Camilla S. Gjengseth and Tollef Svenum

TPG4525 – Drilling Technology

Heave Compensated Manage Pressure Drilling:

A Lab Scaled Rig Design

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NTNU
Norwegian University of Science and Technology
Faculty of Engineering Science and Technology
Department of Petroleum Technology and Applied Geophysics

NTNU
Norwegian University of Science and Technology

Abstract

A significant part of the remaining oil and gas resources are present in harsh environments and depleted reservoirs that are challenging to reach with conventional drilling methods. An ever increasing energy demand forces the drilling industry to develop new techniques, to be able drill in these environments and to improve the efficiency of operations to make uncommercial prospects feasible. Drilling in deep-water and depleted reservoirs are limited by a narrow margin between the fracture and the pore pressure gradients. This requires an accurate control of the pressure in the wellbore. Managed pressure drilling (MPD) represents various techniques to control the pressure in the wellbore developed to meet the challenging demand in the industry. These methods introduces a closed pressurized system where the downhole pressure can be controlled by a choke manifold. In addition to narrow drilling window, drilling from a floating rig is challenged by surge and swab pressures in the wellbore due to the heave motion of the drilling rig. These pressure fluctuations are challenging to control during connections when the drillstring is suspended in slips and follows the movement of the rig.

In this project the design of a scaled drilling rig has been developed to simulate the scenario of connections on a floating rig. By modeling the movement of the drillstring, surge and swab pressures are generated and can be controlled by a choke and a back pressure pump. This is a preliminary study to be continued in the spring, 2012 when the scaled drilling rig is planned to be built. Following simulations and testing of different heave scenarios will be conducted and analyzed. In this way, further directions of theoretical research and practical development can be indicated.

Acknowledgement

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Nomenclature

AFP Annular Friction Pressure

BHA Bottom Hole Assembly

BHP Bottomhole Pressure

CBHP Constant Bottom Hole Pressure

DCM Drilling Choke Manifold

DG Dual Gradient

ECD Equivalent Circulation Density

MPD Managed Pressure Drilling

MWD Measure While Drilling

NPT Non-Productive Time

NRV Non-Return Valve

PLC Programmable Logic Controller

PMCD Pressurized Mud Cap Drilling

RCD Rotating Control Device

RFC Returns Flow Control

ROP Rate of Penetration

RPC Riser Pressure Control

1 Introduction

This project is a corporation between NTNU: The Department of Petroleum Engineering and Applied Geophysics (IPT) , The Department of Engineering Cybernetics and Statoil ASA. During the fall of 2011, three Master Students at IPT have been involved in this project.

1.1 Motivation

As the drilling operations in the oil and gas industry are getting more challenging, the world is challenged by the ever increasing energy demand. The easy accessible oil and gas is rapidly decreasing, now it is time to meet the challenges encountered in drilling problems resulting from narrow margins between collapse and fracture pressures, pore pressure uncertainty, high pressure, high temperature, and wellbore instability. To meet the increasing energy demand, the industry is forced to develop new techniques to make challenging drilling operations possible. Another motivation is improved efficiency and to lower the drilling costs to make uneconomical prospects cost-effective. It is stated that a major part of drilling problems are pressure related issues causing Non-productive-time (NPT) (Rehm et al., 2008). Figure 1.1 shows the results of a study conducted by James K Dodson of drilling operations in the Gulf of Mexico in the period 1993 to 2002, where 22% of the days of drilling operation were lost to NPT. The figure shows that more than 40% of these problems were related to wellbore pressure issues. By developing drilling technologies to improve the wellbore pressure management can cause a reduction in NPT, open doors for uncommercial prospects and better the efficiency and economics of already drill-able wells.(Hannegan, 2007)

A drilling operation is driven by the following factors; safety and efficiency where the objective if the drilling operation is to drill a well as safe and fast as possible. The downhole pressure has to be maintained above the reservoir pressure to avoid formation fluids flowing into the well and below the fracture pressure to avoid loss of drilling fluid due to damage to the formation. When producing, the margins between the reservoir pressure and the fracture pressure is decreasing, resulting in a very narrow mud window potentially impossible to drill conventionally.

Managed Pressure Drilling (MPD) is a solution to these challenging drilling operations where narrow mud windows and uncertain pressure regimes are introduced. By use of MPD techniques, the downhole pressure can be con-

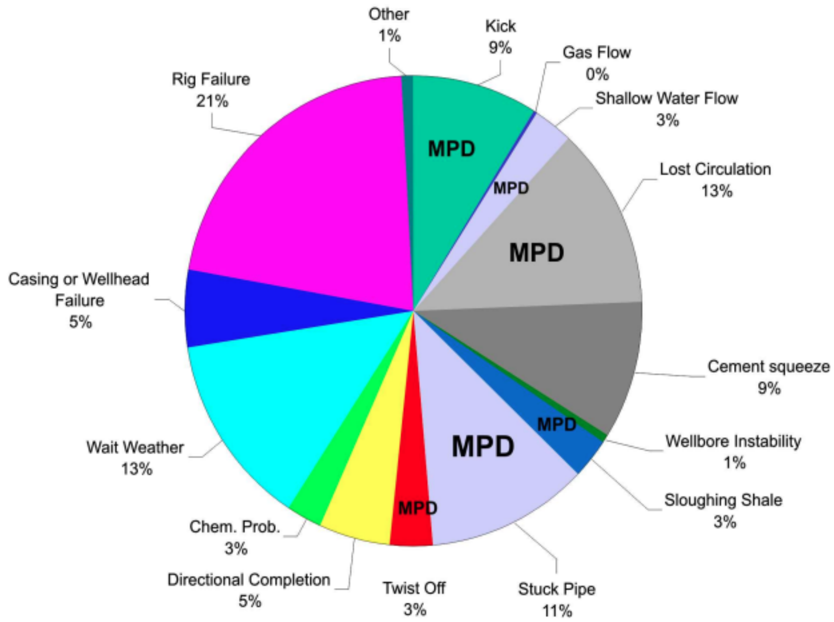

Figure 1.1: *22% of the days of the drilling operation lost to NPT. More than 40% of these problems were related to wellbore pressure issues.(Hannegan, 2007)*

trolled from the surface, and the drilling operation can continue without further problems resulting in NPT. Conventionally the downhole pressure is changed by circulating a new weight of drilling mud down into the well. Circulating the drilling mud takes time, the deeper the well, the more time to circulate new drilling mud. By implementing a MPD system consisting of an automatic control system, a back pressure pump and a control choke, changes in the wellbore pressure can be managed more instantly than with a conventional system. Previously un-drillable prospects with narrow mud window can then be successfully drilled.

The root cause of cost uncertainty is the risk of NPT. A reduction in NPT can therefore lead to a more certain AFE of the drilling operation. The design of the drilling program and decision making are both highly depending on the risk of cost uncertainty, which plays an even bigger role in challenging environments and uncertain pressure regimes. Figure 1.2 illustrates the difference in cost uncertainty of conventional drilling and MPD, where MPD causes a reduction in NPT and leads to a more predictable drilling operation.(Sonic Energy Services LTD., 2011)

The interest for MPD application in offshore environment has been increasing the past decade and offshore MPD operations have successfully been carried

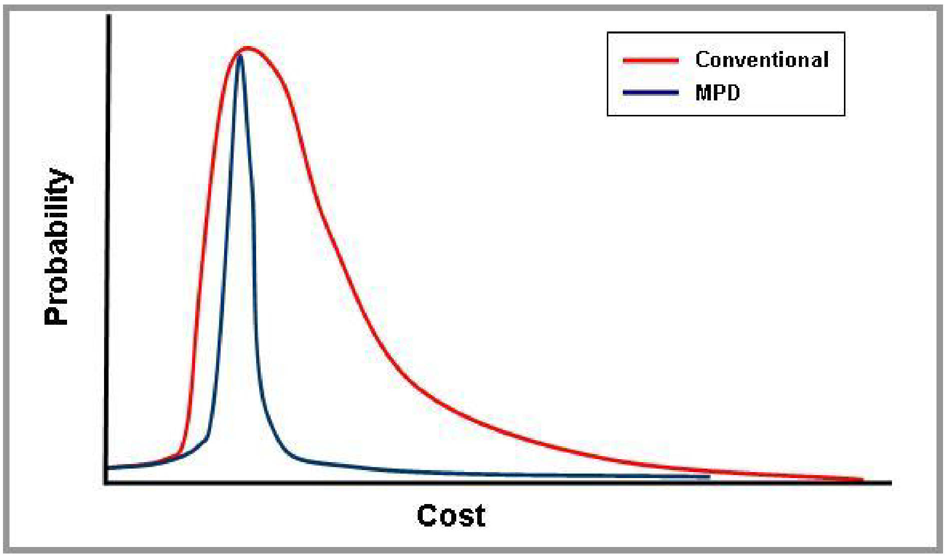

Figure 1.2: *Drilling Cost Uncertainty (Sonic Energy Services LTD.)*

out, but mainly on fixed platforms. While fixed drilling platforms are more stable since it is connected to the seabed, floating rigs are way more sensitive to the heave motions. Controlling the bottomhole pressure within desired limits is therefore more complicated. During drilling mode and tripping mode, the position of the drillstring is controlled by the heave compansator located on the rig, and the bottomhole pressure (BHP) can be controlled. However, during drillstring connections, the drillstring is suspended in slips in the rotary table and the drillstring moves vertically due to heave motions. This results in severe pressure fluctuations that can cause the pressure to drop below the reservoir pressure or exceeding the fracture pressure. This can cause influx from the formation fluid or damage of the formation. In a 8 1/2" hole the changes in BHP may change up to as much as 20 bar depending on the heave motion (Rasmussen and Sangesland, 2007).

Being able to control these pressure fluctuations will make drilling operations from floating rigs in harsh weather conditions, i.e. the North sea, possible. In the Norwegian sea there are several requirements that need to be met for conducting a MPD operation from a floating rig (Solvang et al., 2008). Various attempts have been developed to make MPD operations on floating rigs in harsh weather conditions possible. Examples are new slip joint designs, Riser Pressure Control (RPC) and new Rotating Control Device (RCD) designs. The main focus in this project are the challenges of pressure fluctuations in the borehole due to heave motion while utilizing MPD techniques.

1.1.1 Depleted reservoir example

A narrow mud window is common in deep-water environment, depleted and High Pressure High Temperature reservoirs (HTHP). Unconventional gas resources are commonly over-pressured geological environments where the mud window is narrow. Kristin is currently depleting HTHP gas condensate field (911 bar, 172 Celcius) located offshore Norway in the Norwegian sea(Solvang et al., 2008). The field is producing from existing wells with a rapidly declining pore pressure due to the high initial pressure. A reduction in the pore pressure also affects the fracture pressure, resulting in a change in the mud window. According to Solvang et al. (2008) an additional drilling program is planned to increase the recovery of the already producing fields, but the operators are concerned in uncertainties of the reservoir pressure due to unknown or uneven depletion in the reservoir. It is desired to implement MPD in the new planned wells on the Kristin field to enable better control of the BHP during drilling and well control events as well as an earlier kick detection due to a more sensitive system compared to conventional drilling. But implementation of MPD on the Kristin field is challenged by harsh weather conditions and severe heave motions, where the surge and swab effects due to the heave motion are estimated to be 5 to 10 bar for the volume of a typical well on the Kristin field(Solvang et al., 2008). In a narrow mud window these changes are too big and can result in wellcontrol issues as previously mentioned.

1.2 Previous Work

MPD has a growing interest in the industry and a lot of work and effort has been invested on the topic. The challenges of controlling the BHP within a narrow mud window from a floating rig, exposed to heave, are discussed in a number of papers (Hannegan et al. (2011), Solvang et al. (2008), Rasmussen and Sangesland (2007)). Automatic MPD has been successfully applied offshore by Statoil at the Kvitebjørn field in the North Sea in 2007 from a fixed drilling rig. Godhavn (2010) presents and discusses results on this MPD operation and control requirements for automatic MPD. Development of an automatic control system for the scenario of pressure fluctuations due to heave motion was carried out by a research group from Statoil. Simulations of this system based on a simple model of the drill string hydraulics was successfully carried out. However, a full scale testing on Ullrigg, Stavanger was unsuccessful. A case study of the testing on Ullrigg drilling rig was conducted by Landet et al. (2011) and a master thesis was written on the topic the spring of 2011 (Landet, 2011), where a model for well hydraulics was developed and evaluated against the test data from the mentioned Ullrigg test.

1.3 Objective

The objective of this project is to study different MPD challenges with respect to the drillstring and active compensation of pressure fluctuations due to heave motion of a floating rig. The ultimate target of this project is to design a lab scale model, which can support heave compensation data sets for testing a fast choke controller to obtain constant BHP.

The follow up of this project is to build the proposed model. And preform experiments, produce results and demonstrate both applicability of the proposed solutions and their limitations under practical constraints. In this way, we may indicate further directions for theoretical research and practical developments in this field.

1.4 Outline of Project

The Outline of the project is as follows: Chapter 2 gives an overview over MPD techniques, equipment and challenges related to MPD from floating rigs. Chapter 3 deals with the design of the system and presents simplifications, assumptions and calculations made. Chapter 4 presents the development of the system designed in this project based on changes made as the project has been carried out. In Chapter 5, the final design of the rig model to be built is presented based on the calculations presented in Chapter 4. In Chapter 6 there will be a discussion based on the work, feasibility of the model and suggestions for future work. Appendix 1 presents procurement list made by Samir Rashid. The Appendix 2 contains the MATLAB program developed for simulations made in Chapter 3. Appendix 3 presents simulations done by Ole Morten Aamo.

2 Managed Pressure Drilling

The history of managed pressure drilling goes back to onshore drilling operations in the mid-sixties(Hannegan, 2006), but is a relatively new technology in offshore environment with a growing interest in the industry. Today the industry is facing challenges in difficult remaining reservoirs that can not be drilled by use of conventional methods. Depleted reservoirs and deep-water drilling are challenging areas introducing a very narrow drilling window (figure 2.1). While drilling conventionally it is desired to use a mud with specific gravity smaller than the fracture gradient and bigger than the pore pressure gradient to avoid drilling problems as lost circulation or influx into the wellbore. To stay within this window, while drilling conventionally, can be challenging and sometimes impossible or uneconomical. By a more precise pressure control, MPD, can face these challenges and make previously impossible or uneconomical prospects accessible. (Hannegan, 2006)

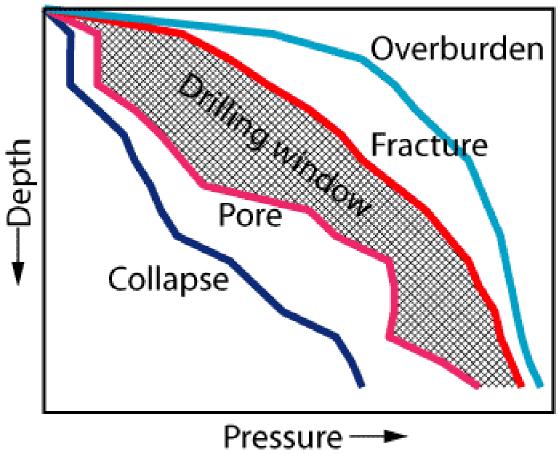

Figure 2.1: *Drilling window limited by the pore pressure and the fracture gradient. From Malloy (2007)*

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2.1 MPD Candidates

Managed pressure drilling is one of three drilling methods in the family of controlled pressure drilling technologies which also includes Underbalanced Operations (UBO) and Air or Gas Drilling. Mutual for these three methods is that they all can be considered as a closed pressurized system and they are all methods used to benefit the operation with cost reductions. (Hannegan, 2006)

To choose best suited drilling method an evaluation of the prospects is needed. Reasons to drill under-balanced or with air or gas as a drilling fluid can be a sub-normally pressured reservoir, hard rock, non-hydrocarbon bearing formation or to simply drill faster with an increased ROP. Candidates for MPD are identified based on previous experiences from offset wells with budget exceeds related to NPT, failure to reach total depth, unknown down-hole pressure, high pressure high temperature or if a closed pressurized system is required for safety related issues. (Hannegan, 2006) MPD is also applied to avoid unwanted wellcontrol events as lost circulation, wellbore instability and well control incidents and to reduce the risk of stuck pipe due differential sticking.

2.2 Various Types of MPD

The International Association of Drilling Engineers (IACD) has made the following definition of Managed Pressured Drilling (MPD), adopted by the Society of Petroleum Engineers (SPE):

MPD is an adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore. The objectives are as ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. Technical Notes

1. *MPD processes employ a collection of tools and techniques which may mitigate the risk and costs associated with drilling wells that have a narrow downhole environment limits, by a proactively managing the annular hydraulic pressure profile.*
2. *MPD may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulation friction, and hole geometry, or combinations thereof.*
3. *MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects.*
4. *MPD techniques may be used to avoid formation influx. Any flow incidental to the operation will be safely contained using an appropriate process.*

Hannegan (2006) divides MPD into two categories; Reactive MPD and Proactive MPD. Reactive MPD is used to react to unexpected downhole changes while drilling with typical conventional drilling methods and to minimize these problems after they occur. Proactive MPD is the most used of the two, and is a part of the planned drilling program for more accurate pressure control during drilling. Proactive MPD will benefit the operation by reducing NPT, reduce the number of casing strings, mud density changes and also decrease wellcontrol risks. (Hannegan, 2006)

The main objective with MPD is to control the wellbore pressure within a narrow pressure window. There are several variations of MPD, but all of them has the same approach - to control the downhole pressure with a closed pressurized system. The benefit with a closed system, is that changes in the pressure can be seen immediately, proactive changes can be made faster than in a conventional system. Possible losses or influx can therefore be detected and handled immediately. This precise control enhances the safety for the rig workers and equipment during the drilling operation. (Malloy et al., 2009)

According to Hannegan (2005) there are four main variations of MPD which each, or a combination of two, are applied to solve commonly detected drilling-related problems. These methods are presented in the following subsections:

- Constant Bottomhole Pressure(CBHP)
- Pressurized Mud Cap (PMCD)
- Dual Gradient (DG)
- Returns Flow Control (RFC)

2.2.1 Constant Bottomhole Pressure

In areas where the difference between the pore pressure and the fraction pressure is large enough, conventional drilling can be used as an optimal drilling method with no additional pressure control. On the other hand, if the mud window is narrow, additional pressure control is needed to avoid unwanted wellcontrol incidents. CBHP is applied to prospects with a narrow or relatively unknown mud window, slow rate of penetration (ROP) or wellcontrol risks. (Hannegan, 2005)

Conventional drilling has traditionally been performed by applying a sufficiently dense drilling fluid in order to stay within the mud window. The BHP is in a static condition when the mud pumps are off and is determined by the hydrostatic mud column. In dynamic condition, during circulation, the BHP is determined by the sum of the hydrostatic mud column and the annular friction pressure(AFP), and is defined as equivalent circulation density (ECD). In a narrow mud window, the well can be under control in static condition, but when the mud pumps are turned on and circulation starts ECD can cause the pressure downhole to exceed the fraction pressure. Lowering the mud weight during circulation, can cause influx from the formation when the well is static again. When these well control events occur, the weight of the mud in the hole has to be changed by adding materials to the mud. Dealing with these "kick-loss" scenarios is a time consuming and costly process , and is also introducing undesired well control situations. (Hannegan, 2005)

In these troublesome wellbore pressure situations, CBHP can be applied to control the downhole pressure faster and more accurately compared to conventional drilling methods. CBHP enables use of a lighter drilling fluid compared to conventional drilling by applying backpressure from the surface when the well is in static condition and the AFP is not present. The RCD seals the annulus above the BOP and the BHP can be adjusted by a choke. Flow through the choke is needed to control BHP, hence a backpressure pump is introduced to provide sufficient flow through the choke at all times (van Riet et al., 2003). During connections when the mudpumps are off, the choke opening can be adjusted (to a smaller opening) or closed and backpressure is applied from the surface. By use of CBHP technique the BHP is maintained constant as the wellbore conditions changes from static to dynamic and the other way around. A lighter drilling fluid causes a lower ECD compared to a conventional drilling situation and the risk of exceeding the fracture pressure is lowered. Hence the risk of loss of drilling mud is less likely to be encountered. The wellbore pressure condition is overbalanced at all times and influx from the formation is therefore avoided. The drilling operation is therefore more efficient compared to conventional drilling methods, resulting in deeper casing setting depths. It may also decrease the number of casing strings to reach total depth.(Hannegan, 2006) In figure 2.2 a comparison of conventional drilling and CBHP can be seen.

