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Abstract

The need for new methods for drilling wells is increasing, and new technology is introduced to the industry in order to solve the challenges we face. We are facing tougher and more challenging fields to drill. This includes depleted fields, HPHT fields and deep-water fields. This brings up challenges which are not so easy to solve by drilling conventionally. Several techniques are introduced to help us, where a group of them is called *managed pressure drilling (MPD).*

In addition to introducing new drilling techniques, the art of automation can help us push our performances even further. Automating a process can lead to a decrease in needed personnel, which can benefit the companies economically. Automation also increases performance, and decreases non-productive time. Furthermore, staff safety is assured, by removing them from high risk areas. There are in other words several benefits one can utilize by implementing an automated system. However, there are also several challenges related to this. Cost and reliability are questions which arises immediately during automation deliberations.

This thesis studies a MPD simulator built by previous students at the University of Stavanger. No proper procedure on how to run the rig is written earlier, which makes it desirable to study the rigs operations procedures, and figure out how to run the rig both manually and automatically. Additionally, the thesis focuses on MPD operations and well control in MPD operations. A code for calculating the volume of a gas kick is written, in addition to a studies on shut in and procedures for kick handling.

Furthermore, when being responsible for managing the MPD simulator, maintenance is expected and required. The rig has several weak spots in construction, which has been exposed during simulations, and subsequently fixed. This involves also tuning and improving automation performance, which involves studying control engineering and PID performance.

Preface

As MPD becomes a more viable method for drilling challenging wells, I wanted to do some research on its benefits and limitations. The MPD rig simulator opens up the possibilities for several different research approaches. One can simulate several different scenarios on the rig, which makes it a good tool for students at both master and PhD level.

However, the MPD simulator has several weakness, sourcing from years of different students working on it. During this semester there has been several challenges. Firstly, there are no procedures available on how to run the rig, which has resulted in lots of trial and error methods to get it up and running. In addition, there has been several pipe leakages. Maintaining the leakages, waiting for parts and pipe to arrive, are all things that have been set backs during the semester.

Nonetheless, the study has been a great learning for me as drilling engineer. The research has introduced me to many different topics that I had limited knowledge about. Automation, signal processing and managed pressure drilling are among the topics I have significantly improved in. The rig maintenance has also challenged my practical skills.

I would like to take the chance to thank my helpful supervisor Dan Sui, which has assisted me whenever needed. I would also like to thank Suranga Chaminda Hemba Geekiyanage, which has helped me as well during the semester at the lab.

Abbreviations

NCS	Norwegian continental shelf
BOP	Blowout preventer
IADC	International Association of Drilling Contractors
TVD	True vertical depth
LOT	Leak-off test
BHP	Bottom hole pressure
FIT	Formation integrity test
SICP	Shut in casing pressure
SIDPP	Shut in drill pipe pressure
HSE	Health, safety and environment
PID	Proportional, integral and derivative
WOW	Wait on weather
NPT	Non-productive time
ECD	Equivalent circulating density
MCD	Mud cap drilling
RCD	Rotating control device
NRV	Non-return valve
CIV	Casing isolation valve
DDV	Drilling down-hole deployment valve
QTV	Quick trip valve
WCV	Well control valve
LPM	Liters per minute
ID	Inner diameter
OD	Outer diameter
SPE	Society of Petroleum Engineers

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Chapter 1 - Introduction

1.1. Rig model

Two students at the University of Stavanger built the rig as a part of a project in 2010. Originally, it was built for simple simulations for Managed Pressure Drilling (MPD). [1] The original scope of the rig was to install a circulation system, where the water could be circulated by the use of a cavity pump. The flow path was resembling a rig circulation system, with representative pressure sensors like stand pipe pressure, pump pressure etc. A MPD choke valve was installed in order to regulate the bottom-hole pressure (BHP). Later it was decided to expand the rig for Dual Gradient Drilling (DGD) simulations. [2] By adding a secondary pump on the annulus side, one could remove a part of the fluid gradient, and regulate the bottom-hole pressure by varying the hydrostatic column height. A schematic of the rig is shown in Figure 1.

This thesis is based on the latest version of the rig, where MPD and DGD can be run by using Labview and Matlab/Simulink. The topic of the thesis is firstly to understand, and figure out how to run the simulator. After being modified several times by different students throughout the years, a proper procedure on how to run the rig is not documented.

Simulations are done on the rig in order to tweak and benchmark the model. Simulink is used to automatically run the simulator, where a PID controllers is used in order to control the BHP. Improvement are especially done on the PID controller, as the automated performance is not ideal. The thesis also includes theory on MPD, well control and control engineering, which supports the tests and studies provided later in the thesis.

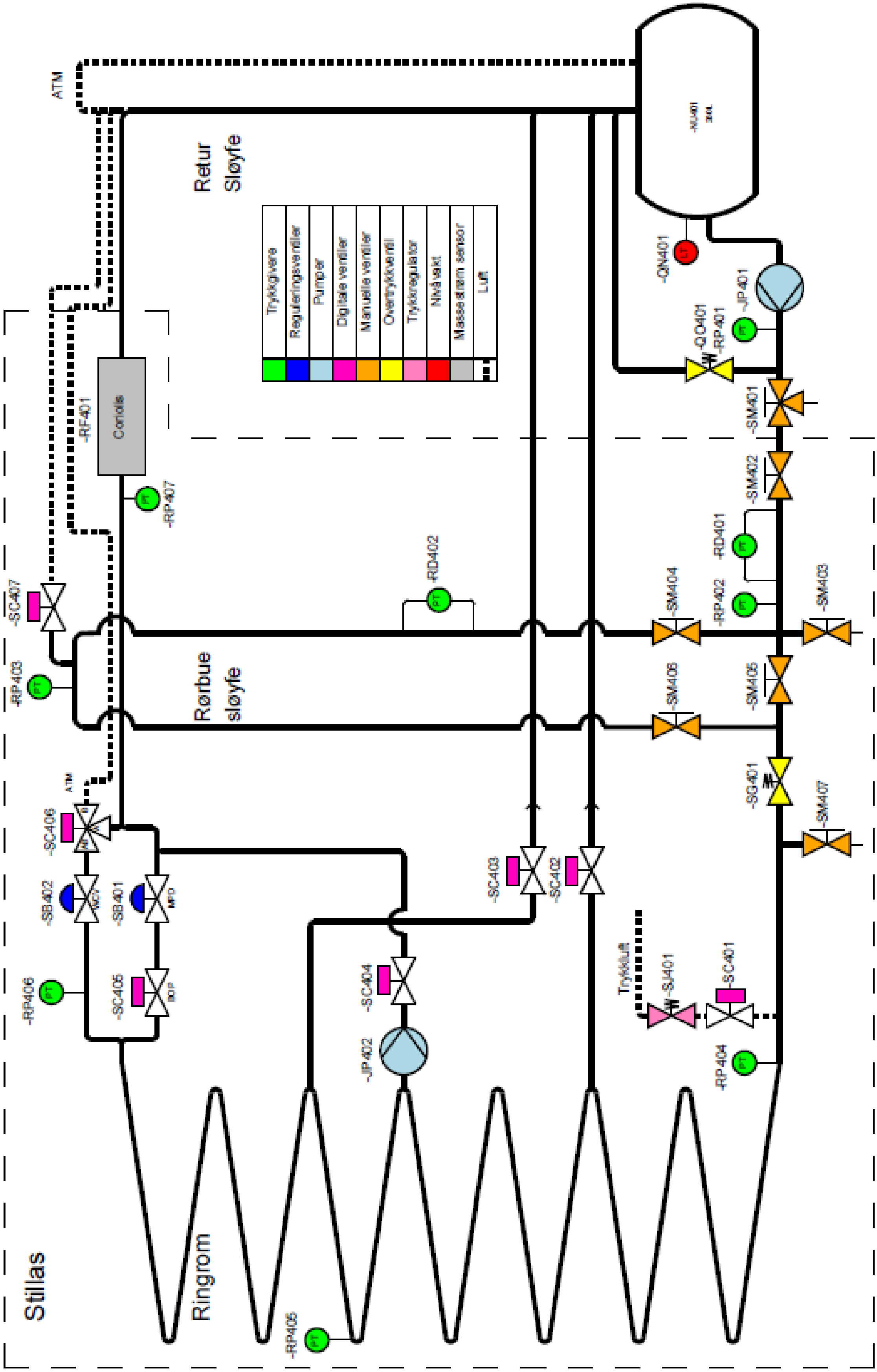

Figure 1 Schematic of rig setup [2]

Figure 2 Picture of rig [2]

1.2. Circulation systems on an offshore rig

A circulation system on an offshore rig typically consists of the following elements:

- Several **mud tanks** consisting of drilling mud.
- A **mud pump** to pump the mud from the tank and into the well
- A **stand pipe** transporting mud from the tank and up to the drilling floor
- **Drill pipe** to transport the mud from the drill floor and to the bit
- **Annulus** is where the drilling mud is transported on the outside of the drill pipe
- A **return line** below the drill floor, where the mud and cuttings are transported out of the well
- **Shale shaker** is where the mud and cuttings are separated

A more detailed picture of the entire circulation system is shown in *Figure 3.*

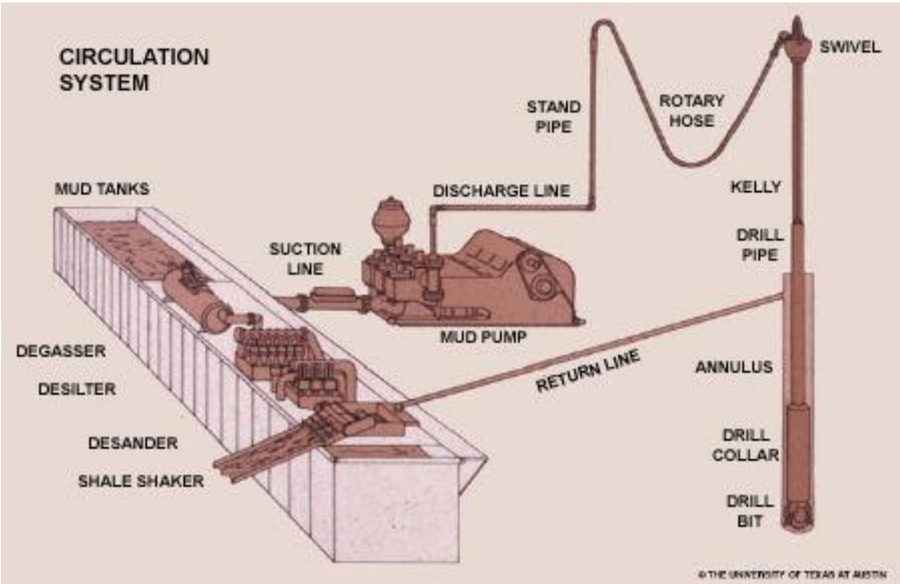

Figure 3 Offshore circulation system [3]

Since the circulation system is directly connecting the drilled formations and the rig floor, it is critical to make sure that the well is under control. This is done by having proper well integrity. An important tool to the well integrity system is the Blowout Preventer (BOP), which is described in Chapter 1.4.1. The simulator is trying to emulate such a system, with matching components.

