RCDs are depends on the drilling operation. Some of the design parameters are [23]:

- Rig substructure
- Seal elements (single and dual)
- Operator's special priorities

Different variations of RCD are given below [26]:

- RCD on floating rigs (rig heave)
    - External Riser RCD
    - Subsea RCD
    - Internal Riser RCD
- RCD on fixed rigs (no rig heave)
    - Passive and Active annular seal design
    - Marine Diverter Converter RCD
    - Bell Nipple Insert RCD

3.1.1 External Riser RCD

This is used for MPD applications on floating vessels which are exposed to movement due to waves. The length of the flexible flow lines is determined by the maximum possible wave heave. The size of flexible flow lines is determined by maximum return flow. It is the part of Riser Cap which makes the applications of Pressurized Mud Cap method possible [23]. Riser Cap is used for pumping down of high viscous fluids into the annulus in order to create a mud cap situation [23].

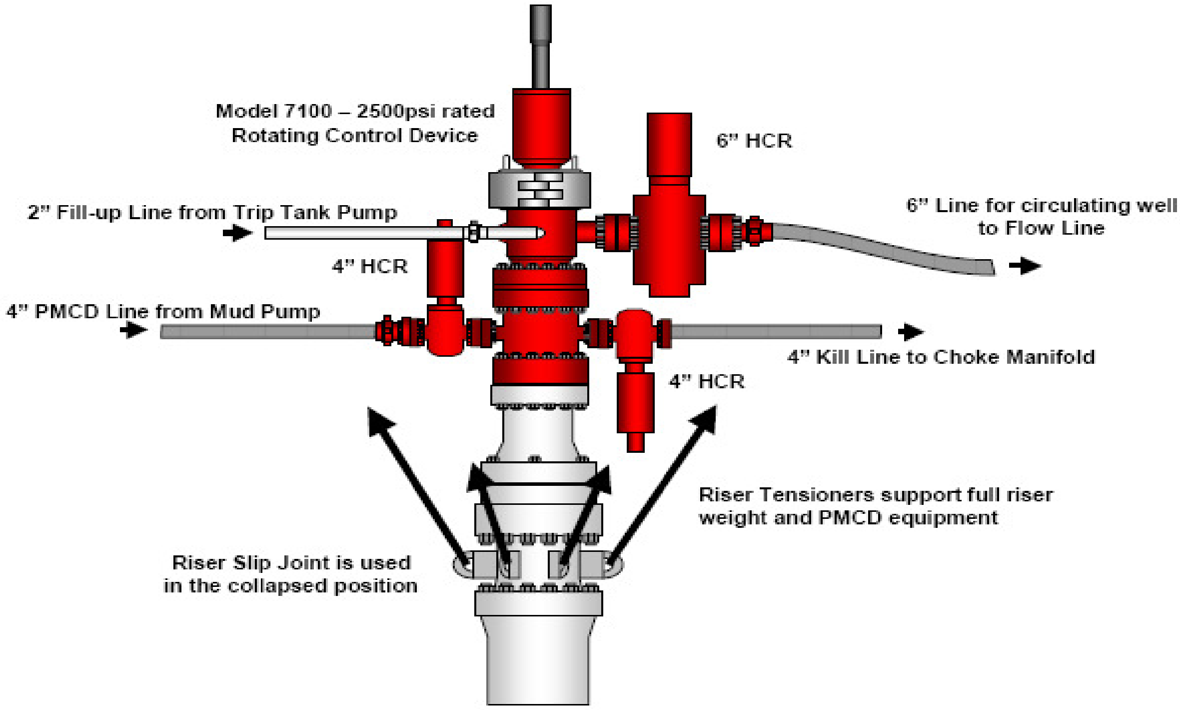

Fig 11: External Riser on Riser Cap [26]

3.1.2 Subsea RCD

It can be used in riserless drilling and also in dual gradient drilling variations with a marine riser system [23].

Fig 12: Subsea RCD Installation [26]

3.1.3 Internal Riser RCD

This is used for performing the MPD operation from a floating rig. With the help of internal riser, a conventional BOP can be nippled up on the marine riser and RCD can be rigged up on the top of the surface BOP. Such rig up for MPD application is almost similar to fixed surface stacks and only difference in between them is the use of hoses instead of fixed pipe stack [23].

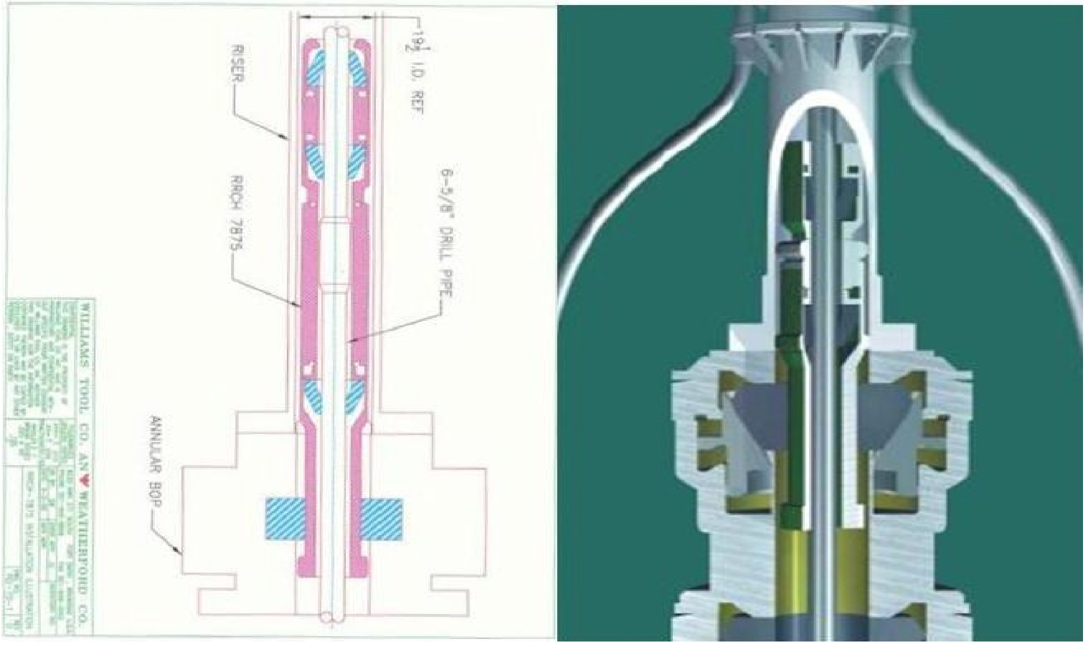

Fig 13: Sowing Internal Riser [23]

3.1.4 Active and Passive annular seal design

Active annular seal design requires external-to-tool source of hydraulic energy [26]. This design is more exposed to troubles due to inflated element which doesn't handle stripping out efficiently under pressure [23]. Dedicated technicians are required to handle the different problems [26].

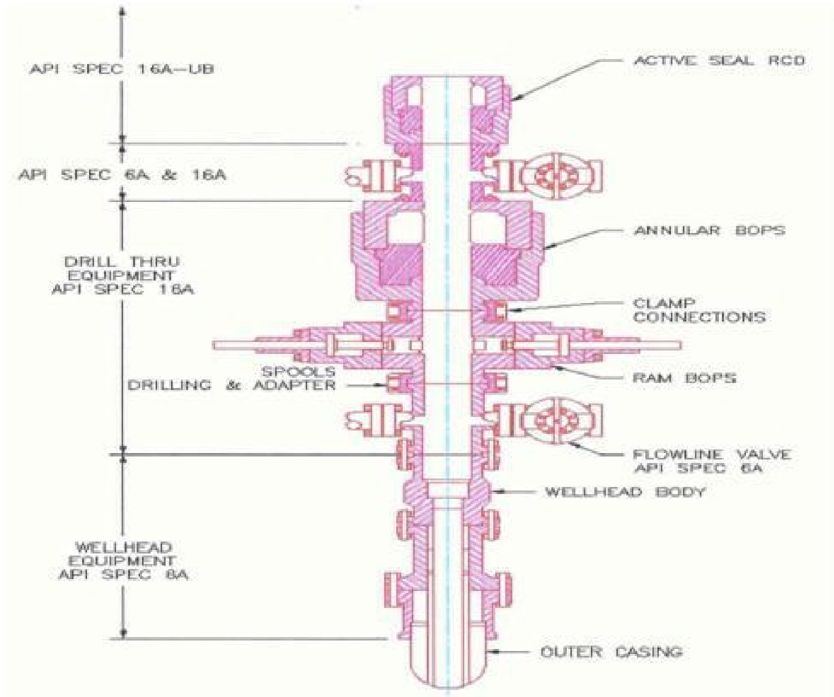

Fig 14: Installation of Active type RCD [23]

Passive annular seal is most commonly used in MPD applications [26]. It is opposite to the active annular seal in hydraulic energy requirement. It doesn't need external-to-tool source for hydraulic energy which gives it advantage over active annular seal RCD [26]. Another advantage is that it doesn't need dedicated technicians. It can handle higher differential pressure which gives more tight annular seal [26].

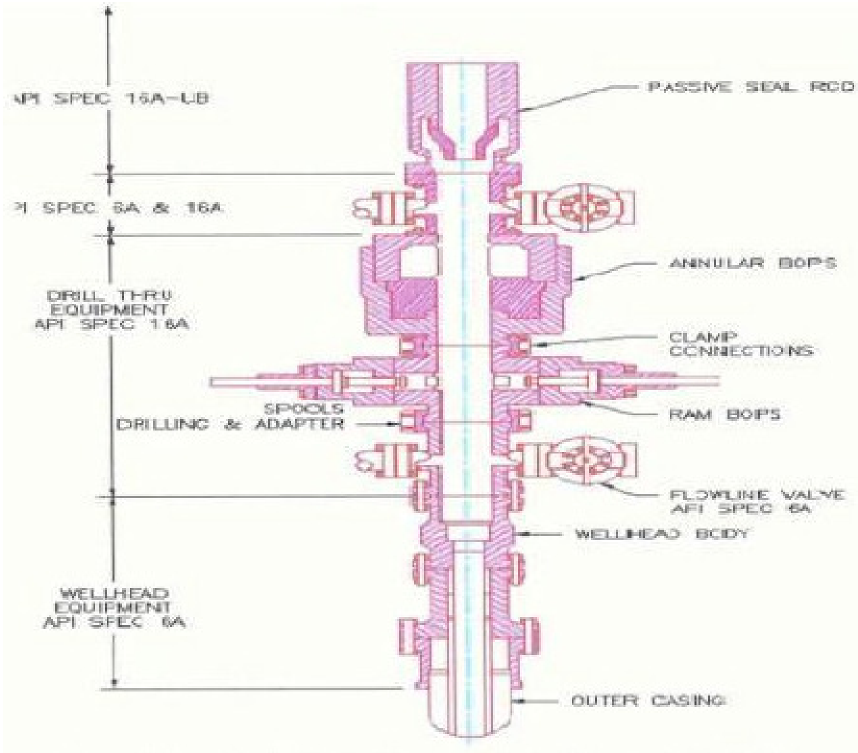

Fig 15: Installation of Passive type RCD [26]

The reason for naming the system as 'passive' is that the rotating packer that uses an annular seal element or stripper rubber which is undersize to drill pipe and is force fit onto the pipe [23]. This makes a seal in zero pressure conditions. The element is exposed to wellbore pressure and more sealing is done by the annular pressure [23].

3.1.5 Marine Diverter Converter RCD

It converts typical marine diverter to rotating diverter [26]. It is used in MPD applications where there is little or no relative movement between rig and drill string. Marine Diverter Converter housing is clamped to a RCD [23]. The housing assembled with the RCD is inserted into a marine diverter above the water surface to allow conversion between conventional open and non-pressurized mud return system drilling, and a closed and pressurized mud return system used in MPD [23]. RCD is installed in a marine diverter, as shown in figure, which enables diverting of any influx effectively under drilling.

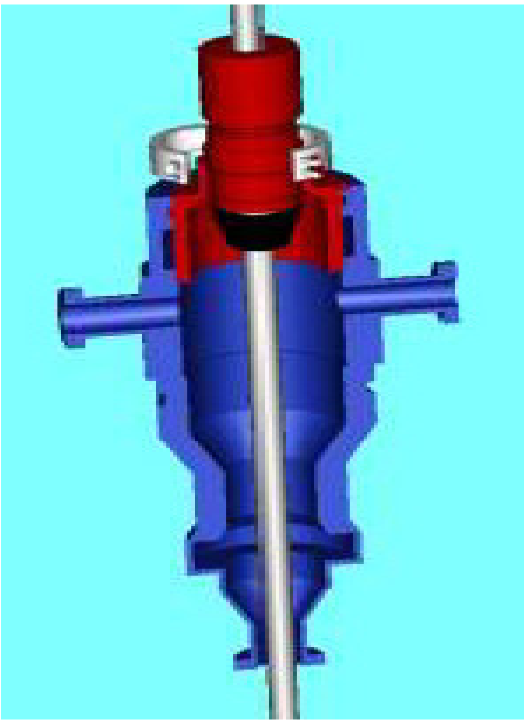

Fig 16: A Marine Diverter Converter [26]

3.1.6 Bell Nipple Insert RCD

This is an upper marine riser RCD [23]. There should be no wave heave due to its fixed design. Bell Nipple Insert RCD in BOP stack is shown below with its components.

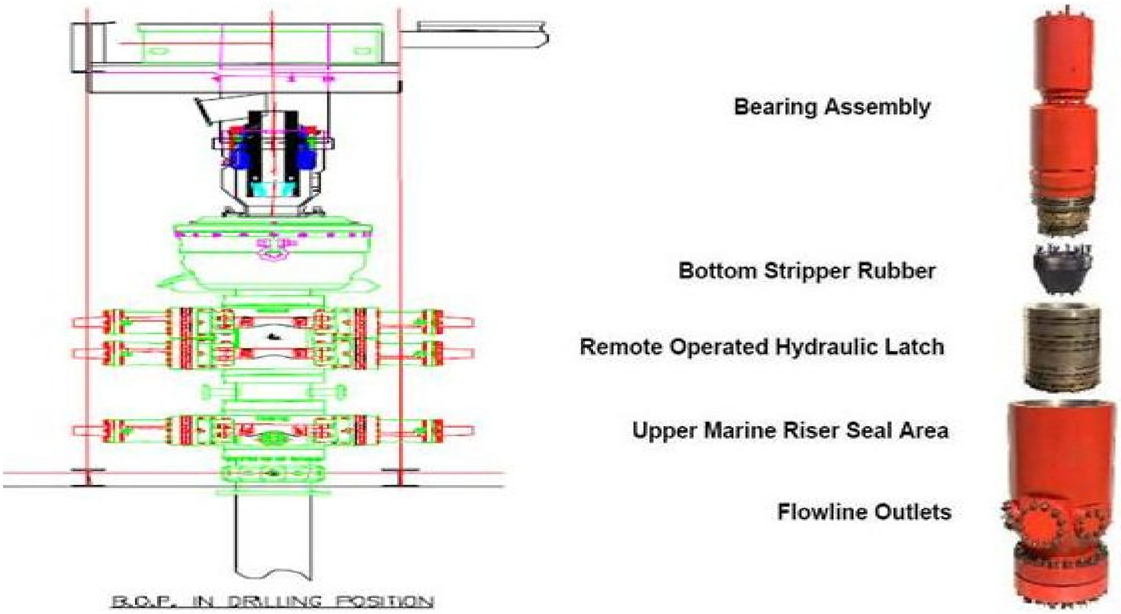

Fig 17: Alignment of Bell Nipple Insert [26]

3.2 Choke Manifold

Another key element in MPD applications needed to control the pressure in an MPD operation is the choke manifold. It must be installed in the return flow line [23]. It allows the backpressure. If there is a need of increasing the BHP to a desire limit, then choke opening at the surface can be reduced in order to make the top part of annulus pressurized. This will helps in keeping the BHP constant throughout the drilling operation. On the other hand if there is a need of reducing the pressure then choke will be operated in the opposite way. There are three choke options which are given below:

Manual Choke is the one which is manually operated. The tendency of making mistakes is higher as it is human operated. The driller and choke operator must have a good communication in between. They both have to work closely and effectively but humans are humans and there is always a probability of making errors [23].

Semi Automatic Choke has all the features of manual choke but also has automatic surface back pressure control in addition. The advantages related to semi automatic choke are maintaining stable BHP during connections, improving kick detection, optimizing mud weight for ROP and instantaneous change in BHP compared to increasing mud weight [23].

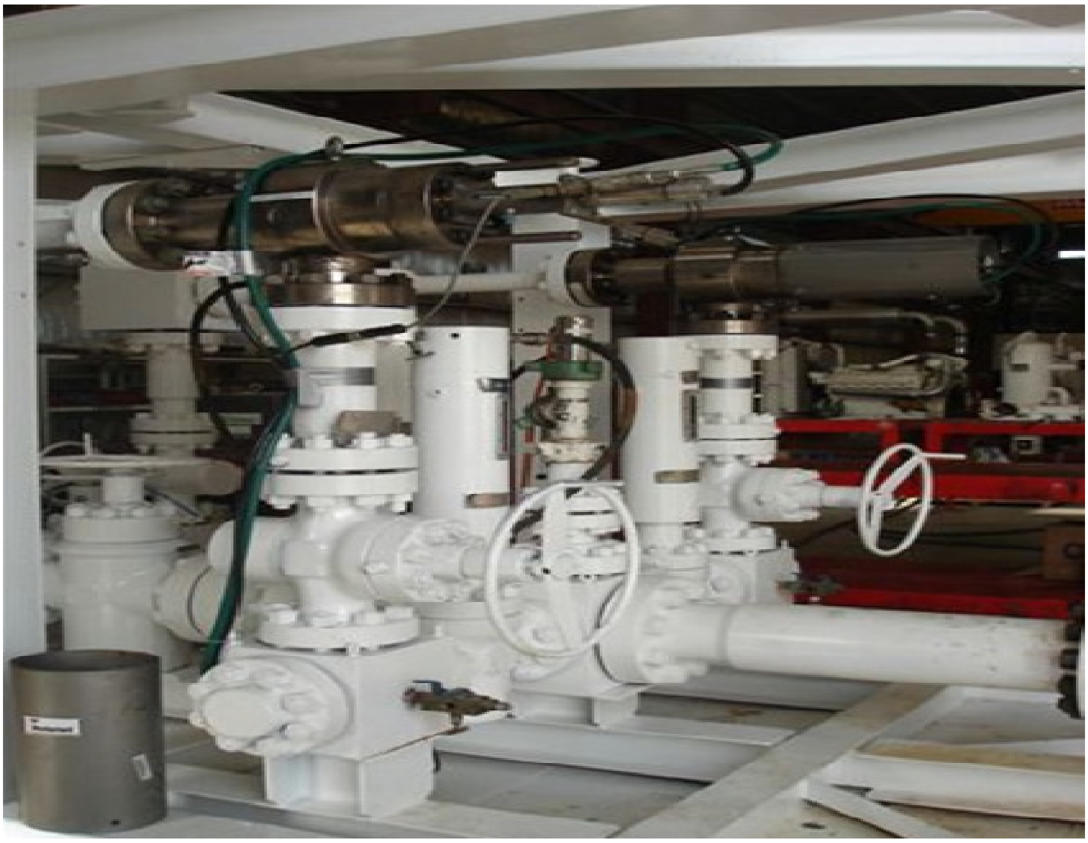

Fig 18: Semi Automatic Choke Manifold [23]

Automatic Choke is the choke which automatically controls the different pressures like stand pipe pressure, bottom hole pressure, back pressure [23]. These types of chokes are commonly used in Constant Bottom Hole Pressure (CBHP) applications to keep the BHP constant during connections [23]. During connections, a back pressure is applied by closing the choke manifold in order to compensate loss of Equivalent Circulating Density (ECD) [23]. There is a less risk of making mistakes by using automatic chokes than manually operated ones. These chokes are more efficient and reliable.