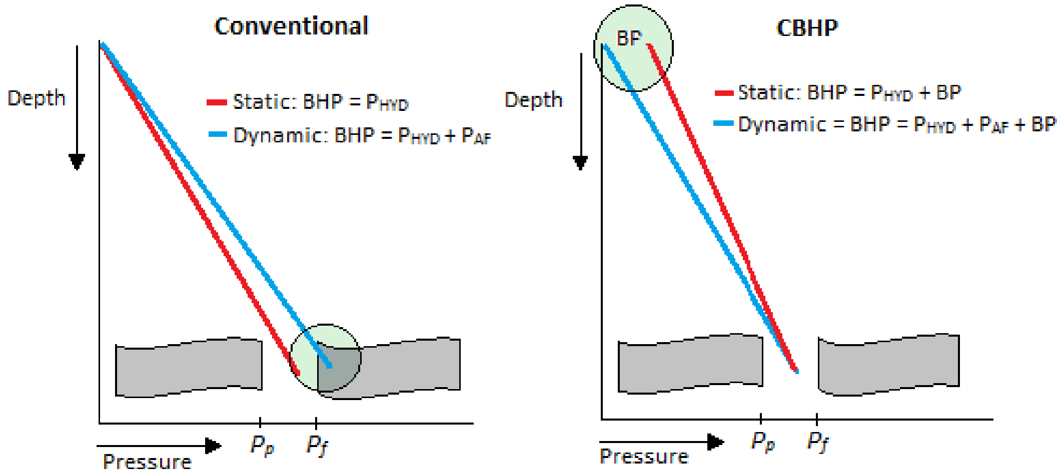

Figure 2.2: *To the left; Pressure versus depth illustration of conventional drilling. The BHP is increased in dynamic conditions due to the AFP (P_{AF}) and the BHP exceeds the fracture pressure (P_f). To the right; pressure versus depth illustration of CBHP. The mud weight is reduced and backpressure is applied to compensate for the reduction in static condition. In dynamic condition, the backpressure is reduced to keep the BHP to compensate for the AFP.*

2.2.2 Pressurized Mud Cap

PMC the recommended technique to use in order to control the well in areas where extreme mud losses are encountered, consequently followed by kicks. Fractured reservoirs and vugular carbonate reservoirs are therefore often candidates for PMCD. This variant is the most commonly MPD method used in the Asia Pacific, where fracture carbonate formations are more common. (Nas et al., 2010)

When drilling conventionally the hydrostatic head is higher than the reservoir pressure. When entering a fractured zone and losses occur, the fluid level in the well will drop and the hydrostatic head is reduced and the wellbore pressure can be significantly lower than the reservoir pressure and a kick is experienced. The following step now is to fill up the well with a rate that exceeds the gas influx rate. To continue drilling in this fractured and challenging zone the PMCD method is used by filling up the annulus with either water or a weighted fluid depending on the hydrostatic pressure in the reservoir. The gas is then flushed back to the fractured zone by filling the annulus with either water or a heavier drilling mud, depending on the reservoir pressure, by continuously filling up the annulus. If water is used,

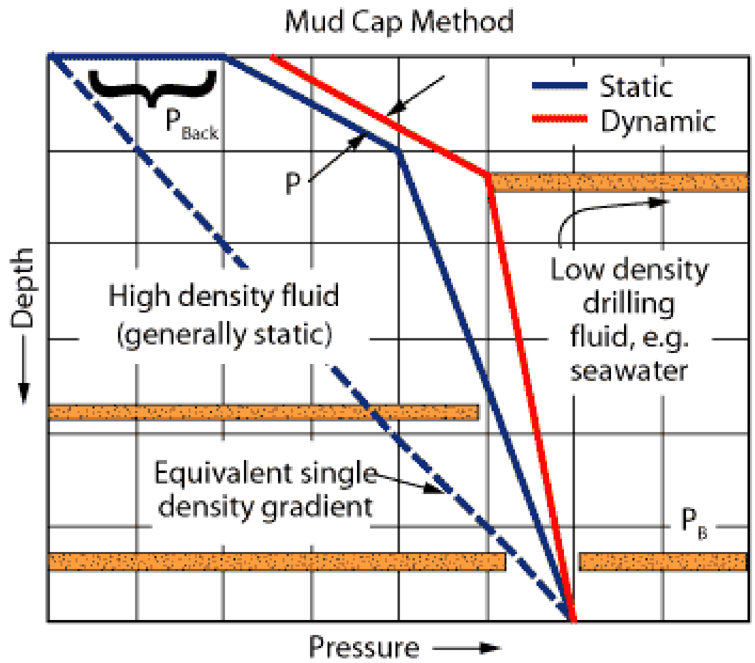

Figure 2.3: *Pressurized Mud Cap. Light weight drilling fluid circulates through the drillpipe and arpound the bit and injected to a weak zone uphole. The annulus on top of the weak zone filled with a denser drilling fluid (Malloy, 2007).*

there is no limit for how long this can keep going, since seawater is available offshore. If a drilling mud is used this process can only keep going for a few hours because of limitation on drilling mud. To meet these limitations, a specific weight lower than the pressure gradient to the reservoir is used in the annulus. An additional pressure is then maintained at the surface by closing the annulus with a RCD, and the reservoir is balanced. Drilling is continued by use of seawater as a drilling fluid to carry the cuttings to the loss zone.(Terwogt et al., 2005)

By use of two drilling fluids, one for the mud cap in the annulus as a barrier, and one as the drilling fluid used for drilling, the PMC method is maintaining the wellcontrol. The drilling fluid used for continuing the drilling operation is lighter, less expensive and less damaging for the weak, fractured zone. Using a lighter drilling fluid will also increase the ROP due to increased hydraulic horsepower and decreased chip hold down effect. Figure 2.3 illustrates the PMC method with the low density drilling fluid injecting to the weak zone and the mud cap as a barrier in the annulus.

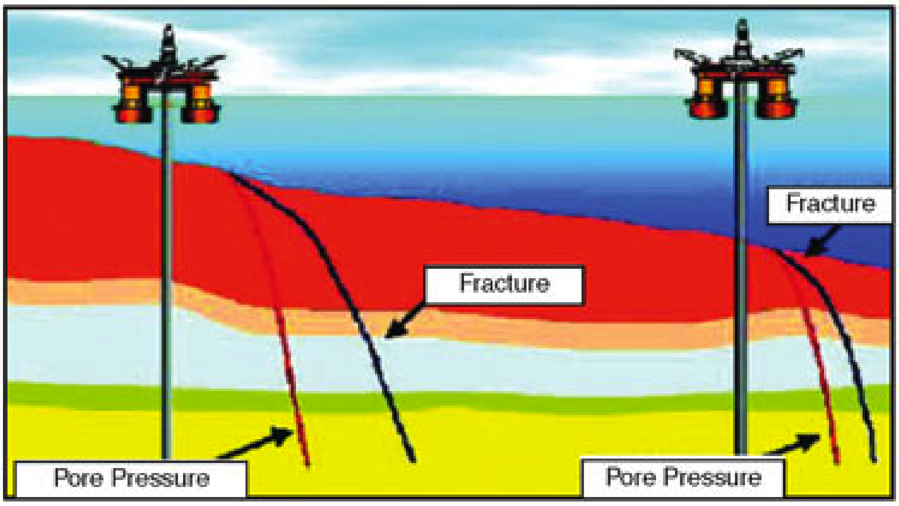

Figure 2.4: *Illustration of reduction in fracture gradient.*

2.2.3 Dual Gradient Variation

The DG method is a relatively new MPD method introduced to offshore environments in the 1990s (Breyholtz et al., 2011). The objective of this MPD method is to reduce the risk of damaging the formation and drilling mud losses when drilling in formations with low fracture pressure. In offshore environments, especially deepwater, the seawater creates significant part of the overburden pressure. The density of seawater is much smaller than a typical rock formation and causes a reduction in the fracture pressure gradient, relative to a normal shallow water situation (figure 2.4). This means reduced margin between the pore pressure and the fracture gradient. In conventional drilling, when a heavy drilling fluid is used, this can lead to a need for multiple casing strings in order to keep within the mud window. (Malloy, 2008) As previously mentioned a decrease in the number of casing strings would be economically beneficial for the operation and is one of the motivations behind dual gradient drilling.

There are various methods of DG drilling systems, some are more complex than others. The main objective is to mimic the saltwater overburden with a lighter-density fluid. This can be done by filling the riser with seawater while diverting and pumping the mud and cuttings from the seabed floor to the surface. Lighter fluid in the riser can also be obtained by injecting less-dense media, like gas, into the drilling fluid within the marine riser.(Malloy, 2008) In this way the hydrostatic column providing the BHP consists of two fluid gradients in stead of one (figure 2.5) (Smith et al., 2001). The pressures in

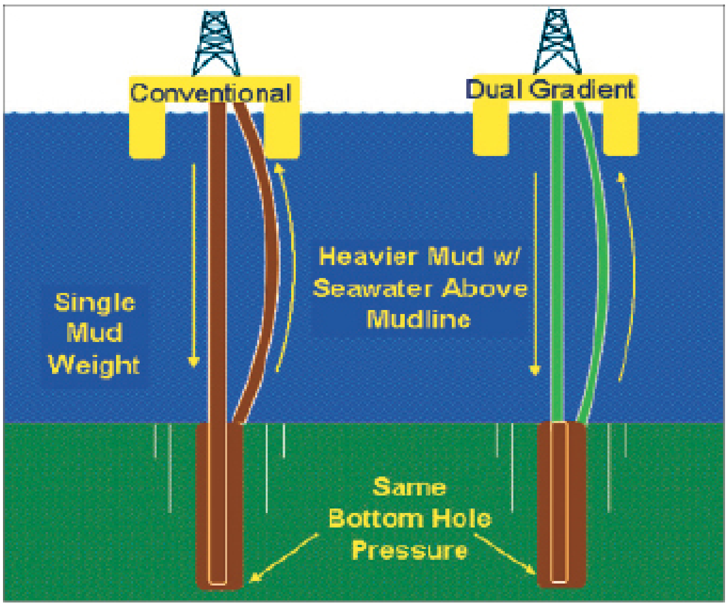

Figure 2.5: *Dual gradient drilling compared to single gradient drilling (Drilling Controactor, 2010).*

the well are the sum of the of gradient of the lighter fluid from surface to the mudline at seabed and the gradient of the drilling fluid in the well.

2.2.4 Returns Flow Control

RFC, or HSE, method is applied to close the mud returns system under the rig floor for health, safety or environmental reasons. This method does not control the annular pressure, like the previous mentioned MPD methods, but is still considered as an MPD variation according to the definition of MPD (chapter 2.2) since it enables the personnel to react more safely and efficiently to downhole surprises.(Nas et al., 2010) Hence the risk to personnel and the environment from drilling mud and well control incidents is reduced. Application of RFC alone or in combination with other MPD methods is common when drilling with hazardous drilling mud or in formations containing toxic gas and where the drilling window is narrow and there is increased chance for influx from the formation.

A closed pressurized system for the annular returns is created by implementing the RCD above the BOP. The system can divert the annular returns away from the rig floor, to avoid spill and release of dangerous gases, i.e. H_2S, to the atmosphere or onto the drillfloor. If a kick is taken, this is done

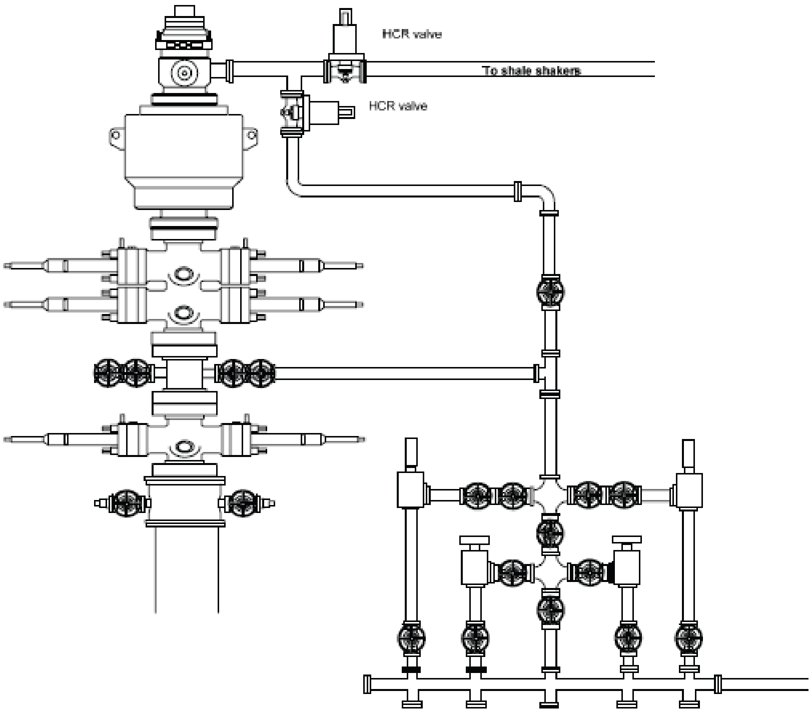

Figure 2.6: *MPD rig up for returns flow control. (Nas et al., 2010)*

by closing the flow-line to the shakers and diverting the return flow to the rig choke manifold. Here the gas influx can be safely circulated out of the hole, and the need for the closing of the BOP is avoided. Hence the risk of release fluids to the drillfloor is minimized (Nas et al., 2010). A rig up for the RFC can be seen in figure 2.6.

2.3 MPD Equipment

Some key tools are present in most variations of MPD. The majority of MPD operations is conducted by use of a closed vessel with a RCD, one or several drill string Non-Return Valves (NRV) and a Drilling Choke Manifold (DCM) (Malloy et al., 2009). The RCD allows the annulus to be pressurized and the return flow is bled-off through the choke manifold. The choke can be manual, semi-automatic or PC Controlled automatic. The amount and the complexity of equipment used during a MPD operation can vary depending on the MPD method applied, type of drilling rig and environment, but some basic equipment is common for all MPD techniques. These key tools have been mentioned in previous subsection when MPD techniques have been described, however, more detailed descriptions of these core elements follow in the next subchapters.

2.3.1 Rotating Control Device

The development of RCDs goes several decades back to onshore air and underbalanced drilling with gas or foam with the purpose of increasing the ROP and lower the cost of drilling in hard formations. (Hannegan, 2005) The RCD seals the annulus and is therefore common to all MPD techniques since all the methods require a closed pressurized system. The variation of the device can be many. The variations depends on the MPD operation, the rig type and can be placed at the surface or subsea. The RCD design can also vary in use with air drilling, geothermal drilling, riser diverters and stripping casing as well as sealing around the drill pipe. In contrast to an annular preventer or a pipe ram, which also seal the annulus, the RCD is used to limit the rotational wear while drilling, and can therefore be applied in a longer time frame.(Rehm et al., 2008) The RCD includes the following basic components (Vargas, 2006):

- *A Bearing Assembly*
- *Cone shaped stretch fit Stripper Rubbers within the bearing.*
- *A Bowl that serves as a diverter housing to which a dedicated choke assembly can be connected.*
- *Mechanocal or Hydraulic Clamps for securing the Bearing Assembly to the Bowl.*
- *A Heat Transfer System to remove excess heat from the Bearing and*

Stripper Rubber Assembly

Typical pressure ratings of RCDs can vary up to 5000 psi in static condition and 2500 psi in dynamic condition with maximum bearing speeds around 200 rpm.(Vargas, 2006; Rehm et al., 2008) The two different categories of RCDs are passive rotating devices and active rotating devices, where the passive RCD system is the most commonly used. The passive system forms a seal around the outside diameter of the drillstring or other tubular in both static and dynamic condition, meaning that the drillstring can move and rotate with a remaining seal. In the active system hydraulic power is used to seal around the drillpipe. This RCD system is more complex and requires more space above the BOP compared to the passive system. (Rehm et al., 2008) Today the RCD is also available for drilling in deepwater where marine riser or riserless drilling is applied, i.e. External Riser RCD, Subsea RCD and Internal Riser RCD.

2.3.2 Drilling Choke Manifold

The choke is a vital part of the MPD system. It is used to control the annular back pressure during the drilling operation, by adjusting the opening of the choke depending on the pressure changes downhole. By decreasing the choke opening the pressure is sealed, and by increasing the opening the pressure is released. Hence, the pressure downhole can be maintained constant if the flow changes. To be able to control the pressure downhole by the choke, sufficient flow through the choke i required. If the mudmumps are shut down and the circulation stops, i.e. during connections or if the mud pumps fail, a backpressure pump is applied to provide flow through the choke. An additional choke can be implemented in the choke manifold to provide redundancy if on choke fails or to allow choke maintenance. (van Riet et al., 2003)

MPD operations can be practiced with manual, semi-automatic or Programmable Logic Controllers (PLC) automatic operated choke. However, PLC automatic operated choke is recommended and often necessary to ensure optimal accuracy and control. The PLC system is using a real-time system software and additional pressure, temperature and flow parameters. It also measure while drilling (MWD) the BHP in order to estimate and maintain control over the BHP, by automating the hydraulically controlled choke.(Hannegan, 2011) In addition to the choke, the pump rate can also be automatically operated, depending on the system applied. However, there is great room for improvement in making the automatic control system optimal for MPD operations in challenging environments and from floating rigs. In these situations the choke has to be operated faster and more accurate than what is available today. The system is relying on measuring the BHP while drilling to compute new positions of the choke and the pump flow. As the well is drilled deeper, and the mud flow rate is changed during the operations these readings can be affected by a time delay for the measurements to travel to the surface. Other downhole conditions and disturbances can also affect the accuracy of the system.

2.3.3 Non-Return Valves

Non-return valves are essential in MPD operations to avoid backflow up the drillpipe. Most MPD operations are practised with at least one drillstring NRV. Specifications for NRV have been published as API Spec 7NRV where several models are specified. (Malloy, 2008) The pressure rating of the drill-string NRV should be equal to or greater than the expected reservoir pressure.