1.3. Rock mechanics

Sub surface parameters defines how the well is drilled. The creation of abnormal, normal, or sub-normal formation pressures is a result of several factors. In order to design a safe drilling program, one must predict parameters such as *overburden pressure, pore pressure and fracture pressure*. Figure 5 below displays the basic principle of mud weight selection. To put it very simple, staying between fracture gradient and pore pressure will result in a stable well.

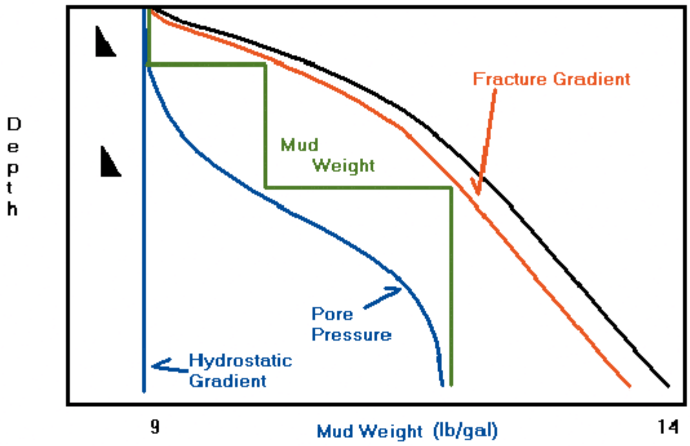

Figure 4 Depth vs pressure gradient plot [4]

1.3.1. Pore pressure

Pore pressure is defined as the pressure of fluid in the pore spaces. It is therefore a result of the hydrostatic pressure exerted by fluid above a reference point. The pore pressure starts at zero at the sea surface, and increases at a rate equal to the hydrostatic column of sea water.

$$Pore\ pressure\ [bar] = Formation\ water\ gradient[s.g.]\ x\ TVD[m]\ x\ 0.0981 \tag{1}$$

This is the simplistic pore pressure equation. However, the straight gradient may offset because of geological properties of the sub surface. This can be due to transition zones, faults or geological discontinuities. Subnormal pressures can occur naturally in formations that have undergone a pressure regression because of deeper burial from tectonic movement. Additionally, production from a field leads to depletion of the formation. [5]

We can also have abnormal formation pressure. Which are regions where formation fluids are trapped due to impermeable surrounding formation. This makes the fluid disconnected to the hydrostatic column, making the fluid take large proportions of the overburden stress. [6]

1.3.2. Overburden pressure

When a well fractures during drilling depends on the in-situ stress sate. The combination of overlying formation, fluids and abnormalities makes up the *overburden pressure.* The abnormalities can be sources like salt domes intruding the areas of the formations.

On integral form, the overburden stress, ρ_O, is given as:

$$\sigma_O = \int_0^D \rho_b(h) g dh \quad (2)$$

The bulk density is given as ρ_b, and is an average on the density of the formation. It can be calculated by using the rocks grain density ρ_R, pore fluid density ρ_F and the porosity of the formation φ.

$$\rho_b = \rho_R(1-\varphi) + \rho_F\varphi \quad (3)$$

The overburden pressure is a result of vertical stress acting on the formation, which means that the underlying formations will deform horizontally due to the Poisson's ratio. These horizontal stresses are what defines our *fracture pressure.* [7]

1.3.3. Fracture pressure

The fracture pressure tells us how much pressure the formation can be exposed to before it fails. A fracture will always propagate in the direction of the minimum principal stress. This is almost always in the horizontal direction. The horizontal stresses are caused due to restriction from nearby formation. Other than the overburden pressure; temperature and natural effects causes changes in the horizontal stresses as well. This makes it hard to easily quantify the size of the horizontal stresses. *[7]*

The fracture pressure can be estimated by using nearby reference wells. There are several methods regarding measurement of in-situ stresses. A Leak-off test (LOT) is a pressure integrity test used for testing the integrity of the formation. Operationally, one pumps mud into the well while shutting in the BOP, causing the BHP to increase. When reaching the fracture pressure, the fluid will start entering the formation. This results in a reference point during further drilling. A LOT is done after casing cementing, and prior to drilling a new section. One can also perform a FIT (Formation integrity test), where one pumps up to a desired pressure limit (and not all the way to fracture).

1.4. Basic principles of well control

The IADC Lexicon for oil & gas defines well control as following:

"Well-control means methods used to minimize the potential for the well to flow or kick and to maintain control of the well in the event of flow or a kick. Well-control applies to drilling, well-completion, well-workover, abandonment, and well-servicing operations. It includes measures, practices, procedures and equipment, such as fluid flow monitoring, to ensure safe and environmentally protective drilling, completion, abandonment, and workover operations as well as the installation, repair, maintenance, and operation of surface and subsea well-control equipment." [8]

Well control is in other words a way to operate and manage a situation where there is a potential for economical, operational, environmental or human life risk. It requires professional and trained personnel to handle, and it also covers the expertise to act in a safe manner.

On the Norwegian Continental Shelf (NCS), the NORSOK standards are developed to ensure value creation, cost effectiveness and elimination of unnecessary activities in offshore field development. NORSOK D-010 is the name of the standard covering the requirements and guidelines regarding well integrity in drilling and well activities. Well integrity is defined as:

"Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well". [9]

To have proper well integrity, one must use well barriers, which are envelopes preventing fluids from flowing unintentionally from the formation to the wellbore.

1.4.1. Blowout Preventer

A blowout preventer (BOP) shall be installed after the surface casing is drilled out. Initially, one only uses drilling fluid as a barrier element. However, after the installation of the BOP, one transitions into a two-barrier system, where the BOP acts as the secondary barrier element. Meaning that the BOP only is in use as a barrier if drilling fluid is unable to act as a primary barrier.

Technically, the BOP is a collection of rams with different purposes. The different features of a BOP is as following:

- **Blind rams** are rams that seal the well if no drill pipe is present
- **Pipe rams** are rams to seal around the drill pipe
- **Shear rams** are rams that cuts the drill pipe, and seal the well after cut
- **Kill lines** are lines that one can pump fluid through after sealing the well
- **Choke line** are lines to take fluid returns if well is sealed. Here, a choke valve is in place in order to manipulate wellbore pressure while circulating.

A BOP can be setup in different ways, with different ram combinations, in order to fit the properties of the well. Additionally, the BOP is different depending on whether it is a fixed platform, or a floater. It is placed topside on a fixed platform, but is installed subsea when drilling from a floater. The BOP is a very important tool when it comes to well control, as it is the only way to shut in the well.

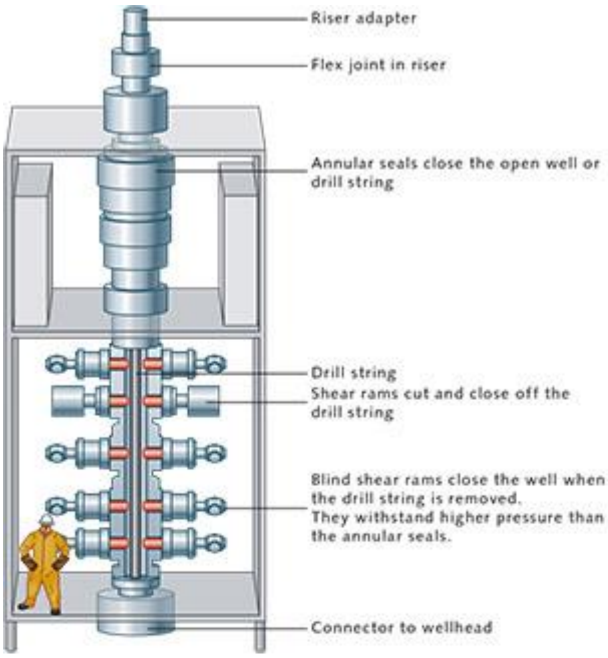

Figure 5 Blowout preventer [10]

1.4.2. Well kick

A well kick is a well control situation, where formation fluids enter the well due to wellbore pressure being lower than the pore pressure. A well kick is also dependent on porosity and permeability in the rock. Meaning that the potential for kicks are more severe in sandstone than shale, due to the porosity and permeability difference. [11] The most common kick during drilling is a gas kick, as it has the most potential for flow. However, we can also have kicks from the following fluids:

- Gas
- Oil
- Salt water
- Magnesium chloride water
- Hydrogen sulfide (sour) gas
- Carbon dioxide

A kick can develop due to drilling into a reservoir with insufficient mud weight. This is a consequence of underestimating the pressure one drills into, and by selecting a mud weight resulting in an underbalanced well. Conversely, one can also get a well kick by having too high of a mud weight. Drilling with a high hydrostatic column can fracture the formation, leading to circulation losses. By going on losses, one loses hydrostatic pressure, which in the worst case can lead to a gas kick.

Additionally, one can risk kicks when pulling out the drill string from the borehole. This is referred to as *swabbing.* A swab pressure is a negative pressure induced by the movement of the drill string upwards, resulting in reduction of hydrostatic pressure. [11]

1.4.3. Kick detection

Being able to handle a kick in a safer manner requires proper training regarding well control, but also regarding detection of if we have a kick situation occurring. We distinguish between primary and secondary indicators during kick detection. [12]

Primary indicators:

- **Pit gain:** Optimally, volume in and out of the circulation system should be constant. An indication of larger volume out of the well is a sign of additional volume entering the circulation system.

- **Increase in return flow rate:** If a gas volume enters the mud flow, the flow rate on the return line will increase due to the additional volume.

- **Well flow during pump shutdown:** Normally we should have no well flow when pumps are shut off. However, a continuing flow when shutting down the pumps can indicate a kick. A method for detecting kick if one suspects a kick, is therefore to shut off the pumps and monitor if the well flows. This is known as a *flow check.*

Secondary indications:

- **Drop in BHP:** As a lighter fluid than the mud enters the wellbore, it reduces the hydrostatic head slightly, which in combination with other factors can determine if a kick is happening.

- **Drop in stand pipe pressure:** Similar to the drop in BHP, one can notice the same pressure drop on the stand pipe pressure (SPP).

- **Increased hook load:** Due to decreasing mud density when gas enters the well, the effect will be an increased hook load due to the buoyancy force. The drill pipe will be measured as heavier.

1.4.4. Lost circulation

Lost circulation is a result of drilling with a wellbore pressure higher than the fracture pressure. Additionally, one can go on losses when drilling into already fractured or high permeable formation. The result is mud entering the fractures. Lost circulation is a well control problem, which leads to non-productive time. We distinguish between partially and total lost circulation. In partial lost circulation, one still has returns to the surface, but notices a difference between volumes in and out of the circulation system. In worst case, one can go on total losses, where no mud returns to surface.

Additionally, there are a considerable amount of lost circulation situations happening during casing running and cementing. [5] Casing runs leads to an additional bottom-hole pressure, and during cementing, a high density fluid is pumped to the bottom of the well. However, these situations are not a part of the scope of MPD, nor this thesis.