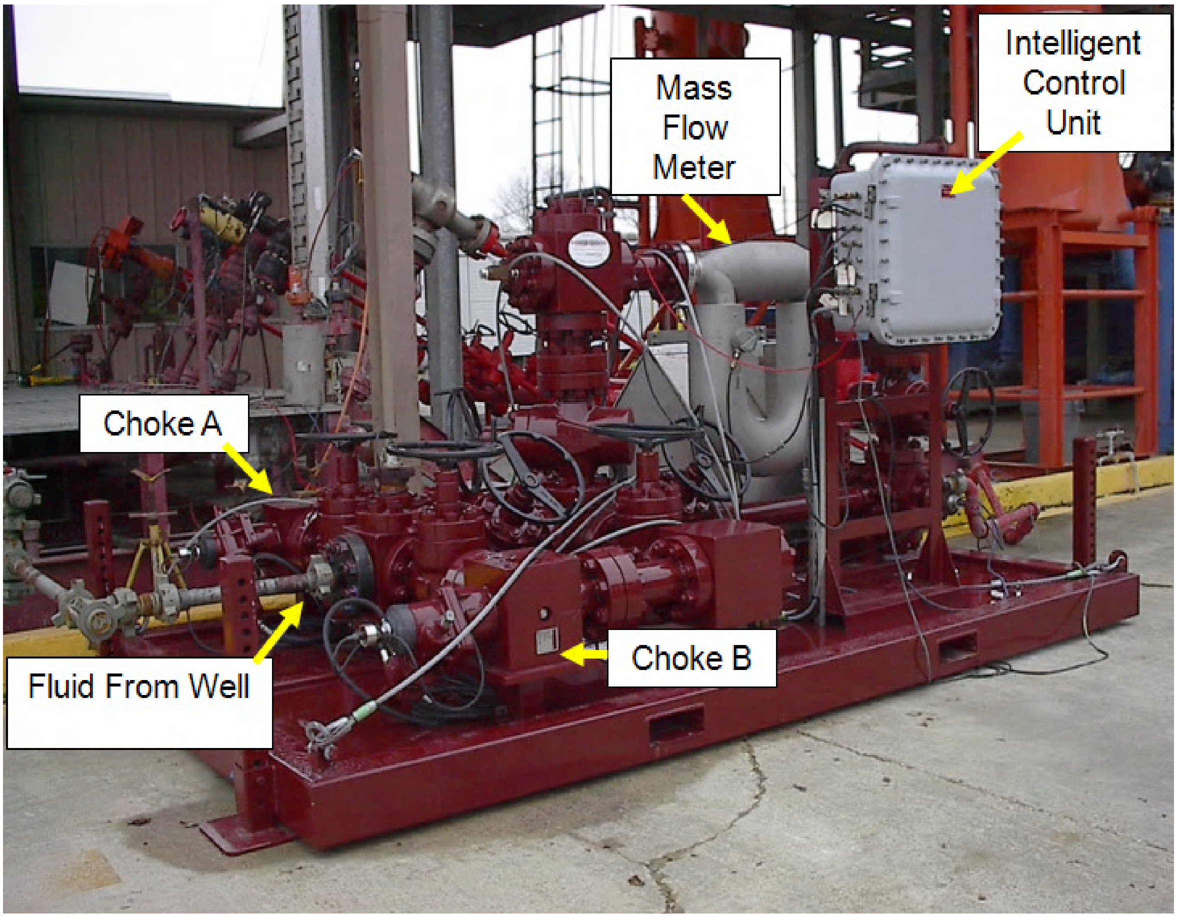

Fig 19: Automatic Choke Manifold [23]

3.3 Downhole Casing Isolation Valve (DCIV)

DCIV is a downhole valve which allows tripping without killing of the well [23]. It is based on technology of casing deployed downhole valve that allows shutting in well for lubrication of drill string or running in completion tool. The top section of the valve is comprised of actuator that controls the flapper movement in the bottom section.

The DCIV is the most positive solution to MPD problem of trips [23]. The pipe is pulled up into the casing until the bit is above the DCIV. Then the DCIV is closed trapping any pressure below it. This allows the tripping in normal mode without killing of the well. The pressure below the DCIV comes to equilibrium with the reservoir pressure [23].

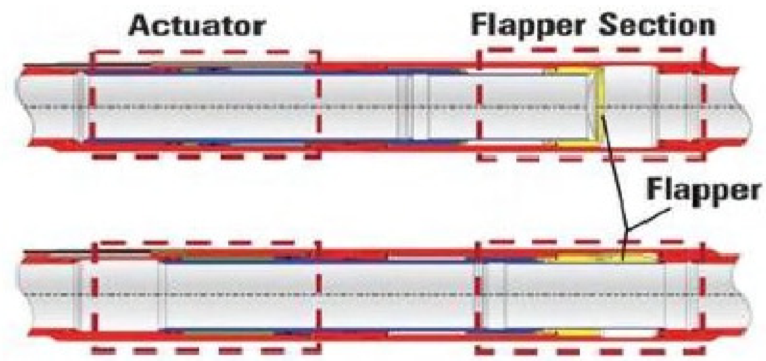

Fig 20: Shows a DCIV [23]

3.4 ECD Reduction Tool

This tool is more commonly used is deepwater drilling [23]. In deepwater drilling a number of casings have to be run in order to reach the target. This reduces the hole size and frictional pressure can be problematic. This tool has also beneficial use in extended reach wells where frictional pressure loss is high due to long hole section.

The ECD can be changed by modifying the annular pressure profile directly [23]. By using a single density drilling fluid, a downhole motor can be used to provide energy that creates an abrupt change in the annular pressure profile [23]. This allows no need of back pressure under static condition. The BHP will be remained same in both static and dynamic conditions.

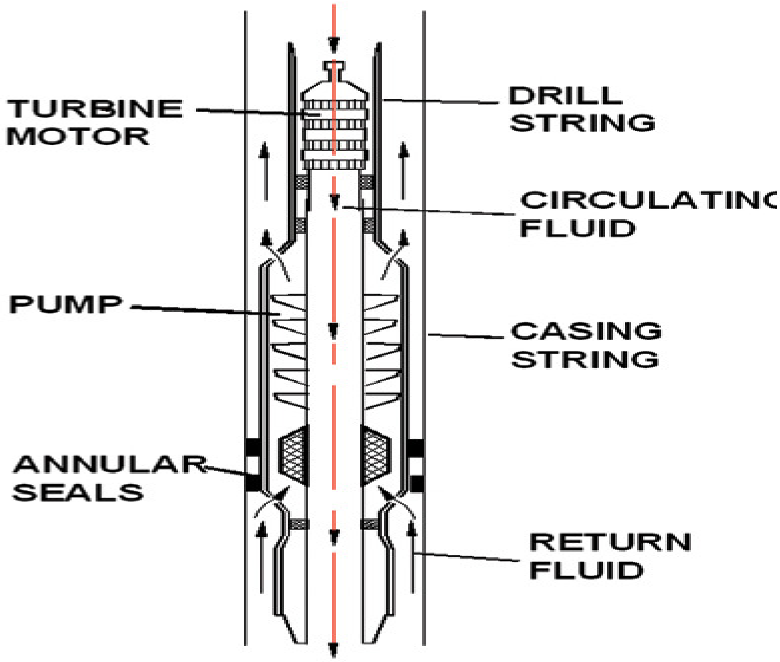

Fig 21: An ECD Reduction Tool [23]

3.5 Continuous Circulation System

It is used to control the annular pressure profile under connection by maintaining the ECD [21]. Pipe rams and a blind ram are configured effectively in order to maintain circulation during the connection. Continuous circulation device diverts the fluid flow across the open connection with the help of specific sequence of operations [21]. It is one of the appreciated technologies in CBHP application [23].

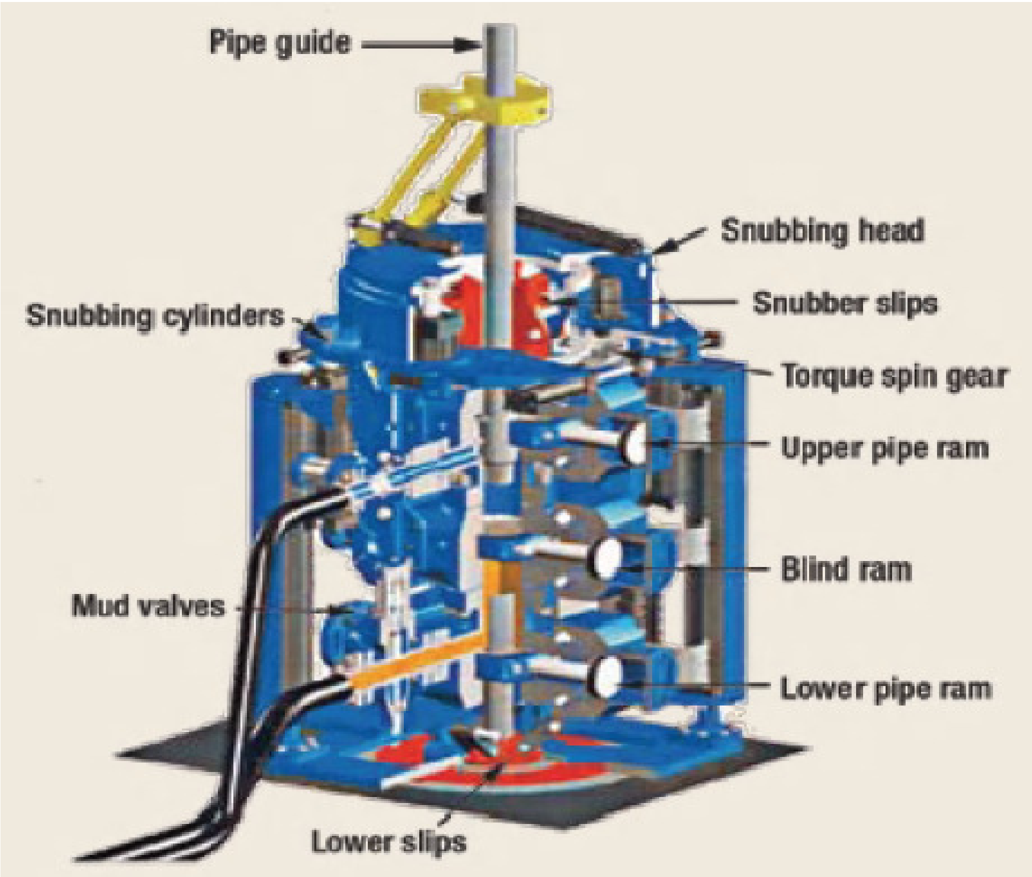

Fig 22: Continuous Circulating System [21]

4. MPD Automation

MPD has emerged as a powerful technology for well control in a more precise way. While giving a precise pressure control of the well on one hand, it also creates some operational problems on the other hand. Such operational problems arise due to requirement of MPD tools (pumps, chokes, valves) that must have coordinated simultaneously [13]. Operational problems can arise due to human operational errors or random errors. Driller and MPD choke operator has to work very closely to adjust the choke according to bottom hole pressure. A very accurate command should be passed between them to operate optimally. But still there is a margin of making mistakes and misunderstandings. The struggle to find a solution for such problems causes the introduction of Automation in the MPD field. However automation isn't unknown for oil industry from before [13]. Oil refineries are operating by automation of different processes. Such useful experiences make it possible to introduce MPD automation that can reduces complexity and make it possible to manage MPD tools more effectively [13].

Manually operations performed by drilling crew can cause BHP disturbances [9]. The BHP is a critical factor for an efficient drilling performance. The pressure should be kept within the operating window (i.e. between pore pressure & fracture pressure) in order to avoid damaging to the wellbore and formation [9]. So the main focus in MPD applications is on utilizing pump systems and choke valves in the best effective way to keep the well pressure; P_{well} , above reservoir pore pressure; P_{pore} , and below the reservoir fracturing pressure; P_{frac} , during drilling operation [9].

$$\boldsymbol{Max\ (P_{coll}\ (t,x)\ ,\ P_{pore}\ (t,x)) < P_{well}\ (t,x) < P_{frac}\ (t,x)}$$

Here 'x' is the position along the open hole section and't' is the time. The upper limit for well pressure is formation fracturing pressure and the lower limit is formation collapse pressure; Pcoll [9]. The reservoir pore pressure is the function of both time and position along the well hole. The density in the formation is higher than the drilling fluid [9]. The well pressure in the upper part of the open hole will be closer to fracture pressure and in the lower part it will be closer to reservoir pressure [9]. This is the reason why casings have to be installed in the hole to protect the formation and allow further drilling of the hole. Every time when it is not possible to drill further without exceeding the operating pressure window (i.e. margin between pore and fracture pressure), a new casing has to be installed [9]. In depleted reservoirs where the operating pressure window is very narrow, it is quite a challenge to control the pressure without introducing automation in the MPD process [9].

The operation of MPD equipment combined with maintaining adequate downhole conditions can be a complex task for the driller. So by making the control of MPD tools automatized, the driller can keep focus on the downhole conditions. This can be done by automatizing control of well pressure by using the choke at the top side. Whenever the BHP get disturbed and show deviation from the desired pressure, the choke valve can be opened and closed according to the condition. By closing of the choke valve, it will pressurize the top side of annulus and in this way pressure can be increased to compensate the missing BHP [9]. On the other hand choke can be opened to reduce the pressure if needed.

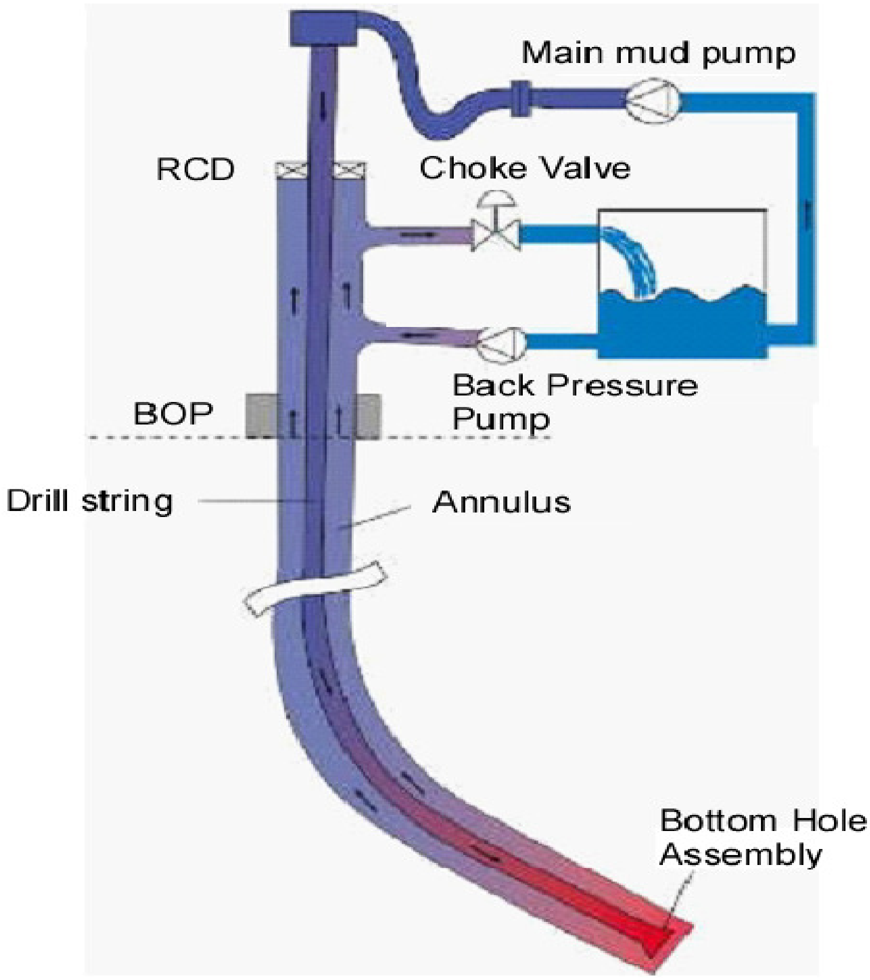

Fig 23: Typical MPD Set Up [13]

All this can be done automatically and it helps to reduce the complexity of MPD applications. The whole operation can be executed more efficiently and without any errors. This is more reliable with respect to eliminating mistakes. The risk of doing mistakes is much higher among humans. Manual operation of such applications has caused communication problems between driller and choke operator. It is also a hard job to operate the choke to achieve the desired BHP. The risk for error is always present. MPD automation is more reliable and effective.

4.1 Control Level (PID controller)

The Proportional-Integral-Derivative (PID) controller is a widely used control loop feedback. PID controller measures error between a set point value and a measured point value and on the base of that error it changes its input parameters to give the desired output [25].

The control technique used mainly in control of pressure with respect to choke opening is PID controller. PID controller has different variations and it is most commonly used in the industry [13]. PID uses one input to control one output (Single-input-single-output control) [13]. The PID equation is given below [25]:

$$\boldsymbol{u = u_0 + K_p e + \frac{K_P}{T_i}\int_0^t e d\tau + K_p T_d \dot{e}}$$

Here,
u is controller output at new level
u_o is value at old level
e = error = Set point – Measured point
K_P is a proportional gain
T_i is an integral time
T_d is a derivative time (rate time)

Proportional term: $\boldsymbol{K_p e}$ makes the change to the output on the base of current error value. The proportional response can be adjusted by multiplying the error by proportional gain.

Integral term: $\boldsymbol{\frac{K_P}{T_i}\int_0^t e d\tau}$ gives the output based upon magnitude of the error and duration of the error. It accelerates the movement of the process towards set point and eliminates the residual error that occurs with a pure proportional controller.

Derivative term: $\boldsymbol{K_p T_d \dot{e}}$ determines the slope of the error over time. This term slows the rate of change of controller output.

The discrete form of the PID equation is given by [25]:

$$\boldsymbol{u_k = u_{k-1} + k_p(e_{pk} - e_{pk-1}) + \frac{k_p T_s}{T_i} e_k + \frac{k_p T_d}{T_s}(e_{dfk} - 2e_{dfk-1} + e_{dfk-2})}$$

Here,
u_k is controller output at new level
u_{k-1} is value at old level
e_k = error = Set point – Measured point
T_s is sampling interval
$e_{pk} - e_{pk-1}$ is error difference between new and old level

The performance of the control system depends upon tuning parameters (K_P, T_i, and T_d) [25]. To achieve the best out of the PID controller these tuning parameters must be adjusted accurately. In [25] Ziegler-Nichols methods have been used to adjust the tuning parameters and those methods are also applied in this thesis to adjust the tuning parameters correctly. The poorly tuned parameters will give a totally unacceptable output. So a lot of work and practice is required to tune the parameters according to the desired conditions.

In this thesis, PI-regulator is used for simulating of a pipe connection while keeping the BHP constant. This has been done with two different approaches, first with regulation of choke opening and secondly with regulation of choke differential pressure. The PI controller equation contains only proportional and integral term and is given by [25]:

$$\boldsymbol{u = u_0 + K_p e + \frac{K_P}{T_i}\int_0^t e\,d\tau}$$

The discrete form of the PI equation is given by [25]:

$$\boldsymbol{u_k = u_{k-1} + k_p(e_k - e_{k-1}) + \frac{k_p T_s}{T_i} e_k}$$

Here,
u_k is controller output at new level
u_{k-1} is value at old level
e_k = error = Set point – Measured point
T_s is sampling interval
k_p is a proportional gain
T_i is an integral time

In this thesis, the discrete equation for PI controller is taken from [13] which is presented as:

$$\boldsymbol{u_k = u_{k-1} + k_p(e_k - e_{k-1}) + \frac{k_p T_s}{2T_i}(e_k + e_{k-1})}$$

4.2 Choke Pressure Control

The most important algorithm for pressure control is choke pressure control loop. This is used to maintain the desired choke pressure according to the BHP. The selection of the right choke valve and valve actuator is strongly recommended for an accurate pressure control. Delay in the opening and closing of the valve will have a bad affect on the controller algorithm. The choke valve differential pressure ΔP helps to maintain the desired BHP. A standard equation for flow through a valve is given below [13]:

$$\boldsymbol{q_{out} = C.u\sqrt{\frac{2.\Delta P}{\rho}}}$$

$$\boldsymbol{\Delta P = \frac{{q_{out}}^2 \cdot \rho}{2.C^2.u^2}}$$

Here,

q_{out} is flow
C is valve constant
u is valve opening
ρ is mud density
ΔP is choke differential pressure

In this thesis, above equation is used in two different approaches. In first approach it is used in regulation of choke opening (u) where choke opening is adjusted in order to maintain constant BHP during connection. In second approach choke differential pressure (ΔP) is regulated directly to obtain the same result.

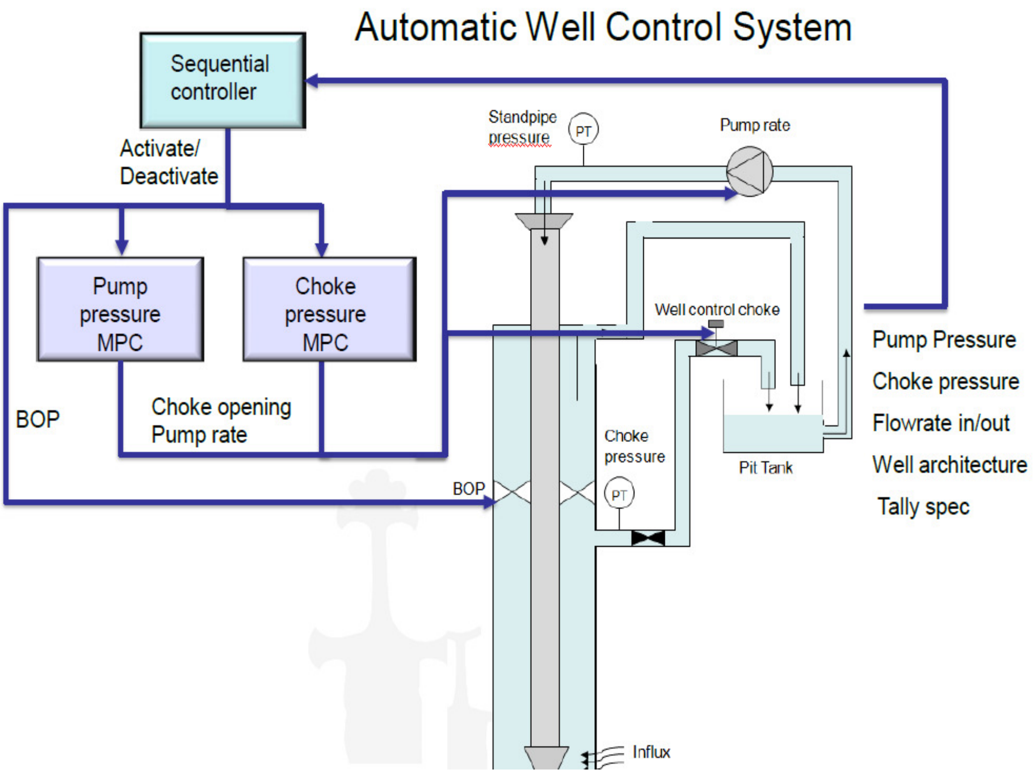

Fig 24: Automatic Well Control [2]

5. MPD Vendors

In this section the main area of focus is on the techniques and equipment used during MPD operations by the known MPD vendors. The market is full of large and small service companies that are providing MPD assistance. The two leading companies which are chosen here for discussion are Halliburton and Weatherford. Both of them have developed a strong position in the field of MPD. An effort is made to discuss the techniques and procedures for MPD operations used by both companies. The type of equipment, hydraulic model, operational techniques and connection procedure are the key points of interest in this section.