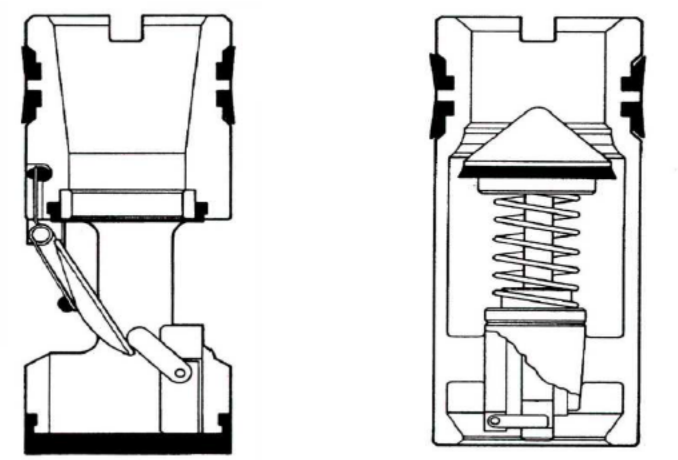

Figure 2.7: *Two types of NRV. To the left: Flapper NRV. To the right: Plunger NRV. (Malloy, 2008)*

2.4 MPD on Floating Rigs

MPD operations have been conducted onshore for a long time, but its only recently that these methods have been deployed offshore. However, it is mainly on fixed drilling units, such as jack-up drilling rigs and platform based rigs. This because MPD operations can on fixed offshore rigs require

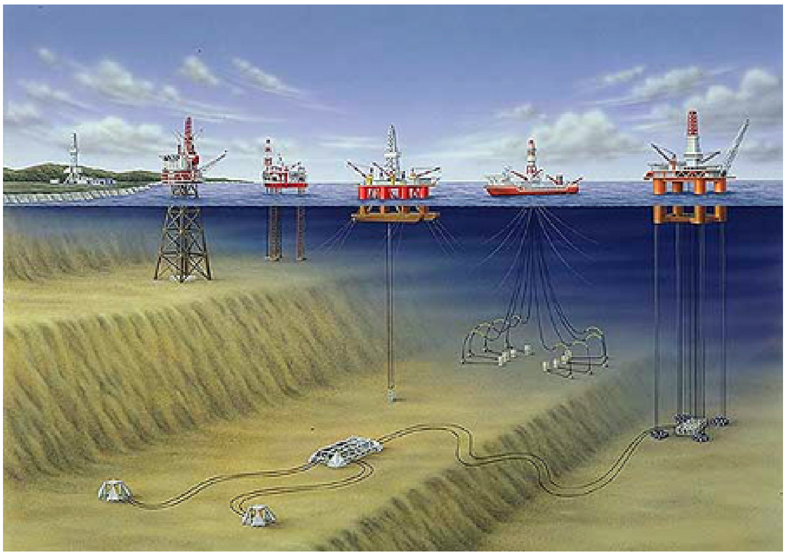

Figure 2.8: *Various drilling rigs. Floating rigs are used in deep-water environment and exploration drilling.*

small modifications due to the similarities between the onshore and fixed installation drilling equipment. On floating rigs the differences in equipment, i.e subsea BOP and marine riser, make application of MPD operations far more challenging (Kozicz and Juran, 2006). Many of the challenging areas with remaining oil and gas resources are located in deep-water where only floating drilling rigs can be applied in the drilling operation.

2.4.1 Challenges

There are various challenges related to the different MPD techniques; PMCD, CPHP, DG and HSE. A closed pressurized system can be challenging when the marine riser is introduced in drilling operations from floating rigs. Several MPD operation require a pressure capacity exceeding the limits of the design of the equipment, i.e. marine riser and BOP. Some of the MPD methods also introduce aerated fluid or gas lift in the riser which also can result in exceeding the pressure capacity limits. (Koicz, 2006) Examples of other components that can be exposed to these pressures are wellhead and auxiliary seals and gaskets. It is possible to increase the internal differential capacity of a particular equipment by changing the material or design, but this might require a complete makeover of the equipment, by disassembling and machining the BOP and other seal related areas, which can be a very costly process.(Kozicz and Juran, 2006)

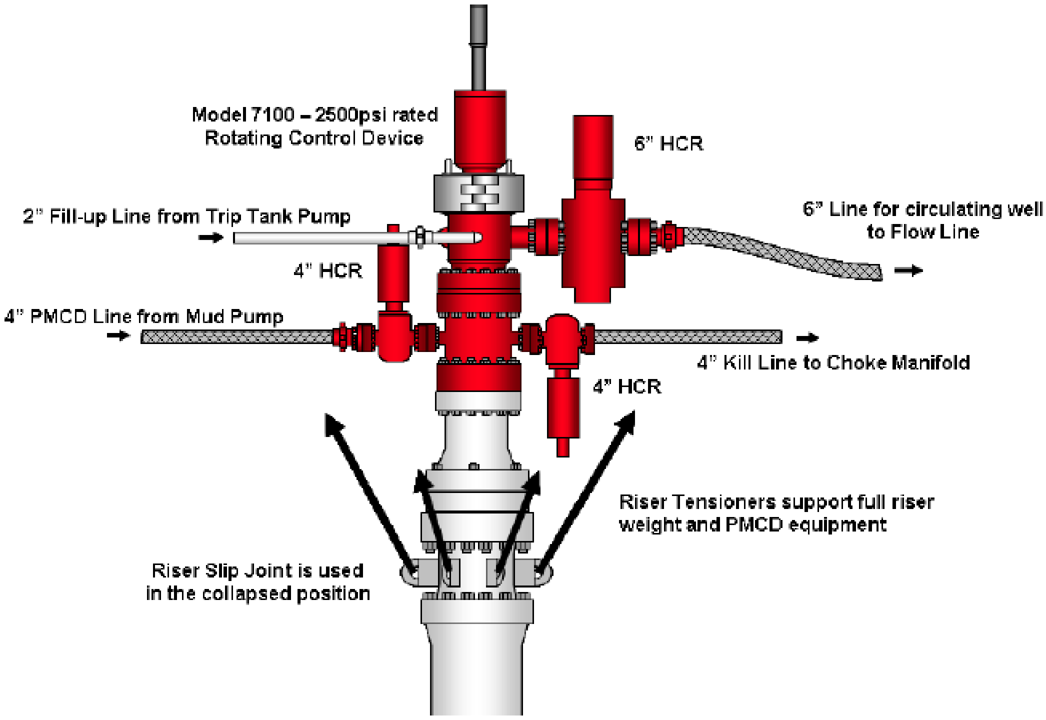

Figure 2.9: *Typical rig up of an RCD on a marine riser (Nas, 2010).*

2.4.2 RCD Design

Common practice on floating rig operations has been to have the Rotating Control Device (RCD) rigged up on the collapsed and locked riser slip joint, on top of the marine riser with a subsea BOP (figure 2.9, Nas (2010)). There has commonly not been any top connections on the RCD's used, this is not allowing the normal configuration of marine riser connected to the diverter housing under the rig floor. The normal practice has been to place the RCD on top of the riser with an air gap between the rig floor and the top of the RCD. (Nas, 2010)

Many MPD operations include back pressure from the surface. This can be a challenge regarding the internal pressure capacity of the marine riser and its components. This is depending on the wall thickness, wear, seal design and axial loading. If the slip joint is exposed to the applied backpressure, its pressure rating (500 psi) will limit the application of the back pressure. This can be solved by removing the slip joint inner barrel and seal assembly, which will allow a maximum surface pressure of 1200 psi (according to most drilling contractors). Removing the slip joint inner barrel can be a costly and time consuming process, but there has been several improvements in this area the past years. (Nas, 2010)

2.4.3 Heave Motion

The operational window of a floating rig is relaying on the weather and the heave motion and can vary, depending on the drilling rig, and type of operation. The wave periods in the area where the operation takes place has a markable impact on the operability. (Anundsen, 2008) The Mediterranean Sea i characterized by short and deep waves, while the Pacific has the opposite wave behavior. The North Sea is a harsh sea environment where the heave on the rig can be as high 12 to 13 m and the operation needs to be shut down. Typically the heave varies from 1 to 6 m, which can allow some rigs to safely continue drilling operations, depending on the rig type configuration. (Romstad et al., 2010) During drilling and tripping mode the heave compensator is activated and allows for greater heave amplitudes than during connections. MPD operations from floating rigs in these environments is still a challenging operation due to the narrow mud window and rough heave motions. The behavior of waves in the ocean resulting in the heave motion is a complex topic which will not be discussed in detail in this project. A lot of work has been invested in research to characterize the movement of the waves in the sea. However, in this project a simplified wave model will be used to model the movement of the drillstring due to the heave motion.

2.5 Surge and Swab during Connections

As previously stated, this project's main focus is the the MPD method CBHP used on floating rigs and the challenges that are met while doing connections. During drilling and tripping modes in MPD operations the mud is pumped down the drill string through the bit and up the annulus. While making drill string connections on a floating rig, the bit is lifted off bottom and the mud pumps are turned off. While the rig pumps are ramped down to zero, the annular friction pressure is decreasing, causing the overall downhole pressure to decrease. If the drilling window is very narrow, this can cause the downhole pressure to drop below the reservoir pressure, and cause influx in the well. To avoid this, the backpressure can compensate for the annular friction pressure drop by applying more pressure from the surface.

However, the main issue with connections during MPD operations on floating rigs is the heave motion. During the connections the drillstring is suspended in slips in the rotary table causing the drillstring to move vertically up and down in the hole, acting like a piston in the riser below the RCD. This can cause severe pressure fluctuations in the wellbore depending on the frequency and magnitude of the heave. This will affect the down hole pressure regime, due to down hole pressure increase (surge) or decrease (swab), which can cause lost circulation or influx from the formation if the drilling window is narrow.(Rasmussen and Sangesland, 2007) It is stated that in mild to moderate seas, with small heave motions, use of the CBHP MPD method to maintain a constant BHP is not commercially effective. However, when the heave motions are more challenging with moderate to severe waves, it is desired to enable CBHP to compensate for the heave motions. Such areas can be deepwater and harsh weather environment areas, like the Norwegian continental shelf, where the drilling window is narrow. (Hannegan et al., 2011)

2.6 Estimating Surge and swab

A number of models have been developed to estimate the surge and swab pressure, some more complicated than others.

Steady state models are commonly used in predicting the surge and swab pressure. Burkhardt (1961) and Schuh (1964) have developed models for computing surge and swab pressures due to pipe movement in a borehole filled with drillingfluid. According to Burkhardt (1961) three effects are generating the surge pressure when a pipe is lowered into the wellbore: Gel strength, fluid Interia and viscous drag. However, use of a steady state model, is simplifying a real case by neglecting issues such as the compressibility effect (Mitchell, 1988). Hence, dynamic surge models have been developed to predict more precisely surge and swab pressures in the borehole. This models are more complex and requires computer programs to carry out the calculations for complex cases. Halliburton delivers a surge module in Landmark WELLPLAN and is based on a dynamic surge model developed by Mitchell.

2.6.1 Volume change

MPD is introducing a closed system compared to an open system in conventional drilling. When the drillstring and BHA is moved up and down in the hole during connections through the RCD, the total mud volume in the well will be compressed due to the displacement of the drillstring. In a closes pressurized system, this will cause a pressure increase in the BHP in addition to the surge pressure, when the drillpipe is moved downwards due to the heave motion. This pressure increase can be released by the choke. For a typical well at the previous mentioned field, Kristin, the surge and swab effects due to the volume change in the annulus are in the order of 5 to 10 bar. (Solvang et al., 2008) This is depending on the geometry of the drillstring and the hole and the size of the drillstring, which causes the displacement, and the volume of the wellbore and the type of drilling mud used. The surge and swab pressures generated due to volume change in the wellbore is relying on the compressibility of the drilling mud used. When the drillstring is moved downwards causing surge pressure in the wellbore, the fluid in the wellbore is compressed. Use of a very compressible drilling fluid, i. e. oil based muds, can minimize these effects.

The pressure increase due to volume change in the hole when a pipe is lowered into the hole due to the heave, can be expressed with the following equation Rasmussen and Sangesland (2007):

$$\Delta P = \frac{A * C}{c * V_{total}} \tag{2.1}$$

where A is the amplitude, C is the capacity of the annulus, c is the compressibility of the mud and V is the total volume.

Rasmussen and Sangesland (2007) present a case example based on calculations made in WELLPLAN, considering closed pipe. In this example the RCD is located above the slip-joint. In order to increase the pressure rating (as mentioned earlier) the slip joint is locked in closed position. A conventional 21" marine riser and a 5" drill pipe is used. With a heave scenario of 1.5 m heave amplitude and a period of 11 sec, resulting in a velocity of the drillpipe to be 0.85 m/s, the surge/swab pressure is calculated to be +/- 22 bar. With a closed choke the compression of the drilling fluid will cause a pressure increase in 7.5 bar. (Rasmussen and Sangesland, 2007)

3 Design and Calculations

The main objective of MPD is to control the the downhole pressure in the well during the drilling operation. As described in previous chapters application of MPD from floating rigs is challenged by the heave motion. During drilling and tripping mode, the heave compensator is controlling the position of the drillstring. However, during connections, the drillstring is suspended in slips and the drillstring is moved up and down due to heave motion. The purpose of the lab scaled rig design is to model for this scenario using MPD control system developed by Hessam Mahdianfar, Department of Engineering Cybernetic at NTNU. In the rig model these pressure fluctuations is generated by use of a step motor connected to a wire pulling the drillstring up and down in a pipe filled of water. To compensate for these pressure fluctuations a backpressure controlled by the control system is applied. The MPD setup used, introduces a choke, backpressure pump and an automated control system. As this project has been carried out, the lab model has changed several times, and these changes are presented in chapter 4. The parameters implemented in the final design are calculated in this chapter, based on the final concept. This chapter presents the assumptions and calculations made to generate a pressure drop of 2 bar over the BHA.

3.1 Field Data

The rig model is based on field data where a drill string of 5" diameter in a 8,5" diameter hole is exposed to a heave with an amplitude of 1.5 m and a period of 11 sec. To model this case the given parameters needed to be scaled down to comprehensive lab sizes. The diameter of the string was reduced to 1" and the diameter of the hole to 1,7", thus maintaining the same ratio between the cross-sectional areas, $\frac{8{,}5^2}{5^2} = \frac{1{,}7^2}{1^2}$. The BHA size in field is 70 m and has a diameter of 6.5". In field and the well can be 4000 m deep, considering a vertical well. In a 4000 m deep vertical well the main contributions to the surge and swab pressure are pressure variation over the different geometries in the well; the drillstring, the drill collar and the bit. In field the BHA consists of the bit and the drill collar. This is simplified to a cylinder shaped volume in the rig model. The pressure drop over this cylinder, from now on called the BHA, is depending on the length and the diameter of the BHA. By varying these parameters the desired pressure drop over the BHA can be produced.

3.1.1 Heave motion

As previously noted, the actual motion of a floating rig can not be expressed by a simple sinus curve, which is the case for this model. The heave motion is dependent on a lot of factors, the mass matrix of the rig, mass matrix of added load, alleviation of the movement of the rig, the fact that not all waves are of the same amplitude, to name a few. However, for this purpose a sinus curve is chosen to represent the motion. The velocity and acceleration follow a cosine and sinus curve, respectively. This movement is considered to be sufficient for a preliminary study of the problem, one faces due to pressure fluctuations during connections of drillpipes.

The velocity of the drillstring can be adjusted by varying the amplitude and the period of the sinus curve and the pressure fluctuations will change. As a base for this a period of 11 sec and an amplitude of 1.5 m is used. Equation 3.1 represents the position curve where t is the only variable. The amplitude and the period are changed to obtain the desired position curve (equation 3.1, figure 3.1). The maximum velocity of the drillstring by use a 11 sec period and a 1.5 m amplitude is 0.856 m/s (equation 3.2, figure 3.2). This velocity is the desired maximum velocity of the drillstring. The period and amplitude have been adjusted to meet requirements for the control system (see explanation below).

$$z(t) = 1,5 * \sin \frac{\pi * 2 * t}{11} \tag{3.1}$$

$$v(t) = \frac{1,5 * 2 * \pi}{11} \cos \frac{\pi * 2 * t}{11} \tag{3.2}$$

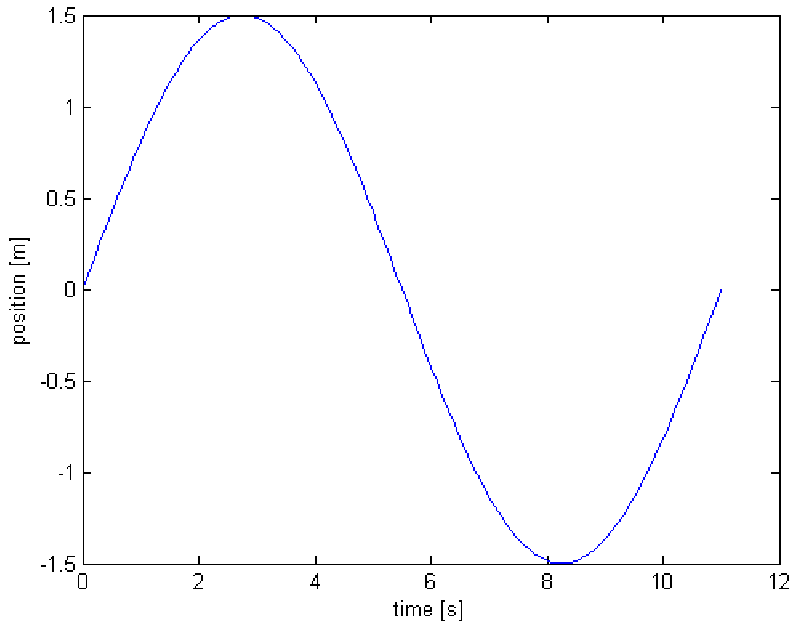

Figure 3.1: *Simplified Position Plot of Heave.*

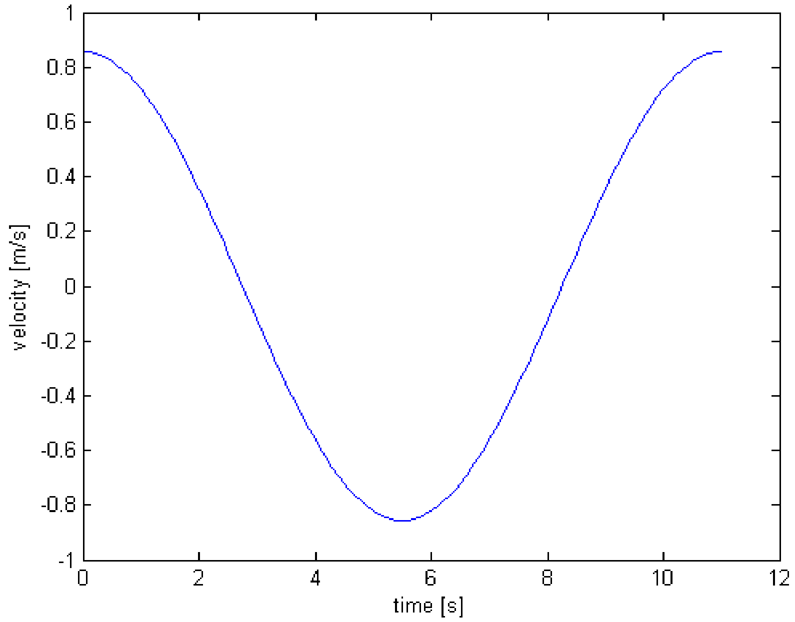

Figure 3.2: *Simplified Velocity Plot of Floating Rig,*

3.1.2 Lag time

To control the downhole pressure the choke at the surface is adjusted to either seal or release the pressure. In the field this pressure impulse will take time to propagate in a well. To simulate the same delay in the lab, a hose is introduced to the system. To have a sufficient delay, in order to make the model realistic, the hose needed to be 900 meters long, based on the propagation of pressure waves and the desired delay of 1/5 of a wavelength in the hose. The speed of sound in water is 1498 m/s. Which gives a disturbance period of $\frac{900}{1498} * \frac{20}{2{,}02} * 0,5 = 2,97$ sec, where the the period of heave disturbance is considered to be 20 sec and 2,02 sec is the time delay, for an offshore system. Because of this delay, the desired period is now 3 sec. In order to have the same maximum velocity of 0.856 m/s as mentioned in the previous subsection, with a period of 3 sec, the amplitude is changed to 0,41m. Equation 3.3 and 3.4 shows the new position and velocity curves.

$$z(t) = 0,41 * \sin \frac{\pi * 2 * t}{3} \tag{3.3}$$

.

$$v(t) = \frac{0,41 * 2 * \pi}{3} \sin \frac{\pi * 2 * t}{3} \tag{3.4}$$

3.2 Basic Assumptions

The assumptions presented below have been made to reduce the complexity of challenges met.