1.4.5. Well control techniques

In order to get a good understanding of well control during MPD operations, it is important to have a knowledge on basic well control during conventional drilling. As mentioned, a kick is a well control situation, which needs to be handed by using well control procedures. Two methods of handling a kick are *Drillers method* and *wait and weight method*. [12]

Driller's method

This method is a two circulation process. The first circulation involves shutting in the well and circulating out the kick with the initial mud weight. Constant bottom-hole pressure is obtained by manipulating the choke valve to hold the drill-pipe pressure constant while circulating out the kick.

The second circulation includes a displacement of the drill-pipe and annulus to a new kill mud.

The new kill mud is calculated by using the *shut-in drill-pipe pressure (SIDPP):*

$$\rho_2 = \frac{SIDPP}{0.052 * TVD} + \rho_1 \tag{4}$$

Where,

ρ_1 = Original mud weight, ppg

ρ_2 = Kill mud weight, ppg

SIDPP = Shut in drillpipe pressure, psi

TVD = True vertical depth, ft

While the new mud displaces the drillpipe, the BHP is kept constant by holding casing pressure constant during displacement. When the new mud starts displacing the annulus volume, drillpipe pressure is kept constant. When the total displacement is finished, the casing pressure and drillpipe pressure should be equal in order to conclude a successful well kill.

Wait and weight method

This well control technique is a one circulation method, where the well gets killed by using only one circulation. After well is shut in, and pressure is stabilized, kill mud is calculated and pumped down the drill string. The choke valve at the choke line is then used to manipulate drill pipe pressure. The weight of the kill mud is designed to make the hydrostatic height of mud in the drillstring balance the formation pressure.

The data that needs to be recorded to calculate the kill mud:

- Shut-in casing pressure (SICP)
- Initial shut-inn drill pipe pressure (SIDPP)
- Pit gain

The wait and weight method requires more calculations than the drillers method, hence why it is also referred to as the *Engineering method.* [12]

Chapter 2 - Control engineering and automation

Control engineering is the engineering discipline of having methods and techniques for automated control of physical systems. The goal is to have a system where sensors, or other forms of detectors, makes a process variable as close as possible to a reference variable. If the system is designed to perform without having human input, it is defined as an automatic control system. [13]

Automatic control systems removes the need of human involvement. Human errors can lead to non-productive time, as well as increasing the risk of HSE damaging related situations. A fully automated system removes these risks. However, this means that the control system needs to be designed as best as possible. In order to obtain such a system, one has to define the desired behavior of the system.

2.1. A regulation process

Figure 5 below a block diagram of an open loop control process:

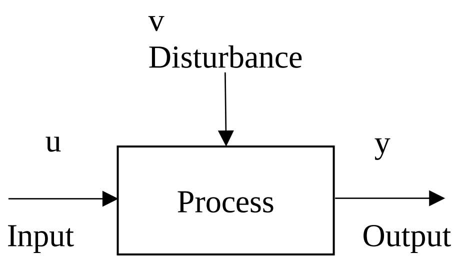

Figure 6 Block diagram of an open loop process

The definitions of the variables on the figure are:

- **Process** is the physical system that can do the regulations
- **Input** is the measured variable that we can manipulate to reach our desired behavior. Commonly, the input is noted *u*.
- **Output** is the variable that needs to be regulated. We note this output *y*.
- **Disturbance** is an unwanted variable that influences the output. The disturbance needs to be compensated for, and its value is noted as *v*.

We also define:

- **Set point** is the desired value we want to regulate our system to. We note this y_r.
- **Error** is the difference between our set point and the output. We note it *e*.

Conclusively, the regulation challenge is finding the input that minimizes the outputs error. [13] Or in the words; finding the gain *u* which makes the error *e* within acceptable limits.

The **open loop process** uses a constant gain in order to control the process. If there are no changes in the set point, or in the disturbance, using a constant gain is an acceptable solution. However, in most practical systems the error will become too big when using an open loop process with constant gain. This type of process is most used when finding *u* can be done experimentally or from the mathematical models of the process.

Nevertheless, it is more common to use a continuous, deviation based gain. This makes the system robust to changes of the set point, as the gain can be adjusted based on new set points. This makes it possible to continuously calculate the gain as a function of the gains error to the set point. In order to make this happen, we have to be able to continuously measure the output *y*, to be able to measure the error and regulate the gain accordingly. This is a **closed-loop process**, and is presented in figure 7 below.

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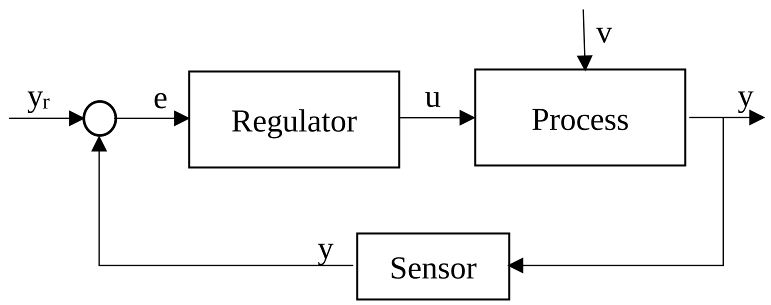


Figure 7 Block diagram of a closed loop process

To be able to regulate the error to approximate zero, the most common regulators in the industry are PI- and PID-regulators. [13]

2.2. PID-controller

In control engineering, the available regulation functions are:

- P-controller (Proportional)
- PI-controller (Proportional-integral)
- PID-controller (Proportional-integral-derivative)

One can choose whether one wants to run only a P-controller, or extend it to a PID-controller. What controller one chooses depends on the system, and what regulation properties is desired. PI- and PID-controllers are the most used in the industry [13], as they provide the best regulation. However, inclusion of the derivative controller can cause problems, depending on how much disturbance the system is subject to.

2.2.1. P-controller

The proportional regulator calculates the gain in the following way:

$$u = u_0 + K_p e \tag{5}$$

Where the error, $e = y_r - y$

U_0 is used as the initial value for the regulator when the process starts. $K_p e$ is the proportional part of the regulator, and can be noted as u_p. We call K_p the proportional gain, which means that the regulator produces an output value that is proportional to the error. Meaning, that if the input is less than the set point, the error is positive. This provides a positive K_p. However, K_p can also be negative, if the input is larger than the set point. Also, the regulator requires a non-zero error in order to solve it (A steady-state error), which is why we can't in most cases remove the error completely by a pure proportional-controller. [13]

Depending on the system, selecting a high K_p can result in an unstable system. On the other hand, selecting a too small value can result in a too slow response time when exposed to a disturbance. Meaning that finding the correct value can be challenging, and requires tuning techniques. More on controller tuning for MPD PID controller in Chapter 6.1.

2.2.2. PI-controller

The proportional-integral regulator calculates the gain in the following way:

$$u = u_0 + K_p e + \frac{K_p}{T_i}\int_0^t e dt \tag{6}$$

Still, we have the proportional gain K_p involved in the integral term. But the PI-controller involves integrating the error as well, using T_i as the integral time, and integrating continuously. As the PI-controller tries to regulate the gain towards the set point, the integral term accelerates the process towards the set point, and is able to remove the steady-state error found in the P-controller.

2.2.3. PID-controller

The proportional-integral-derivative regulator calculates the gain in the following way:

$$u = u_0 + K_p e + \frac{K_p}{T_i}\int_0^t e dt + K_p T_d \frac{de}{dt} \tag{7}$$

This controller includes the term u_d, which derivate the error. As mentioned for the PI-controller, it is possible to remove the steady-state error, which is why a PI-controller in most cases are sufficient. However, including derivation of the error makes the regulation happen quicker.

It seems therefore obvious that the PID-controller is the optimal regulator. Why is even a PI-controller use, if a PID-controller regulates faster? The answer to this is that the PID-controller is very sensitive to noise, which the regulator will respond with an excessive gain. This is a big challenge regarding tuning a PID-controller. Nonetheless, it is possible to moderate the noise by the help of *filters*. [13]

2.3. Filters

There always exists noises to a greater or lesser extent. The noise can source vibrations from motors, or even small frequency noises from electrical components. Depending on the properties of the noise, one can design a filter, which to an extent can remove the noise recorded by the sensors.

We can write the measured signal y_m as:

$$y_m = y + w \tag{8}$$

Where *w* is the noise, and y is the ideal measurement. Continuing from the block diagram from earlier, we extend the block diagram with noise as illustrated in Figure 8.

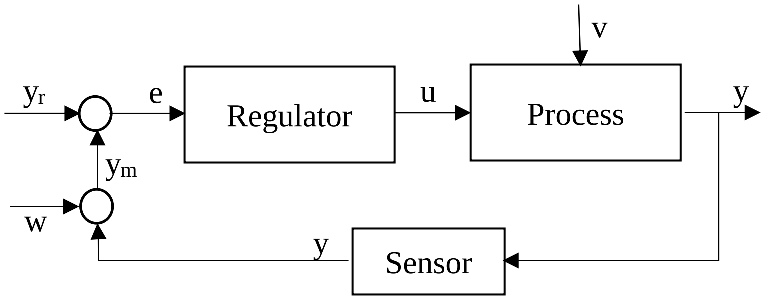


Figure 8 Block diagram with noise, w

To demonstrate how noise can lead to a very unstable gain when using the derivative term, we insert the error = y_r-y_m for e in the PID equation (7):

$$\begin{aligned} u_d &= K_p T_d \frac{de}{dt} = K_p T_d \frac{d\,(y_r - y_m)}{dt} = K_p T_d \frac{d\,(y_r - (y + w))}{dt} \\ &= K_p T_d \frac{d\,(y_r - y)}{dt} + \underbrace{K_p T_d \frac{dw}{dt}}_{\frac{de}{dt}} \end{aligned} \tag{9}$$

The formula shows that the term *dw/dt* will be included in the gain, hence the unstable derivative term when noises are of high frequency. Meaning, that if the incoming noise, w, is of high frequency, the derivative of its value will add a large gain to the regulator. This is the case when running the simulator in automated mode, as adding a derivative term will lead to large gains and unstable regulation. More on this in Chapter 6.4.

2.3.1. Low-pass filter

A standard solution for solving this challenge, is to reduce the measured noise *w* before it is derived by the help of a low-pass filter. A low-pass filter includes a cut-off frequency, meaning that frequencies lower than the selected limit will pass the filter, and therefore cutting off unwanted high-frequency noises.

We introduce the term e_f as the filtered error, thus the PID-regulator becoming:

$$u = u_0 + K_p e + \frac{K_p}{T_i}\int_0^t e dt + K_p T_d \frac{de_f}{dt} \tag{10}$$

A first order low-pass filter can be written by using Laplace notation:

$$Y(s) = \frac{1}{T_f s + 1} X(s) \tag{11}$$

And by setting the filtered error, e_f, as the function Y(s):

$$e_f(s) = \frac{1}{T_f s + 1} e(s) \tag{12}$$

2.3.2. High-pass filter

A high pass filter is based on the same principle as a low-pass filter, but cuts off the lower frequencies, instead of the high ones. Meaning that one wants to filter out the low frequencies, but let the high frequencies pass. One can also write the high-pass filter as a first order transfer function:

$$Y(s) = \frac{T_f s}{T_f s + 1} X(s) \tag{13}$$

And by setting the filtered error, e_f, as the function Y(s):

$$e_f(s) = \frac{T_f s}{T_f s + 1} e(s) \tag{14}$$

2.3.3. Higher order low-pass filter

Introducing a higher order low-pass filter will give a gain closer to its ideal characteristic [14]. However, implementing a filter of high order requires several electrical components, and a heavier programmed filter algorithm. Additionally, the time delay will also increase, creating a small offset from the original data. An example of a higher order filter is a Butterworth filter.