Kjetil Knudsen from Halliburton [20] and Henrik Sveinall from Weatherford [19] were contacted and interviewed regarding to the MPD techniques and equipment which are being used by both companies.

5.1 Halliburton

The information used in this section is obtained from [20]. Halliburton is a key vendor in the MPD market. The sub-department of Sperry Drilling i.e. GeoBalance is the one which deals with MPD and UBD worldwide. In Norway they have done MPD operations for Statoil and Hydro. In North Sea, Halliburton has supplied its services on the fields of Grane and Gullfaks [20]. In the start, manual choke pressure control was provided. In manually operating choke they used to trap the pressure under connections. Later on, an automatic choke system was deployed on Gullfaks field where backpressure pump is used to have a cross flow when main pumps were off and in this way a backpressure is generated under connections [20].

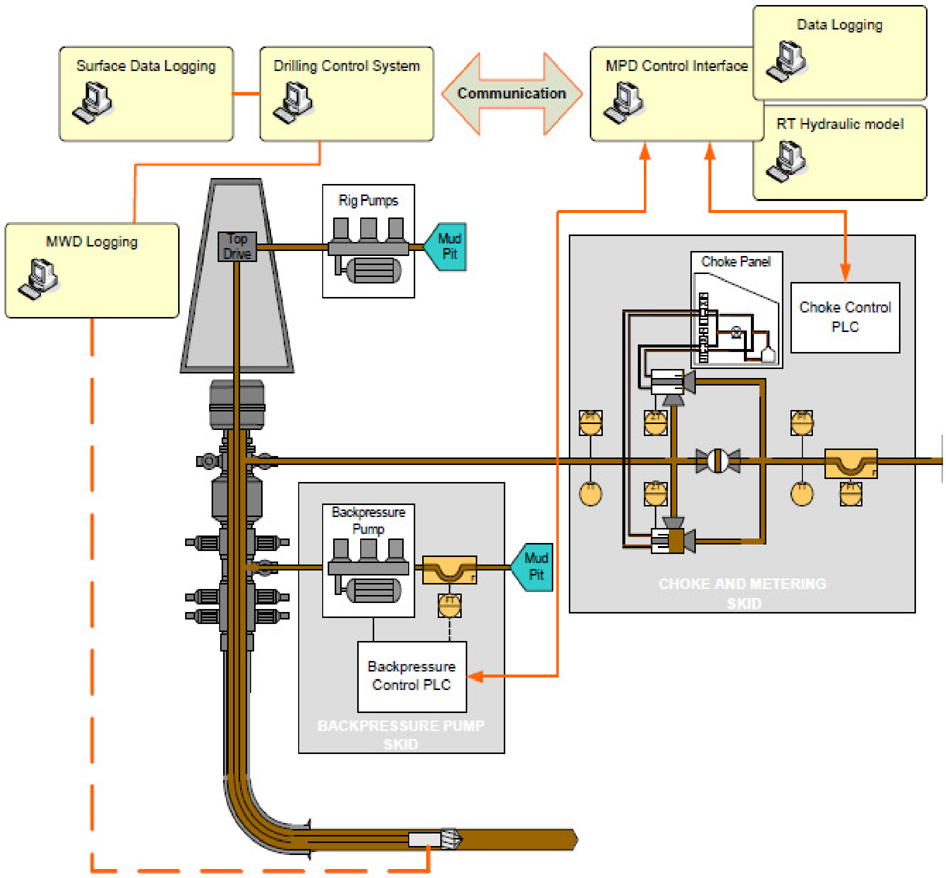

Fig 25: MPD Set Up of Halliburton [20]

Main Pumps

Basically this is rig equipment but company prefer to have pumps which have an independent relationship between speed and pressure i.e. pressure has no effect on speed and flow. Such pumps are mainly provided in North Sea [20]. Halliburton don't prefer pumps for the operations where speed gets reduced due to increase in pressure and which results in a reduced flow [20].

Choke Valve Type & Quantity

Halliburton used Power Chokes [20] which are much tougher ones than other. They are quite resistant against wear and tend to last long. These chokes can be equipped with 3´´, 2´´ and 1.5´´ choke trim. In North Sea, Halliburton is using 3´´ choke trim [20]. Both 3´´ and 1.5´´ trims have relative linear choke flow characteristic [Control Valve Curve or Cv-Curve]. The flow characteristic is very important for simulation purposes. But the 2´´ trim doesn't show linear choke flow characteristic. Therefore, for control purpose, company doesn't prefer to use 2´´ trim.

Halliburton used a dual choke manifold with double block and bleed isolation [20]. If one choke get plugged then it can be isolated with double barriers for maintenance. The system will detect the plugged choke and swap chokes automatically. The first barrier valves are hydraulic and can be operated from control system and locally on the choke. It handles flow rate up to 4000 liters per minute and can handle pressure up to 345 bars [20].

Fig 26: Automatic Choke Skid [20]

Type of Measurements

The measurements which are important for MPD automation are [20]:

- ***Pressure is obtained by the following:***
  - Suction side of Back pressure pump
  - Discharge side of Back pressure pump
  - Upstream of choke (3 sensors)
  - Downstream of choke

- ***Temperature is obtained by the following:***
  - Suction side of Back pressure pump (Coriolis meter)
  - Upstream of choke
  - Downstream of choke (Coriolis meter)

- ***Density is obtained by the following:***
  - Suction side of Back pressure pump (Coriolis meter)
  - Downstream of choke (Coriolis meter)

- ***Flow Rate is obtained by the following:***
  - Suction side of Back pressure pump (Coriolis meter)
  - Downstream of choke (Coriolis meter)
  - Rig pump flow i.e. reading from rig system

Fig 27: A Metering Skid [20]

Hole depth, bit depth, RPM, torque, block position, weight on bit are all values obtained by the rig system. All these values come from sensors with one second sample rate. In addition to them, temperature and density measurements are also taken in the pump room from the mud. Mud rheological measurements are taken every 6 hour by the mud engineer. Downhole data such as pressure, ECD and temperature are obtained from the MWD tool [20].

Type of Model (Steady or Transient)

Halliburton used Sintef Hydraulic MPD Model [20] which is a Transient model. Halliburton does have their own hydraulic models both steady state and transient but they are not developed at the same level as the Sintef Model [20].

Backpressure pump

Halliburton used a backpressure pump which can deliver up to 930 liters per minute at 50 bars. The speciality with this pump is that it ramps up in a very controlled manner and in this way flow rate through choke changes in a very minimum way. Therefore, pressure is not greatly affected when rig pumps are ramped down and backpressure pump is ramped up [20].

Operation Procedure

Halliburton are using different modes for MPD system and operations and these modes reflect the type of control system [20].

- Standby mode: It means that no remote actions are possible and only reading of data is possible.
- Manual mode: In this mode one can run pumps and open/close choke remotely with the help of human machine interface (HMI) from control cabin.
- Surface pressure control mode: Operator gives a desired surface pressure in HMI and choke will be automatically controlled to achieve the desire pressure. It means that the hydraulic model is not going to be used in this mode.
- Bottom hole pressure control mode: Operator gives a desire bottom hole pressure in the hydraulic model and the model calculates pressure which will be controlled by the choke automatically. This is the most commonly used mode.

It is bottom hole pressure control mode which is normally used during operation and everything in this mode is automatically operated. When rig pumps ramp down during connection, then the backpressure pump will ramp up automatically and all the calculations will be based on real time data. If a problem occurs the integrated inbuilt Data Validation module will ensure that system is always in a safe state [20]. For example, if there is a breakdown in communication of rig data (flow rate, depth etc), the MPD system will detect that and automatically switch to surface pressure control mode since the hydraulic model can't be trusted in such situations. In addition to that an alarm will also be pop up and warn the operator and driller and they will keep the flow rate and RPM stable.

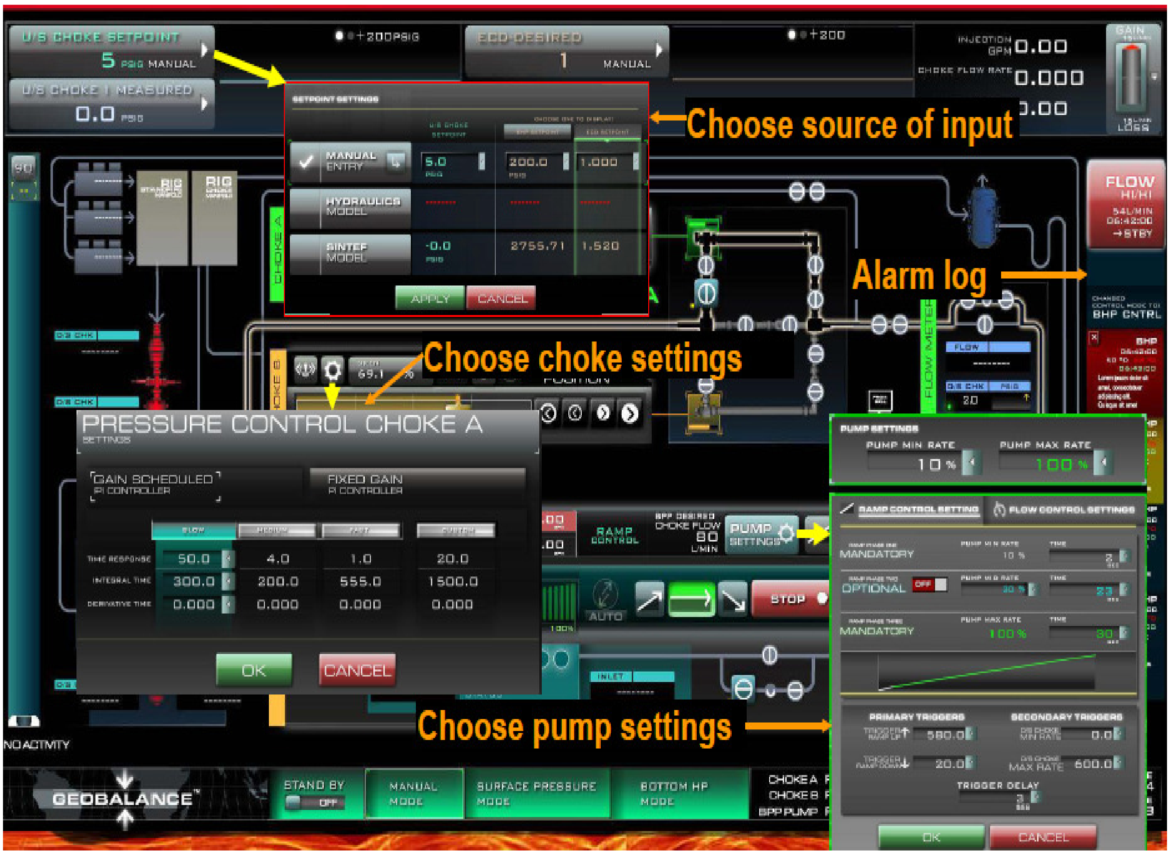

Fig 28: Operating Software Screen for MPD [20]

Connection Procedure

The up and down ramping of pumps happens in the same way during connection. Let's assume level 1 and level 2 refer to rate ramping with rig pumps (company desired ramping). All the communication is carried out on radio [20].

- **Break Out**
  - Stop rotating (Driller)
  - Inform Halliburton and ramp down rig pumps (Driller)
  - Set slips and select connection mode (Driller)
  - Confirm connection mode (Halliburton)
  - Bleed off Stand Pipe Pressure and close IBOP (Driller)
  - Disconnect Top Drive (Driller)

- **Make Up**
  - Make up new stand (Driller)
  - De-select connection mode (Driller)
  - Halliburton confirm out of connection mode (Halliburton)
  - Open IBOP and pull out of slips (Driller)
  - Start rotation 50-60 RPM (Driller)
  - Fill pipe and break circulation using level 1 ramp (Driller)
  - Confirm stable conditions (Halliburton)
  - Stop rotation, release torque (Driller)
  - Continue up to drilling rate using level 2 ramp (Driller)
  - Continue drilling when survey is confirmed (Driller)

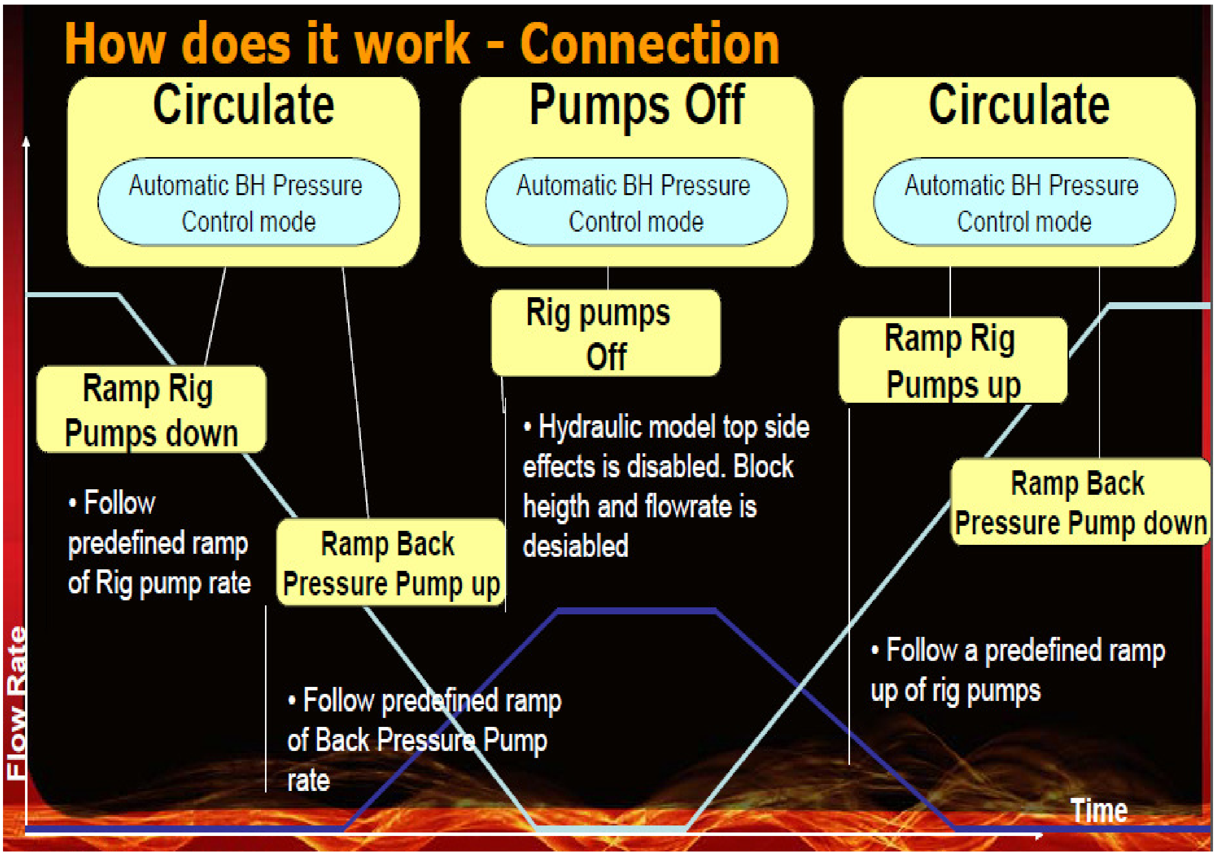

Fig 29: Halliburton Connection Procedure [20]

5.2 Weatherford

The information used in this section is obtained from [19]. Weatherford is another key vendor in the MPD field. They have done MPD operations on the Kvitebjørn field where they have used Sintef Hydraulic Model [19]. But usually they use DrillSim Hydraulic Model. Weatherford perform their drilling operations based on MicroFlux Control System (MFC). It is a closed loop system that analysis drilling data in real time and detects kicks or losses. This system adjusts the surface backpressure in order to balance the flow in and out resulting in maintaining a correct pressure in a well [19]. In MPD operations MFC system technology is used to measure flow in and out and bottom hole pressure. The pressure will be constant in case of flow in is equal to flow out. The MFC system is designed in such a way that it can be incorporated with the existing drilling and pressure control equipment like Rotating Control Device (RCD), chokes, degassers, pressure sensors and mass flow meters. The flexibility of the MFC system enables many options for drilling such as [19]:

- Flow out control: Manual or Automatic
- Pressure control; annular pressure, surface backpressure, stand pipe pressure: Manual or Automatic
- Automatic loss detection and control; fracture pressure determination
- Automatic detection of many common drilling events

The options mentioned above are selected on the base of well design, well problems, well objectives, rig footprint capability and equipment availability on rig. Among many other, the most important features of MFC are given below:

- It has the ability to maintain a constant bottom hole pressure (BHP)
- It identifies and manages losses through early identification of micro fluid losses
- It manages pressure during circulation and also during kill mud displacement
- It determines the fracture gradient more accurately
- It monitors surge/swab pressure effect
- It interprets shoe leak-off and casing tests more accurately

The Secure Drilling Hydraulic Model [19] was specially developed to provide a predictive software package for detecting losses and influxes. It also determines backpressure required to keep wellhead pressure, bottom hole pressure or standpipe pressure constant. The Secure system also allows maintaining a desired constant annular pressure at any depth.

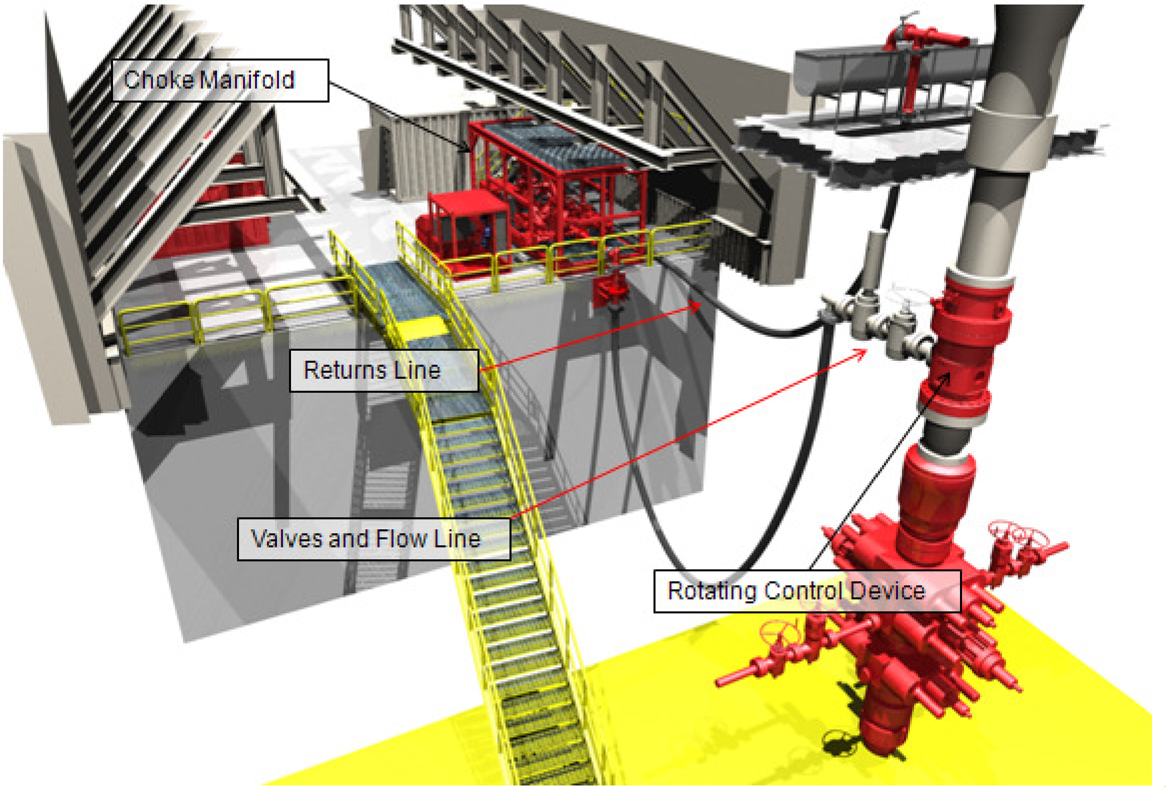

Fig 30: General Rig Up of MPD [19]

Main Pumps

Weatherford usually make use of the available mud pumps on the rig. Weatherford used to assign one mud pump as a backpressure pump or an extra pump in addition to rig pumps can also be used as a backpressure pump [19].

Choke Valve Type & Quantity

Weatherford used two power chokes SCB2 worm gear operated drilling chokes [19]. The nose and seat are built of Tungsten Carbide which provides excellent durability. These are available in two trim sizes 2´´ and 3´´. Weatherford normally used two 3´´ SCB2 drilling chokes that allow higher flow rates with less pressure drop and also allow bigger cuttings to pass through them [19].