3.2.1 Newtonian Model

The drilling fluid used in the rig model is water, unlike typical oilbased or waterbased mud in the field. Water follows the rheological model of a newtonian fluid. In a newtonian fluid there is a linear relationship between the shear rate or strain rate, and shear stress, where the viscosity of the fluid denotes the slope.

$$\tau = \mu \frac{du}{dy} \tag{3.5}$$

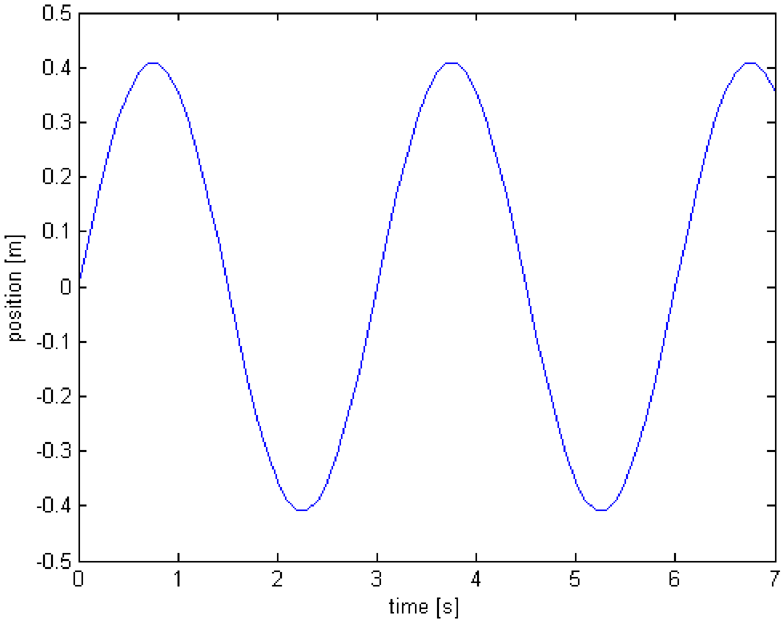

Figure 3.3: *Position plot for the model.*

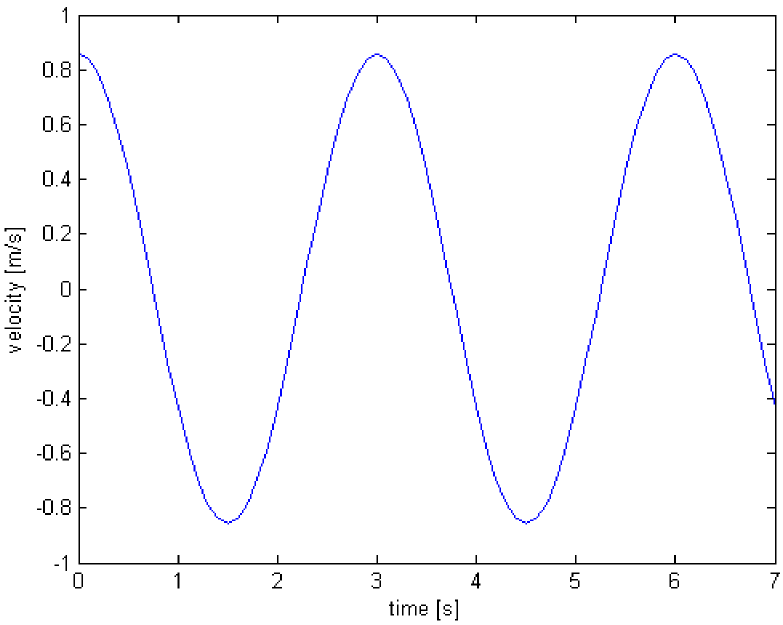

Figure 3.4: *Velocity plot for the model.*

By definition, the viscosity of a newtonian fluid is only dependent on temperature and pressure. Water is more dependent on temperature than pressure, and the dependency to pressure is considered to be negligible as we have relatively small variations in pressure(0 to 16 bar).

The viscosity of water is very sensitive to variations in temperature (figure 3.5). At 20^{o}C the viscosity of water is 1,003 cp. At 18^{o}C the viscosity is 1,054 cp and at 22^{o}C the viscosity is 0.955 cp. The change of -2^oC and $+2^oC$ gives a change of -5,01% and 4,8% of the viscosity of the water, respectively. The variation of temperature therefore constitutes a major uncertainty when it comes to calculations where viscosity is a variable, more on this in chapter 3.6

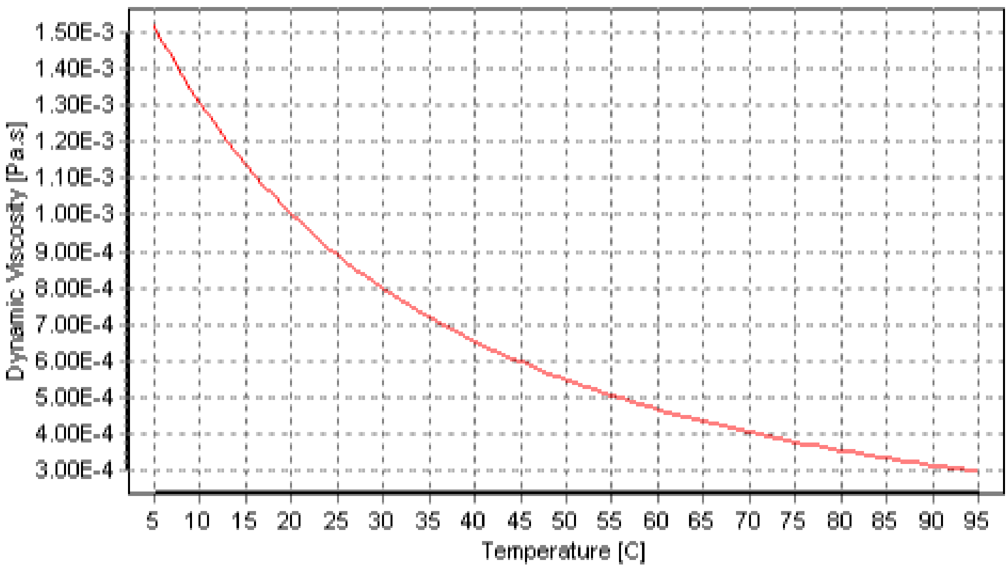

Figure 3.5: *Graph showing viscosity of waters dependency on temperature. (Pramuditya, 2011)*

3.2.2 Fluid Compressibility

Water is often considered to be an incompressible fluid. To verify that this can be misleading, we look at an estimate of how much compression there would be in the system, if it was subjected to a difference in pressure of 16 bar. The compressibility of water is a function of both temperature and pressure. The temperature is constant and the dependency of pressure is in, this case, negligible as there is relatively small variation in pressure.

$$\frac{dV}{V} = c_f * \Delta P \tag{3.6}$$

where the compressibility of water, $c_f = 4.58918 * 10^{-10} Pa^{-1}$ at 20^oC and 1 atm pressure. Here V is the total volume in the hose, $V = l * A$ =0,2565m^3.

While, pressurizing the system to its limit, the system, will experience a variation in pressure up to 16 bar. Then, $dV = 4,58918 * 10^{-10} Pa^{-1} * 0,2565 m^3 * 16 * 10^6 Pa = 1,88 * 10^{-4} m^3$. Hence, the system will compress a volume of 1,88 dl. The compressed-/total volume-ratio is then, $dV/V = 1,88 * 10^{-4}/0,2565 = 7,3 * 10^{-4}$, which corresponds to a change of 0,073%.

It should be noted that the system is not designed, with respect to pressure variations, (see chapter 3.3) to be exposed to pressure variations of more than 5 bar. Resulting in a compression of 0,6 dl or 0,023%. Of the total maximum flow, 0,6 dl is $0,06/1,2 = 0,05$. In other words 5% of the maximum flow may be compressed rather than displaced. The compressibility will be further discussed in chapter 3.4.

Expansion of the hose may be considered the same as having a more compressible fluid, when it is subjected to various pressures, as the change of volume will be larger than that of the fluid alone. The expansion of the hose is, however, not obtained yet. The effect of this expansion will be discussed in more detail in chapter 3.6, Sources of Error.

3.3 Pressure Variations

As previously mentioned, the movement of the string is what creates the pressure variations downhole. The pressure variations are referred to surge and swab pressures, created by flow as the string is displacing more and less fluid, respectively. The majority of the pressure losses the control system is to equalize, is created over the bottom hole assembly (BHA), as this is where the string has the smallest annular clearance.

The diameter of the hole and the diameter of the upper string was decided to be 42,6 mm and 25 mm in the beginning of the project. The parameters were scaled down with the same ratio between the cross-sectional areas. They were also chosen because of the availability, as they are standard sizes and easy to procure. The maximum velocity is presented in chapter 3.1.1. The diameter of the BHA was calculated on the basis of creating the wanted pressure drop

Property	**Value**	**Unit**
Length BHA	330	mm
Diameter BHA	40,9	mm
Diameter hole	42,6	mm
Diameter upper rod	25	mm
Diameter lower rod	24,4	mm
Maximum velocity	0,86	m/s
Density	998,2	kg/m^3
Viscosity	1,002	cp

Table 1: *Parameters used in Calculations*

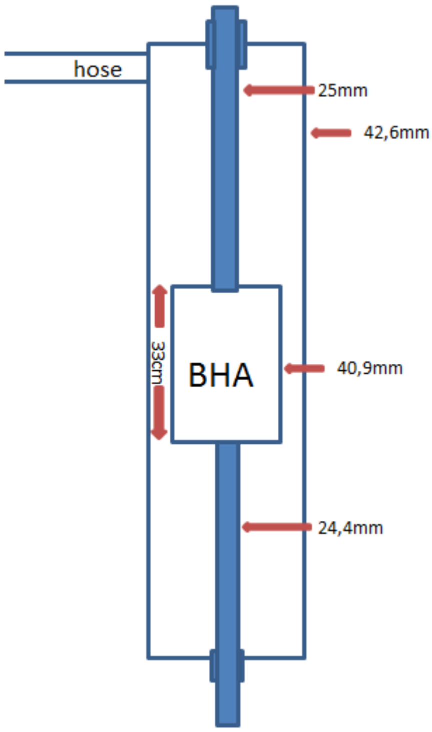

Figure 3.6: *Figure of the model, with parameter values, same as presented in table 1.*

of 2 bar over the BHA. This pressure drop was decided based on producing a sufficient security factor with respect to the equipment used in the model.

3.3.1 Clinging effect

When presenting the pressure variations it is important to consider how the volumetric flow has been calculated. The clinging factor is thought to have an impact on the flow. The clinging factor does, however, not present a vast contribution to the total flow.

The clinging factor is created in the hole by the movement of the string, and as the string moves, the fluid will follow. This is validated by "no-slip". No-slip at the wall, or V(r = b) = 0, is normal to assume with flow in a pipe, where b is the radius of the pipe. As we have annular flow it is also intuitive to assume that the velocity of the flow, relative to the string, also will be zero at the wall of the string, $\hat{V}(r = a) = 0$, where a is the radius of the string and $\hat{V}$ is velocity of the fluid relative to the string. Therefore, as the string has vertical movement, fluid will follow this movement in a layer around the string. We have assumed this layer to be linearly decreasing with respect to distance from the string, and that the length of the affected area is 10% of the length of the annulus. (Skalle, 2011)

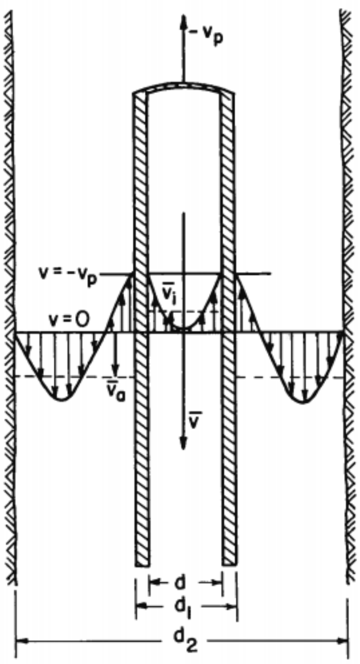

Figure 3.7: *The figure shows flow pattern when a drillstring is pulled out of the hole. The clinging effect causes an inner layer of the fluid to follow the drillstring uppward. (Bourgoyne et al., 1986)*

The displaced fluid is always flowing in the opposite direction of the movement of the string. In order to equalize the flow due to clinging, the same amount will be added to the flow due to displacement, thus fulfilling material balance. The majority of the studies done on this phenomena, is done on fluids following other rheological models than newtonian, which is the case here. These studies do, however, indicate that the velocity profile of the fluid, in turbulent flow, is independent of rheology. (Burkhardt, 1961)

The clinging factor will result in a larger flow, and consequently lead to a higher pressure drop. To calculate the pressure drop for the different layers, with different properties, would be demanding and is full of uncertainties. The assumption that all flow, in any direction, contributes to a pressure drop, simplifies this task. The total flow used to calculate the pressure drop is

$$Q_{tot} = Q_{disp} + 2 * Q_{cling} \tag{3.7}$$

Where Q_{tot} is the total flow, Q_{cling} is the flow created by no-slip at the wall of the string and Q_{disp} is the flow due to displacement of fluid, which is

$$Q_{disp} = v * \frac{\pi}{4}(D_{BHA}^2 - D_{lowerrod}^2) \tag{3.8}$$

where v is the velocity of the string.

The clinging factor is assumed to be linearly decreasing with respect to distance from the string. And it is assumed to have the same velocity as the the string at the wall. With these assumptions we can calculate the average velocity of the flow, with the flow equal zero at the end of the affected area, and the same as the string at the wall. With these assumptions, the average velocity of the fluid in the affected area is equal to $\frac{Vstring}{2}$. Q_{cling} then becomes

$$Q_{cling} = \frac{V_{string}}{2} * \frac{\pi}{4} * ((D_i + (D_o - D_i) * 0,10)^2 - D_i^2) \tag{3.9}$$

where D_i is the inner diameter or diameter of string/BHA, and D_o is the diameter of the hole.

At maximum velocity the contribution of the cling to total flow is approximately 3,2% of the total flow, where the total flow is $7,39 * 10^{-4} m^3/s$.

3.3.2 Friction loss over BHA

As previously mentioned, the pressure loss through the annulus of the BHA will be higher than the rest of the annulus. Because of the relatively small clearance,the fluid will have a higher velocity, there will be a larger area in contact with the flow, resulting in higher internal strain in the fluid.

The first thing one needs to do when working flow, is to investigate whether we have a turbulent or laminar flow, in order to be certain to use the correct assumptions and equations as laminar and turbulent flow may act differently. When a flow has a Reynolds number higher than 4000 it is considered to be turbulent. The Reynolds number is calculated from

$$Re = \frac{\rho * v * D_H}{\mu} \tag{3.10}$$

Where ρ is the density of the fluid, v is the average velocity, μ is the viscosity of the fluid. D_H is the hydraulic diameter, which is given by

$$D_H = \frac{4 * A}{P} \tag{3.11}$$

Where A is the area and P is the wetted perimeter. Which for annular flow is $D_H = D_o - D_i$. And v is the average velocity, given by

$$v = \frac{Q_{tot}}{A_{annulus}} = 6,36m/s \tag{3.12}$$

Q_{tot} is defined in equation 3.7 and includes the clinging factor which affects the average velocity. The Reynolds number is $Re = 11257$, which clearly is turbulent.

For stable, turbulent annular flow the pressure loss is, in field units, given by

$$\frac{dp_f}{dL} = \frac{\rho^{0,75} * V_{avg}^{1,75} * \mu^{0,25}}{1396 * (d_2 - d_1)^{1,25}} \tag{3.13}$$

where dp_f is the pressure loss, dL is the length, ρ is the density of the fluid, V_{avg} is the average velocity, μ is the viscosity, d_2 is the outer diameter and d_1 is the inner diameter.

At a temperature of 20^{o}C, the viscosity, μ, of water is 1,002cP, or 0,001002 Pas and the density of water is 998,2kg/m^3. With length of the BHA,

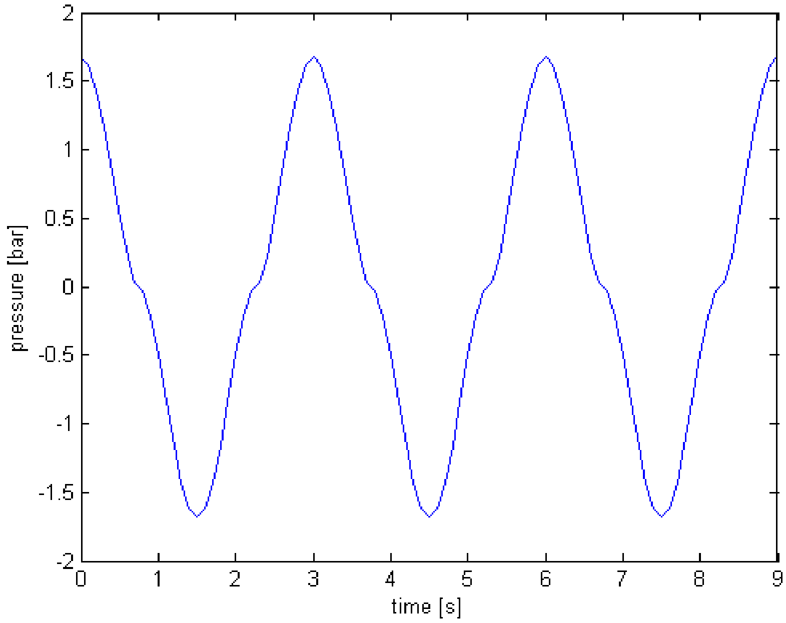

Figure 3.8: *Friction loss over BHA.*

L_{BHA} = 0,33 m, an inner diameter, $d_1 = D_{BHA}$ = 40,9 mm, and outer diameter, $d_2 = D_{hole}$ = 42,6 mm, the pressure drop due to friction over the BHA becomes **1,691 bar**.

3.3.3 Entrance and Exit losses

When a flow goes form a pipe with one cross-sectional area to another it will be accelerated, and this acceleration will lead to higher pressure losses than one would see if flowing in a medium with constant shape and cross-sectional area. When the flow enters a smaller area, it is here referred to as entrance loss and when it enters a annulus with larger cross-sectional area it is referred to as exit loss. What happens is that the stable flow is disrupted and it will take some length of flow before it is once again stable, referred to as entrance length, L_e. Under this length, in which the flow matures to reach a steady form, it is under a regime where it has higher pressure losses than it would if stable. (White, 2008)

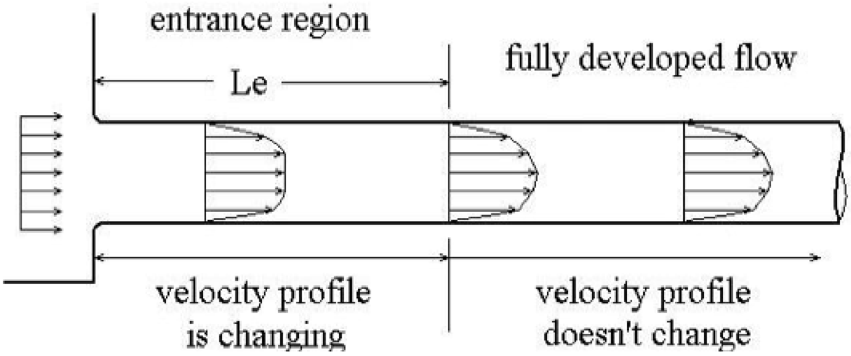

Figure 3.9: *Development of flow going from on diameter to another.*

In order to maintain wether the flow gets fully matured over the BHA, one needs to estimate the entrance length of the flow. If the entrance length is shorter than the length of the BHA, one has significant proof that the entire calculated entrance loss will occur.