Chapter 3 - Managed pressure drilling

Managed pressure drilling (MPD) is a general term for several methods for controlling bottom hole wellbore pressure while drilling. Each method tries to improve weaknesses that other methods has. The main goal of introducing MPD drilling is to reduce non-productive time (NPT) while increasing safety. Risk scenarios such as well kicks, lost circulation and differential sticking are critical risk situations that MPD helps with. Reducing the number of casing strings required to reach the target depth is an important goal in MPD as well. We are also moving more over to automated methods to improve NPT even further. [5]

Some challenges MPD helps with:

- Reducing number of casings to reach target depth, which also avoids unnecessary hole-size reduction.
- Less risk of differentially stuck pipe
- Limiting lost circulation
- Increasing the penetration rate
- Deepwater drilling with limited pore- and fracture pressure windows

Non-productive time can be defined as unexpected events that occur during operation. These events leads to prolonging of the operational time frame that is planned for the operation, which is economically damaging for the operators. A study done on deepwater operations in the Gulf of Mexico by James K. Dodson Company shows that 41% of the total NPT is due to wellbore stability problems [15]. This excludes waiting of weather (WOW). Meaning, that there is a huge potential for saving time and cost by reducing this number if one manages to increase wellbore stability. This is where MPD has a huge potential.

We distinguish between a reactive, and a proactive approach to MPD. The proactive approach utilizes MPD equipment at all times, focusing on eliminating problems before they have a chance to appear. The reactive approach is about having MPD equipment on standby, and being ready if one sees the necessity of MPD.

The International Association of Drilling Contractors (IADC) defines MPD as an adaptive drilling process. This means that the process shall be able to perform calculations in real time, and regulate to variations immediately. E.g. the MPD process can react instantly if pore pressure is lower than what one predicted, and increases BHP to adjust to the anomaly. It is crucial to have a flexible system to be able to reduce NPT in drilling operations.

3.1. Constant bottom-hole pressure

This is a term which is used to describe the method for maintaining a constant bottom-hole pressure while drilling and reducing the circulating friction loss (ECD). The ultimate goal is to stay within the drilling window. We can divide the term into two groups; Constant bottom-hole pressure with pressure as primary control, and constant bottom-hole pressure with flow as primary control.

A fluid column has a pressure profile equal to the following equation:

$$Pstatic = \rho g h \tag{15}$$

ρ = Density of fluid

g = Gravitational constant

h = TVD of fluid column

Conventionally, the BHP is written as:

$$BHP = \rho g h + Pdynamic \tag{16}$$

BHP	=	Bottom hole pressure
ρ	=	Mud density
g	=	Gravitational constant
H	=	Height from reference to bottom of well
$Pdynamic$	=	The pressure created by friction when circulating with the mud pumps.

Meaning that a wellbore bottom-hole pressure is only equal to the hydrostatic pressure exerted by the fluid column in conventional drilling. $P_{dynamic}$ only has a value when mud pumps are running and fluid is circulated. When taking connections during drilling, mud pumps has to be shut off. This leads to a drop in bottom-hole pressure every stand of drilling, as the dynamic pressure from circulation friction goes to 0.

During drilling, the drilling window is usually limited by the following parameters

- P_p Pore Pressure
- P_{wbs} Well bore stability
- P_{ds} Differential sticking
- P_{ls} Lost circulation
- Pf Fracture pressure

Normally during conventional drilling, the BHP is kept inside a following window:

$$Pp < Pwbs < \boldsymbol{BHP} < Pds \le Pls \le Pf \tag{17}$$

The wellbore stability pressure, P_{wbs}, is somewhat a more complex variable than the pore pressure, P_o, and indicates at what minimum pressure the wellbore is stable before collapsing. It is not quite the same as the pore pressure, which represents which pressure a reservoir kick influxes into the well. The difference between P_p and P_{wbs} can be as small as 0.002 s.g., and as large as 0.36 s.g [5]. Using pore pressure or well bore stability pressure as lower boundary depends on the field. One can find narrow drilling windows (Equation **17**) in e.g. depleted fields, deep water field and fields with fractured carbonates. This is where constant bottom-hole drilling is helpful, as narrow drilling windows are hard to navigate through with conventional drilling methods, where fluctuations in bottom-hole pressure is normal.

Equation **16** represents an open circulation system, where mud returns goes to atmospheric pressure at surface. However, for a closed system, such as during constant bottom-hole pressure drilling, the mud flows out of the wellhead under pressure. The annulus side of the wellhead is sealed off, and the flow is redirected through a choke manifold. This choke manifold adds one additional BHP variable, as it gives back pressure to the wellbore. While drilling and circulation of mud, the BHP becomes:

$$BHP = Pstatic + Pdynamic + Pc \tag{18}$$

Where P_c is the back pressure from the surface choke manifold. Managing this choke manifold means that the BHP can be kept constant during drilling. If one shuts off the pumps to take a connection, the BHP will drop due to one losing $P_{dynamic}$. However, having P_c available means that one can compensate for this drop by increasing P_c.

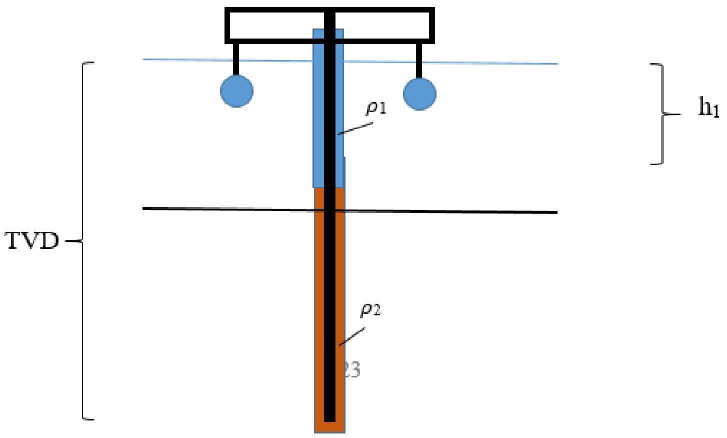
3.2. Dual-gradient drilling

Dual-gradient drilling (DGD) is a method for managing bottom-hole pressure by having two different density fluids in the annular space of the wellbore. The mud does not return to surface through a conventional drilling riser, but are either dumped straight at the sea floor, or returned to the rig through a return conduit. To take the returns through a conduit, a subsea pump is installed to take returns from well annulus. [5]

Due to having two pressure gradients in the annular, we now calculate the BHP the following way:

$$BHP = \rho_1 g h_1 + \rho_2 g (TVD - h_1) + P_{dynamic} \tag{19}$$

BHP	=	Bottom hole pressure
ρ_1	=	Light mud density
ρ_2	=	Heavy mud density
g	=	Gravitational constant
h_1	=	Height from reference to sea floor
TVD	=	Height from reference to bottom of well
$Pdynamic$	=	The pressure created by friction when circulating with the mud pumps.



Studying **Equation 19** shows we can regulate the BHP by regulating the height (h_1) of the heavy-fluid column. This is where the subsea pumps comes in. If one wants to reduce the BHP, the subsea pump can remove heavy fluid from the annular, which reduces BHP due to more light fluid in the annular. Alternatively, if one wants to increase the BHP, the subsea pump feeds the annular with heavy fluid ρ_2 to reduce the light fluid column h_1.

Having a lighter fluid ρ_1 in the top part of the annulus allows for a heavier fluid ρ_2 at the bottom of the well, compared to drilling with only one gradient. A larger gradient ρ_2 widens the drilling window, allowing fewer casings and larger final well-bore size. Figure 9 displays this, by comparing a conventionally drilled well with a well with dual gradients. Basically, as ρ_2 is heavier than what is used for conventional drilling, the gradient is able to fit into the drilling window for a longer interval, which results in longer sections.

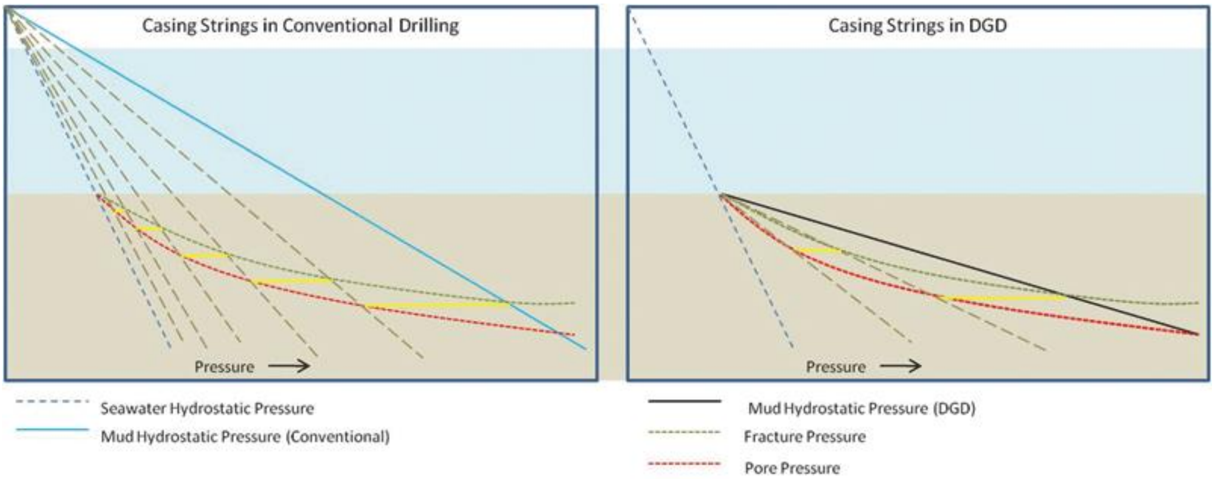


Figure 9 Conventional vs DGD pressure window [16]

3.2.1. The AGR riserless mud return system

AGRs riserless system is used on top-hole drilling, and utilizes the subsea pump to take returns from the annulus to the drilling vessel. The subsea pump is autonomously run, meaning that BHP is regulated to a set point. The speed of the subsea pump is used to regulate this, which means that a higher pump speed will remove returns quicker, leading to lower BHP. And on the other hand, lowering the pump speed will lead to slower mud return, and larger BHP.