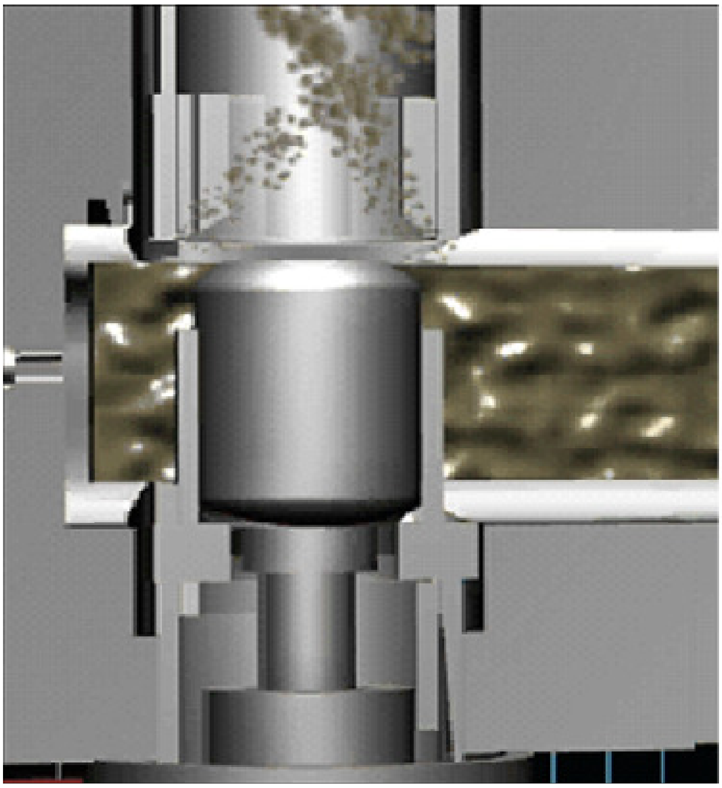

Fig 31: Power Choke [19]

Type of Measurements

During the operation, the MPD crew will measure flow rates, temperature, density, choke pressure and stand pipe pressure with the help of sensors and mass flow meter (Coriolis). All the measured parameters are then inserted into hydraulic model to check the flow in and out with respect to the pumps speed. The change in flow in/out is seen as influx/losses. If the flow out is higher than flow in and the stand pipe pressure increases, it gives an indication of a kick.

Fig 32: Combined Choke Manifold, Coriolis Flow meter and control system [19]

A Coriolis, mass flow meter, is used to measure fluid density, mass flow and temperature. Then, a volumetric flow can be calculated. It is simple to use and it is durable. It works by splitting up the flow into two vibrating tubes [19]. The vibration changes as a function of flow and density of the fluid. In this way density, flow and temperature can be measured [19]. The accuracy of the measurements is +/- 0.15%.

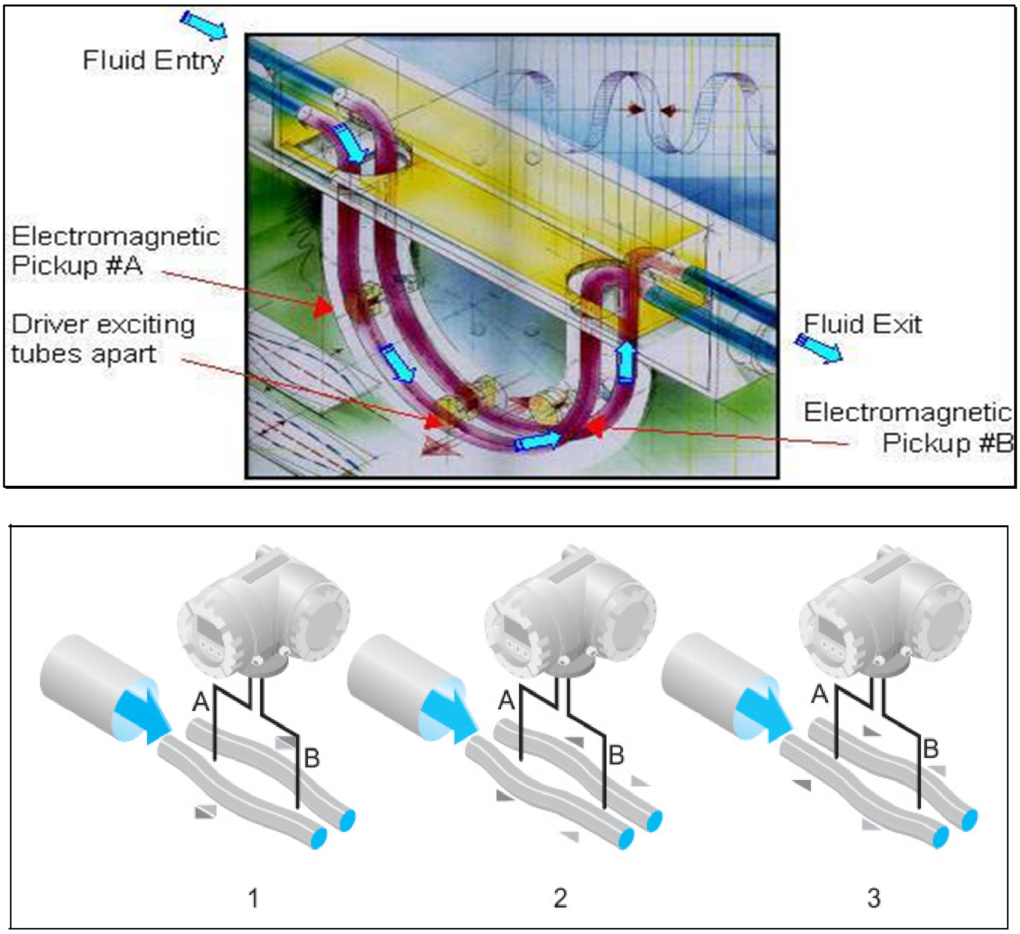

Fig 33: Shows a Coriolis Meter [19]

Type of Model (Steady or Transient)

The model, Weatherford, is used is a transient model as it is more reliable to changes and it allows modeling the changes at any stage. Sintef Hydraulic Model was used at Kvitebjørn [19].

Operation Procedure

There are two main operational modes in MicroFlux Control system (MFC) which is selected by Driller during operation. They are given below [19]:

- Drilling
  This mode enables the detection capabilities of the system. Any abnormal behavior during drilling can be detected quickly. Abnormal flow behavior can be due to kick or loss. So this can be detected quickly in this mode and operator can be informed.

- Not-Drilling
  This mode disables the detection capabilities of the system and it is used for preventing any false alarms that can be triggered due to abrupt change in flow by pipe movement.

In addition to two operation modes there are also two control modes as well which are selected by the MFC operator. They are given below [19]:

- Auto-Control On
  This mode enables the automatic reaction of the choke i.e. if an influx is detected then the system will turn to Kick Mode to automatically operate the choke in order to control and circulate influx out of the well.

- Auto-Control Off
  This mode disables the automatic reaction of the choke. This means that choke will not take any action when an influx is detected but influx can still be detected as before and operator will be warned.

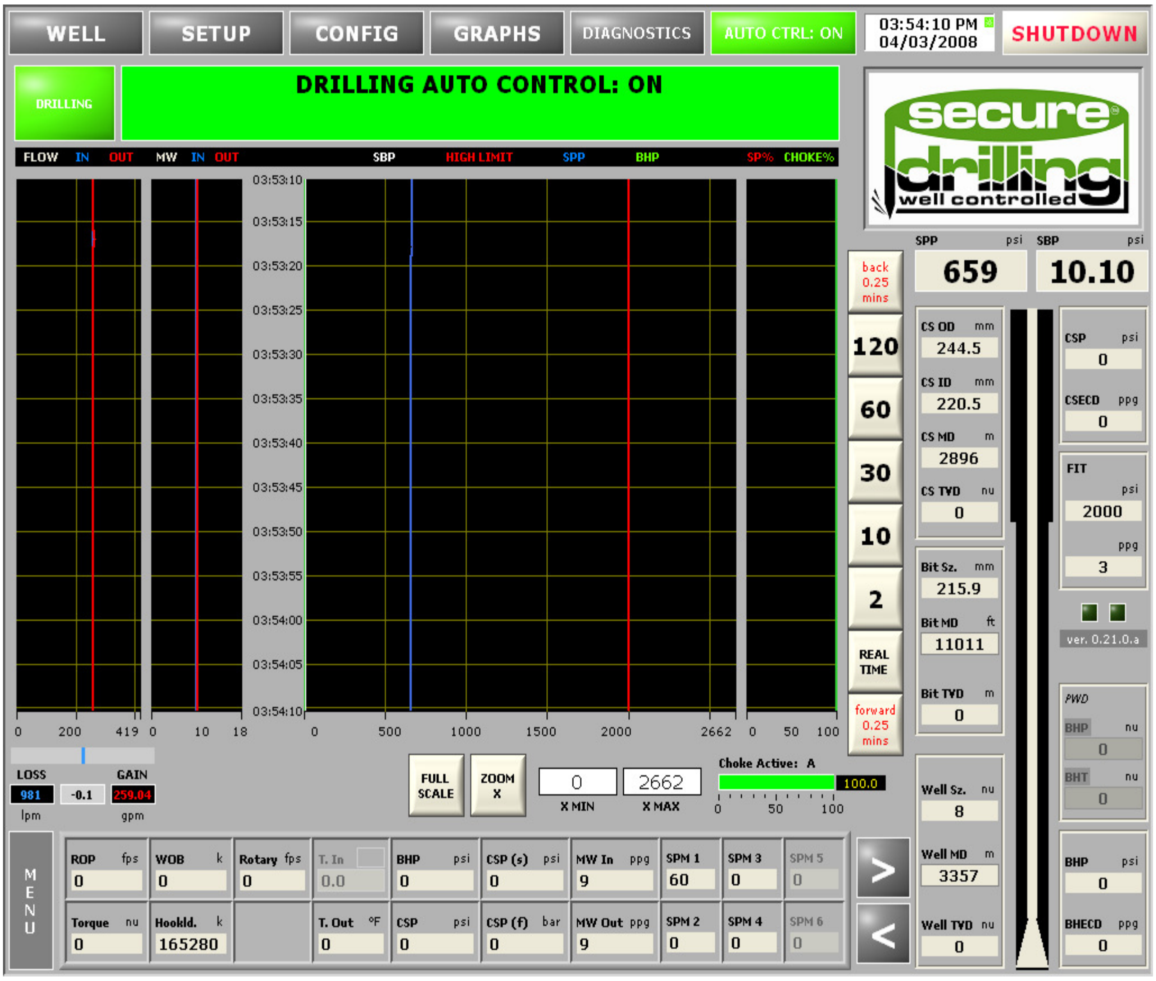

Fig 34: Operating Software Screen [19]

Connection Procedure

The basic connection procedure under MPD operation will be as following [19]:

- The Driller should inform the Weatherford's operator ten minutes in advance to any connection. The Secure Drilling (SD) operator will change the Pressure Relief Valve (PRV) set point if it is needed prior to connection.
- Weatherford crew will line up for circulation from a mud pump e.g. mud pump 3.
- The SD operator then confirms that system is ready for connection by ensuring that system is in annular pressure control mode. The SD operator will also increase the pressure in the choke algorithm to allow for a faster choke reaction.
- The auxiliary pump will be ramped up slowly to 200 gallons per minute (760 lpm)
- After this Driller will inform the MPD operator that he is ready to start decreasing mud pump 1. The MPD operator instructs the Driller to slowly decrease mud pump 1 to 5-7 SPM.

- The Annular Pressure Control software will apply a surface back pressure in order to compensate the missing ECD pressure.
- After getting a stable pressure the SD operator will instruct the Driller to reduce the SPM of mud pump 1 from 5-7 to 0.
- After this MPD operator will instruct the Driller to slowly decrease mud pump 2 to 5-7 SPM and after getting the stable pressure the SD operator will give a message to Driller to turn off the mud pump 2. (This is in the case of using two mud pumps)
- Stop the rotation and bleed off any remaining drill pipe pressure and monitor the bleed off line to confirm that the float valves are holding before breaking off the Top Drive.
- At this point the rig crew can make a connection according to standard connection procedures.
- After making the connection the Driller will inform the SD operator when he is ready to restart the drill pipe circulation.
- The SD operator will confirm that system is ready.
- Now the Driller will slowly start the mud pump to fill the stand of drill pipe that was picked up under connection. After seeing any drill pipe pressure, mud pump will be shut down.
- The MPD operator will be informed by the Driller about initiating of circulation.
- The MPD operator will guide the Driller to start mud pump 1 at 5-7 SPM. Now the software will reduce the back pressure to compensate for rise in ECD pressure.
- The Annular Pressure Control software will reduce the annular pressure based on ECD calculations.
- The ramping up of the pumps will be similar to the ramping down of the pumps.
- The ramp up procedure may have to pause at a set point for a correct acquiring of MWD data.
- After getting a stabilized pressure MPD operator will inform Driller to slowly increase mud pump 1 from 5-7 SPM to full drilling rate.
- In case of two mud pumps, MPD operator will inform the Driller to start mud pump 2 at 5-7 SPM. After getting a stabilized pressure the SD operator will then inform the driller to slowly increase SPM to full drilling rate.
- Now mud pump 3 will be ramped down slowly until the pump is shut down.
- Weatherford crew will now isolate mud pump 3 from the MPD manifold.
- After achieving the drilling parameters, SD operator will reset the PRV to the drilling set point and reset the pressure in choke algorithm.
- After this SD operator will inform Driller and further drilling can be continued.

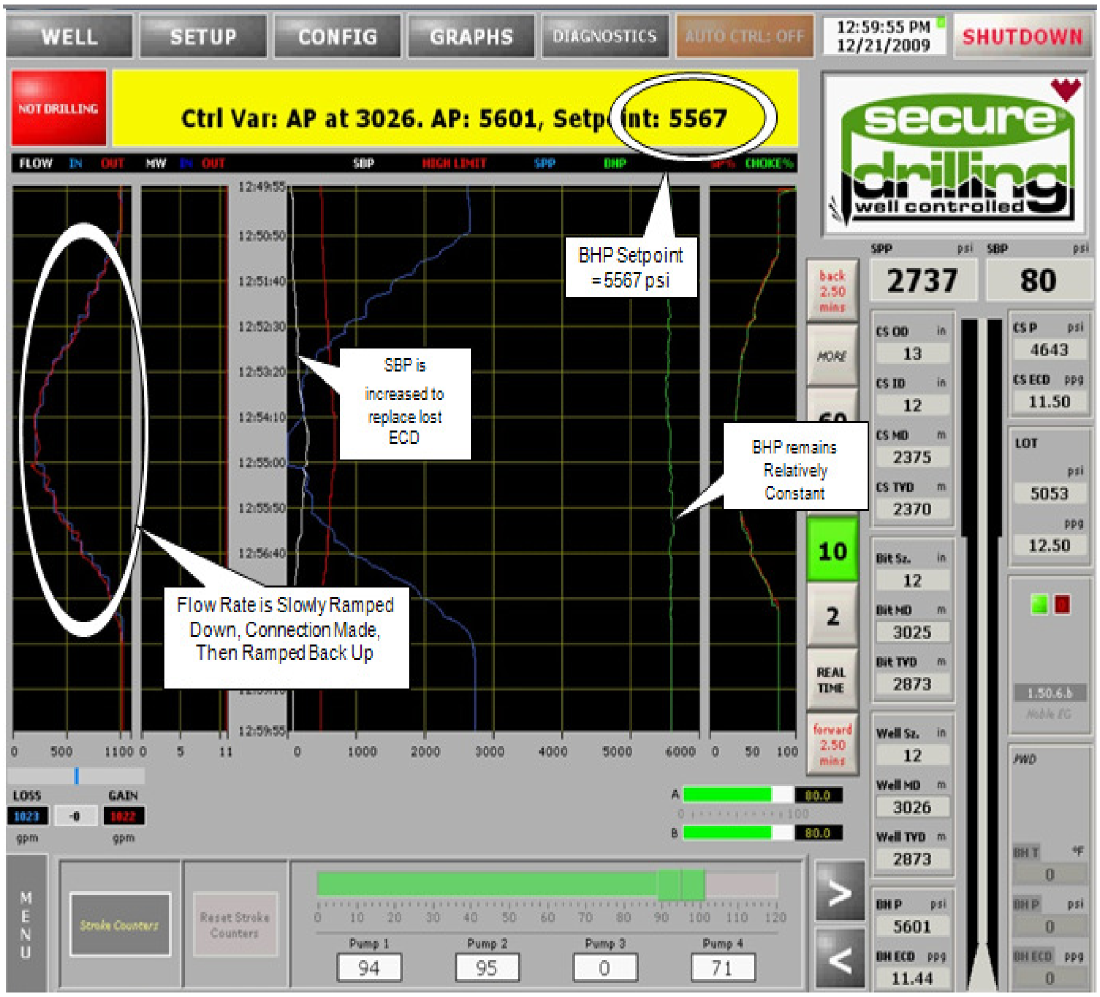

Fig 35: Screen Display during Connection [19]

6. AUSMV SCHEME

The basis for the simulations in this thesis is the AUSMV scheme [11]. A simple Drift Flux Model has been used to model the hydraulic flow transient in the well. The starting point was a code developed in [27]. This model was then extended to include a more advanced frictional pressure loss model and implementation of PI controller to be able to control well pressure by automatic choke control. AUSMV scheme [11] is an explicit of type 'flux vector splitting' and is able to predict both mass transport and sonic waves. Below a short description of the Drift Flux Model and the form of the AUSMV scheme is given. The original code was able to handle area changes in the well flow.

Two-Fluid model is very complicated and difficult to solve for many reasons as given in [11]. A Drift-Flux Model is more preferable due to its simplicity and less complex computations. This model is basically based upon Two-Fluid Model but with the addition of liquid and gas momentum and energy equations together. This helps in canceling out the phase interactions and the missing information is replaced by an empirical slip equation which gives a relation between the phase velocities [11].

The Drift-Flux model is given below for isothermal flow [11, 26]:

$$\partial_t[\alpha_l \rho_l] + \partial_x[\alpha_l \rho_l v_l] = \Gamma_l$$

$$\partial_t[\alpha_g \rho_g] + \partial_x[\alpha_g \rho_g v_g] = \Gamma_g$$

$$\partial_t[\alpha_l \rho_l v_l + \alpha_g \rho_g v_g] + \partial_x[\alpha_l \rho_l v_l^2 + \alpha_g \rho_g v_g^2 + p] = -q$$

Here,
α_l and α_g are volume fractions of liquid and gas ($\alpha_l + \alpha_g = 1$).
ρ_l and ρ_g are densities of liquid and gas.
v_l and v_g are velocities of liquid and gas.
Γ_l and Γ_g are mass exchanges between liquid and gas phase.
p is pressure.
q is a source term (external forces acting on the fluid e.g gravitational forces)

Assume there is no mass transfer between two phases.

$$\Gamma_l = \Gamma_g = 0$$

A Slip law is taken as

$$v_g = K.v_{mix} + S$$

There,

$v_{mix} = \alpha_l v_l + \alpha_g v_g$ is the mixture average velocity and K, S are flow dependent parameters. In this work K and S are taken as 1.2 and 0.5 respectively.

Liquid density is given by:

$$\rho_l = \rho_{lo} + \frac{p - p_{lo}}{{a_1}^2}$$

In this thesis a_l is taken as 1000 m/s which is the velocity of sound in liquid phase and $\rho_{lo} = 1500\ kg/m^3$, $p_{lo} = 1bar$. In the original code the mud weight was 1000 kg/m^3 but this was changed to 1500 kg/m^3 to have a more realistic mud weight in a MPD operation.

Gas density is given by:

$$\rho_g = \frac{p}{{a_g}^2}$$

Here a_g = 316 m/s is the velocity of sound in the gas phase.

Source term is given by:

$$q = F_w + F_g$$

Here F_g is gravitational constant and F_w is frictional force term. In this work, the following frictional pressure loss model was implemented [28]:

$$F_w = \frac{2f\rho_{mix}v_{mix}abs(v_{mix})}{(d_{out} - d_{in})}$$

The basis for this model was the PhD work of A.C.V.M. Lage [28]. The mixture variables are obtained by volume averaging and d_{out} , d_{in} are outer and inner diameter of the annular flow area. The friction factor f is based on laminar and turbulent flow. For laminar flow f = 24/Re where Re<2000. For turbulent flow f = $0.052Re^{-0.19}$ where Re >3000.

Discretization is important in solving the two phase flow problems. It gives more correct results. In this thesis the well is discretized into 25 boxes for simulation purposes. The Drift-Flux model equations are applied on each box as it is used to be done in transient modeling. The figure given below is showing the well which is discretized into finite boxes.

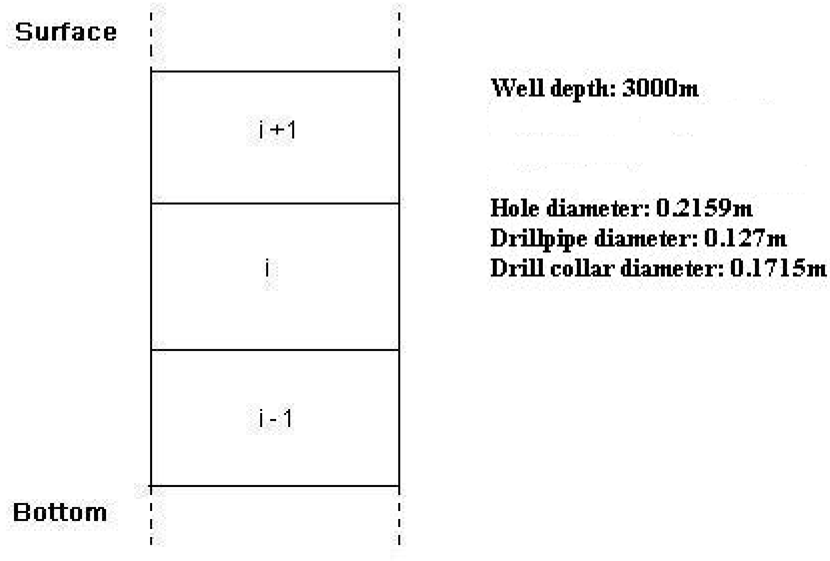

Fig 36: Well discretization &Well data

The AUSMV scheme gives the variables at the new time level by [11].

$$w_{i,j}{}^{n+1} = w_{i,j}{}^{n} - \frac{\Delta t}{\Delta x}\left(F_{j+\frac{1}{2}}{}^{AUSMV} - F_{j-\frac{1}{2}}{}^{AUSMV}\right) - \Delta t q_i{}^{n}$$

$w_{i,j}{}^{n+1}$ at new time level is based on values on the previous time level $w_{i,j}{}^{n}$. The discrete fluxes ($F_{j+\frac{1}{2}}{}^{AUSMV}$ *and* $F_{j-\frac{1}{2}}{}^{AUSMV}$) are treated explicitly in time (using old values) and complete expressions for these can be found in [11]. When stepping the scheme forward in time using time steps dt, one should be aware that the time step is limited by the CFL criterion.

$$\Delta t = CFL\,\frac{\Delta x}{\max\left(\lambda_1, \lambda_2, \lambda_3\right)}$$

$\lambda_1 = v_l - w$

$\lambda_2 = v_g$

$\lambda_3 = v_l + w$

They $\lambda's$ represent the propagating of 'waves' in the system (mass and sonic waves). Where 'w' is the sound velocity given by:

$$w^2 = \frac{p}{\alpha_g \rho_l (1 - K\alpha_g)}$$

In this work flow area discontinuity is also taken into consideration for AUSMV scheme. The flow area discontinuity is placed in the centre of the numerical box and mass conservation is applied [11].

$$(A\alpha_l \rho_l v_l)_{left} = (A\alpha_l \rho_l v_l)_{right}$$

$$(A\alpha_g \rho_g v_g)_{left} = (A\alpha_g \rho_g v_g)_{right}$$

Assuming the pressure, average phase volume and corresponding densities constant across the discontinuity, the numerical scheme will take the following form [11]:

$$w_{i,j}{}^{n+1} = w_{i,j}{}^{n} - \frac{\Delta t}{\Delta x}\left(A_{right} F_{m,j+\frac{1}{2}} - A_{left} F_{m,j-\frac{1}{2}} + A_{avg}\left(F_{p,j+\frac{1}{2}} - F_{p,j-\frac{1}{2}}\right)\right) - \Delta t q_i{}^{n}$$

Here, $A_{avg} = 0.5(A_{right}+A_{left})$ is the average flow area. F_m is representing convective fluxes. F_p is pressure fluxes. The above equation is applied on all discrete boxes and average phase volume and pressure will be found after every new time step. This can be found with the help of mass conservative variables ($w_{1,j} = A\alpha_l\rho_l$ and $w_{2,j} = A\alpha_g\rho_g$) by divided them with A_{avg}. The phase velocity is then can be found by ($w_{3,j} = A(\alpha_l\rho_l v_l + \alpha_g\rho_g v_g)$) in combination with the gas slip relation (w_3 + slip) → (v_g , v_L).