The entrance length,L_e, is affected by the Reynolds number and the diameter. For turbulent flow the entrance length is estimated to be

$$\frac{L_e}{d} = 4,4 * Re_d^{1/6} \tag{3.14}$$

where d is the hydraulic diameter.

With a Reynolds number of 11290 and a hydraulic diameter of 1,7 mm, the entrance length will be 0,035 m, which is well within the length of the BHA, one can therefore confirm that the entrance loss can be calculated without reductions. Over the BHA there will be no doubt as to wether the flow gets stable as it has a lower Reynolds number and a longer distance to get stable.

As the calculation of the pressure drop over the entrance regime would be extensive, for the purposes of this project, one has chosen to use empirical formulas.

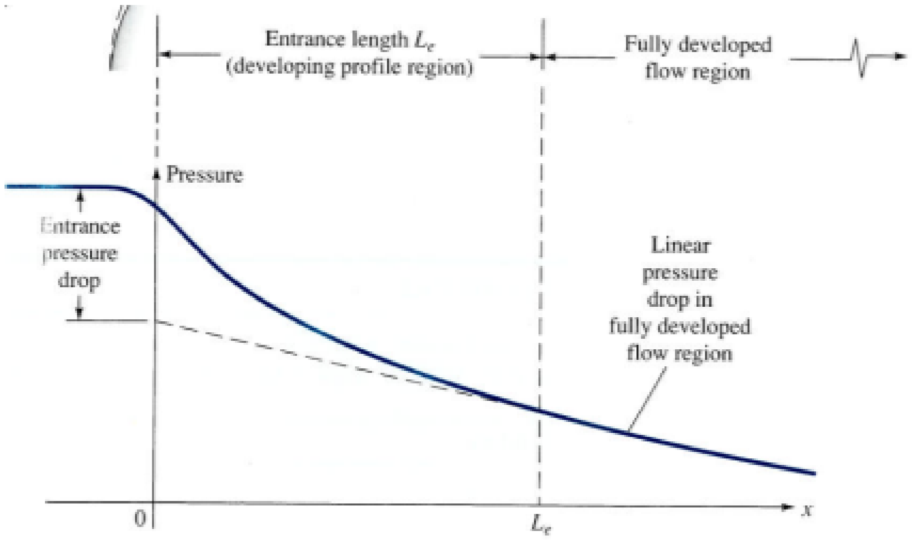

Figure 3.10: *Entrance loss combinded with friction loss.*

For variations in equivalent cross-sectional areas, $d/D > 0,76$, the entrance loss will follow the same regime as for an exit loss. d and D is the hydraulic diameter of the smaller and larger annulus, respectively. The hydraulic diameter is 1,7 mm over the BHA, 17,6 mm for the upper annulus and 18,2 mm for the lower annulus. The d/D-ratio for entrance from lower annulus to the BHA then becomes 1,7/18,2 = 0,093, which is << 0,76. This is not under the same regime as exit losses (figure 3.11).

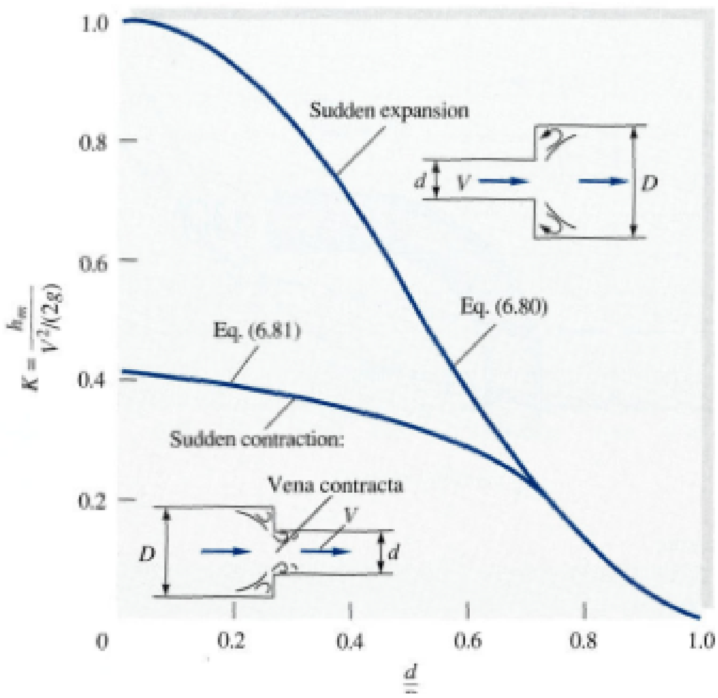

Figure 3.11: *Coefficients for sudden contraction and sudden expansion.*

The entrance loss for sudden contraction is given by

$$K_{SC} = 0,42(1 - \frac{d^2}{D^2}) = \frac{h_m}{V^2/(2 * g)} \tag{3.15}$$

where K_{SC} is the coefficient for sudden contraction.

The exit loss for sudden expansion is given by

$$K_{SE} = (1 - \frac{d^2}{D^2})^2 = \frac{h_m}{V^2/(2 * g)} \tag{3.16}$$

where K_{SE} is the coefficient for sudden expansion, where d is the smaller diameter, D the greater diameter, h_m the velocity head loss and g the gravitational constant. (White, 2008)

The loss for coefficient for sudden contraction, K_{SC}, is

$$K_{SC} = 0,42(1 - \frac{d^2}{D^2}) = 0,416$$

giving a maximum pressure loss of **0,091bar**. Figure 3.12 shows how the entrance pressure loss varies with time.

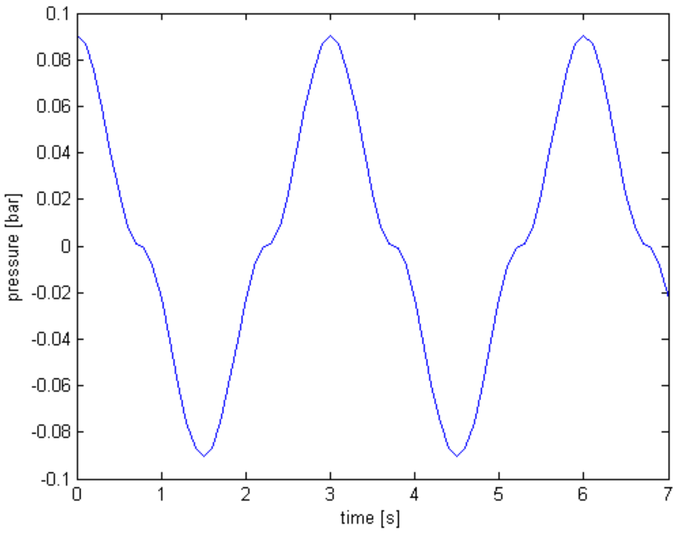

Figure 3.12: *Entrance loss for the model varying with the velocity of the string*

The coefficient for sudden expansion, K_{SE}, is

$$K_{SE} = (1 - \frac{d^2}{D^2})^2 = 0,98$$

which gives a pressure drop of **0,215 bar**. Figure 3.13 shows how the exit pressure loss varies with time.

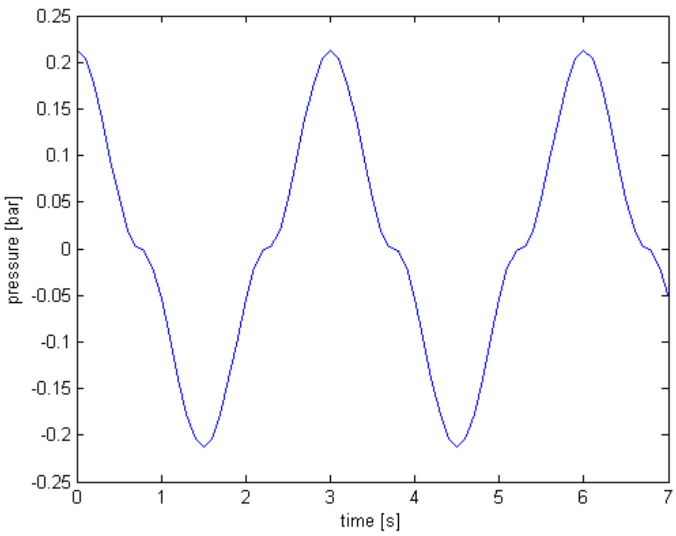

Figure 3.13: *Exit loss for the model varying with the velocity of the string*

From equation 3.15, 3.16 and figure 3.11 it is clear that the exit loss will be higher than entrance loss, when $d/D < 0{,}76$, which is the case here. Figure 3.14 illustrates the difference of the two functions plotted in with the same scale.

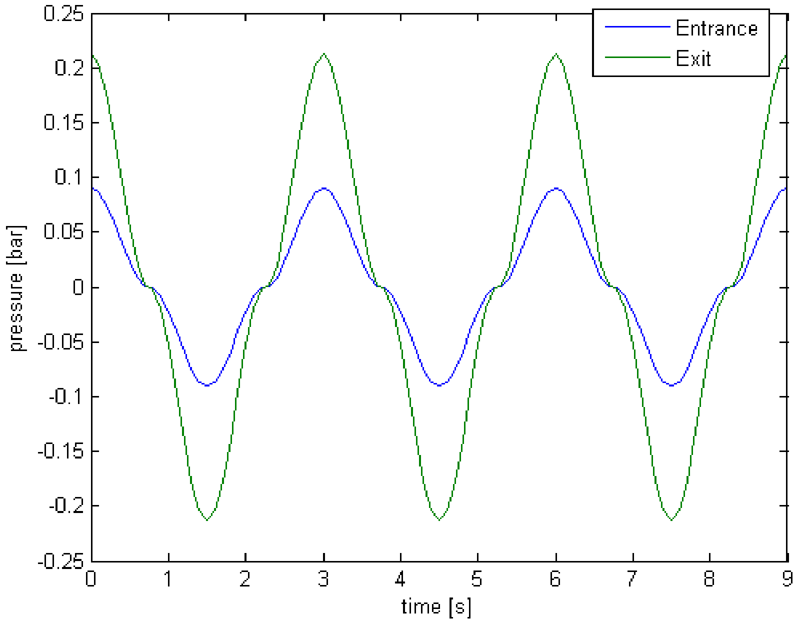

Figure 3.14: *Entrance loss and exit loss on same scale.*

The combination of the loss due to friction, entrance and exit losses are assumed to be representative for the actual pressure loss for the BHA. The sum of the three is **2,00 bar**. The variation with time is presented in figure 3.15.

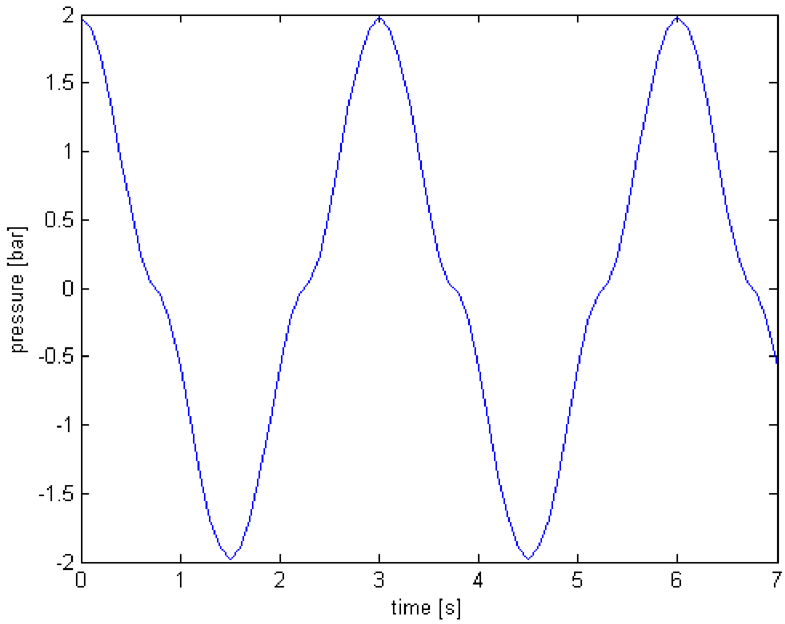

Figure 3.15: *Total loss over BHA.*

3.3.4 Annulus

In the lower annulus there is no displacement of fluid. The pressure loss will therefore be defined by the clinging factor only. This makes the fluid, in direct contact with the string, form a layer with flow in the same direction as the string. In order to maintain mass balance there will be a flow outside the clinging area, in the opposite direction. However, as the clinging area is small, relative to the area not influenced by the clinging factor, the fluid velocity in this part will be too small to create measurable losses.

In the annulus above the BHA, we will have a flow defined by the clinging factor, as well as the displaced fluid. If we assume a clinging factor of 10% the area influenced by clinging will be $A_{cling} = \pi/4*((D_i+(D_o-D_i)*0,10)^2-D_i^2)$, and the area not influenced by clinging will be $A_{total} - A_{cling} = \pi/4*(D_o^2 - (D_i+(D_o-D_i)*0,10)^2)$, where D_o is the outer diameter and D_i is the inner diameter.

The outer diameter is 42,6 mm and the inner diameter is 25 mm. If we then assume a linear relationship between fluid velocity and distance from the string, flowing in the same direction as the string, at a velocity of 0,857 m/s, the flow will become: $Q_{cling} = A_{cling} * 0,857/2 = 1,25 * 10^{-4} m^3/s$. This will again create a flow going in the opposite direction to equalize the clinging effect. With the assumption that both flows contribute to a pressure drop, it is assumed that the absolute value of the flows will be the total flow, to calculate the pressure drop. The average velocity will then be the total flow divided by the area of the annulus.

$$v_{avg} = \frac{2 * Q_{cling} + Q_{displaced}}{A_{annulus}}. \tag{3.17}$$

With a D_o of 42,6 mm, D_i of 25 mm and when the lower rod is 24,4 mm, the average flow velocity is 0,105 m/s. This creates a pressure drop of 0,0006 bar, which is negligible. Even without the lower rod, the velocity in the upper annulus would be relatively low, not creating more than a pressure drop of 0,003 bar. One can therefore conclude that the pressure drop in the annulus is negligible, with or without the lower rod.

3.3.5 Hose

As previously mentioned there will be a 900 m long hose between the choke system and the hole-string-system. And through this hose there will be flow due to displacement of fluid as the string moves up and down. When the string moves at maximum velocity, it creates the largest flow rate, which is of most interest when designing the system. At maximum velocity the string displaces

$$Q_{disp} = v_{string} * \Delta A_{cross-sectional} = 0,859 * \frac{\pi}{4} * \frac{25^2 - 24,4^2}{10^6} = 1,2 l/min$$

First we need to investigate wether we have a turbulent or laminar flow in the hose. If the flow has a Reynolds number lower than 2300 it is considered to be laminar, larger than 4000 the flow is fully turbulent. Reynolds number is calculated from equation 3.10, and gives a value of 1333. Thus, the flow is laminar.

The flow results, in a 3/4" pipe, in a velocity of 0,082m/s. To calculate the the pressure drop through the hose, at maximum velocity we have used the following equation

$$\Delta p = \frac{f * d * \rho * v^2}{2 * L} \tag{3.18}$$

where d is the diameter of the pipe, equal to 0,01905 m, ρ is the density of the fluid, equal to 998,2 kg/m^3, v is the velocity of the fluid, and L the length of the hose. For laminar flow the friction factor is independent of the roughness of the hose, and is expressed by the Darcy friction factor for laminar flow,

$$f = \frac{64}{Re} \tag{3.19}$$

With the values given above, we will see a pressure drop of 0,065 bar through the hose. This pressure variation will also be compensated for by the choke.

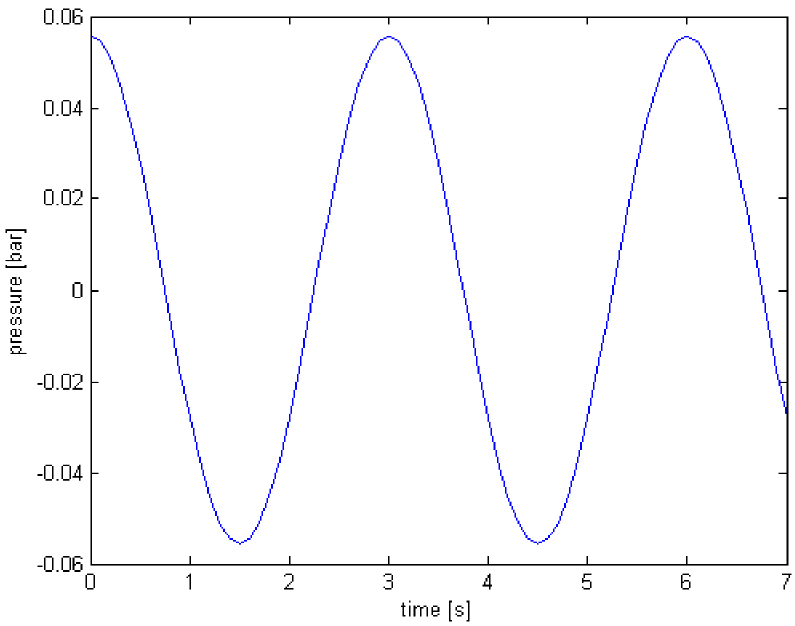

Figure 3.16: *Friction loss in hose.*

The hose will consist of sections from 25 m to 120 m, which would give, a maximum of 36 and a minimum of 8 sections, respectively. These sections will be connected through a pipe with larger diameter and glued inside that pipe. It is not expected that these connections will add any pressure drop as they will be connected on the outside, without locally reducing the inner diameter of the hose.