The riserless mud system has several advantages. The main point to consider is that we now have a closed-loop system, which is in contrary to dumping straight to sea bed. This allows for an engineered BHP, removing the need for a riser. Drilling top-side can in some locations be challenging, such as for environmental sensitive areas. Having a closed loop, removes the need to dump returns to surface, and instead returns everything to the vessel. This is also convenient for volume control and kick detection. To give an example, if shallow gas is present during top-side drilling, having a closed-loop gives the vessel the possibility for monitoring if kick enters the flow. [5]

3.2.2. AGR Dual-gradient system and EC-drilling

AGRs dual-gradient system utilizes the concept as described in the introduction. The riser is filled with a secondary fluid, which enables the primary fluid to be relatively denser. This opens up the possibility for steering through a narrow drilling window. This system is most suited for deep-water wells, as replacing a large riser volume with a lighter fluid makes the well much more drillable.

In 2013 AGR Enhanced Drilling demerged from the AGR group, resulting in Enhanced Drilling. The dual-gradient system continued to develop, leading to the EC-drilling dual gradient system. [17] The system was built for PC Gulf Ltd. in 2011 [18], and was proven successful on 3 Caribbean wells [19].

3.3. Mud cap drilling

Sometimes the targeted formation is highly depleted or very naturally fractured, that lost circulation are ineffective during drilling. Mud cap drilling (MCD) is a MPD method developed to help with drilling operations where keeping circulation during drilling is challenging. This is solved by pumping fluid down the well bore and drill pipe, and injecting the mud into the formation fractures in the well, so drilling can continue. [5]

The way MCD drilling works, is that high viscous mud is pumped down the annular space. Then, a secondary light mud is used as drilling fluid. This secondary mud is often referred to as a sacrificial mud [12], as it is used as drilling fluid and is lost to the formations fractures. This creates a dual gradient pressure profile showed in Figure 10 MCD gradient profilesbelow.

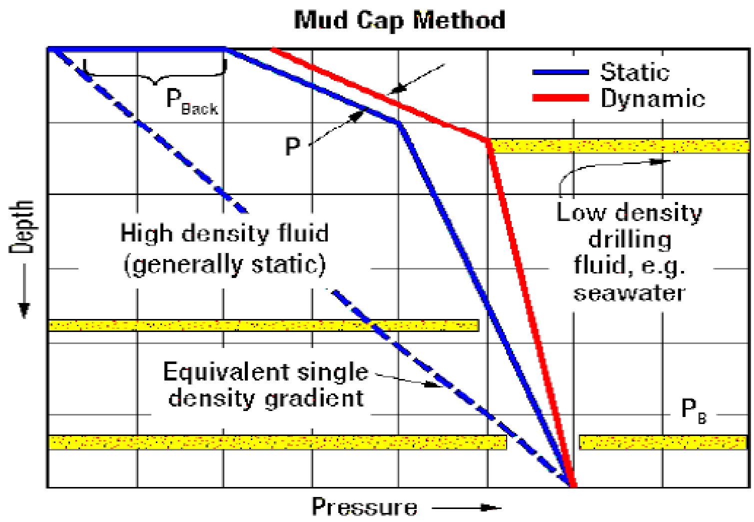


Figure 10 MCD gradient profiles [12]

3.4. Common MPD equipment

Below are some equipment that are critical to MPD operations. This does not include standard rig equipment, but rather equipment that is exclusively made for MPD operations.

3.4.1. Rotating control device

In order to have a closed circulation system, and to redirect the mud return to the choke manifold, a **rotating control device (RCD)** is mounted on the wellhead. The RCD shuts off the annular side of the wellbore, as well as allowing pipe to be rotated during drilling. Although the BOP below the RCD has an annular preventer, it is not rated for rotation of the pipe, thus the requirement of a RCD. The annular preventer is installed in addition to the BOP rams, as it is required to be able to strip the drill pipe into the pressurized wellhead. Figure 11 below displays the basic principle of a closed circulation system, with a BOP stack and a RCD. [5]

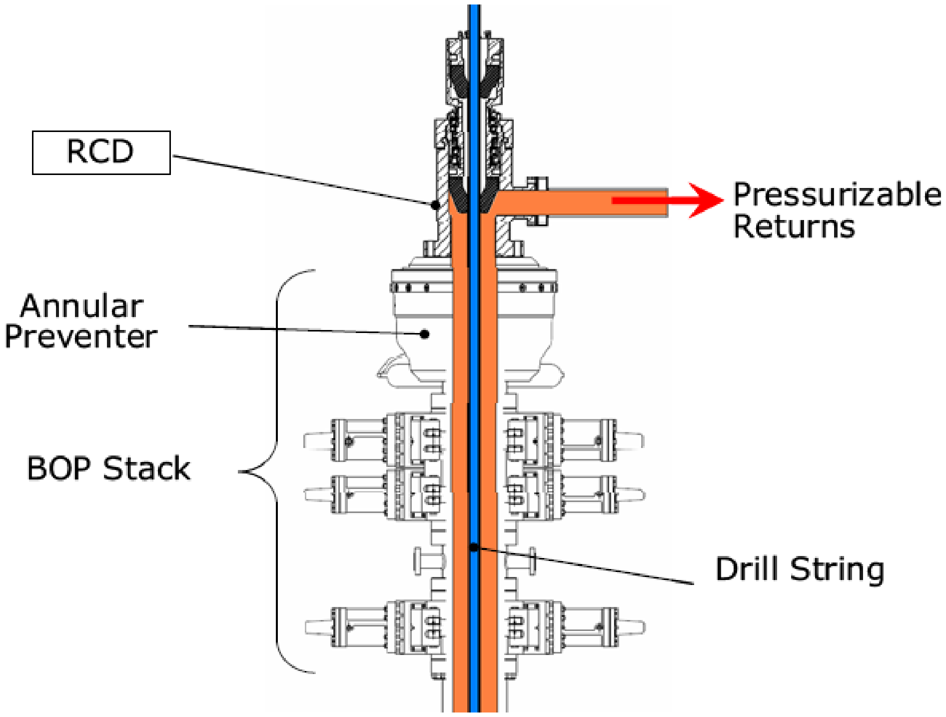


Figure 11 Weatherford RCD equipment [12]

We distinguish between two types of annular seals. The *passive systems* utilizes the well pressure to assist in the sealing. The RCD is used in a passive system. However, the *active systems* utilizes a rotating annular preventer, which is an external hydraulic pressure seal. A hydraulic ram is used to force the seal tight. [5]

3.4.2. Chokes

As mentioned earlier, MPD operations involves topside chokes to manipulate the BHP. These chokes are not to be confused with the standard well control chokes, as the well requires separate chokes for well control. The MPD chokes are constantly in use during drilling, and is extra equipment mobilized exclusively for the MPD rig up. Operationally, the chokes increase the pressure by decreasing the flow surface area through them.

Some common chokes used in MPD operations [5]:

- Power choke
- Swaco Super Choke
- Swaco Auto Super Choke

3.4.3. Backpressure pump

To maintain the wanted bottom-hole pressure, it is sometimes required to use a back pressure pump. Situations where this is required is during low-flow and/or when rig pumps are shut off, like they are when taking drillpipe connections. Then, closing the choke valve does not provide enough back pressure itself, and requires support from the back pressure pump.

3.4.4. Drillpipe Non-return Valves

Due to applying backpressure P_c during MPD operations, it is essential that we avoid a u-tube effect. This effect happens when annulus BHP is larger than drillpipe BHP, and fluid is forced up the drillpipe, which is problematic regarding well control and plugging of pipe. The non-return valve (NRV) is placed inside the drillpipe, and allows flow in only one direction. If fluid flows up the drillpipe, the valve shuts close, and stops the u-tube effect. Another word for a non-return valve, is a *float*, which is also common in other operations, such as during cementing.

Some NRV valves [5]:

- Basic Piston-Type Float
- Hydrostatic Control Valve
- Inside BOP (Pump-Down Check Valve)
- Retrievable NRV or Check Valve (Weatherford)

3.4.5. Downhole Annular Valves

The **Casing Isolation Valve (CIV)** is an annular valve integrated in the casing. A topside choke manifold solves the challenge regarding drilling with constant BHP. However, pressure instabilities when tripping is still an issue. The CIV is a flapper valve which closes when POOH past it. This makes it possible to trip above the valve without affecting the pressure profile below it. To avoid large pressure buildup, it is necessary to select as deep placement as possible. However, the valve requires the casing to be larger than necessary, which can be challenging regarding design of casing program.

Due to the requirement of larger casing for the CIV, the **Drilling Down-Hole Deployment valve (DDV™)** by Weatherford is designed. This tool allows for installation in standard casing programs. The mechanism itself isn't a standard flapper like the CIV, but rather a curved, saddle-type flapper, which is controlled hydraulically by a control line.

Halliburton has also designed such a valve, named **Quick Trip Valve (QTV™).** The valve is a fully mechanical valve, which requires no surface equipment.

3.4.6. Coriolis Flowmeter

A Coriolis flowmeter is a part of the closed circulation system, and is a measurement instrument that can measure:

- Mass flow rate
- Volumetric flow rate
- Density of mud
- Temperature

The flowmeter is based on the principle of Coriolis. The big advantage of using a Coriolis flowmeter compared to other flowmeters is the advantage of being able to have cuttings in the flow as it passes through the Coriolis flowmeter. [5]

3.5. Well control in MPD

Though MPD is intended to avoid kick or lost circulation situations; it is unavoidable to provoke a well control situation during drilling. This can be a result of wrongly predicted downhole properties of the formation, such as larger pore pressure than anticipated. Therefore, even though MPD systems are created to avoid well control situations, they need to be designed with methods for handling such a situation.

3.5.1. NORSOK guidelines on MPD operations

NORSOK D-010 chapter 13 covers MPD operations with regards to well integrity, and provides guidelines and requirements to follow. It states the acceptance criteria for MPD, with several remarks on required equipment and measures. For example, it is stated that the BHP shall be kept at a level above the maximum defined pore pressure, and shall also include a safety factor, which takes into consideration inconsistent BHP. Also, it also states that the secondary well barrier is the same as for conventional drilling. Furthermore, due to having an additional choke system for MPD operations; NORSOK states the requirement for having the flow path independent of the rig choke manifold. Meaning that the rig choke manifold shall always vacant for well control scenarios. [9]

3.5.2. Shut in procedures

When the BHP goes below the pore pressure, a kick situation can occur (See 1.4.2). A kick will keep flowing until the well is shut in, and the well bore pressure cam build up. We can mainly distinguish between two types of shut in procedures; a **soft shut-in** and a **hard shut-in.** [20]

- The **hard shut-in** procedure is defined as first shutting of the pumps, followed by a 15 minute flow check. If flow is detected, the BOP is closed. The choke line stays closed while closing the BOP.
- The **soft shut-in** procedure is similar to the hard shut-in, but the choke-line is opened when closing the BOP. It's not until after the BOP is closed that the choke-line is closed.

Which one of the two methods for shutting in the well to use are widely discussed. The hard-shut in results in an immediate pressure spike, as the flow is stopped instantaneously, and in worst case can lead to equipment failure or formation damage. The soft shut-in is much nicer with regards to pressure spikes, but the shut-in is slower, and could lead to more gas influx before shutting the well closed.

After well is shut in, either by using hard- or soft shut-in, one needs to stop the influx. By increasing surface back pressure, one is able to quickly increase the BHP above the pore pressure.