7. Simulations

In this section the AUSMV scheme is used to simulate an automatic pipe connection while keeping the bottom hole pressure (BHP) constant. By automatic, it means here that choke will be adjusted by itself in order to keep the bottom hole pressure constant. The PI controller is used for this purpose. The simulation of a pipe connection is done by adjusting the choke opening and also with choke diffential pressure regulation. A given mass flow rate 42.5kg/sec is circulated through the well and choke. The initial opening of the choke was 0.05%. The set pressure i.e. required bottomhole pressure for the whole simulation process is given to be 455 bar. The system (% choke opening) will be regulated itself in order to keep the BHP constant. The well used as a case for simulation is 3000m in vertical depth with 8.5′′ hole diameter, 5′′ drill pipe and 6.75′′ drill collar of 180m. The well data used in simulation of a pipe connection is given below:

Well depth: 3000m
Fluid density: 1500kg/m3
Liquid viscosity: 0.05 Pa.s
Gas viscosity: 0.000005 Pa.s
Hole diameter: 0.2159m
Drillpipe diameter: 0.127m
Drill collar diameter: 0.1715m

Well Data used in Simulation

First of all tuning parameters (k_p and t_i) have been found by using only a proportional term in PI controller ($u_k = u_{k-1} + k_P * e$). Here; e = Set pressure – Simulated bottomhole pressure. Critical values are found, as in Ziegler Nichols [25], for both k_P and t_i and they are $-0.0015/1.e^5$ and 15 seconds respectively. Then according to Ziegler Nichols [25], (k_p = critical value * 0.45) and (t_i = critical value /1.2). This will give the tuning parameters. So, $k_P = (-0.0015/1.e^5)*0.45$ and $t_i = 15/1.2$ are used as tuning parameters. A reasonable answer is obtained for operating the choke with respect to maintaining a constant bottomhole pressure.

Regulator	K_p	T_i	T_d
P	$0{,}5K_{pk}$	∞	0
PI	$0{,}45K_{pk}$	$\frac{T_k}{1{,}2}$	0
PID	$0{,}6K_{pk}$	$\frac{T_k}{2}$	$\frac{T_k}{8}$

Fig 37: Ziegler Nichols Formulas for Regulator Parameters [25]

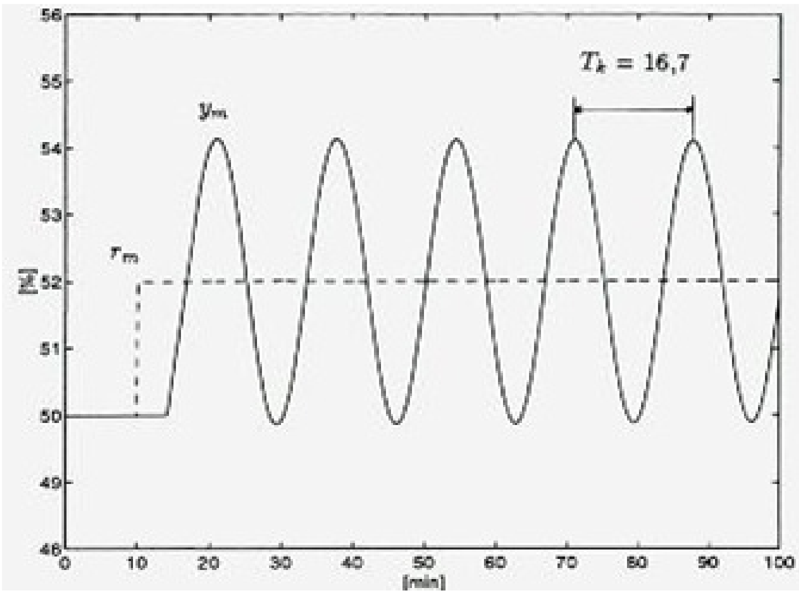

Fig 38: Ziegler Nichols Method for Critical Values [25]

The liquid flow rate for simulation is taken as 1700 lpm (0.028 m3/sec) which is multiplied by fluid density i.e. 1500 kg/m3 to get a mass flow rate equal to 42.5 kg/sec. The desired bottomhole pressure is 455 bars. The whole simulation process is divided into three parts. First a simple model is run by using the adjusted tuning parameters in order to make PI controller and choke opening regulation work correctly. Then after getting this right a pipe connection is introduced into the model. The connection time is taken as 3 minutes i.e from 310 to 490 seconds. During connection, a back pressure pump with a flow rate of 700lpm (q_{mix} = 0.011 m^3/s) is implemented into the model. In conection interval an attempt is made to adjust the choke opening (u) correct in order to get a stable bottomhole pressure but it didn’t work as expected. Then it was decided to regulate directly on choke differential pressure (ΔP) to obtain desired BHP (as explained in section 4.2) and this worked quite good. A different set of tuning parameters were used in this case.

7.1 Simulation of Setting constant BHP during Circulation

The Appendix I is showing a simple model for PI-regulator and choke with the adjusted tuning parameters. The PI-regulator and choke pressure control (explained in section 4.1 & 4.2) has worked very efficienlty with the adjusted tuning parameters. In this case choke opening is regulated to keep the constant BHP during circulation. The choke is closing down to keep the bottomhole pressure constant. The starting point of choke is taken as 0.05 and it get reduced with time to keep the pressure constant. This case is just to develop a working relationship between PI-regulator and choke regulating and to check if it works properly or not.

The figure 1 is showing desired bottom hole pressure with a dotted line i.e. 455 bar and the other line is showing simulated bottom hole pressure with respect to time. The figure 2 is showing choke operating with respect to time. The choke is closing down to make the pressure constant at the bottom of hole. The figure 3 is showing the liquid flow out. This is the liquid which is coming out of drillstring at the bottom and moving out at the surface.

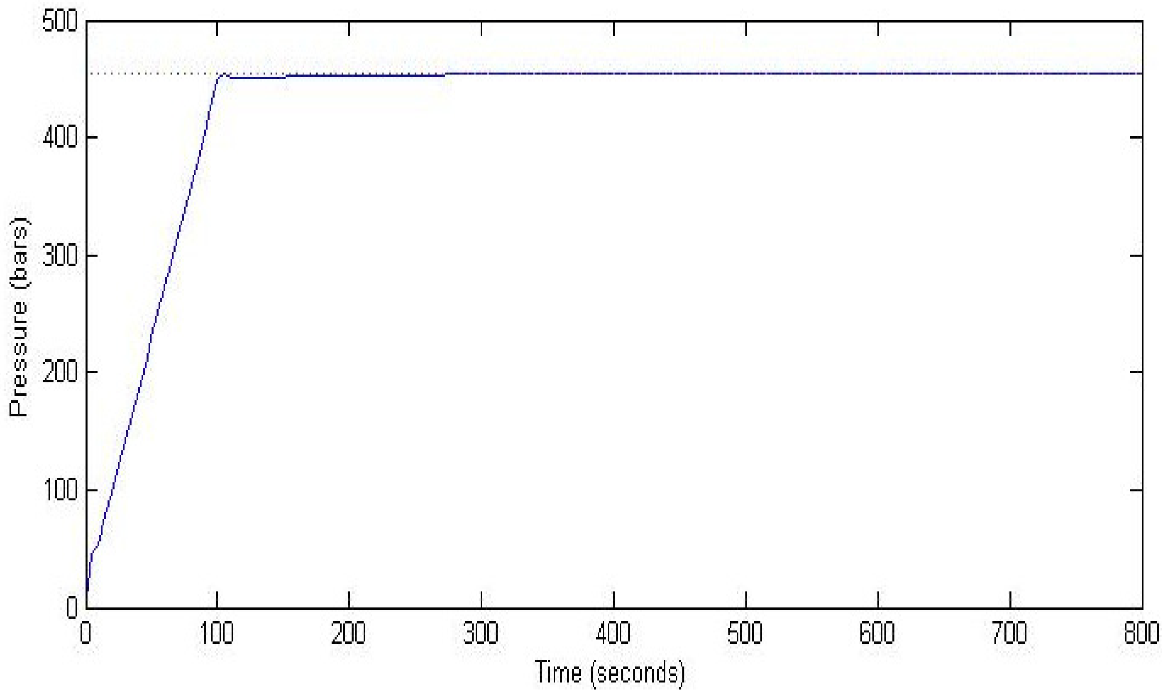

Figure 1: Shows the simulated BHP and the set BHP during circulation

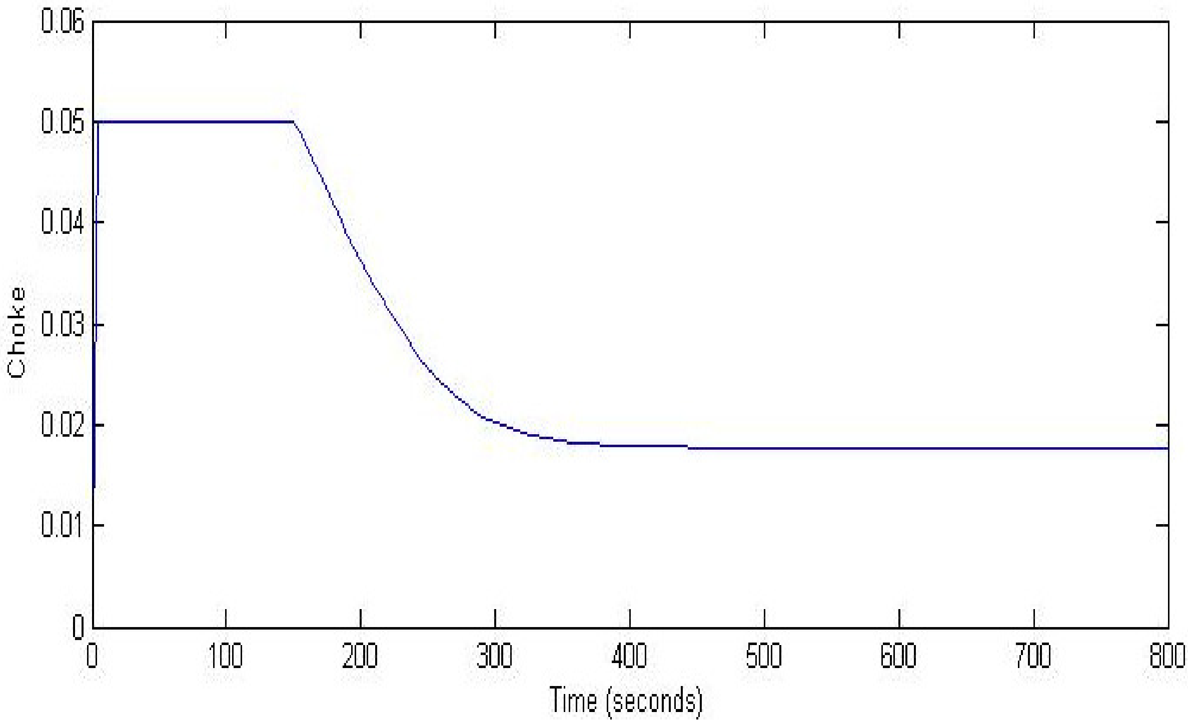

Figure 2: Shows how the Choke opening is automatically adjusting to achieve the set BHP

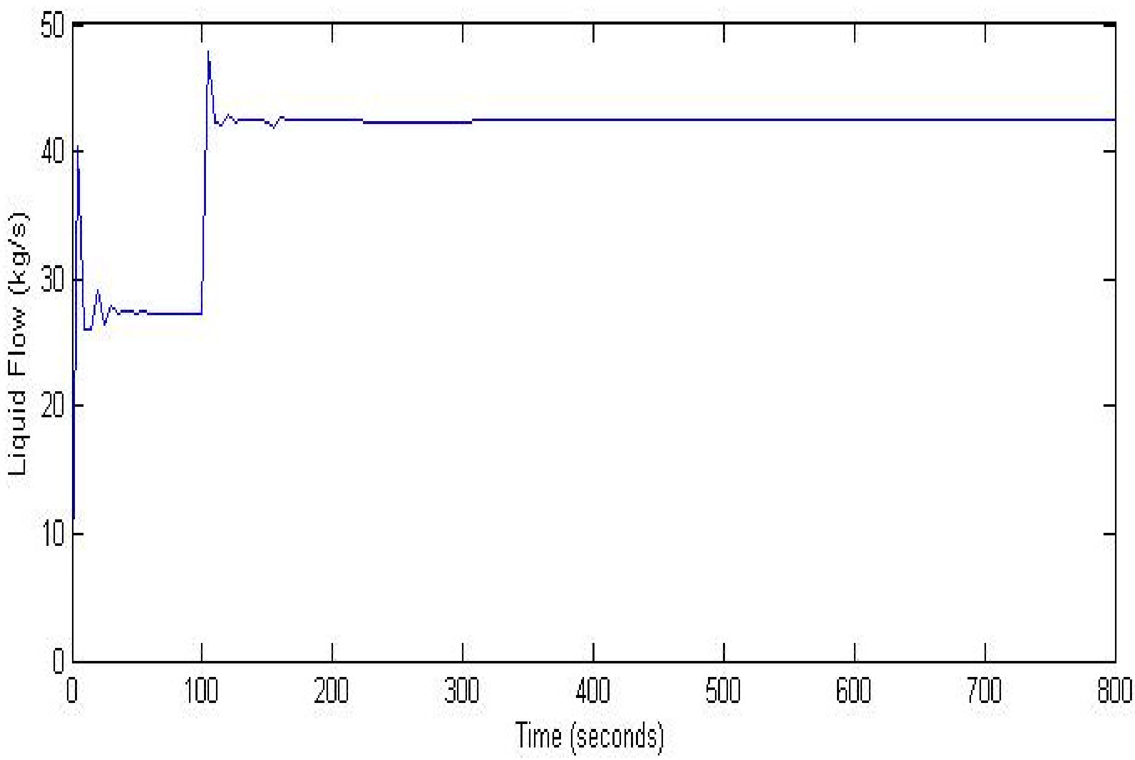

Figure 3: Shows normal liquid flow through the system

7.2 Simulation of a Pipe Connection with Choke regulation

During a conventional pipe connection, pumps are turned off to stop the flow and then a connection can be made according to standard procedures. In MPD operations turning off of the pumps can cause an influx as drilling is used to be carried out close to pore pressure. The operating window is small enough such that any larger disturbance in bottom hole pressure is unacceptable. A backpressure pump is required to keep the pressure constant during connection by supplying sufficient choke pressure. So a pipe connection is simulated first by stopping the flow between 310 to 490 seconds. This simulation is based upon the regulating of choke opening. The choke is operated (opening/closing) according to the objective of keeping the bottom hole pressure constant. The figure 4 is showing the reduction in bottom hole pressure under connection because a backpressure pump is not introduced yet into the model. Here the dotted line is showing the desired bottom hole pressure same as the previous section. The figure 5 is showing the operating of choke with respect to time. During the connection, the choke is fully closed and after the connection choke opening is stabilized again. The figure 6 is showing the liquid flow out and during the connection no liquid is flowing out as expected.

After this a backpressure pump is introduced into the model to make the pressure constant during connection. A pump providing 700lpm (q_{mix} = 0.011 m^3/s) is introduced as a backpressure pump in Appendix I. The problem raised here is that pressure is not getting stable during connection as it is showing in figure 7. In this case, it has been tried to regulate the choke opening to maintain BHP constant. An effort is made to adjust the tuning parameters again to make it work but it didn't help as it is quite a difficult task to obtain suitable tuning parameters. The reason for not achieving a stable pressure can be due to non-linear nature of the choke model. It is very sensitive to changes. A slight change in the choke opening (u) will lead to large changes in the choke pressure (ΔP). This can be seen from the formula given below:

$$\Delta P = \frac{{q_{out}}^2 \cdot \rho}{2.C^2.u^2}$$

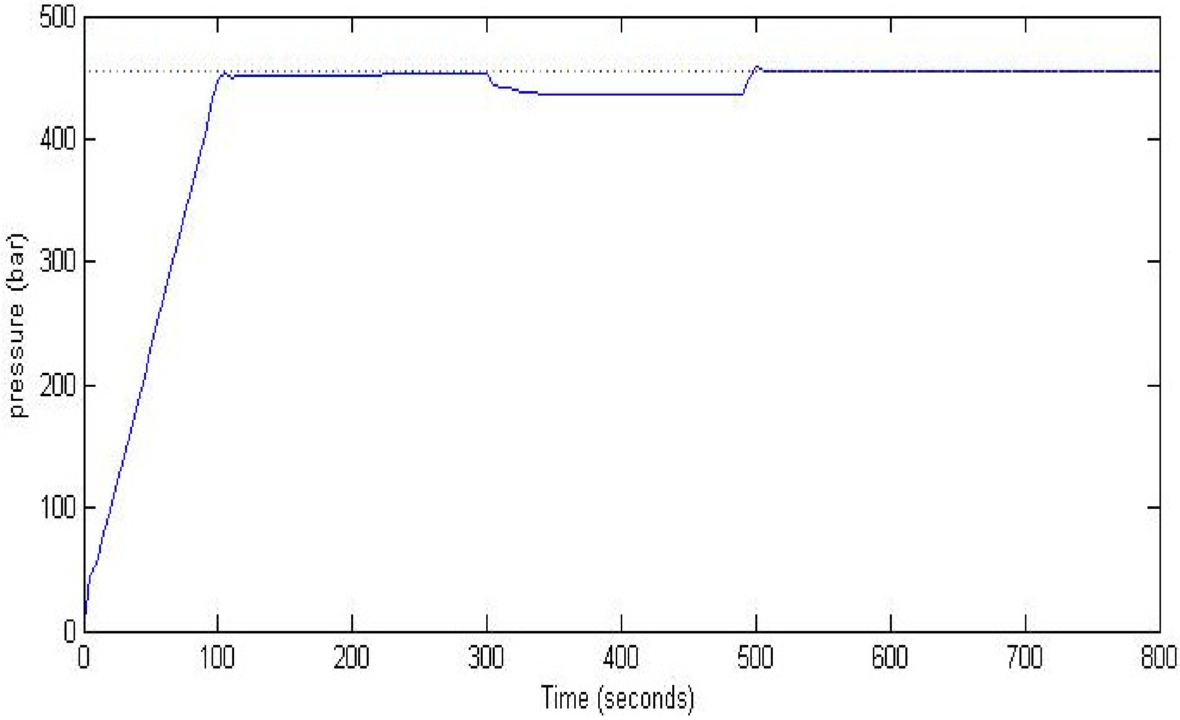

Figure 4: Shows BHP during Connection without Backpressure Pump

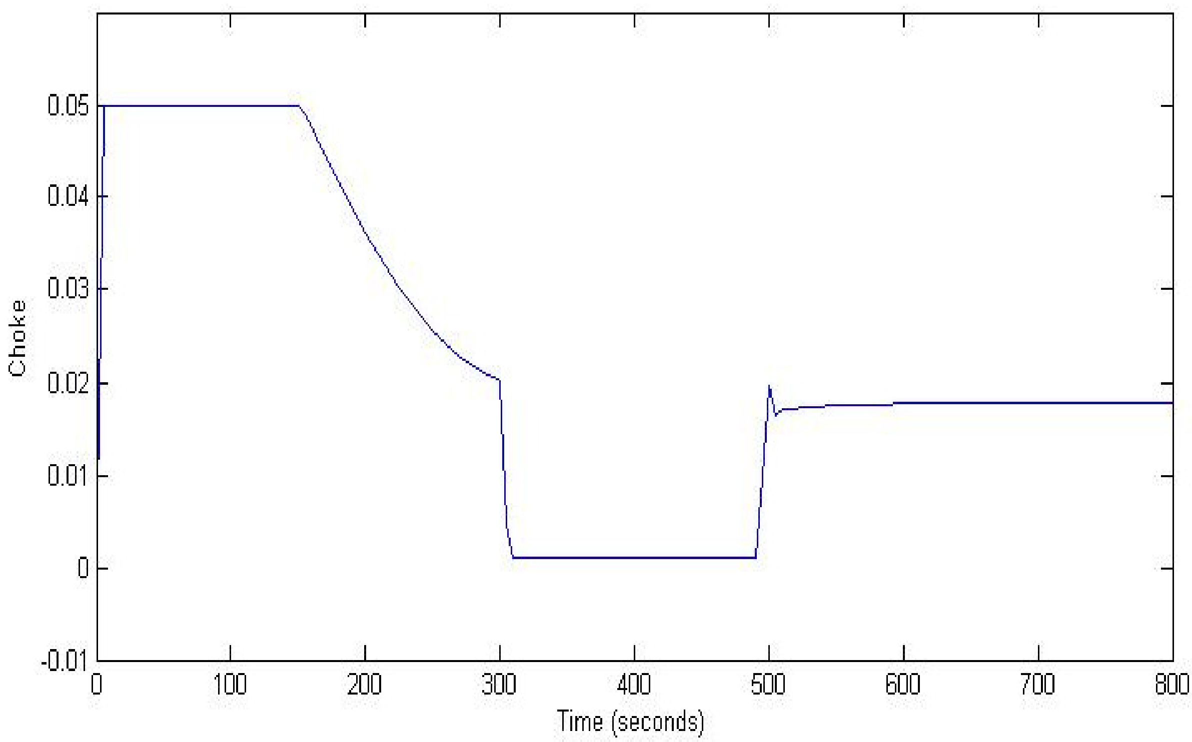

Figure 5: Shows the Choke operation during Connection without Backpressure Pump

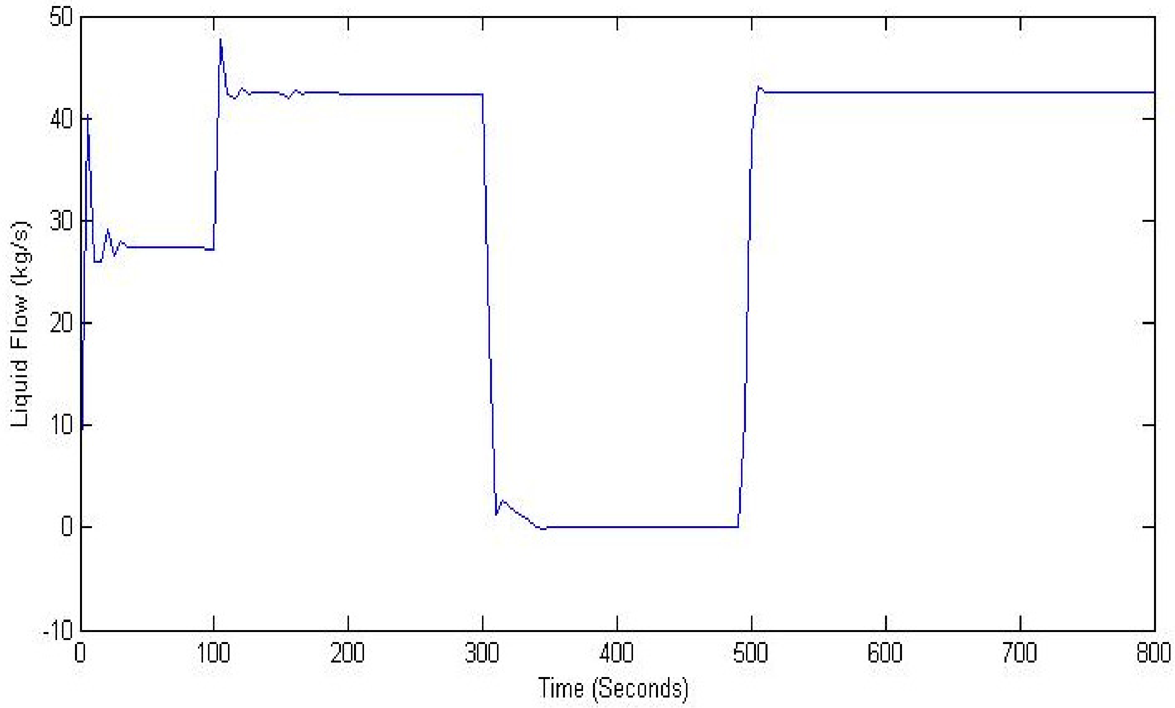

Figure 6: Shows liquid flow during Connection

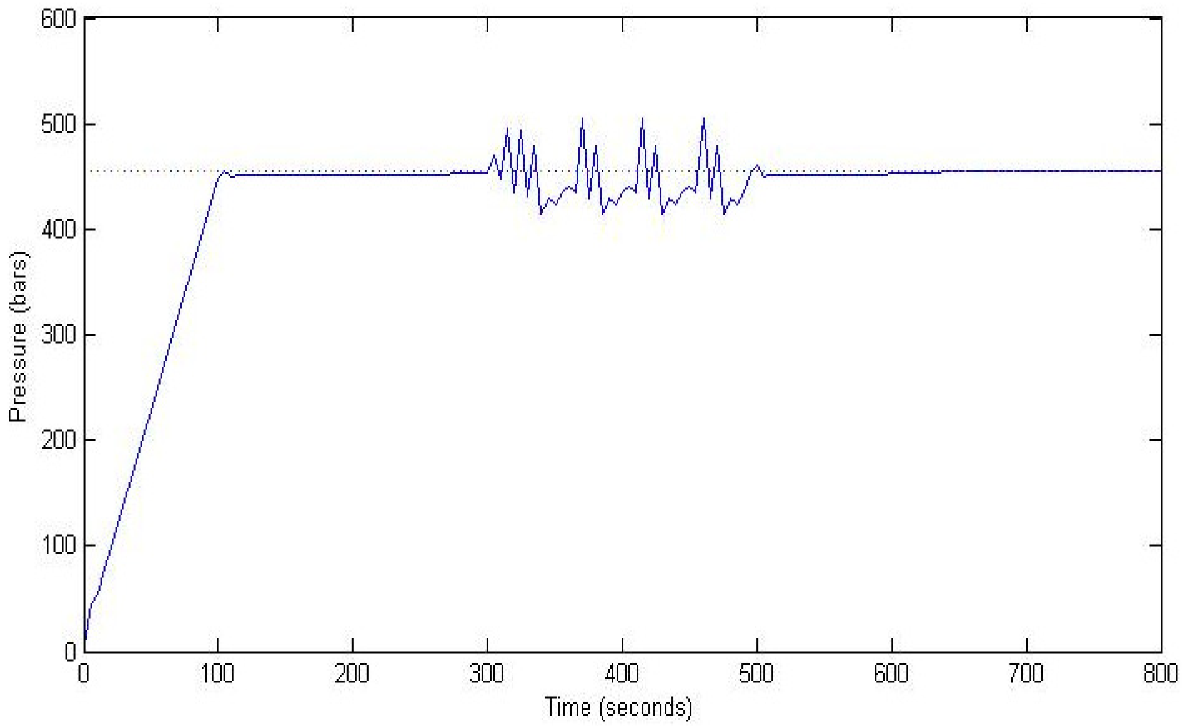

Figure 7: Shows the BHP during Connection when the choke opening is adjusted automatically (Backpressure Pump is used)

7.3 Simulation of a Pipe Connection with Choke Pressure

As seen in figure 7, it was not possible to regulate the choke opening properly during connection. Further work would have to be done to tune the parameters properly. It was therefore decided to regulate directly on the choke differential pressure (ΔP) to obtain a constant BHP during connection (Appendix II). The required choke opening can then be found from the formula (given in section 4.2). This works quite brilliantly and expected results are obtained. The well and flow data are the same as in the previous case. The tuning parameters used in this model are $k_P = -0.75 * 0.3$, $t_i = 10$ and sample time = 5.

The figure 8 is showing the constant bottom hole pressure during connection. The figure 9 is showing the choke pressure with respect to time. During connection choke pressure is at its maximum and then gets stabilized after the connection. The figure 10 is showing the liquid flow out; it is reduced from its initial level that was 42.5 kg/sec to zero during connection and then raised again to its initial value after connection as expected.

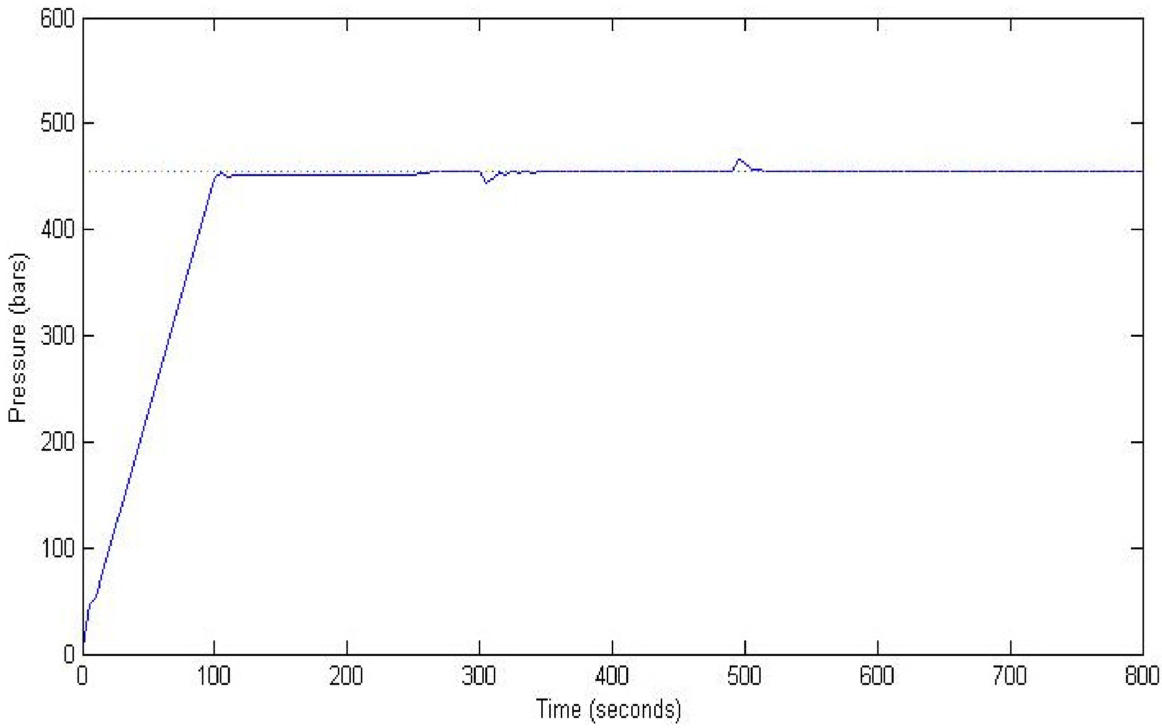

Figure 8: Shows the stable BHP during Connection by using Choke differential Pressure

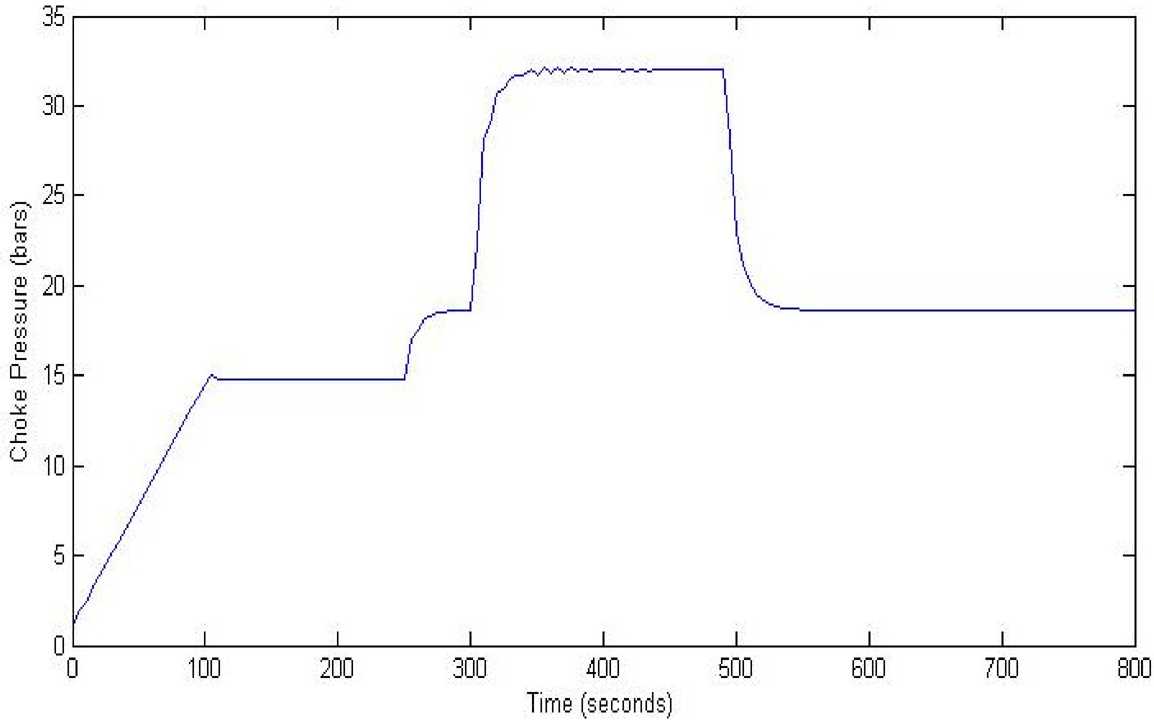

Figure 9: Shows the Choke differential Pressure during Connection

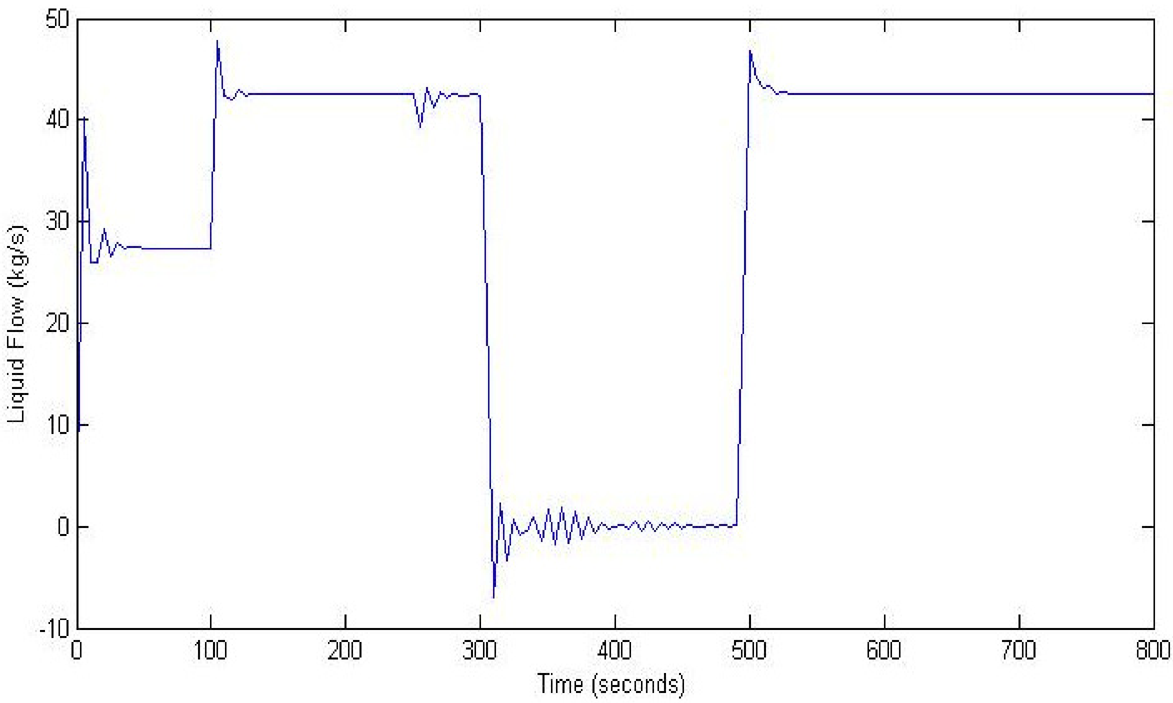

Figure 10: Shows Liquid Flow during Connection

8. Discussion of Results

- The simulation of an automatic pipe connection by using PI-regulator in AUSMV scheme has been performed with two different approaches. An effort has been made to keep the bottom hole pressure constant during connection as this is the main priority in MPD operations. The first approach is related to operating the choke (opening/closing) in order to keep the bottom hole pressure constant. The second approach is related to regulate directly on the choke differential pressure in order to maintain bottom hole pressure constant.

- The tuning parameters are very important in the functionality of PI-regulator. Incorrect tuning of parameters can cause big errors and unacceptable results. A lot of practice and understanding is required to tune them in order to make them work satisfactory.

- The figure 4 shows a drop in bottom hole pressure from 310 to 490 seconds i.e. during connection. The pressure get disturbed as the liquid flow is stopped during connection as shown in figure 6. The choke is fully closed during connection as shown in figure 5. To make the bottom hole pressure constant during connection, a back pressure pump is used and an effort is made to tune the regulating parameters.

- The figure 7 is showing the result after the use of back pressure pump. The fluctuations in pressure during connection are showing improper regulating of tuning parameters. The failure in adjusting the tuning parameters properly emphasis the use of second approach i.e. direct adjustment of choke pressure.

- The figure 8 is showing a stable bottom hole pressure during connection. This is obtained by regulating of choke differential pressure. The choke pressure is adjusted to compensate the pressure loss caused during the connection. This model worked brilliantly in achieving the desired results. The choke pressure as shown in figure 9 is at its maximum during connection and get stabilized after the connection. The figure 10 is showing the liquid flow out which falls to zero during connection and then stabilizes again to its initial value 42.5 kg/s after the connection.

- The simulation results of a pipe connection using two different approaches for maintaining stable BHP has been presented. The first approach didn't work properly in keeping the bottom hole pressure constant. The reason is the sensitivity of the choke model. It has a non-linear behavior and it is very sensitive to the small changes. A small change in choke opening can result in large changes in choke differential pressure which makes it hard to control with respect to maintain a constant bottom hole pressure. Therefore, it is seen that proper tuning of regulating parameters is very critical to obtain a stable and robust pressure control system and it is not easy to find parameters that work for all conditions. This was especially seen when trying to regulate the opening directly.

- On the other hand it has been observed that dealing with choke differential pressure is far easier in this case. This turned out to be a much more robust approach which made it possible to maintain constant BHP during connection.

9. Conclusion

- MPD has opened a new era of possibilities for drilling into depleted reservoirs. It has made this possible which wasn't possible with conventional drilling. The oil industry has achieved many goals with the help of MPD techniques and tools. MPD is a reliable drilling method which can detect the influx quickly and circulate it out safely. It has reduced the risk elements of drilling hazards. Different MPD systems have provided better flexibility for the drilling companies by improving the drilling performance and production rates.

- MPD Automation has replaced the manually operating drilling systems because of its high reliability and accuracy. It has given the advantages to the companies by reducing the drilling time and improving the performance of wells having narrow pressure margins. The automatic control of the down hole pressure with the help of choke has provided highly accurate pressure control in depleted reservoirs.

- The tools and operational techniques used by known MPD vendors (Halliburton & Weatherford) have been explained in detail. An effort is made to describe the procedures both companies are using during connections to maintain constant BHP.

- In this work, it was shown that the complex tuning of parameters in the PI-regulator can be difficult without a lot of practice and understanding.

- However, it was found much more robust and stable to regulate directly on the choke differential pressure. By using this, it was possible to maintain well pressure constant during connections.