3.3.6 Acceleration

The acceleration of the flow will be governed by the acceleration of the string (equation 3.20, figure 3.17). Flow into the system, is defined as the positive direction. Hence, the acceleration is positive when increasing the influx, or reducing the outflow of water. The acceleration of the string is

$$a(t) = \frac{d^2 z(t)}{dt^2} = -\frac{0,41 * \pi^2 * 2^2}{3^2} \sin \frac{\pi * 2 * t}{3} \tag{3.20}$$

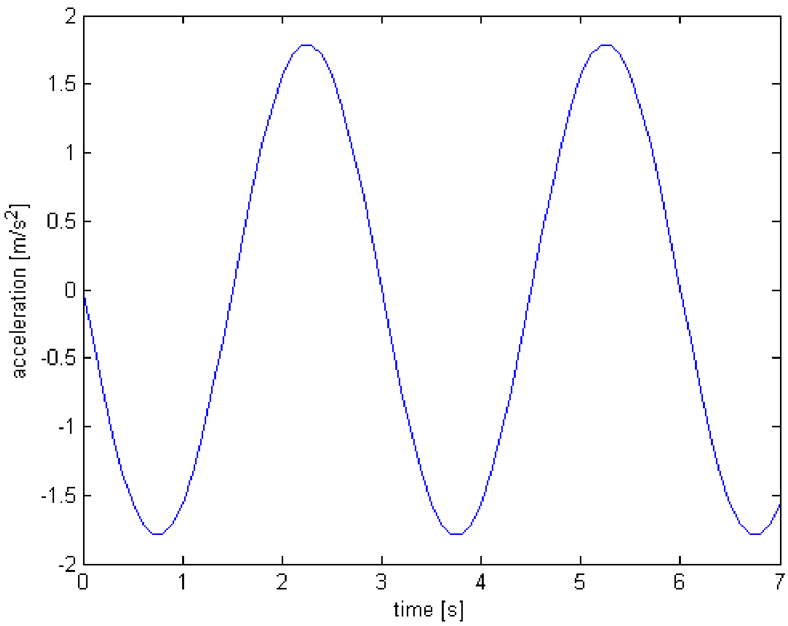

Figure 3.17: *Acceleration plot*

When $sin(2 * \pi * t/3) = -1$, the acceleration is at its maximum, which is the case for t = [9/4, 21/4, 33/4...]. When $sin(2 * \pi * t/3) = 1$, the acceleration is at its maximum in the other direction, this occurs when t=[3/4, 15/4, 27/4...]. From equation 3.20, the maximum and minimum acceleration is $1,798 m/s^2$ and $-1,798 m/s^2$, respectively. This acceleration is, however, only proportional to the acceleration of the fluid in the hose. The movement of the fluid is generated from a smaller area than where the fluid flows. The difference in area between the two rods is the basis for the displacement:

$$\Delta A_{rods} = \frac{\pi}{4}(D^2_{upperrod} - D^2_{lowerrod}) \tag{3.21}$$

Where it is decided that the upper rod should have a cross-sectional area 5% larger than that of the lower rod. This gives the area, $A_{lowerrod} = A_{upperrod} * 0,95$, which yields $D_{lowerrod} = \sqrt{D^2_{upperrod} * 0,95.}$, with $D_{upperrod} = 25mm$, $D_{lowerrod} = 24,37mm$, with these values $\Delta A = 24,4mm^2 = 2,44 * 10^{-5}m^2$.

The diameter of the hose, D_{hose}, is 3/4", gives a cross-sectional area, $A_{hose} = D^2_{hose} * \pi/4 = 28,5 * 10^{-5}$. The acceleration of the fluid in the hose is directly proportional to the ratio of the respective areas. The derivative of the volumetric flow is the same for both the flow in the hose and the flow displaced by the string. Which yields

$$\frac{dQ}{dt} = \frac{dv(t)}{dt} * A = a_i * A_i \tag{3.22}$$

where i indicates whether it is the string or the hose. This means that the relationship between the unknown acceleration in the hose is directly proportional to the acceleration of the string, with respect to the areas of flow.

$$a_{hose} = \frac{A_{string}}{A_{hose}} * a_{string} \tag{3.23}$$

Where a_{hose} is the acceleration of the fluid in the hose, a_{string} is the acceleration of the string displacing water, A_{hose} the cross-sectional area of the hose and A_{string} is the area displaced by the string. Inserting maximum acceleration of the string in eq. 3.23 we get $a_{hose} = \frac{2,44*10^{-5}m^2*1,7980m/s^2}{25,5*10^{-5}m^2} = 0,1539m/s^2$.

The force, F, acting on the fluid in order to accelerate the fluid in the 900 meter long hose is given by Newtons second law of motion, $F = m * a$. The mass needed to be accelerated is $m = \rho * L * A_{hose}$, where L is the length of the hose. The difference in force acting on the fluid from both sides of the hose is equal to the pressures divided by the area:

$$\Delta F = \Delta P * A = m * a$$

$$\Delta p * A = \rho * L * A * a$$

$$\Delta p = \rho * L * a \tag{3.24}$$

This gives a difference in pressure of 1,38 bar. It is important to remember that the maximum acceleration occurs when the velocity of the string is zero, as they both are cosine and sine curves, respectively, of the same product of t. This simplifies the problem with handling both pressures simultaneously, when one is at the maximum, the other is zero.

The variations in difference in pressures for acceleration, over three cycles, is presented in figure 3.18.

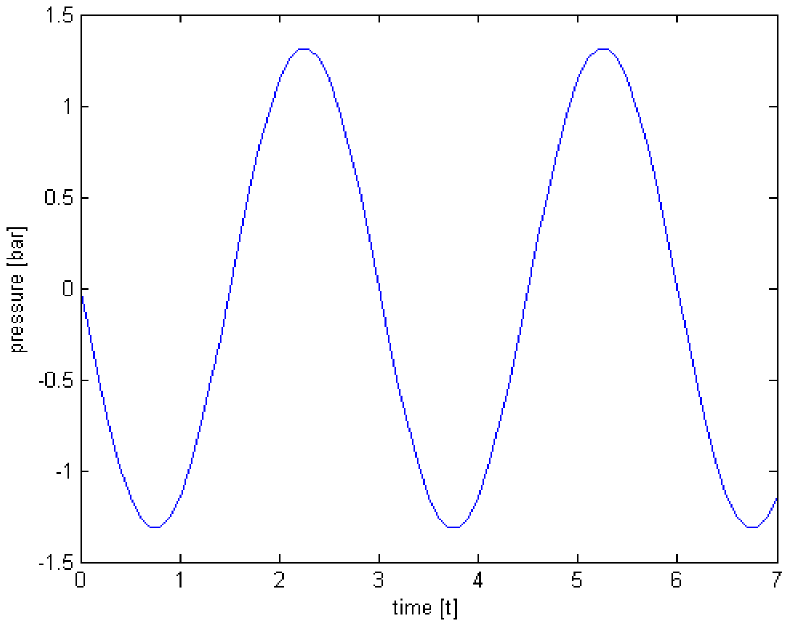

Figure 3.18: *Variation in pressure needed to accelerate the fluid in the hose.*

3.4 Compression

When increasing pressures are exerted on a fluid in a closed system, the fluid will be compressed. The compression is given in 3.2.2. In this chapter we will examine what happens with the pressure of the system when there is no water out flux through the choke and the mud pump is shut off. The change in volume, dV, will then be the difference in area between the two rods multiplied by the amplitude of the heave. $dV = d_{upper}^2 - d_{lower}^2 * \pi/4 * L$, where L is the amplitude equal to 82 cm. $dV = 1,9 * 10^{-5} m^3$. The total volume is, as previously mentioned, $V = 0,2565\ m^3$, and the compressibility of water is $c_f = 4.58918 * 10^{-10} Pa^{-1}$. The change in pressure in the whole system is give by 3.25, which gives a value of 1,62 bar.

$$\Delta p = \frac{dV}{V * c_f} \tag{3.25}$$

If the control system was to fail, in accurately compensating for the movement of the string, the lower annulus could see a large compression (dV/V), when the string is moving downward, as the fluid would be compressed rather than to flow through the annulus over the BHA. Due to the small volume, small change in volume (dV) could lead to a large pressure variation in BHP.

3.5 Modeling of Expected Data

In the previous parts of this chapter it has been focused on the maximum velocity, with corresponding pressure loss. In this subchapter the pressure variations for a complete cycle will be presented.

First to show the dissimilarity between the losses over the BHA and the difference in pressure needed to accelerate the fluid, figure 3.19, shows the two plots in the same window.

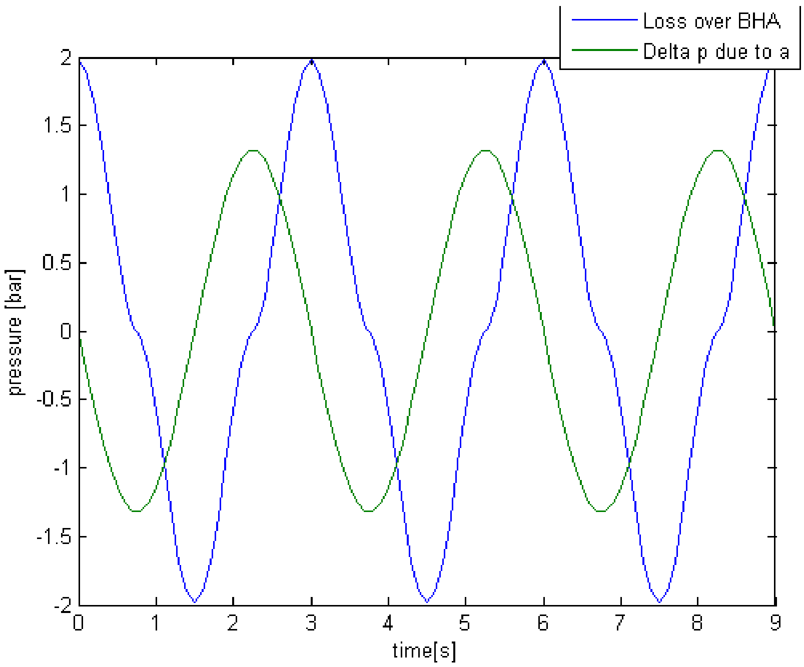

Figure 3.19: *Shows the separate contribution to variations in pressure the control system needs to compensate for.*

In figure 3.19, the loss over the BHA is a combination of the friction (eq 3.13), entrance (eq 3.15)) and exit loss (eq 3.16), and the difference in pressures needed to accelerate the fluid in the hose (eq 3.24) is presented.

The loss over the BHA and the acceleration can be added together and with the inclusion of the friction loss in the hose (eq 3.18 and figure 3.16), they define the change in BHP when the choke pressure is kept constant. In figure 3.20, the pressure at the choke is set to be 6 bar.

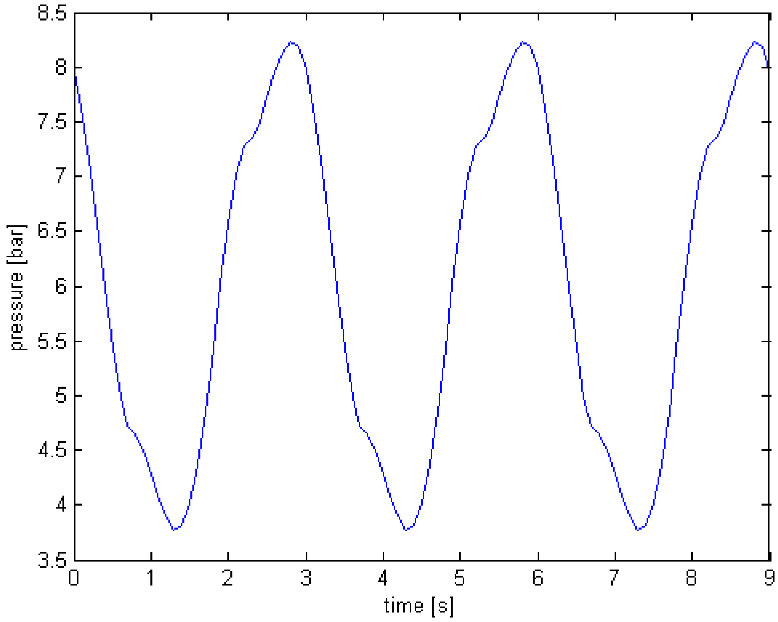

Figure 3.20: *The figure shows variations in BHP with a constant back pressure at the choke of 6 bar.*

3.6 Sources of Errors

As mentioned in chapter 3.2.1, the temperature is very dependent on the temperature. This effect on the viscosity may be a source of error in what is calculated and what is actually observed. A change in viscosity is directly proportional to variations in the calculated pressure loss from the flow through the hose. Potential variation in viscosity, as a consequence of variation in temperature, is reduced with respect to the calculated pressure loss over the BHA, as the viscosity, in equation 3.13, is expressed in the power of 1/4. This reduces the effect of changes in temperature. Here, a -2^{o}C or +2^{o}C change will only lead to a a variation of + 1,2% and - 1,2%, respectively.

The flexibility of the hose is, at the time of writing, not yet obtained, but could be severe to the flow through the choke. With a too flexible hose, the fluid would expand the hose rather than to be displaced, leading to a flow through the choke, too low for the control system to work effectively. The flexibility of the hose should be obtained by supplier or tested, to map out wether it would influence the flow or not.

There has been taken a few assumptions in this project, and these assumptions may not be correct. The clinging factor is one of them. The fact that clinging will take place as the BHA is displacing fluid and turbulent flow is developed around it, is significantly documented. The area affected by the clinging effect, however, is not well defined. And further study should be done to find a value with more certainty. As previously mentioned, a clinging factor of 10% does only contribute by a factor to the total flow of more than 1,037. The consequence of having an incorrect clinging factor would therefore not affect the outcome much.

4 Development of the Rig Model

The design of the lab model has changed several times as the project has been carried out. This chapter presents the changes made based on the calculations and assumptions presented in chapter 3.

4.1 Proposed Rig Model

Figure 4.1 shows the first lay out of the MPD system to be built in the lab. A winch operated by a motor was suggested to generate the heave motion with an amplitude of 3 m (+/-1.5 m). The drillstring is connected to a wire from the winch and moves vertically up and down in a pipe where the annulus is sealed. The inflow of the drilling mud is provided by the main mud pump and flows through the drillstring and up the annulus and back to the mudpit. The outflow is controlled by a choke valve, supported by a backpressure pump, to provide sufficient flow through the choke.

In the field, the mud is pumped through the drillstring, the bit and up the annulus during drilling. During connections, the rig pump is ramped down before the drillstring is suspended in slips and starts to move vertically up and down due to the heave motion. A non-return valve in the drillstring avoids backflow through the drillstring. In this model there was no delay form the string-hole system to the control system, with choke and back pressure pump.

4.1.1 Challenges and Solutions

The idea, on which the project was based, is a simplified, but still quite similar version to a normal drilling operaiton where the BHA is the lowest part of the drillstring. The string were meant to follow the heave motion, of the floating rig, up and down, causing pressure drop and displacement flow. However, the inclusion of the 900 meter long hose, needed to make the model more realistic (chapter 3.1.2), presented a problem with the corresponding pressure drop there would be through that hose. There would be a maximum displacement of $Q = v_{max} * \pi/4 * D_{string}^2 = 26,1 l/min$. To be able to handle such a flow, the diameter of the hose would have to be at least 1", and capable of handling such a pressure. In hindsight, it was discovered that an even larger problem is the variation of difference in pressure in order to accelerate the fluid. One would need a difference of 15,7 bar, at the outlet and at the inlet of the hose. This variation is unpractical to achieve within

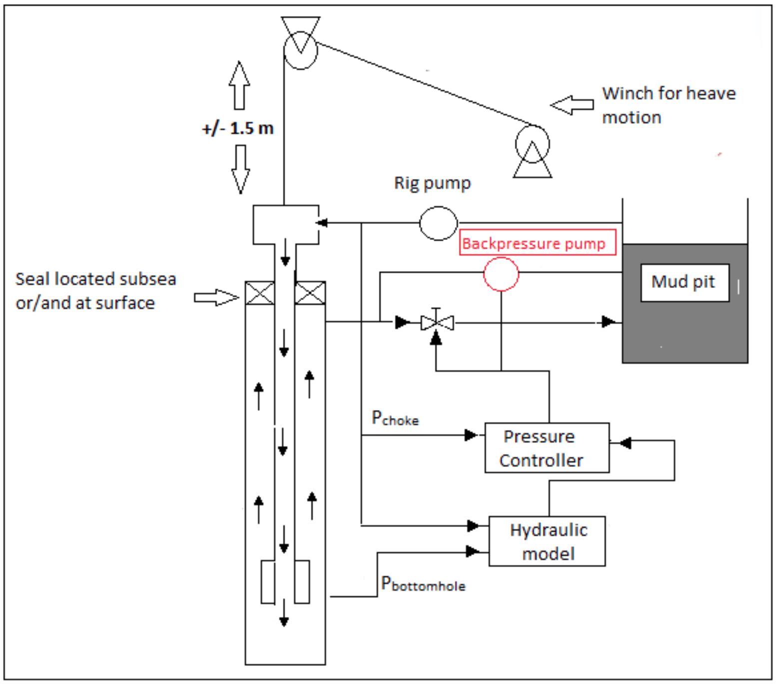

Figure 4.1: *Figur tekst*

our budget. We also want the string-hole system to be transparent, and transparent material with a working pressure above 31,4 bar is not easy to procure. The actual working pressure would have to be higher than 31,4, as we would need a safety factor. The reasoning behind, and the equations used for the acceleration calculations is presented in larger detail in chapter 3.20.

As there was no means of stabilizing the string, one could experience instabilities in the hole, as the string could move relatively freely. Because the first model also included a mud pump, the string would need to be hollow, and the stiffness of the string would be quite reduced relative to a rod. By having the string move off centrum of the hole, one could also see a variation in created pressure, as the hydraulic diameter would vary. A practical problem would also be to force the string down in the wanted velocity as it would meet a significant resistance from the difference in pressure on the upper and lower side of the BHA. When moving the string downward at maximum velocity, the desired difference in pressure over and under the BHA would be 2 bar.

To analyze the problem with forcing the string down the whole, lets, for convenience, say there was no additional BHP than the difference due to flow over the BHA. Thus, excluding the complexity of the difference in cross-sectional areas of the upper and lower side of the BHA (due to the string being attached on the upper side). The gauge pressure under the BHA is then 2 bar. Over the BHA it will be atmospheric pressure. The force acting upward on the string is then $F = p * A$, where A is the area of the BHA, calculated from the parameters given in table 1. The force is 262,7 N. The weight of the string would be

$$W = m * g = \beta * l * A * \rho * g \tag{4.1}$$

where l is the length of the pipe, $\beta = 1 - 998,2/7840 = 0,87$ is the buoyancy factor, ρ is the density of steel, 7840kg/m^3 and A is the cross-sectional area of the pipe. Which, with a wall thickness of 0,2", is 3,14$*10^{-4}$. The weight is then $21N$. The string would need to be pushed down the hole with a force

$$F = m * a + 262,7N - 21N + friction \tag{4.2}$$

At maximum velocity, when we have the 2 bar difference, the acceleration, $a = 0$, and the force would then be $F = 241,7N + friction$. This force would be even higher if there were included a BHP higher than 2 bar. The actual BHP would work on an area on the bottom side of the BHA, not worked against on the upper side, as the corresponding area is covered by the drill string, subjected to atmospheric pressure. This force could be enough to, if not buckle, bend a significant amount, of the relatively thin pipe, depending on the length of unsupported pipe. The bending could influence the velocity of the BHA as some of the traveling distance would be replaced by bending of the drill pipe, especially at maximum velocity. If the drill pipe were to bend, the drill pipe and the BHA would no longer be parallel to the hole, leading to a locally increase and decrease of the hydraulic diameter, creating pressure variations differing from the expected.

4.2 Second Design

The first action to meet the challenges met in the first proposed design was to exclude the mud pump. This project was to test for surge and swab, during connections when subjected to heave. As, during connections there, normally, is no flow, unless there is a continuos circulating system, which is not the case here. The mud pump did not serve any purpose. When the mud pump was removed there was no need for the drill string to be hollow, as no flow was to be pumped through it. The pipe was replaced by a rod, which offers more stability.

Two solutions were suggested to overcome the problem with high pressure losses in the pipe; increasing the diameter of the hose or reducing the displacement of fluid. The chosen solution was to, not only reduce the flow, but to eliminate the flow completely by introducing a rod under the BHA, of the same diameter as the rod above it. Both the problem with acceleration of the fluid and friction loss was eliminated. The thought was that the control system would be able to keep a constant BHP by detection of the pressure variation. The lower rod did not only remove the challenges of having a relative high flow, it was also the solution to the stability issues one might have seen without it. Not only would it be helpful as a point of stability, reducing the risk of bending, the string could then be pulled in alternating direction, rather than to alternate between pushing and pulling.