To be able to remove the influx, one mainly has two options with MPD systems: [21]

- If the influx is small, one can continue to circulate and reciprocate pipe while removing the influxes through RCD and MPD choke.
- The MPD choke is used to maintain a constant BHP, and pumps are shut off. BOP is then closed when well is in static conditions, and influx are removed using surface equipment.

A kicks severity is based on its volume and intensity, which are the defining factor when deciding to circulate it through the choke/kill lines, or the MPD choke. It is worth noting that circulating it through the MPD equipment means that the kick is circulated through the riser as well. The riser has a much larger diameter than the choke/kill lines, meaning that less hydrostatic pressure is lost when circulating the kick up the riser, instead of up the choke/kill lines. This leads to reduction in peak pressure seen at surface. [22]

3.5.3. Automated well control in MPD systems

Having an automated MPD system opens up the possibility of create an autonomous well control procedure. **The dynamic shut-in procedure** [20] is a method that uses a kick detection method, followed by shut in procedure and a pressure control. The procedure starts off with identifying a kick by its indications. Typical kick indications are pit gain and increase in return flow rate. More indications are given in Chapter 1.4.3. As MPD flow are close-looped, the Coriolis flowmeter is used to detect increase in return flow rate. Since we have a closed-loop system, the kick will also lead to increased friction through the MPD choke, which will lead to an increase in BHP. A combination of increased BHP and flow rate are good indicators of a kick in MPD operations.

After a kick scenario is identified, the dynamic shut-in procedure takes place. One starts off with setting a higher set point for BHP, and manipulating the MPD choke. Taking into account the current flow rate, one can also use the backpressure pump if one needs more pressure at the current rate. If the pressure increase has successfully stopped the influxes, the kick must be circulated out of the system by using a new kill mud, which can be calculated the following way:

$$\rho_k = k\frac{P_{BHP}}{gh} \tag{20}$$

- ρ_k Kill mud weight
- k Mud compressibility factor (Usually between 0.995-0.998)
- P_{BHP} Recorded BHP where kick stops
- g Gravitational constant
- h Well depth, TVD

Basically, an automated algorithm can be implemented to handle the kick:

1. Identify kick by monitoring BHP and flow changes. If anomalies are acknowledged as a kick: Initiate shut-inn procedure.
2. Increase BHP, either by decreasing MPD choke opening or by using back pressure pump, until influxes are stopped.
3. The new BHP is recorded, and used in order to calculate kill mud.

Chapter 4 - Using Labview to operate the rig

The rig is sketched in the figure below

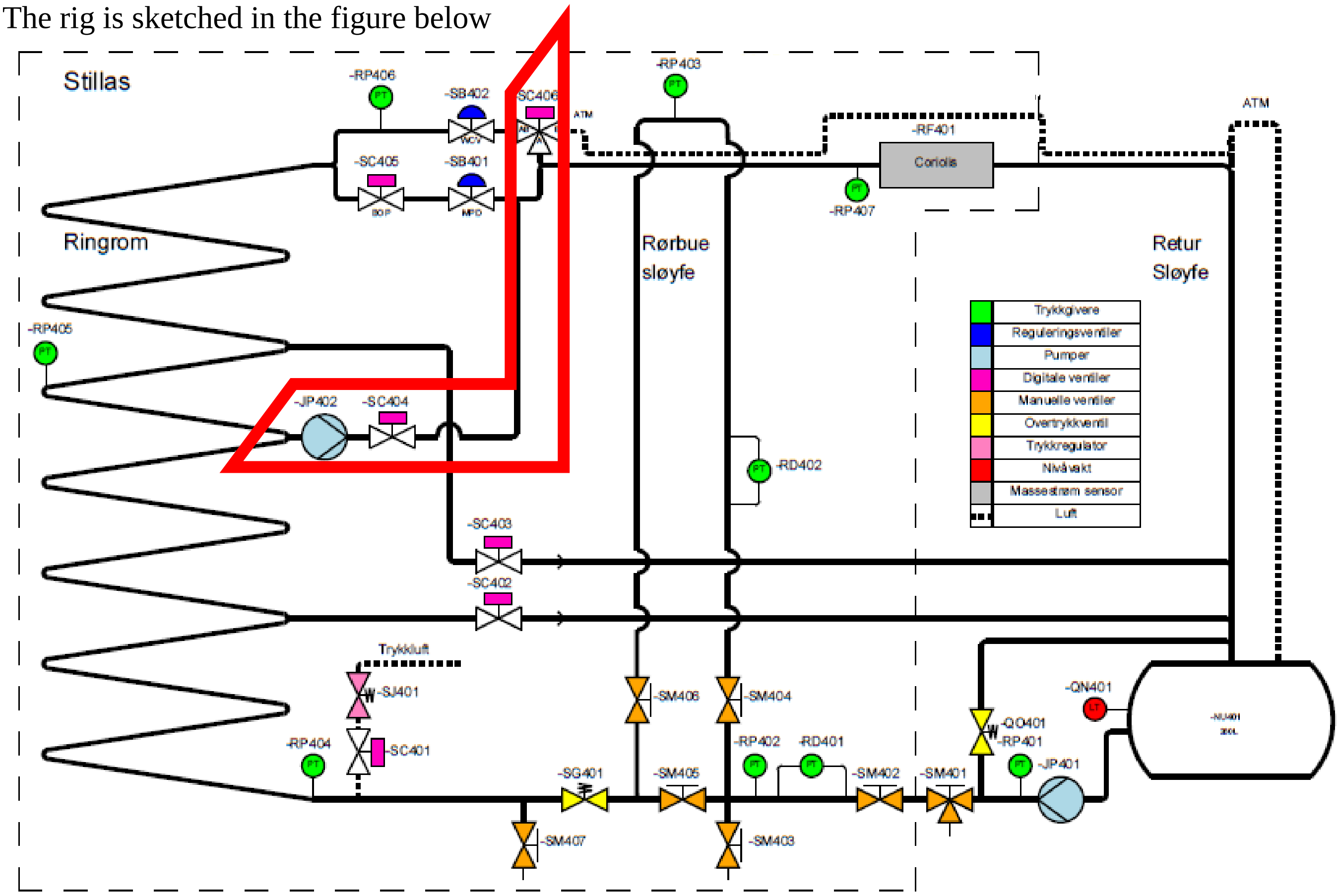


Figure 12 Sketch of rig

The rig was originally built in 2011/2012 for MPD operations. [1] In 2016 it was further developed, with adding a DGD system. The extension of the DG is marked in red in figure 12. A DG pump (JP402) and an electric valve (SC404) was added, in addition to a three-way valve (SC406).

Pump

The rig uses a PCM cavity pump (JP401) to circulate water from the tank and through the system. The pump itself is over dimensioned for its use, as the rig has a maximum pressure lower than what the pump can deliver. This means that one must set a maximum pump flow when operating the pump. Due to it running at lower speed than what it's dimensioned for, its cooling system is not working properly. It is therefore installed an external fan JV401 [2].

Choke valves

SB402 and SB401 are choke valves, which are pneumatically operated. They receive electrical signals from the PCs output, deciding an opening between 0 and 100%, where 0% is fully closed, and 100% is a fully open valve. SB401 is representing the MPD valve, where flow can be choked in order to manipulate the BHP. In case of a kick, SB402 represents the choke line from the BOP. The two choke valves are identical.

Pressure relief valve

A pressure release valve QO401 is installed near the pump outlet, which is calibrated to open at 5 bars. The valve redirects the flow from the pump straight back in to the tank. The valve is installed in case the pressure in the pipe gets dangerously large, risking leakages and burst of pipe. Closing valves while the pump is running will lead to a pressure build up in the system, making the pressure relief valve redirect the flow from the pump to the tank, releasing the pressure in the system.

Pressure sensors

The rig has several pressure sensors installed on different parts of the rig. The most important with regards to MPD operations, is the RP404 sensor. This replicates the BHP sensor, giving the pressure in the pipe after water exiting drill pipe. The rig also has a stand pipe pressure sensor (RP403), shut in casing pressure sensor (RP406), Coriolis pressure sensor (RP407) and pump pressure sensor (RP401), in addition to some other sensors.

Coriolis flow meter

Similarly to a real life MPD operation, a Coriolis flow meter is a part of the circulation system. The Coriolis measures flow out of the system, and can be used to detect anomalies, such as a kick. More information on the use of a Coriolis is seen in Chapter 3.4.6.

The Coriolis flow meter used in this system can only handle one type of fluid through it at a time. Meaning that when circulating out a gas kick, the combination of water and air will give distorted measurements.

Gas injection

SC401 is a solenoid valve, switching gas injection on or off, based on input from the PC. The gas is air, which is redirected from the same flow as the air operating the choke valves.

Opening SC401 gives a continuous flow of air into the bottom of the rig. Additionally, there is a mechanical valve after SC401, which must be opened as well. This can be used to manually choke the air injection when SC401 is in open position. SJ401 is a pressure gauge, which is used to measure the pressure of the air being injected.

4.1. Rig start-up procedure

To successfully start the rig, follow these steps:

1. Make sure all valves are in the correct positions for the desired flow path. Especially check the following valves: SM401, SM403, SM405 and SM407

Figure 13 Correct position for valves in flow position

2. The MPD- and WCV valves are pneumatically run. It is very important that the pneumatic is turned on before running the rig, as starting the rig with closed valves can lead to burst pipe.

   To turn on the pneumatic, follow the map in figure 14.

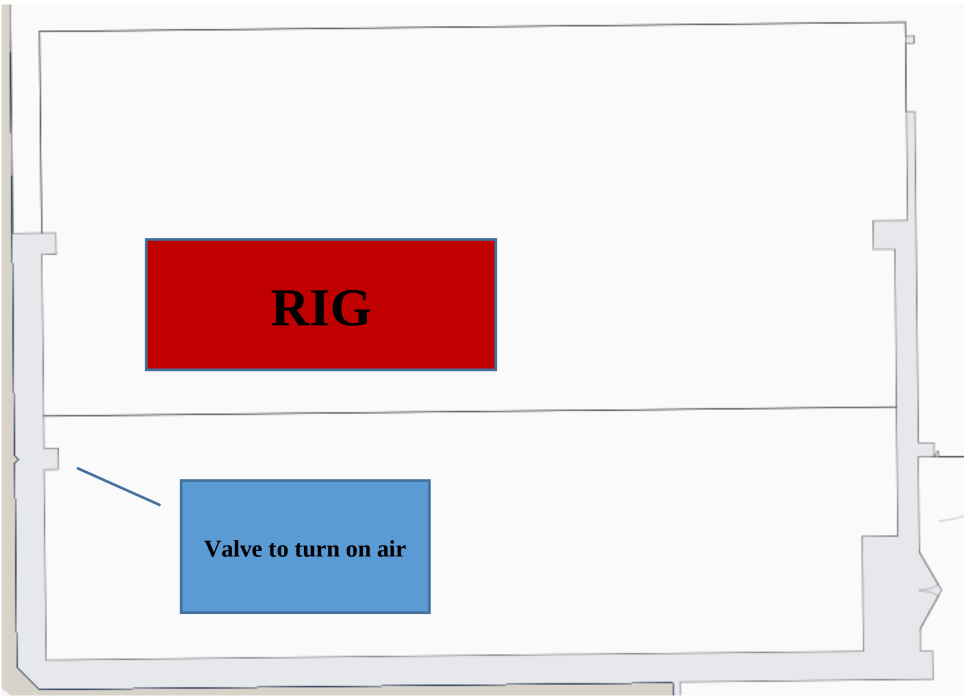


Figure 14 Map of lab with position of air valve

3. Make sure there is sufficient amount of water in the tank. Fill up the tank and monitor sensor QN401. The water level should be in between the minimum and maximum mark.