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11. APPENDICES

Appendix I

Transient AUSMV scheme

```
clear;

% Geometry data/ Must be specified
welldepth = 3000;
nobox = 25;
nofluxes = nobox+1;
dx = welldepth/nobox;   % Bokslengde
%dt = 0.005;
dt= 0.025; % Tidsteg må reguleres i forhold til valgt bokslenge og CFL krav.
dtdx = dt/dx;
time = 0.0;
endtime = 800; % Lenge på simulering i sekund
nosteps = endtime/dt;
timebetweensavingtimedata = 5;
nostepsbeforesavingtimedata = timebetweensavingtimedata/dt;

% Slip parameters of gas/can be adjusted vg = Kxvmix+s
k = 1.2;
s = 0.5;

% Viscosities (Pa*s)
viscl = 0.05;
viscg = 0.000005;

% Density parameters

% liquid density at stc and speed of sound in liguid. Viss vi skal inn
% med en mud i stedet for vann må vi endre her.
  dstc = 1500.0;  %Mudvekt
  pstc = 100000.0;
  al = 1000;
  t1 = dstc-pstc/(al*al);
% Ideal gas law constant
  rt = 100000;

% Gravity acceleration

  grav = 9.81;

% BOP Well status (open = 1, closed = 0)
```

```
  opening = 1.0;

% Choke status
  choke = 0;




% Assume 8 1/2" hole and 5" Drillpipe, Use 180 meters of 6.75´´ DC
% On bottom! Area change in mid of box no 2

% Define and intilalize flow variables. Geometry is the only variable
% that need to be changed.



% Check area:

   for i = 1:nobox
    do(i) = 0.2159;
    di(i) = 0.127;
    areal(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    arear(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    area(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
   end
    temp = arear(2);

% Geometry in the lower part of the well.
   for i = 1:2
    do(i)=0.2159;
    di(i)=0.1715;
    areal(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    arear(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
   end
    arear(2)=temp;

    for i = 1:nobox
        dl(i) = dstc;
        dlo(i)= dl(i);
        dg(i)= 1.0;
        dgo(i)=dg(i);
        vl(i) = 0.0;
        vlo(i)= 0.0;
        vg(i)= 0.0;
        vgo(i)= 0.0;
        p(i) = 100000.0;
        po(i) = p(i);
        eg(i)= 0.0;
        ego(i)=eg(i);
        ev(i)=1-eg(i);
```

```
        evo(i)=ev(i);

        vg(i)=0.0;
        vgo(i)=0.0;
        vl(i)=0.0;
        vlo(i)=0.0;

        vgr(i)=0.0;
        vgor(i)= 0.0;
        vgl(i)= 0.0;
        vgol(i)= 0.0;

        vlr(i)=0.0;
        vlor(i)=0.0;
        vll(i)=0.0;
        vlol(i)=0.0;

       qv(i,1)=dl(i)*ev(i)*(areal(i)+arear(i))*0.5;
       qvo(i,1)=qv(i,1);

       qv(i,2)=dg(i)*eg(i)*(areal(i)+arear(i))*0.5;
       qvo(i,2)=qv(i,2);

       qv(i,3)=(qv(i,1)*vl(i)+qv(i,2)*vg(i))*(areal(i)+arear(i))*0.5;
       qvo(i,3)=qv(i,3);

    end

% Intialize fluxes

for i = 1:nofluxes
  for j =1:3
   flc(i,j)=0.0;
   fgc(i,j)=0.0;
   fp(i,j)= 0.0;
  end
end



%  Main program. Here we will progress in time. First som intializations

countsteps = 0;
counter=0;
printcounter = 1;
pbot(printcounter) = p(1);
pchoke(printcounter)= p(nobox);
pcasingshoe(printcounter)=p(25);
liquidmassrateout(printcounter) = 0;
gasmassrateout(printcounter)=0;
```

```
timeplot(printcounter)=time;
eo=0; %refererer til choke regulator
chokecounter=0; %refererer til choke regulator
chokevalve = 0.05;
%chokevalve = 1.0;

for i = 1:nosteps
  countsteps=countsteps+1;
  counter=counter+1;
  time = time+dt;

% First of all a dirty trick is used in order to make the well vertical.
% The pipe was initialised for a horisontal case. However, for a vertical
% case we would need a steady state solver. Since the programmer in this
% case is quite lazy, he rather chose to adjust the gravity constant g from
% zero to 9.81 m/s2 during 100 seconds (corresponds to hoisting the well
% from a horisontal postion to vertical case.

      if (time <= 100)
        g = grav*time/100;
      else
        g = grav;
      end

% Horisontal case.
%       g = 0.0;

% Then a section where we check the boundary conditions.
% Operational changes must be changed here since it is here we "control"
% the changes (e.g inflow rates, BOP status etc).

% First specify the outlet pressure (either open to atmosphere or a choke
% pressure. Initially we are circ to shaker which have atmospheric
% pressure.

%%% Her må vi inn med en chokemodell!

   if (time < 150)
  pressureoutlet = 100000.0;
    else
      qmix =  (vlo(nobox)*evo(nobox)+vgo(nobox)*ego(nobox))*area(nobox);

%      qmix = 0.011;

   densmix = dlo(nobox)*evo(nobox)+dgo(nobox)*ego(nobox);
%     chokevalve = 0.05;
  C = 0.1;

    deltaP = (densmix*qmix*qmix)/(C*C*chokevalve*chokevalve);
    pressureoutlet = 100000.0+deltaP;
```

```
    end
% Then specify the inlet rates. Interpolates so that we have smooth rate
% changes. The rates is in kg/s. The outlet pressure is in Pascal.
% Assume dowhole reservoir pressure equal to 400 bars which gives a gas
% density downhole of approx 400 kg/m3 (ideal gas law).
% Pumprate. Given in lpm. Converted to downhole rate in kg/s by
% using mud density is constant.

%   pumprate = 200;
%   mudratedrilling = pumprate/(60*1000)*dstc;
  killrate = 1000;  %lpm
  mudratekilling = killrate/(60*1000)*dstc;
  kicksize = 4 ; % Volume of kick in m3 at downhold cond (same as pit increase)
  kickmass = kicksize*400; % Convert this volume to mass (kg)at downhole cond
  kickinflowtime = 60; % how fast the kick enters in seconds
  kickmassrate = kickmass/60; % Gas rate into well in kg/s

% Please note that if you change the influx time, you also have to adjust
% the timeintervall for taking the kick accordingly so you get the correct
% kick size. (Note that the integrated area of outlet gasrate in kg/s should
% be the same as the integrated inlet rate (principle of mass conservation)
% Please also note that we let the pump rate be zero while taking the kick, i.e.
% we could look upon this as a swabbed kick.

% Please also note how we use linear interpolation when changing
% flowvariables (ramp the upp gradully, if you turn them on immediately,
% you create a pressure puls that can cause major problems (water hammering
% effect)

%    if (time < 120)
% % % Well is hoisted
%      inletligmassrate = 0;
%      inletgasmassrate = 0;
%    elseif ((time>120) & (time<=130))
%   %  Kick is started to be taken
%      inletligmassrate = 0;
%      inletgasmassrate = kickmassrate*(time-120)/10;
%    elseif ((time>130)&(time<=190))
%   % The kick is taken
%      inletligmassrate = 0;
%      inletgasmassrate = kickmassrate;
%    elseif ((time>190)&(time<=200))
%   % The kick is seasing to be taken
%      inletligmassrate = 0;
%      inletgasmassrate = kickmassrate-kickmassrate*(time-190)/10.0;
%    elseif ((time > 200)&(time<=245))
%   % Well open, wait upon closing BOP!
%      inletligmassrate = 0;
%      inletgasmassrate = 0;
%    elseif ((time>=245)& (time<=500))
```

```
%   % BOP, closed, opening = 0.
%      inletligmassrate = 0;
%      inletgasmassrate = 0;
%      opening = 0;
%      psave = p(nobox); % Tar vare på innestengningstrykket SICP
%    elseif ((time> 500)& (time<=510))
%   % Choke åpnes, pumperates rampes opp
%      inletligmassrate = mudratekilling*(time-500)/10;
%      inletgasmassrate = 0;
%      choke = 1.0;
%      pressureoutlet = psave; % Choketrykk settes lik SICP
%    elseif (time>510)
%   % Sirkulerer kicket ut. Må endre choketrykk (variablene pressureoutlet nedenfor)
%      inletligmassrate = mudratekilling;
%      inletgasmassrate = 0;
%      pressureoutlet = psave;

%    end
%

% % Old commandlines for controlling the flow in
% % at the bottom of the well. Can be used or deleted.
%
%if (time < 300)
 %inletligmassrate = 42.5;
 %inletgasmassrate = 0.0;

 if  (time < 300)
     inletligmassrate = 42.5;
     inletgasmassrate = 0;
 elseif ((time > 300) & (time <= 310))
     inletligmassrate = 42.5-((time-300)/10)*42.5;
     inletgasmassrate = 0;
 elseif ((time > 310) & (time <= 490))
     inletligmassrate = 0;
     inletgasmassrate = 0;
 elseif ((time > 490) & (time <= 500))
     inletligmassrate = ((time-490)/10)*42.5;
     inletgasmassrate = 0;
 elseif (time > 500)
     inletligmassrate = 42.5;
     inletgasmassrate = 0;

 end

%   inletligmassrate=mudratekilling;
%   inletgasmassrate=mudratekilling;
%
% elseif ((time>=300) & (time < 310))
%   inletligmassrate = mudratekilling+(42.5-mudratekilling)*(time-300)/10;
```

```
% %  inletgasmassrate = 1.0*(time-300)/10;
%   inletgasmassrate=0.0;
%
% elseif (time >= 310)
%   inletligmassrate = 42.5;
%   inletgasmassrate = 0.0;
%end

% if time<150
%     chokevalve=0.05;
% elseif time<200
%     chokevalve=0.04;
% elseif time<250
%     chokevalve=0.03;
% elseif time<300
%     chokevalve=0.02;
% elseif time<350
%     chokevalve=0.01;
% elseif time<400
%     chokevalve=0.008;
% end


% Based on these boundary values combined with use of extrapolations techniques
% for the remaining unknowns at the boundaries, we will define the mass and
% momentum fluxes at the boundaries (inlet and outlet of pipe). Disse treng
% ikke endres

% inlet fluxes first.

     flc(1,1)= inletligmassrate/areal(1);
     flc(1,2)= 0.0;
     flc(1,3)= flc(1,1)*vlo(1);

     fgc(1,1)= 0.0;
     fgc(1,2)= inletgasmassrate/areal(1);
     fgc(1,3)= fgc(1,2)*vgo(1);

     fp(1,1)= 0.0;
     fp(1,2)= 0.0;
     fp(1,3)= po(1)+0.5*(po(1)-po(2));

%     end


% Outlet fluxes (open & closed conditions)

    if (opening>0.01)
% randkrav når brønnen er åpen initielt
        flc(nofluxes,1)= dlo(nobox)*evo(nobox)*vlo(nobox);
```

```
        flc(nofluxes,2)= 0.0;
        flc(nofluxes,3)= flc(nofluxes,1)*vlo(nobox);

        fgc(nofluxes,1)= 0.0;
        fgc(nofluxes,2)= dgo(nobox)*ego(nobox)*vgo(nobox);
        fgc(nofluxes,3)= fgc(nofluxes,2)*vgo(nobox);

        fp(nofluxes,1)= 0.0;
        fp(nofluxes,2)= 0.0;
        fp(nofluxes,3)= pressureoutlet;
    else
% randkrav som slår inn når brønnen er stengt eller etter
% at den blir åpnet igjen.

        if (choke == 0.0)
         flc(nofluxes,1)= 0.0;
         flc(nofluxes,2)= 0.0;
         flc(nofluxes,3)= 0.0;

         fgc(nofluxes,1)= 0.0;
         fgc(nofluxes,2)= 0.0;
         fgc(nofluxes,3)= 0.0;

         fp(nofluxes,1)=0.0;
         fp(nofluxes,2)=0.0;
         fp(nofluxes,3)= po(nobox)-0.5*(po(nobox-1)-po(nobox));

        else

         flc(nofluxes,1)= dlo(nobox)*evo(nobox)*vlo(nobox);
         flc(nofluxes,2)= 0.0;
         flc(nofluxes,3)= flc(nofluxes,1)*vlo(nobox);

         fgc(nofluxes,1)= 0.0;
         fgc(nofluxes,2)= dgo(nobox)*ego(nobox)*vgo(nobox);
         fgc(nofluxes,3)= fgc(nofluxes,2)*vgo(nobox);

         fp(nofluxes,1)= 0.0;
         fp(nofluxes,2)= 0.0;
         fp(nofluxes,3)= pressureoutlet;  % Her hentes choketrykket spes lengre oppe


        end

    end

% Now we will find the fluxes between the different cells. Treng ikke
% endres
```

```
    for j = 2:nofluxes-1
     cl = csound(ego(j-1),po(j-1),dlo(j-1),k);
     cr = csound(ego(j),po(j),dlo(j),k);
     c = max(cl,cr);
     pll = psip(vlor(j-1),c,evo(j));
     plr = psim(vlol(j),c,evo(j-1));
     pgl = psip(vgor(j-1),c,ego(j));
     pgr = psim(vgol(j),c,ego(j-1));
     vmixr = vlol(j)*evo(j)+vgol(j)*ego(j);
     vmixl = vlor(j-1)*evo(j-1)+vgor(j-1)*ego(j-1);

     pl = pp(vmixl,c);
     pr = pm(vmixr,c);
     mll= evo(j-1)*dlo(j-1);
     mlr= evo(j)*dlo(j);
     mgl= ego(j-1)*dgo(j-1);
     mgr= ego(j)*dgo(j);

     flc(j,1)= mll*pll+mlr*plr;
     flc(j,2)= 0.0;
     flc(j,3)= mll*pll*vlor(j-1)+mlr*plr*vlol(j);

     fgc(j,1)=0.0;
     fgc(j,2)= mgl*pgl+mgr*pgr;
     fgc(j,3)= mgl*pgl*vgor(j-1)+mgr*pgr*vgol(j);

     fp(j,1)= 0.0;
     fp(j,2)= 0.0;
     fp(j,3)= pl*po(j-1)+pr*po(j);
    end

% Fluxes have now been calculated. we will Now update the conservative
% variables in each of the numerical cells. First liguid mass, then gas
% mass and finally momemtum equation. Her kan det kun være aktuelt
% å forandre friksjonsmodellen!

    for j=1:nobox
     vmixfric = vlo(j)*evo(j)+vgo(j)*ego(j);
     viscmix =  viscl*evo(j)+viscg*ego(j);
     densmix = dlo(j)*evo(j)+dgo(j)*ego(j);
     a2 = arear(j);
     a1 = areal(j);
     avg = (a2+a1)*0.5;

     temp = dpfric(vlo(j),vgo(j),evo(j),ego(j),dlo(j),dgo(j),po(j),do(j),di(j),viscl,viscg);

% De to første ligningene er bevaring av masse for de to fasene.
     qv(j,1)=qvo(j,1)-dtdx*((a2*flc(j+1,1)-a1*flc(j,1))...
                  +(a2*fgc(j+1,1)-a1*fgc(j,1))...
                  +(avg*fp(j+1,1)-avg*fp(j,1)));
```

```
    qv(j,2)=qvo(j,2)-dtdx*((a2*flc(j+1,2)-a1*flc(j,2))...
                 +(a2*fgc(j+1,2)-a1*fgc(j,2))...
                 +(avg*fp(j+1,2)-avg*fp(j,2)));

    qv(j,3)=qvo(j,3)-dtdx*((a2*flc(j+1,3)-a1*flc(j,3))...
                 +(a2*fgc(j+1,3)-a1*fgc(j,3))...
                 +(avg*fp(j+1,3)-avg*fp(j,3)))...
             -dt*avg*(temp + g*densmix);
%             -dt*avg*(32*10*vmixfric*viscmix/(do(j)*do(j))+g*densmix);
% Merk den siste lign er moment der friksjon, hydrostatisk grad inngår. Her ganget
% jeg friksjonen med 10 for å drepe pulsene. Vi kan prøve å få inn en mer
% realistisk friksjonsmodell. Se nyttpaper!
   end

% Section where we find the physical variables (pressures, densities etc)
% from the conservative variables. Some trickes to ensure stability. Treng
% ikke endres. (sjekk viss vi endrer fra vann til mud)


   for j=1:nobox

    qv(j,1)= qv(j,1)/(areal(j)+arear(j))*2.0;
    qv(j,2)= qv(j,2)/(areal(j)+arear(j))*2.0;

    if (qv(j,1)<0.00000001)
      qv(j,1)=0.0;
    end

    if (qv(j,2)< 0.00000001)
      qv(j,2)=0.0000001;
    end


    a = 1/(al*al);
    b = t1-qv(j,1)-rt*qv(j,2)/(al*al);
    c = -1.0*t1*rt*qv(j,2);

    p(j)=(-b+sqrt(b*b-4*a*c))/(2*a);
    dl(j)= dstc + (p(j)-pstc)/(al*al);
    dg(j) = p(j)/rt;
    eg(j)= qv(j,2)/dg(j);
    ev(j)=1-eg(j);

    qv(j,1)=qv(j,1)*(areal(j)+arear(j))/2.0;
    qv(j,2)=qv(j,2)*(areal(j)+arear(j))/2.0;
%     vg(j)=qv(j,3)/(dl(j)*ev(j)+dg(j)*eg(j));
%     vl(j)=vg(j);
```

```
% Part where we interpolate in the slip parameters to avoid a
% singularities. In the transition to one-phase gas flow, we need to
% have a smooth transition to no-slip conditions.

    xint = (eg(j)-0.75)/0.25;
    k0 = k;
    s0 = s;
    if ((eg(j)>=0.75) & (eg(j)<=1.0))
      k0 =1.0*xint+k*(1-xint);
      s0 = 0.0*xint+s*(1-xint);
    end

    if (eg(j)>=0.999999)
      k1 = 1.0;
      s1 = 0.0;
    else
      k1 = (1-k0*eg(j))/(1-eg(j));
      s1 = -1.0*s0*eg(j)/(1-eg(j));
    end
%     help1 = dl(j)*ev(j)*k1+dg(j)*eg(j)*k0;
%     help2 = dl(j)*ev(j)*s1+dg(j)*eg(j)*s0;

%     vmixhelp = (qv(j,3)-help2)/help1;
%     vg(j)=k0*vmixhelp+s0;
%     vl(j)=k1*vmixhelp+s1;
    help1 = qv(j,3)/(dl(j)*ev(j)+dg(j)*eg(j));

    vll(j)= help1/areal(j);
    vlr(j)= help1/arear(j);
    vgl(j)= vll(j);
    vgr(j)= vlr(j);


%    Test slip parameters & areachange!

    help1 = dl(j)*ev(j)*k1+dg(j)*eg(j)*k0;
    help2 = dl(j)*ev(j)*s1+dg(j)*eg(j)*s0;

    vmixhelpl = (qv(j,3)/areal(j)-help2)/help1;
    vgl(j)=k0*vmixhelpl+s0;
    vll(j)=k1*vmixhelpl+s1;

    vmixhelpr = (qv(j,3)/arear(j)-help2)/help1;
    vgr(j)=k0*vmixhelpr+s0;
    vlr(j)=k1*vmixhelpr+s1;
```

```
 %  Averaging velocities.

      vl(j)= 0.5*(vll(j)+vlr(j));
      vg(j)= 0.5*(vgl(j)+vgr(j));

     end

% Her har vi funnet beregnet nye verdier. Vi må nå sjekke ny chokeåpning.
%  PI regulator
     if time>150
        chokecounter=chokecounter+1;
        pset=45500000;
%          kp=-0.01/1e5; % Settes lik kritisk verdi*0.45
%          kp=-0.0005/1e5; % Settes lik kritisk verdi*0.45 , noenlunde ok
%          kp=-0.0015/1e5; % Settes lik kritisk verdi*0.45
        % med denne finner vi kp_krit = -0.0015/1e5 og ti_krit = 15 s
        % finner da kp = -0.0015/1e5*0.45 og Ti = 15/1.2
        %ti=1000000000*1e5; % Settes lik kritisk periode/1.2
%          kp = -0.0015/1e5*0.45;  % etter ziegler nichols
        kp = -0.0015/1e5*0.75;  % for å få den raskere
        ti = 15/1.2;
%             kp = kp*0.18;
%             ti = ti*0.18;
        sampletime=1;
        e=pset-p(1);

        if chokecounter==1
%              chokevalve = 1;
           eo=e;
        elseif round(chokecounter*dt/sampletime)==chokecounter*dt/sampletime
        chokevalve=chokevalve+kp*(e-eo)+kp*sampletime*(e+eo)/(2*ti);
%          chokevalve=chokevalve+kp*(e); % ren P-regulator
%          disp(chokevalve);
%          disp(e);
        eo=e;
        end
        if chokevalve<=0.001, chokevalve=0.001; elseif chokevalve>1, chokevalve=1; end
     end
%
% Old values are now set equal to new values in order to prepare
% computation of next time level. Treng ikke endres

%   pbunnold = po(1)
   for j = 1:nobox
     po(j)=p(j);
     dlo(j)=dl(j);
     dgo(j)=dg(j);
     vlo(j)=vl(j);
     vgo(j)=vg(j);
     ego(j)=eg(j);
```

```
    evo(j)=ev(j);

    vlor(j)=vlr(j);
    vlol(j)=vll(j);
    vgor(j)=vgr(j);
    vgol(j)=vgl(j);

     for m =1:3
      qvo(j,m)=qv(j,m);
     end
   end


% Section where we save some timedependent variables in arrays.
% e.g. the bottomhole pressure. They will be saved for certain
% timeintervalls defined in the start of the program in order to ensure
% that the arrays do not get to long! Pass på at casingskotrykk hentes fra
% rett boks.

  if (counter>=nostepsbeforesavingtimedata)
   printcounter=printcounter+1;
   time
   pbot(printcounter)= p(1);
   pchoke(printcounter)=p(nobox);
   chokevalve_ar(printcounter)= chokevalve;
   pcasingshoe(printcounter)=p(10); % NB! Denne må skrive ut rett boks.
%    liquidmassrateout(printcounter)=dl(nobox)*ev(nobox)*vl(nobox)*area(nobox);
%    gasmassrateout(printcounter)=dg(nobox)*eg(nobox)*vg(nobox)*area(nobox);
   liquidmassrateout(printcounter)=dl(nobox)*ev(nobox)*vl(nobox)*arear(nobox);
   gasmassrateout(printcounter)=dg(nobox)*eg(nobox)*vg(nobox)*arear(nobox);
   timeplot(printcounter)=time;
   counter = 0;


  end
end

% end of stepping forward in time.

% Printing of resultssection


countsteps

bunntrykk = pbot/100000;
castrykk = pcasingshoe/100000;
choketrykk = pchoke/100000; % NB! Merk at dette trykket er i midt i boksen under choke.
% Egentlig er choketrykket variabelen pressureoutlet.
pset = 45500000/100000;
close all; % stenger alle plotvindu
```

```
figure
plot(timeplot,bunntrykk)
hold on
plot(timeplot,pset,':')
hold off

figure
plot(timeplot,chokevalve_ar)

%plot(timeplot,castrykk)
%plot(timeplot,choketrykk)
figure
plot(timeplot,liquidmassrateout)
%  figure
%  plot(timeplot,gasmassrateout)
```