4.2.1 Challenges and Solutions

The lower rod was meant to be of the same diameter as the upper rod, thus maintaining a constant volume of solids in the hole. Which means there would be no displacement through the hose, only pressure waves, generated by flow over the BHA, would propagate through the hose. The problem with this was that the control system needed a flow in order to recognize the variations in the hole-string-system, in order counteract the pressure variations and keep a constant BHP. The pressure waves was not sufficient information to get the job done. To oblige the request of flow, the idea of still including the lower rod, but with a lower cross-sectional area was presented. The upper rod would still have a diameter of $D_{upperrod}$ = 25 mm and the diameter of the lower rod was decided to be, $D_{lowerrod}$ = 22 mm. This would give a flow through the hose of 6,5 l/min.

With a $D_{lower-rod}$= 22 mm, and a hose diameter, D_{hose}= 3/4" the pressure drop through the hose would be 1,17 bar. A problem then realized was that the acceleration of the fluid would demand a difference in pressure of 7,2 bar, which, as for the case of the first design, is too large for the system. The idea of increasing the diameter of the hose could be a solution to this problem. The possibility of reducing the flow was also evaluated. It was found that the control system did not need a flow larger than 1 l/min in order to maintain a constant BHP.

The lower rod was selected to be 5% smaller in cross-sectional area than the upper, resulting in a flow of 1,2 l/min. With this flow the friction loss in the hose and the difference in pressures needed to accelerate the fluid was further reduced. The result was that the additional losses other than the loss over the BHA, only constitutes a small fraction of the total loss. By keeping the diameter of the hose the same, 3/4", this makes the system more adaptable to changes, as the system would allow an increase of the displacement, by introducing a slightly smaller rod beneath the BHA, or to increase the friction loss in the hose by introducing, a limited length, of smaller cross-sectional area of flow. Implementing this, would force the flow to accelerate, and consequently a loss will take place. The pressure loss due to acceleration, can be expressed simplified by

$$\Delta p = \rho * v * \Delta v \tag{4.3}$$

where v is the velocity of the fluid before the change, and Δv is the change of the of velocity. As the flow will have such a low velocity in the hose there will be a great reduction in diameter to achieve larger values i pressure loss due to acceleration. If the reduction of the diameter was to be reduced for longer lengths of the hose, there could also be produced larger losses due to friction.

5 Final Design

A final set up is presented in figure 5.1.

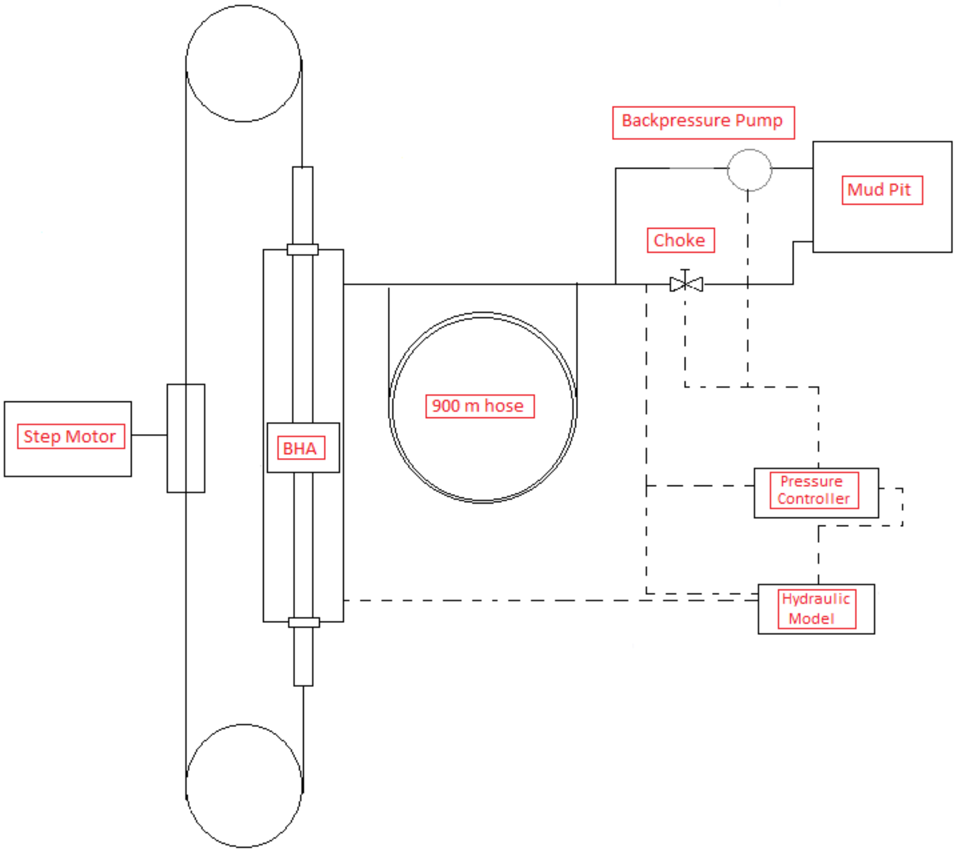

Figure 5.1: *Final model.*

5.1 Control System

The automated MPD system which automates the choke manifold control is consisting of a hydraulic model and a pressure control system. The hydraulic model estimates the downhole pressure in real-time and outputs a desired choke pressure based on the desired downhole pressure. The pressure control system is automating the choke manifold so the desired choke pressure is maintained. Figure 5.2 shows the main parts of this automated system. This system has a similar setup to a control system developed by Kaasa et al.

(2011), where a simplified hydraulic model is used. Derivation and assumptions for this simplified hydraulic model capturing the dominating hydraulics of the well is not specified here, but can be found in the article "Intelligent Estimation of Downhole Pressure Using a Simple Hydraulic Model", Kaasa et al. (2011), published in IADC/SPE the spring of 2011.

The control system is developed by Hessam Mahdianfar and is using "Real-Time Windows Target" software, which is a software provided in MATLAB by Mathworks Co. It is used for Running Simulink® and Stateflow® models in real time on PC for hardware-in-the-loop simulation of control system algorithms. In addition for making the interface between computer and process we need two control cards. One input card for receiving and collecting measurements from sensors and gauges, such as pressure transmitter, flowmeters, the position of valves, in the process; and one output card for sending signals and commands to the actuators, such as pumps, valves. The input/output cards should be installed in PCI slots of the computer. The wiring is also necessary between the cards, sensors and actuators. Finally the MATLAB should be configured by setting the system's parameters. The control system

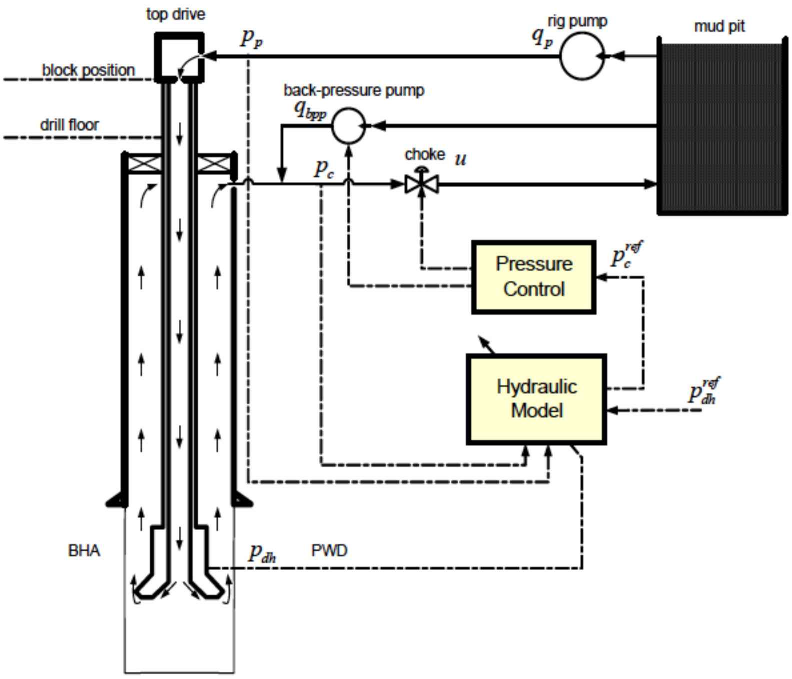

Figure 5.2: *Simplified illustration of an automated MPD system (Kaasa et al., 2011).*

applied in this model is similar a control system applied in a Well Control lab set up for MPD-model project carried out in Stavanger in the fall 2010 to spring 2011. This project was a cooperation between The University of Stavanger and IRIS and was presented Torsvik (2011) in his master thesis. The University of Stavanger as experienced that control cards from National Instruments in combination with Matlab and Simulink is a good solutions that works well for this purpose. Based on this it is decided to use the same vendor for control cards also in this project. Figure 5.3 shows an example of the interface between the control system (PC) and the process based on the Well Control Project in Stavanger.

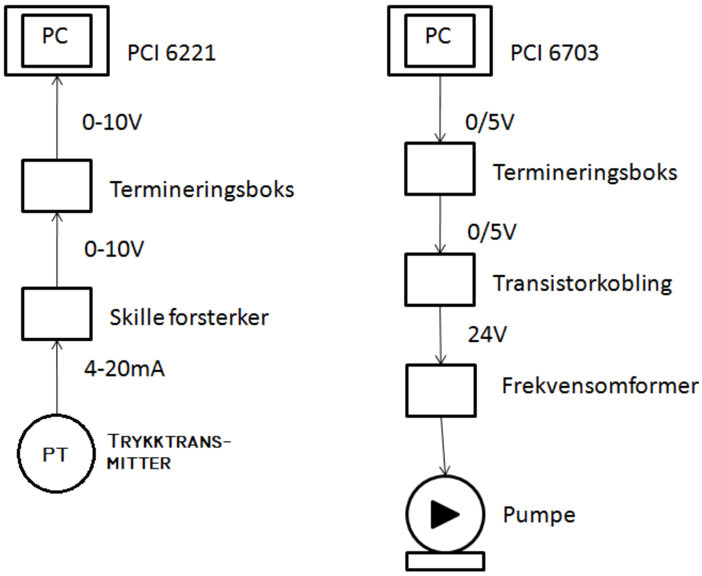

Figure 5.3: *Interface between control system and process. To the left: The levels from one pressure transmitter to the input card in the computer. To the right: the levels from the computer to the pump. (Torsvik, 2011)*

5.2 Choke and Pump

The maximum flow rate of the pump is 80 l/min. The pump needs to deliver a constant rate independent of the pressure at the outlet of the pump. A Triplex type Plunger pump is suggested to do the job, and is expected to do so satisfactory.

Opening time 0-100% is specified to 2-3 sec. A tailer-made choke, fit for purpose in this model, is to be designed by Jarle Glad. An alternative to this is suggested in Appendix 1.

Calculations regarding choke and back pressure pump is done by Samir Rashid and the information handed to us is given in Appendix 1. The choke opening needs to be

5.3 Hole and String

The hole will consist of a 1,9 m long PVC pipe with an outer diameter of 50 mm and a wall thickness of 3,7 mm. Yielding a inner diameter of 42,6 mm. This PVC pipe is in a standard size and can withstand a pressure of 16 bar. The rods will be made of steel. One will come in standard size of 25 mm in diameter, and the other will be made in the workshop and have a diameter of 24,4 mm. Both will be approximately 1,3 m long. The BHA will be made of PVC and will be 33 cm long and have a diameter of 40,9 mm. The BHA will be connected to the strings by excavating female threads on both sides of the it, making it possible to screw the upper and lower rod into it.

The hole is sealed on the top with a lid. This top will have a hole, the string will move through, sealed with an "o-ring" seal. On the top there should also be included a vent, through which, potential air in the system, can be circulated out. Beneath the top there will be a connection to the hose, and in this connection there will be a closing mechanism to the seal the hose from the hole, which will ensure that no air will go into the hose, if for any reason there should be need for maintenance in the hole.

On the bottom of the hole there will be, as on top, a seal to the atmosphere this bottom side as well. There should be possible to disconnect this part of the hole, in order to make it possible to make alterations inside the hole. I.e. to change the BHA or the lower rod. On the bottom side there will be, as on the top, a vent to help circulate out eventual air present in the system.

5.4 Hose

The hose connected to the hole, will, as previously mentioned be 900 m long. The hose is of "Gulslange 1"-type and has a working pressure of 15 bar. The inner diameter is 19 mm and the outer diameter is 27 mm. The hose will then occupy a volume of 0,515 m^3. For convenience, the hose will be coiled inside one or two barrels, to have a more tidy working area.

5.5 Pull Mechanism

The upper and lower rod will be connected to a wire, and pulled in alternating directions by the use of a step motor and two wheels. The step motor is calculated to need an effect of approximately 500 W [Rashid, S., Semester Project]. This motor will be controlled by a computer, and will pull the string in accordance with the position plot (figure 3.3 and eq 3.3).

6 Discussion and Future Work

The result of this project is thought to be a model, sufficiently realistic with respect to key variables, to simulate surge and swab pressures, and have a control system to compensate for these effects. There will be variation in pressure as the string moves vertically with variating velocity, and the model has a sufficient delay between the control system and the hole.

A dissimilarity between this model and the case in the industry, is that in our case more than 95% of the pressure loss due to friction is caused by the flow around the BHA. In the industry a larger part of the surge and swab pressures are due to flow in the annulus between the drill pipe and borehole wall, due to its long distance relative to the length of the BHA. The loss per unit length is in both cases largest for flow over BHA. This is, however, not thought to be destructive for the simulations, as there will be focus on the the control systems ability to compensate for changes in pressures based on flow through the choke and pressures measured at the choke. If needed, the system is adaptable to alterations when it comes to a locally increase in friction loss, in order to distribute the losses more realistically.

The applicability could be quite reduced with respect to different formations farther up the hole, as one might have a to high pressure increase over the BHA, in order to compensate for the surge and swab effects. This is dependent on the distribution of the friction losses as mentioned in the previous paragraph.

This project will continue the Autumn of 2012. The model will then be built and the control system will be tested. What needs to be done in between building of the model and now is to evaluate the hose, in order to make sure it rigid enough to withstand expansion in a satisfactory manner.

The compression of the water in the system is something that has to be studied in larger detail. It was previously thought that steady state was a valid assumption, however, this is proven to be false. The distribution of the compression and the effect of the compression needs to be calculated. These calculations should be simulated with respect to the variation in velocity of the drill string.

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APPENDICES

A Appendix 1

The list of procurement needed for this project is created by Samir Rashid and is given in this appendix. The list contains specs for the equipment, vendor and a prize estimate. In the end of the Appendix, there is also a preliminary budget.

The Choke:
-Control Valve: Fisher GX
-Actuator System: DVC2000 Digital Valve Controller
-Fully open to fully close in less than 3 seconds
-Flow Coefficient, Cv, for 50% open is 3,8 [gpm/(psi $\frac{1}{2}$)] and 7,8 [gpm/(psi $\frac{1}{2}$)]

Total price for the Valve including the actuator system 33 895, - NOK
Vendor: Solberg & Andersen AS v/ Stian Andersen
Tel. +47 90 17 54 99
Delivery in 4 weeks

The Pump:

-CAT 2530
-Triplex type Plunger pump
-Borring 32 mm, stroke 38,5mm
-Leveringsmengde per RPM på akselen er 0,093 liter

Total price including, motor, connections, manometer etc. is 28000,- NOK
Vendor: Alfsen & Gundersen v/ Espen Opheim
Tel: +47 90 60 53 66
Deliverance in 2 weeks

The Motor:

-Servo motor
-Elektronisk styreboks
-Effect around 500 W

-RPM = 164 and Moment = 11,7 Nm
Total price including motor, gear, omformer and software around 30000,- NOK
Vendor: Lenze AS v/Frode Uddveg
Tel: +47 91 72 45 93
Delivery in 6 weeks

The Hose:
-Type: Gullslange 1
-Arbeidstrykk 15 bar
-Lengde pr. Stk 120 m
-Inner diameter = 19 mm outer diameter = 27 mm
-Total volume of hose = 516 L
-Drum from Tess with inner radius 28 cm and outer radius 45 cm and wideness of 48 cm.

Total price for the whole 900 m is 40 x 900 = 36000,- NOK
Vendor: Tess Trondheim v/ Rune Forseth
Tel: +47 73 95 20 00
Delivery within one week

Wire + Wheel

-Kjede/Tannrem
-Thickness $\frac{1}{2}$?
-Need 10-12 meter
-Wheel with diameter of 10 cm

Total price of wheel and belt is around 7000,- NOK
Vendor: Tess Trondheim v/ Rune Forseth
Tel: +47 73 95 20 00
Delivery within two week

The o-ring

-Inner diameter 25 mm outer diameter 35 mm
-EPDM Vannmaterialet
-Quad ring
-Tåler Over 10% strekk
-Forutsatt at o-ring har egen spor

Total price for 3 (three)o- rings is 25 x 3 = 75,- NOK
Vendor: Gummi&MaskinTeknikk v/ Frode Bang
Tel: +47 73849940
Delivery at place

The flow meter

-Usikkerhet mindre enn 1% av totale strømningen
-Teck Skotselv Instrumenting
-Total number of 3

Vendor: Teck Skotselv Instrumenting v/ Kjell Mølster
Tel: +47 90 70 87 30

The pressure gauges

-Usikkerhet mindre enn 0,1 bar
-Type tilkobling
-Type trykkmåler
-Antall = 15

Vendor: Teck Skotselv Instrumenting v/ Kjell Mølster
Tel: +47 90 70 87 30

The Pipes and CSG

-Rod of diameter 25,4 mm, length of 1,5 m
-Rod of diameter 24,6 mm, length of 1,5 m
-Rod of diameter 24,2 mm, length of 1,5 m
-CSG of diameter 43,2 mm and length of 4 meter
-The pressure range of all of these steel pipes and CSG is greater than our worki
Total price for the whole arrangement of pipes is around 15000,- NOK
Vendor: Tess Trondheim v/ Rune Forseth
Tel: +47 73 95 20 00
Delivery within two weeks

The total budget:

Choke 33895,-
Pump 28000,-
Motor 30000,-
Hose 36000,-
WireandWheel 7000,-
O-rings 100,-
PipeandCSG 15000,-
Pressure gauges 40000,-(not yet verified)
Flow meter 25000,-(not yet verified)
Stationary PC 10000,-
NI-cards 15000,-