4. In the main fuse box, there are 3 switches for starting up all the components for the rig. The switches are marked in red in figure 15, and they must all be switches on in order to fully operate all the components of the rig.

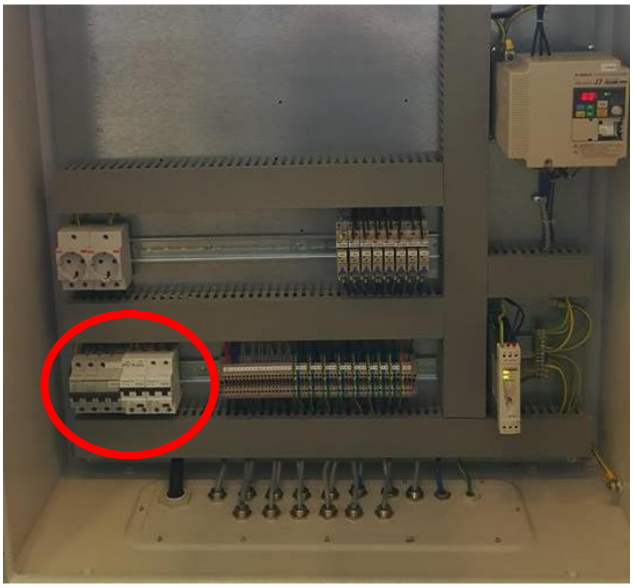


Figure 15 Main fuse box

5. Flip the switch on the secondary fuse box from AV to PÅ. Due to risks of short circuit due to leakages, the fuse boxes are separated, keeping the high voltage connections in a safe distance from the rig.

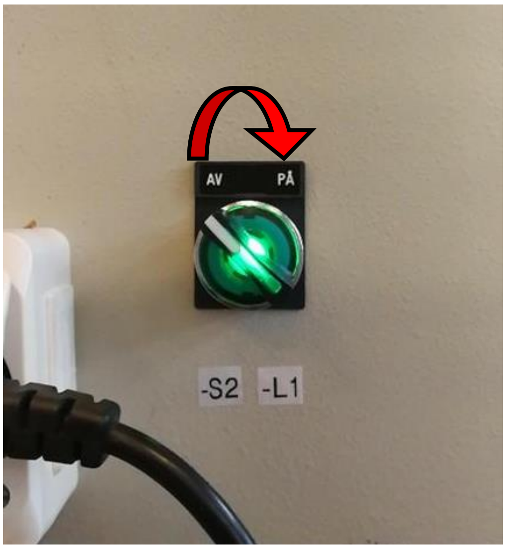


Figure 16 Secondary fuse box switch

6. Push the on-button on the PC to boot it up. LabView should start automatically after the PC is completed its boot-up. After LabView is opened, the script should be set to run automatically, opening the relevant valves and starting the fan for the pump.

Following is Chapter 4.2, describing the interface of LabView, and how to function the rig for manual operations.

4.2. How to use LabView to run the rig

The following setup is displayed when opening LabView:

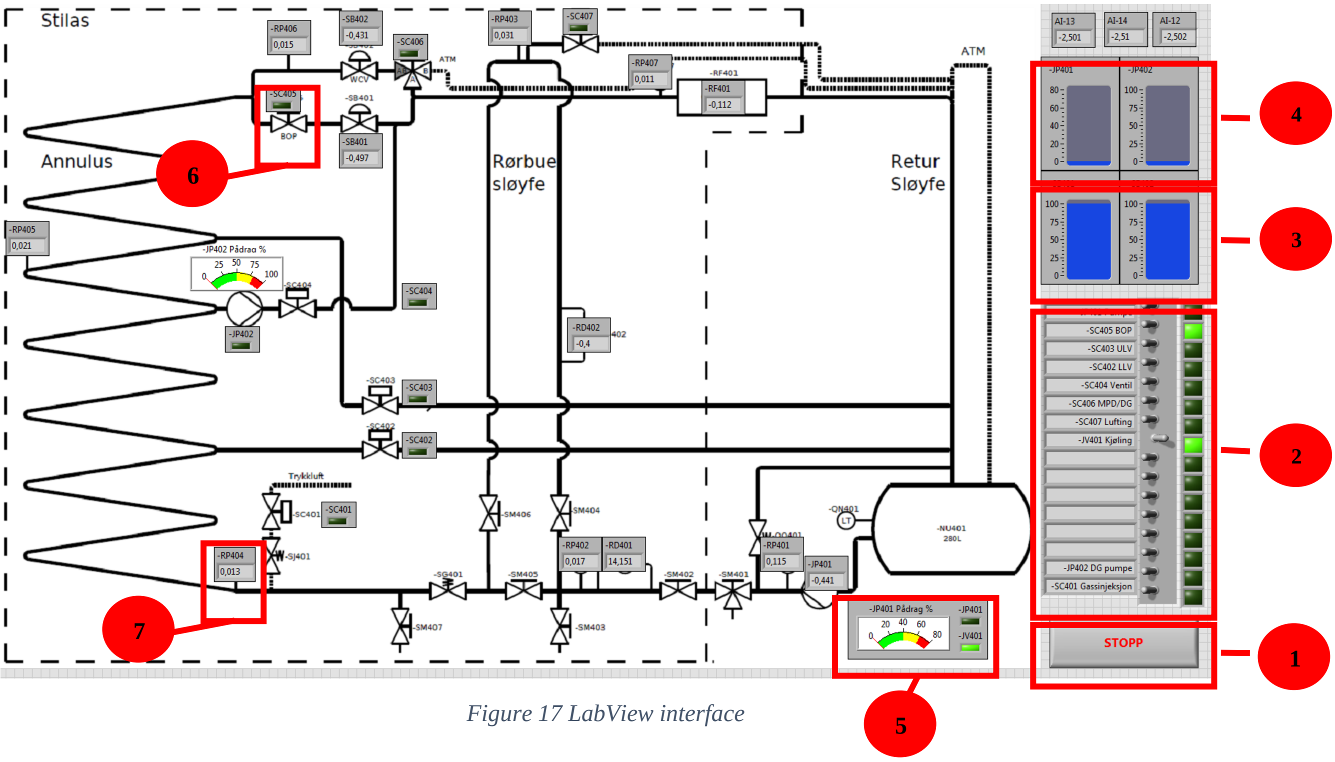


Figure 17 LabView interface

One can stop the script by hitting the button in the bottom right corner (1). Using the stop button stops the rig pump, as well as returning all components to their initial conditions. Meaning that valves such as MPD (SB401) will fully open when stopping the script. After the script is stopped, one can run it again by pressing CTRL+R.

The button panel on the right (2) is used to switch on and off components on the rig. The following components can be controlled by using the panel:

Component	ID
Rig pump	JP401
BOP close/open	SC405
Upper Leakage Valve (ULV)	SC403
Lower Leakage Valve (LLV)	SC402
Dual gradient valve	SC404
Fan for cooling	JV401
Dual gradient pump	JP402
Gas Injection Valve	SC401

Table 1 Operatable components in Labview

Panel #3 is used to adjust the opening for SB401 and SB402 (WCV and MPD valve). The opening is scaled from fully closed (0%) to fully open (100%). When booting up LabView, the valves are pre-set to fully open.

Panel #4 is used to regulate the effect for the two pumps JP401 and JP402. The unit for the two scales are in percentage, and the rig pump JP401 has a maximum of 80%, and the DGD pumps has a maximum of 100%. JP401 is over dimensioned for this rig, meaning that running it on high speed will result in too high pressure in the pipes. It is therefore available a window for monitoring the pump effect (5), alerting the user if the pump is running on higher than 40% of its max effect.

The pumps properties state that it can maximum pump 14 m^3/hr. This is equivalent to 233.33 lpm. Using equation 21 calculates the pumps flow in liters per minute using the % effect.

$$lpm = Effect\ (\%) * 233.33lpm \tag{21}$$

It is stated that one should pump at a maximum of 40%, which is equivalent to **93lpm**. This is relative to a fully open MPD valve. A smaller opening on the MPD valve will result in a lower maximum pump speed. The maximum pump speed is set as a safety factor, as high pressure and flow will lead to large vibrations on the rig. As the rig is made of lots of PVC bends and glue, it is not designed for large vibrations. Table 2 below shows maximum pump speed relative to MPD opening.

Valve opening	Q_{max} (%)	Q_{max} (lpm)
100	40	93
75	38	89
60	35	82
50	32	75
40	28	65
35	20	47
30	0	0

Table 2 Maximum safe pump flow based on MPD opening

There are indicators (#6) showing the status for the different electronic valves. Green light indicates open valves, where dark green indicates closed valve. There are also indicators (#7) available to show the value for the different sensors. Table 3 below shows the units for all the different components:

Component	Unit
JP401	%
RP401	Bar
RD401	mBar
RP402	Bar
RD402	mBar
RP403	Bar
RP404	Bar
RP405	Bar
RP406	Bar
SB401	%
SB402	%
RP407	Bar
RF401	lpm

Table 3 Components on MPD rig

Chapter 5 - LabView simulations

5.1. Effects of gas kick on BHP and flow

One can operate LabView to study the effects a gas kick has on the system. One especially wants to study the effect on BHP and Coriolis flow. From MPD well control theory, a gas kick will result in increased frictional pressure across the choke, which leads to an increase in BHP. [20] Additionally, the Coriolis flow measurement will increase straightaway, as a result of the additional flow in the system. These points needs to be validated by using the MPD rig.

One of the limitations on the rig, is that one does not have a meter measuring the gas flow through the system. The only thing one has available for flow measurement, is the Coriolis flow meter. It is wanted to calculate the kick size while the circulation system is flowing. In LabView, one can manipulate the script, to export all the data to Excel. Figure 18 below showcases a small section of the Labview script, which showcases how the script is changed to get the wanted data in Excel. Basically, the sensors are linked with a *Dynamic Data Attributes* box, before connecting to an array, which brings together the signals when inputting to the *Write to Measurement File* box. The *Dynamic Data Attributes* is inserted to name the columns in Excel, which cleans up the output file and creates an “out of the box”-ready export file.