Appendix II

Transient AUSMV scheme

```
clear;

% Geometry data/ Must be specified
welldepth = 3000;
nobox = 25;
nofluxes = nobox+1;
dx = welldepth/nobox;   % Bokslengde
%dt = 0.005;
dt= 0.025; % Tidsteg må reguleres i forhold til valgt bokslenge og CFL krav.
dtdx = dt/dx;
time = 0.0;
endtime = 800; % Lenge på simulering i sekund
nosteps = endtime/dt;
timebetweensavingtimedata = 5;
nostepsbeforesavingtimedata = timebetweensavingtimedata/dt;
nostepsbeforereg = 1.0/dt;

% Slip parameters of gas/can be adjusted vg = Kxvmix+s
k = 1.2;
s = 0.5;

% Viscosities (Pa*s)
viscl = 0.05;
viscg = 0.000005;

% Density parameters

% liquid density at stc and speed of sound in liguid. Viss vi skal inn
% med en mud i stedet for vann må vi endre her.
  dstc = 1500.0;  %Mudvekt
  pstc = 100000.0;
  al = 1000;
  t1 = dstc-pstc/(al*al);
% Ideal gas law constant
  rt = 100000;

% Gravity acceleration

  grav = 9.81;

% BOP Well status (open = 1, closed = 0)

  opening = 1.0;
```

```
% Choke status
  choke = 0;


  enew = 0;
  eold = 0;
  oldvalve = 0.05;
  newvalve = 0.05;




% Assume 8 1/2" hole and 5" Drillpipe, Use 180 meters of 6.75´´DC
% On bottom! Area change in mid of box no 2

% Define and intilalize flow variables. Geometry is the only variable
% that need to be changed.



% Check area:

   for i = 1:nobox
    do(i) = 0.2159;
    di(i) = 0.127;
    areal(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    arear(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    area(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
   end
    temp = arear(2);

% Geometry in the lower part of the well.
   for i = 1:2
    do(i)=0.2159;
    di(i)=0.1715;
    areal(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
    arear(i) = 3.14/4*(do(i)*do(i)- di(i)*di(i));
   end
    arear(2)=temp;


    for i = 1:nobox
        dl(i) = dstc;
        dlo(i)= dl(i);
        dg(i)= 1.0;
        dgo(i)=dg(i);
        vl(i) = 0.0;
        vlo(i)= 0.0;
        vg(i)= 0.0;
        vgo(i)= 0.0;
```

```
        p(i) = 100000.0;
        po(i) = p(i);
        eg(i)= 0.0;
        ego(i)=eg(i);
        ev(i)=1-eg(i);
        evo(i)=ev(i);

        vg(i)=0.0;
        vgo(i)=0.0;
        vl(i)=0.0;
        vlo(i)=0.0;

        vgr(i)=0.0;
        vgor(i)= 0.0;
        vgl(i)= 0.0;
        vgol(i)= 0.0;

        vlr(i)=0.0;
        vlor(i)=0.0;
        vll(i)=0.0;
        vlol(i)=0.0;

       qv(i,1)=dl(i)*ev(i)*(areal(i)+arear(i))*0.5;
       qvo(i,1)=qv(i,1);

       qv(i,2)=dg(i)*eg(i)*(areal(i)+arear(i))*0.5;
       qvo(i,2)=qv(i,2);

       qv(i,3)=(qv(i,1)*vl(i)+qv(i,2)*vg(i))*(areal(i)+arear(i))*0.5;
       qvo(i,3)=qv(i,3);

    end

% Intialize fluxes

for i = 1:nofluxes
  for j =1:3
   flc(i,j)=0.0;
   fgc(i,j)=0.0;
   fp(i,j)= 0.0;
  end
end
```

```
%  Main program. Here we will progress in time. First som intializations

countsteps = 0;
counter=0;
countreg=0;
printcounter = 1;
pbot(printcounter) = p(1);
pchoke(printcounter)= p(nobox);
pcasingshoe(printcounter)=p(25);
liquidmassrateout(printcounter) = 0;
gasmassrateout(printcounter)=0;
timeplot(printcounter)=time;
% eo=0;
% chokecounter=0;
% chokevalve = 0.05;

for i = 1:nosteps
  countsteps=countsteps+1;
  counter=counter+1;
  countreg=countreg+1;
  time = time+dt;

% First of all a dirty trick is used in order to make the well vertical.
% The pipe was initialised for a horisontal case. However, for a vertical
% case we would need a steady state solver. Since the programmer in this
% case is quite lazy, he rather chose to adjust the gravity constant g from
% zero to 9.81 m/s2 during 100 seconds (corresponds to hoisting the well
% from a horisontal postion to vertical case.

     if (time <= 100)
       g = grav*time/100;
     else
       g = grav;
     end

% Horisontal case.
%       g = 0.0;

% Then a section where we check the boundary conditions.
% Operational changes must be changed here since it is here we "control"
% the changes (e.g inflow rates, BOP status etc).

% First specify the outlet pressure (either open to atmosphere or a choke
% pressure. Initially we are circ to shaker which have atmospheric
% pressure.
```

```
%%% Her må vi inn med en chokemodell!

  if (time < 150)
   pressureoutlet = 100000.0;

  else
   qmix =  (vlo(nobox)*evo(nobox)+vgo(nobox)*ego(nobox))*area(nobox);
   densmix = dlo(nobox)*evo(nobox)+dgo(nobox)*ego(nobox);
   chokevalve = 0.5;
   C = 0.1;

   deltaP = (densmix*qmix*qmix)/(C*C*oldvalve);
   deltaP = oldvalve;
    pressureoutlet = 100000.0+deltaP;
%   pressureoutlet = 100000.0;
  end

% Then specify the inlet rates. Interpolates so that we have smooth rate
% changes. The rates is in kg/s. The outlet pressure is in Pascal.
% Assume dowhole reservoir pressure equal to 400 bars which gives a gas
% density downhole of approx 400 kg/m3 (ideal gas law).
% Pumprate. Given in lpm. Converted to downhole rate in kg/s by
% using mud density is constant.

%   pumprate = 200;
%   mudratedrilling = pumprate/(60*1000)*dstc;
   killrate = 1000;  %lpm
   mudratekilling = killrate/(60*1000)*dstc;
   kicksize = 4 ; % Volume of kick in m3 at downhold cond (same as pit increase)
   kickmass = kicksize*400; % Convert this volume to mass (kg)at downhole cond
   kickinflowtime = 60; % how fast the kick enters in seconds
   kickmassrate = kickmass/60; % Gas rate into well in kg/s

% Please note that if you change the influx time, you also have to adjust
% the timeintervall for taking the kick accordingly so you get the correct
% kick size. (Note that the integrated area of outlet gasrate in kg/s should
% be the same as the integrated inlet rate (principle of mass conservation)
% Please also note that we let the pump rate be zero while taking the kick, i.e.
% we could look upon this as a swabbed kick.

% Please also note how we use linear interpolation when changing
% flowvariables (ramp the upp gradully, if you turn them on immediately,
% you create a pressure puls that can cause major problems (water hammering
% effect)

%    if (time < 120)
% % % Well is hoisted
%      inletligmassrate = 0;
%      inletgasmassrate = 0;
%    elseif ((time>120) & (time<=130))
```

```
%   %  Kick is started to be taken
%      inletligmassrate = 0;
%      inletgasmassrate = kickmassrate*(time-120)/10;
%    elseif ((time>130)&(time<=190))
%   % The kick is taken
%      inletligmassrate = 0;
%      inletgasmassrate = kickmassrate;
%    elseif ((time>190)&(time<=200))
%   % The kick is seasing to be taken
%      inletligmassrate = 0;
%      inletgasmassrate = kickmassrate-kickmassrate*(time-190)/10.0;
%    elseif ((time > 200)&(time<=245))
%   % Well open, wait upon closing BOP!
%      inletligmassrate = 0;
%      inletgasmassrate = 0;
%    elseif ((time>=245)& (time<=500))
%   % BOP, closed, opening = 0.
%      inletligmassrate = 0;
%      inletgasmassrate = 0;
%      opening = 0;
%      psave = p(nobox); % Tar vare på innestengningstrykket SICP
%    elseif ((time> 500)& (time<=510))
%   % Choke åpnes, pumperates rampes opp
%      inletligmassrate = mudratekilling*(time-500)/10;
%      inletgasmassrate = 0;
%      choke = 1.0;
%      pressureoutlet = psave; % Choketrykk settes lik SICP
%    elseif (time>510)
%   % Sirkulerer kicket ut. Må endre choketrykk (variablene pressureoutlet nedenfor)
%      inletligmassrate = mudratekilling;
%      inletgasmassrate = 0;
%      pressureoutlet = psave;

%    end

% % Old commandlines for controlling the flow in
% % at the bottom of the well. Can be used or deleted.
%
if (time < 300)

  inletligmassrate=42.5;
  inletgasmassrate=0.0;

elseif ((time>300) & (time <= 310))
  inletligmassrate = 42.5-42.5*(time-300)/10;
%  inletgasmassrate = 1.0*(time-300)/10;
  inletgasmassrate=0.0;
```

```
elseif (time > 310 & time <= 490)
  inletligmassrate = 0;
  inletgasmassrate = 0.0;

elseif (time > 490 & time <= 500)
  inletligmassrate = (time-490)*42.5/10;
  inletgasmassrate = 0.0;
elseif (time > 500)
  inletligmassrate = 42.5;
  inletgasmassrate = 0.0;

end




% Based on these boundary values combined with use of extrapolations techniques
% for the remaining unknowns at the boundaries, we will define the mass and
% momentum fluxes at the boundaries (inlet and outlet of pipe). Disse treng
% ikke endres

% inlet fluxes first.

     flc(1,1)= inletligmassrate/areal(1);
     flc(1,2)= 0.0;
     flc(1,3)= flc(1,1)*vlo(1);

     fgc(1,1)= 0.0;
     fgc(1,2)= inletgasmassrate/areal(1);
     fgc(1,3)= fgc(1,2)*vgo(1);

     fp(1,1)= 0.0;
     fp(1,2)= 0.0;
     fp(1,3)= po(1)+0.5*(po(1)-po(2));


%     end

% Outlet fluxes (open & closed conditions)

    if (opening>0.01)
% randkrav når brønnen er åpen initielt
        flc(nofluxes,1)= dlo(nobox)*evo(nobox)*vlo(nobox);
        flc(nofluxes,2)= 0.0;
        flc(nofluxes,3)= flc(nofluxes,1)*vlo(nobox);

        fgc(nofluxes,1)= 0.0;
        fgc(nofluxes,2)= dgo(nobox)*ego(nobox)*vgo(nobox);
        fgc(nofluxes,3)= fgc(nofluxes,2)*vgo(nobox);
```

```
        fp(nofluxes,1)= 0.0;
        fp(nofluxes,2)= 0.0;
        fp(nofluxes,3)= pressureoutlet;
    else
% randkrav som slår inn når brønnen er stengt eller etter
% at den blir åpnet igjen.

        if (choke == 0.0)
         flc(nofluxes,1)= 0.0;
         flc(nofluxes,2)= 0.0;
         flc(nofluxes,3)= 0.0;

         fgc(nofluxes,1)= 0.0;
         fgc(nofluxes,2)= 0.0;
         fgc(nofluxes,3)= 0.0;

         fp(nofluxes,1)=0.0;
         fp(nofluxes,2)=0.0;
         fp(nofluxes,3)= po(nobox)-0.5*(po(nobox-1)-po(nobox));

        else

         flc(nofluxes,1)= dlo(nobox)*evo(nobox)*vlo(nobox);
         flc(nofluxes,2)= 0.0;
         flc(nofluxes,3)= flc(nofluxes,1)*vlo(nobox);

         fgc(nofluxes,1)= 0.0;
         fgc(nofluxes,2)= dgo(nobox)*ego(nobox)*vgo(nobox);
         fgc(nofluxes,3)= fgc(nofluxes,2)*vgo(nobox);

         fp(nofluxes,1)= 0.0;
         fp(nofluxes,2)= 0.0;
         fp(nofluxes,3)= pressureoutlet;  % Her hentes choketrykket spes lengre oppe


        end

    end

% Now we will find the fluxes between the different cells. Treng ikke
% endres

     for j = 2:nofluxes-1
      cl = csound(ego(j-1),po(j-1),dlo(j-1),k);
      cr = csound(ego(j),po(j),dlo(j),k);
      c = max(cl,cr);
      pll = psip(vlor(j-1),c,evo(j));
      plr = psim(vlol(j),c,evo(j-1));
      pgl = psip(vgor(j-1),c,ego(j));
      pgr = psim(vgol(j),c,ego(j-1));
```

```
      vmixr = vlol(j)*evo(j)+vgol(j)*ego(j);
      vmixl = vlor(j-1)*evo(j-1)+vgor(j-1)*ego(j-1);

      pl = pp(vmixl,c);
      pr = pm(vmixr,c);
      mll= evo(j-1)*dlo(j-1);
      mlr= evo(j)*dlo(j);
      mgl= ego(j-1)*dgo(j-1);
      mgr= ego(j)*dgo(j);

      flc(j,1)= mll*pll+mlr*plr;
      flc(j,2)= 0.0;
      flc(j,3)= mll*pll*vlor(j-1)+mlr*plr*vlol(j);

      fgc(j,1)=0.0;
      fgc(j,2)= mgl*pgl+mgr*pgr;
      fgc(j,3)= mgl*pgl*vgor(j-1)+mgr*pgr*vgol(j);

      fp(j,1)= 0.0;
      fp(j,2)= 0.0;
      fp(j,3)= pl*po(j-1)+pr*po(j);
     end

% Fluxes have now been calculated. we will Now update the conservative
% variables in each of the numerical cells. First liguid mass, then gas
% mass and finally momemtum equation. Her kan det kun være aktuelt
% å forandre friksjonsmodellen!

     for j=1:nobox
      vmixfric = vlo(j)*evo(j)+vgo(j)*ego(j);
      viscmix =  viscl*evo(j)+viscg*ego(j);
      densmix = dlo(j)*evo(j)+dgo(j)*ego(j);
      a2 = arear(j);
      a1 = areal(j);
      avg = (a2+a1)*0.5;

      temp = dpfric(vlo(j),vgo(j),evo(j),ego(j),dlo(j),dgo(j),po(j),do(j),di(j),viscl,viscg);

% De to første ligningene er bevaring av masse for de to fasene.
      qv(j,1)=qvo(j,1)-dtdx*((a2*flc(j+1,1)-a1*flc(j,1))...
                      +(a2*fgc(j+1,1)-a1*fgc(j,1))...
                      +(avg*fp(j+1,1)-avg*fp(j,1)));

      qv(j,2)=qvo(j,2)-dtdx*((a2*flc(j+1,2)-a1*flc(j,2))...
                      +(a2*fgc(j+1,2)-a1*fgc(j,2))...
                      +(avg*fp(j+1,2)-avg*fp(j,2)));

      qv(j,3)=qvo(j,3)-dtdx*((a2*flc(j+1,3)-a1*flc(j,3))...
                      +(a2*fgc(j+1,3)-a1*fgc(j,3))...
                      +(avg*fp(j+1,3)-avg*fp(j,3)))...
```

```
                 -dt*avg*(temp + g*densmix);
%                  -dt*avg*(32*10*vmixfric*viscmix/(do(j)*do(j))+g*densmix);
% Merk den siste lign er moment der friksjon, hydrostatisk grad inngår. Her ganget
% jeg friksjonen med 10 for å drepe pulsene. Vi kan prøve å få inn en mer
% realistisk friksjonsmodell. Se nyttpaper!
    end

% Section where we find the physical variables (pressures, densities etc)
% from the conservative variables. Some trickes to ensure stability. Treng
% ikke endres. (sjekk viss vi endrer fra vann til mud)


    for j=1:nobox

     qv(j,1)= qv(j,1)/(areal(j)+arear(j))*2.0;
     qv(j,2)= qv(j,2)/(areal(j)+arear(j))*2.0;

     if (qv(j,1)<0.00000001)
       qv(j,1)=0.0;
     end

     if (qv(j,2)< 0.00000001)
       qv(j,2)=0.0000001;
     end


     a = 1/(al*al);
     b = t1-qv(j,1)-rt*qv(j,2)/(al*al);
     c = -1.0*t1*rt*qv(j,2);

     p(j)=(-b+sqrt(b*b-4*a*c))/(2*a);
     dl(j)= dstc + (p(j)-pstc)/(al*al);
     dg(j) = p(j)/rt;
     eg(j)= qv(j,2)/dg(j);
     ev(j)=1-eg(j);

     qv(j,1)=qv(j,1)*(areal(j)+arear(j))/2.0;
     qv(j,2)=qv(j,2)*(areal(j)+arear(j))/2.0;

%      vg(j)=qv(j,3)/(dl(j)*ev(j)+dg(j)*eg(j));
%      vl(j)=vg(j);

% Part where we interpolate in the slip parameters to avoid a
% singularities. In the transition to one-phase gas flow, we need to
% have a smooth transition to no-slip conditions.
```

```
    xint = (eg(j)-0.75)/0.25;
    k0 = k;
    s0 = s;
    if ((eg(j)>=0.75) & (eg(j)<=1.0))
      k0 =1.0*xint+k*(1-xint);
      s0 = 0.0*xint+s*(1-xint);
    end



    if (eg(j)>=0.999999)
      k1 = 1.0;
      s1 = 0.0;
    else
      k1 = (1-k0*eg(j))/(1-eg(j));
      s1 = -1.0*s0*eg(j)/(1-eg(j));
    end
%     help1 = dl(j)*ev(j)*k1+dg(j)*eg(j)*k0;
%     help2 = dl(j)*ev(j)*s1+dg(j)*eg(j)*s0;

%     vmixhelp = (qv(j,3)-help2)/help1;
%     vg(j)=k0*vmixhelp+s0;
%     vl(j)=k1*vmixhelp+s1;
    help1 = qv(j,3)/(dl(j)*ev(j)+dg(j)*eg(j));

    vll(j)= help1/areal(j);
    vlr(j)= help1/arear(j);
    vgl(j)= vll(j);
    vgr(j)= vlr(j);


%    Test slip parameters & areachange!

    help1 = dl(j)*ev(j)*k1+dg(j)*eg(j)*k0;
    help2 = dl(j)*ev(j)*s1+dg(j)*eg(j)*s0;

    vmixhelpl = (qv(j,3)/areal(j)-help2)/help1;
    vgl(j)=k0*vmixhelpl+s0;
    vll(j)=k1*vmixhelpl+s1;

    vmixhelpr = (qv(j,3)/arear(j)-help2)/help1;
    vgr(j)=k0*vmixhelpr+s0;
    vlr(j)=k1*vmixhelpr+s1;

%  Averaging velocities.

    vl(j)= 0.5*(vll(j)+vlr(j));
    vg(j)= 0.5*(vgl(j)+vgr(j));

   end
```

```
% Her har vi funnet beregnet nye verdier. Vi må nå sjekke ny chokeåpning.

%    if (time > 350)
%       kp = 0.1;
%       ts = 0;
%       ti = 10.0;
%       pset = 46500000;
%
%       enew = (p(1)-pset)/100000.0;
%       newvalve = oldvalve+kp*(enew-eold)+kp*ts/ti*enew;
%
%       if newvalve < 0.01
%         newvalve = 0.01;
%       elseif newvalve>1.0
%         newvalve = 1.0;
%       end
%
%    end

  if (countreg>=nostepsbeforereg)
    if (time > 250)
    kp = -0.75*0.3;
    ts = 5;
    ti = 10;
    pset = 45500000;

    enew = (p(1)-pset);
    newvalve = oldvalve+kp*(enew-eold)+kp*ts/ti*(enew+eold)*0.5;

%        if newvalve < 0.01
%          newvalve = 0.01;
%         elseif newvalve>1.0
%         newvalve = 1.0;
%        end

    if newvalve < 0
      newvalve = 0;
    end


    end

    countreg=0;
    eold = enew;
    oldvalve=newvalve;
  end
```

```
% Old values are now set equal to new values in order to prepare
% computation of next time level. Treng ikke endres

%   pbunnold = po(1)
  for j = 1:nobox
    po(j)=p(j);
    dlo(j)=dl(j);
    dgo(j)=dg(j);
    vlo(j)=vl(j);
    vgo(j)=vg(j);
    ego(j)=eg(j);
    evo(j)=ev(j);

    vlor(j)=vlr(j);
    vlol(j)=vll(j);
    vgor(j)=vgr(j);
    vgol(j)=vgl(j);

     for m =1:3
      qvo(j,m)=qv(j,m);
     end
  end



% Section where we save some timedependent variables in arrays.
% e.g. the bottomhole pressure. They will be saved for certain
% timeintervalls defined in the start of the program in order to ensure
% that the arrays do not get to long! Pass på at casingskotrykk hentes fra
% rett boks.

 if (counter>=nostepsbeforesavingtimedata)
   printcounter=printcounter+1;
   time
   pbot(printcounter)= p(1);
   pchoke(printcounter)=p(nobox);
   pcasingshoe(printcounter)=p(10); % NB! Denne må skrive ut rett boks.
%    liquidmassrateout(printcounter)=dl(nobox)*ev(nobox)*vl(nobox)*area(nobox);
%    gasmassrateout(printcounter)=dg(nobox)*eg(nobox)*vg(nobox)*area(nobox);
   liquidmassrateout(printcounter)=dl(nobox)*ev(nobox)*vl(nobox)*arear(nobox);
   gasmassrateout(printcounter)=dg(nobox)*eg(nobox)*vg(nobox)*arear(nobox);
   timeplot(printcounter)=time;
   chokepressure(printcounter)=pressureoutlet/100000.0;
   counter = 0;

 end
end

% end of stepping forward in time.
```

```
% Printing of resultssection

countsteps
pset = 45500000/100000;
bunntrykk = pbot/100000;
castrykk = pcasingshoe/100000;
choketrykk = pchoke/100000; % NB! Merk at dette trykket er i midt i boksen under choke.
% Egentlig er choketrykket variabelen pressureoutlet.
figure
plot(timeplot,bunntrykk)
hold on
plot(timeplot,pset,':')
hold off
%plot(timeplot,castrykk)
figure
plot(timeplot,choketrykk)
figure
plot(timeplot,liquidmassrateout)
% plot(timeplot,gasmassrateout)
```