Total procurement 239995,- NOK
Work hours 150000,- NOK
Final Budget 389995,- NOK

B Appendix 2

```
%Simulations regarding heave compensated MPD systems
%Created by: Camilla Sunde Gjengseth and Tollef Svenum
%Date: 17.12.2011
%NTNU, Trondheim


%Basic Parameters
Dbha=40.9;
Dhull=42.6;
D=0.33;
D_ft=D/0.3048;

RHO=8.35;%in field

A_annulus_bha=((Dhull/1000)^2-(Dbha/1000)^2)*pi/4;
Dbha_in=Dbha/25.4;
Dhull_in=Dhull/25.4;
Dupper_rod=25;
Dlower_rod=24.4;
rhowater=998.2;
dhose=0.01905
fhose=0.034147;
Lhose=900;
visc=1;
BHP=6
t=(0:0.1:9);
z=0.41*sin(2*pi*t/3);
V=2*pi*0.41/3*cos(2*pi*t/3)
cling=0.1;
viscwater=0.001002;

%flow in and out of the system
%funciton of backpressure og compressibility...

%Loss in hose
Ahose=0.019^2*pi/4;
Qhose=V.*((Dupper_rod/1000)^2-(Dlower_rod/1000)^2)*pi/4;
Qho=Qhose.*60*1000
```

```
for i=1:91;
    Vhose(i)=Qhose(i)/(Ahose);
    if V(i)>=0
        Re(i)=(1000*Vhose(i)*dhose/viscwater);
        f_hose(i)=64/Re(i);
        dphose(i)=f_hose(i)*Lhose*1000*Vhose(i)^2/(2*dhose)/10^5;
    elseif V(i)<0
        Re(i)=-((1000*(Qhose(i)/Ahose)*dhose/viscwater));
        f_hose(i)=64/Re(i);
        dphose(i)=-f_hose(i)*Lhose*1000*Vhose(i)^2/(2*dhose)/10^5;
    end
end

%Flow velocity in annulus
Q_disp=V.*((Dbha/1000)^2-(Dlower_rod/1000)^2)*pi/4;
Q_cling=V./2*(((Dbha+(Dhull-Dbha)*cling)/1000)^2-(Dbha/1000)^2)*pi/4;
Q_tot=Q_disp+2*Q_cling;
V_avg=Q_tot/A_annulus_bha;

V_avg_ft=V_avg/0.3048;

%Friction loss over BHA
for i=1:91;
if V_avg_ft(i)>=0
P_losspsi(i)=(RHO^0.75*V_avg_ft(i)^1.75*visc^0.25)/(1396*(Dhull_in-Dbha_in)^(1.25))*D
elseif V_avg_ft(i)<0
V_avg_ft(i)=V_avg_ft(i)*(-1);
P_losspsi(i)=-(RHO^0.75*V_avg_ft(i)^1.75*visc^0.25)/(1396*(Dhull_in-Dbha_in)^(1.25))*
end
end
P_loss=P_losspsi/14.5;

%ENTRANCE AND EXIT
V_avg2=V_avg
hdiabha=0.0018
hdiaover=0.0176
hdiaunder=0.0182
Ksc=0.42*(1-hdiabha^2/hdiaunder^2)
Kse=(1-hdiabha^2/hdiaover^2)^2
for j=1:91;
```

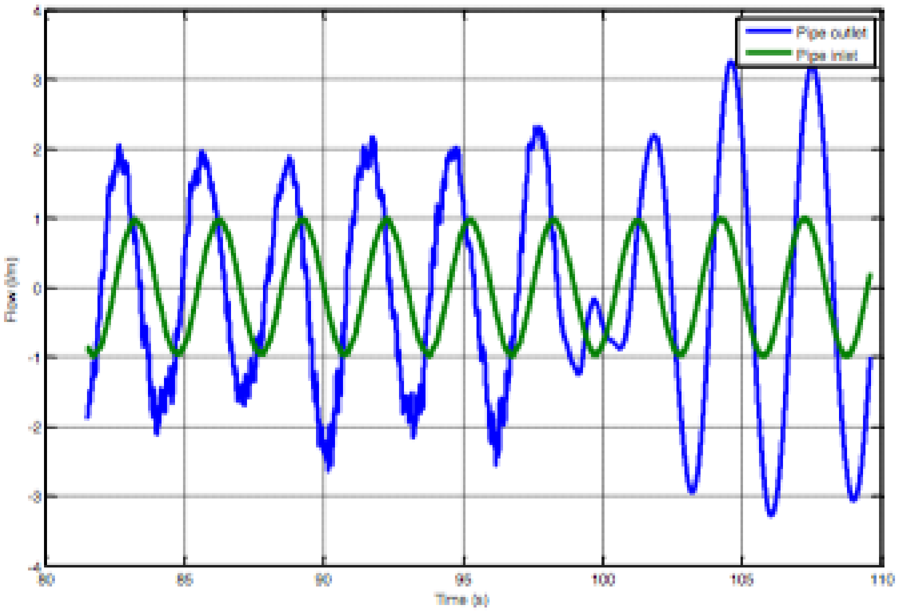
```
    if V_avg2(j)>=0;
        entrh(j)=Ksc*V_avg2(j)^2/(2*9.81);
        exith(j)=Kse*V_avg2(j)^2/(2*9.81);
    elseif V_avg2(j)<0
        V_avg2(j)=V_avg2(j)*(-1);
        entrh(j)=-Ksc*V_avg2(j)^2/(2*9.81);
        exith(j)=-Kse*V_avg2(j)^2/(2*9.81);
    end
end
pentr=entrh.*9.81*1000/10^5;
pexit=exith.*9.81*1000/10^5
total_bha=pentr+pexit+P_loss

%acceleration
aks=-0.41*4*pi^2/9*sin((2*pi*t)/3);
aksh=aks*((Dupper_rod/1000)^2-(Dlower_rod/1000)^2)/(dhose^2);
dp_aks=aksh*rhowater*Lhose/10^5;


%forsinkelse:
dt=900/1498

%FLOW
pBHP2=6
%compressibility of the fluid
%when the choke is giving a backpressure of
comp=4.45918*10^(-5) %bar^-1
%flow in and out of the hole is governed by displacement, small volume
%leads to small variations in compressed fluid.
flowhole=V.*((Dupper_rod/1000)^2-(Dlower_rod/1000)^2)*pi/4*1000*60;
pchoke2=pBHP2+total_bha+dp_aks+dphose
for m=1:91;
flowchoke=(V(m)*((Dupper_rod/1000)^2-(Dlower_rod/1000)^2)*pi/4);
end
plot(t,flowchoke);
%Variation of BHP with constant choke=6bar
pchoke1=6;
for l=1:91
pBHP1=pchoke1+total_bha+dp_aks+dphose;
end
Knut=size(V)
```

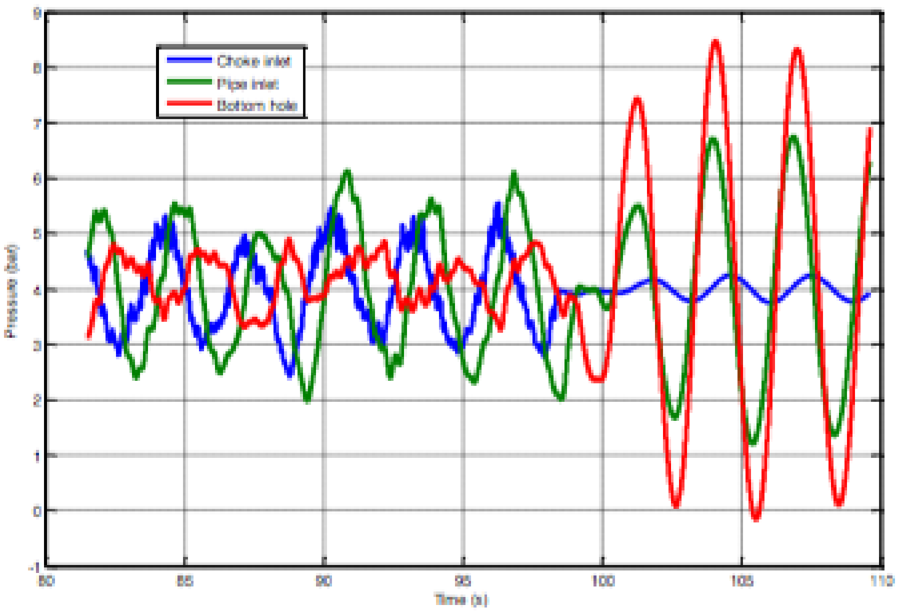
```
Berit=size(pchoke2)
pBHP2=6

%variation of choke to keep constant BHP
pchoke2=pBHP2+total_bha+dp_aks+dphose

plot(t,pchoke2);
```

C Appendix 3

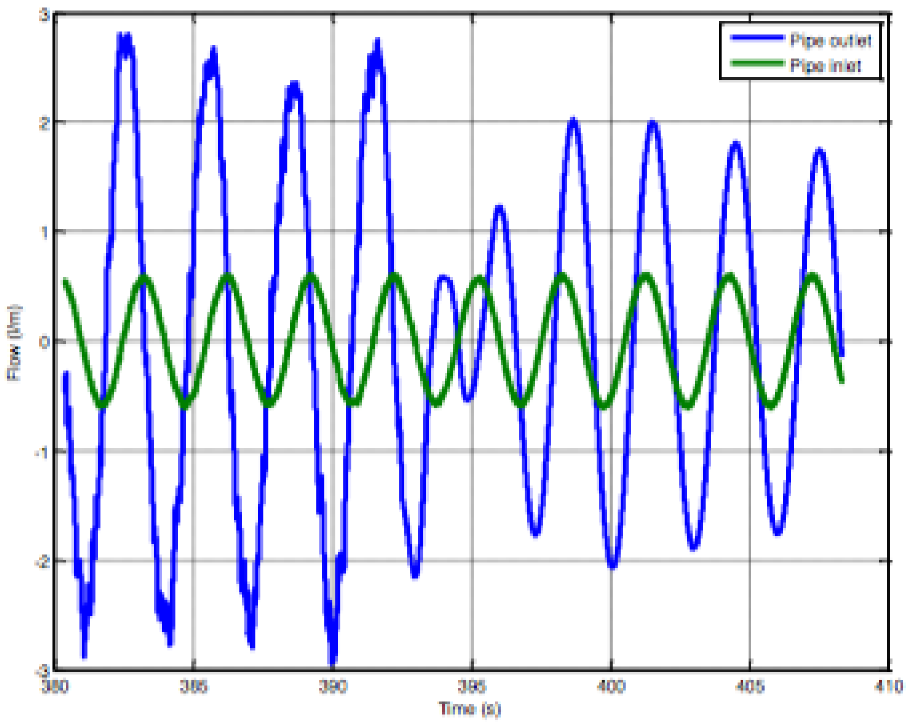
This appendix consists of simulations performed by Ole Morten Aamo at NTNU. And on basis of these simulations it was decided that it was possible to increase the cross-sectional area of the lower rod from 22 mm to 24,4 mm.

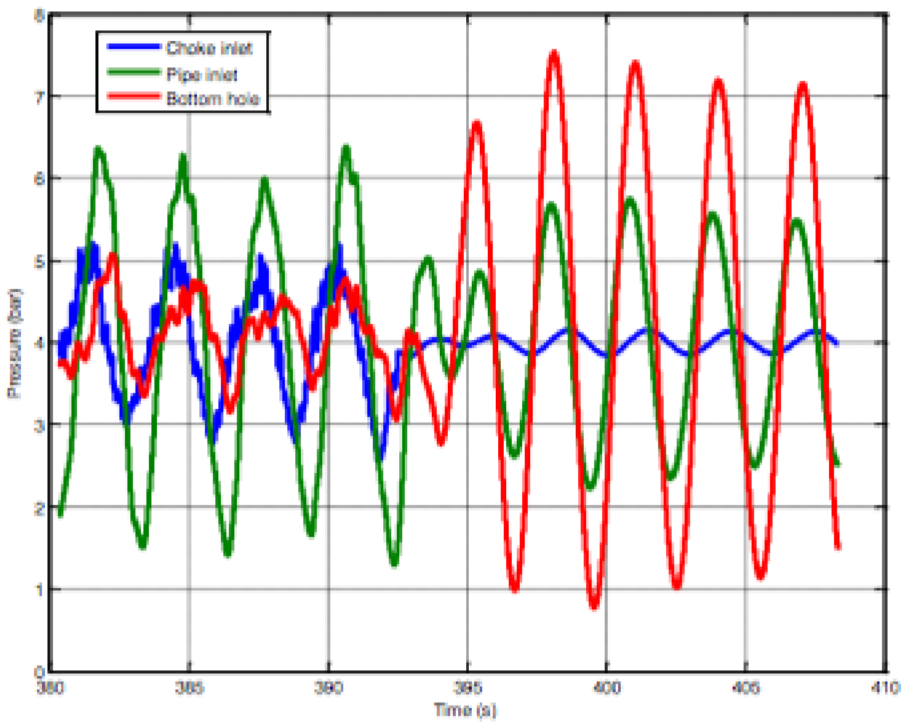
Cross sectional area of upper rod is 5% larger than CS of lower rod



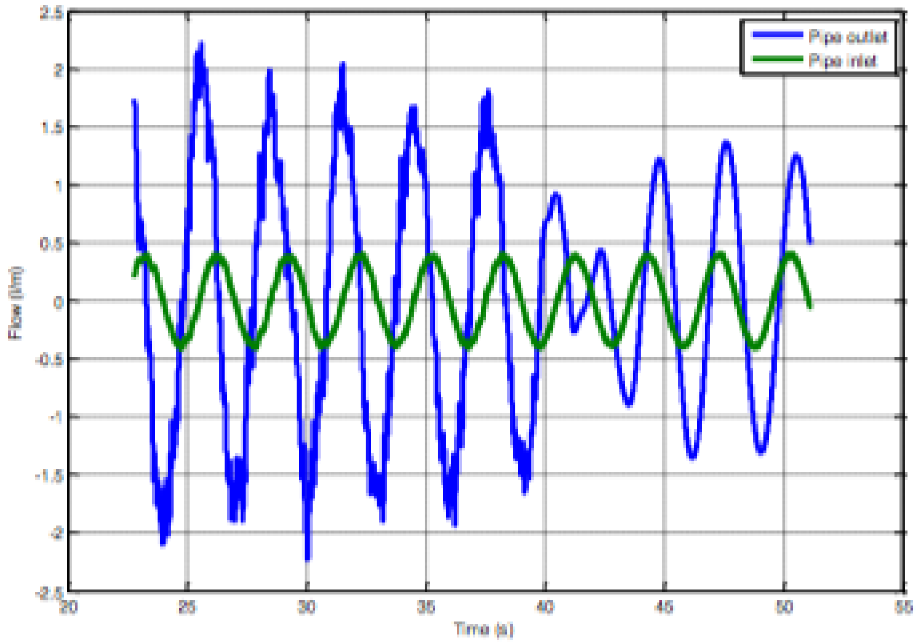


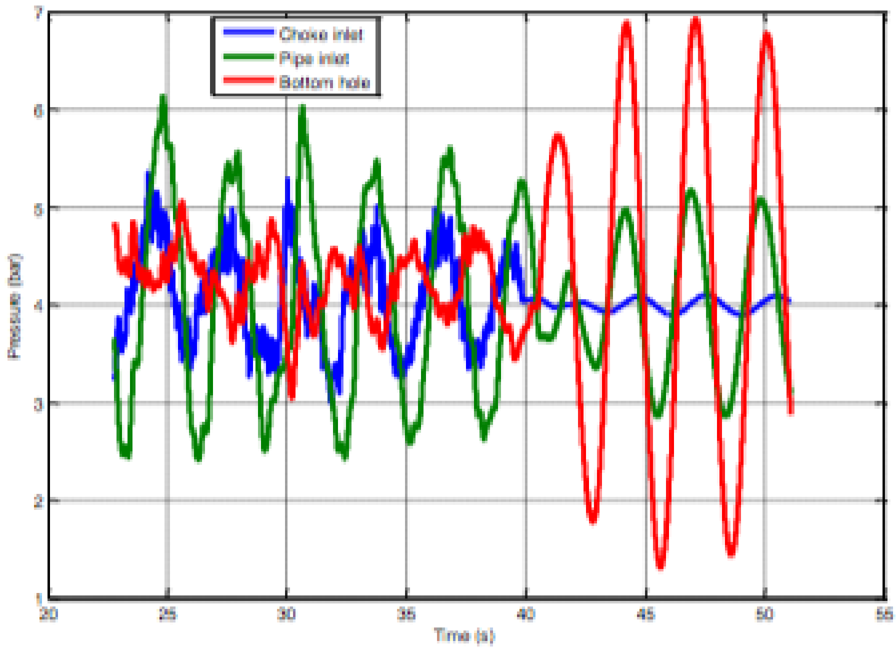
Cross sectional area of upper rod is 3% larger than CS of lower rod



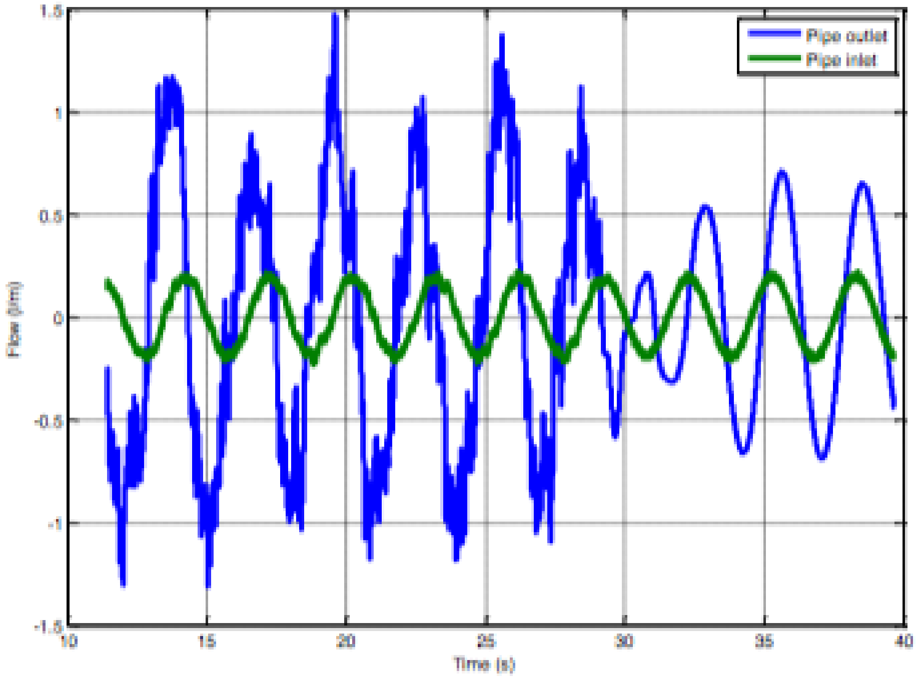


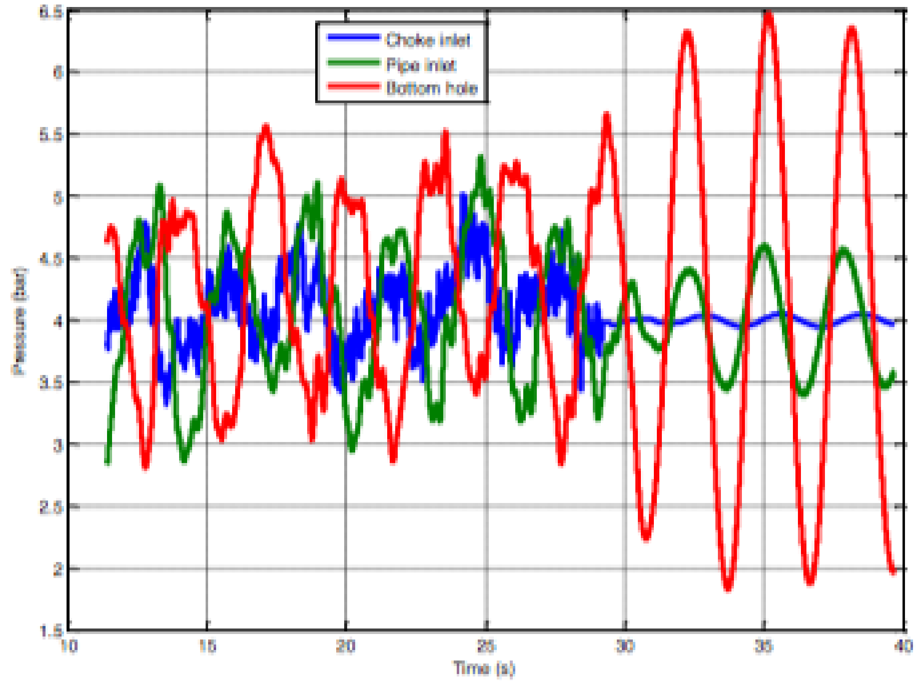
Cross sectional area of upper rod is 2% larger than CS of lower rod





Cross sectional area of upper rod is 1% larger than CS of lower rod





Cross sectional area of upper rod is 3% larger than CS of lower rod, outlet flow computed from choke equation.