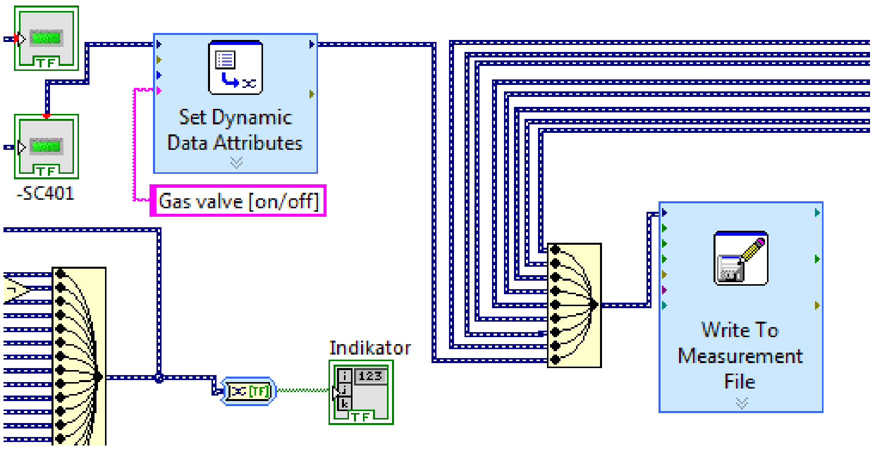


Figure 18 Editing Labview script view

The data that is selected to be exported is as followed:

- RP401
- RP403
- BHP
- RP406
- RP407
- Flow out (Coriolis)
- Flow in (Pump)
- Time elapsed
- Gas valve

The *time elapsed* column is a code created to record the time from the script starts running, until it is stopped. This is created in order to be able to have a time to relate to, with regards to comparing two measurements.

The gas valve column is a code returning either 1 or 0. When activating valve SC401 to inject gas, the code outputs 1 to Excel. This means that we can precisely capture how long we have injected gas for, by comparing the returns of 1 in the column with the time elapsed column. Additionally, we can study the effect of the Coriolis and the BHP when gas is injecting, and find out if there is any time delay as well.

So with injecting gas, we get the following data:

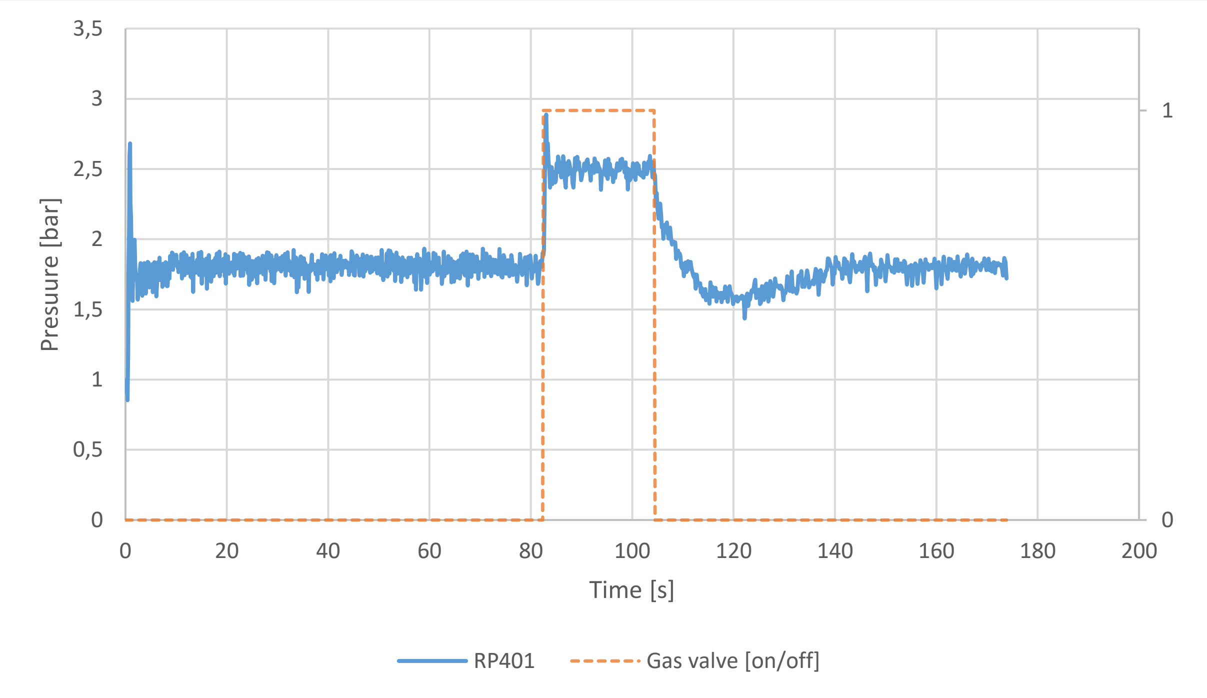


Figure 19 RP401 test results, gas injection

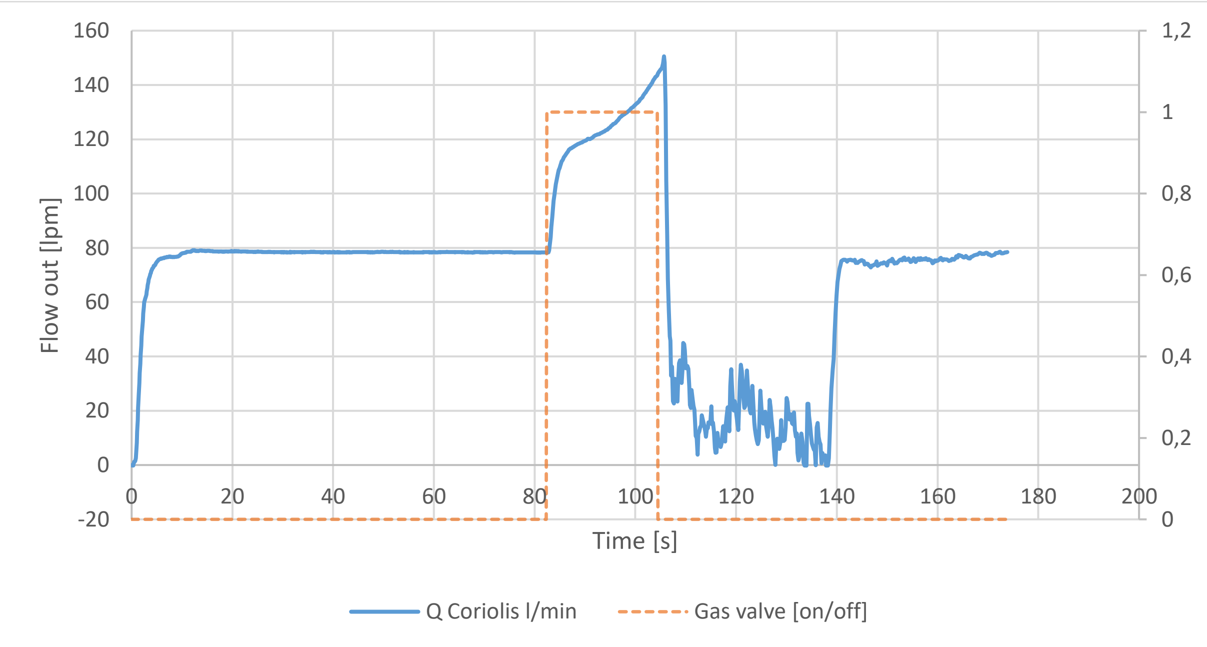


Figure 20 Coriolis test results, gas injection

Figure 19 and 20 shows the raw data of the BHP and the Coriolis flow meter respectively. The orange line displays the time interval for gas injection. By reading the raw data, the gas was injecting for **22.04 seconds.**

One can confirm that gas injection leads to an immediate increase in BHP, due to the increase in frictional flow through the system. In addition, the Coriolis flow meter responds instantly to the gas injection. Figure 20 shows an S-shaped curve when gas is injecting, and the flow keeps increasing a few seconds after the gas influx is stopped. However, we see a sudden drop in the flow measurement. This is a result of the influx reaching the Coriolis. A combination of water and air flow through the Coriolis creates clustered and arbitrary data. This is due to the properties of the Coriolis flow meter, which states that it is only intended for one fluid at a time.

One thing that is interesting to have a look at, is how the BHP goes below its initial state while the air is circulating out of the system (Time 104s – 137s). First, the BHP decreases due to air leaving the system, and therefore decreasing the additional friction pressure. Also, the BHP even more than its initial value. When injection stops and the gas mitigates up the annular, it expands because of the pressure differences. At this point, the drop in BHP because of lower hydrostatic head is more dominant than the frictional pressure drop across the choke. When the annular is completely free of gas, the BHP is back to its initial state.

5.2. Calculating a large gas kick size

NORSOK D-010 chapter 13.3.3 states the following with regards to MPD operations:

"*A minimum kick tolerance shall be specified. Based on the MPD system's capability of recognizing small influxes and minimizing influx volumes, the kick tolerance can be smaller than for conventional operations."* [9]

As drilling of a well requires a knowledge of the kick tolerance; being able to determine how big a kick one is taking is crucial. Meaning, risking an influx larger than the kick tolerance, can lead to unwanted well control situations. Therefore, one wants to find out how to calculate the gas kick on the MPD rig.

One wish with regards to the rig, was to get another flowmeter, which records the gas flow from the inlet (SC401). However, it was decided against this, and one rather went with a calculation approach. A Matlab script is written, which acts as a post analysis calculation. The script calculates the gas size based on data exported from Labview. This code can be viewed in Appendix A. The first part of the code is for importing all the columns from Excel. The import section of the code is designed to be independent of rows, as the number of rows vary from each experiment. This makes it quick to import the desired file, and do the necessary calculations.

Generally, to calculate a gas volume, one simply uses Equation 22:

$$V_g = Q_g * t \tag{22}$$

V_g Volume gas

Q_g Gas flow

t Injection time

When injecting the gas, Coriolis records the increased flow. The difference between the initial flow, and the new and increased flow, determine the gas flow. Which on equation form is displayed:

$$V_g = \int_{t1}^{t2} (Q - Qi)dt \tag{23}$$

V_g Volume gas

Q Flow (gas + water)

t_1 Injection start

t_2 Injection stop

Q_i Initial flow

By summing the number of samples between start of injection time, to end of injection time, one is able to calculate the gas volume in Matlab. Figure 21 below shows the plot for the calculations from the Matlab script. As described in Chapter 5.1, we see an S-shaped curve when gas is injecting. Q_{gas} is the gas flow calculations at each sample. We get the volume by summing all the samples together, and multiplying by *dt*, which is the time of the experiment per sample.

We can basically write the total volume as:

$$V_{mix} = V_l \alpha_l + V_g \alpha_g \tag{24}$$

V_{mix}	Volume of mixture in system
V_l	Volume liquid
V_g	Volume gas
α_l	Volume fraction liquid
α_g	Volume fraction gas

From initial conditions, $\alpha_g = 0$. When gas starts injecting, the volume fraction of gas increases. The total volume of liquid stays constant all the time, as we do not change the pump rate. Meaning that the total volume, V_{mix}, increases during injection. This is shown in Figure 21 and Figure 24.

Additionally, a low pass filter is applied to the values, which eliminates high frequency noises. The script for the low-pass filter can be found in Appendix A.2.

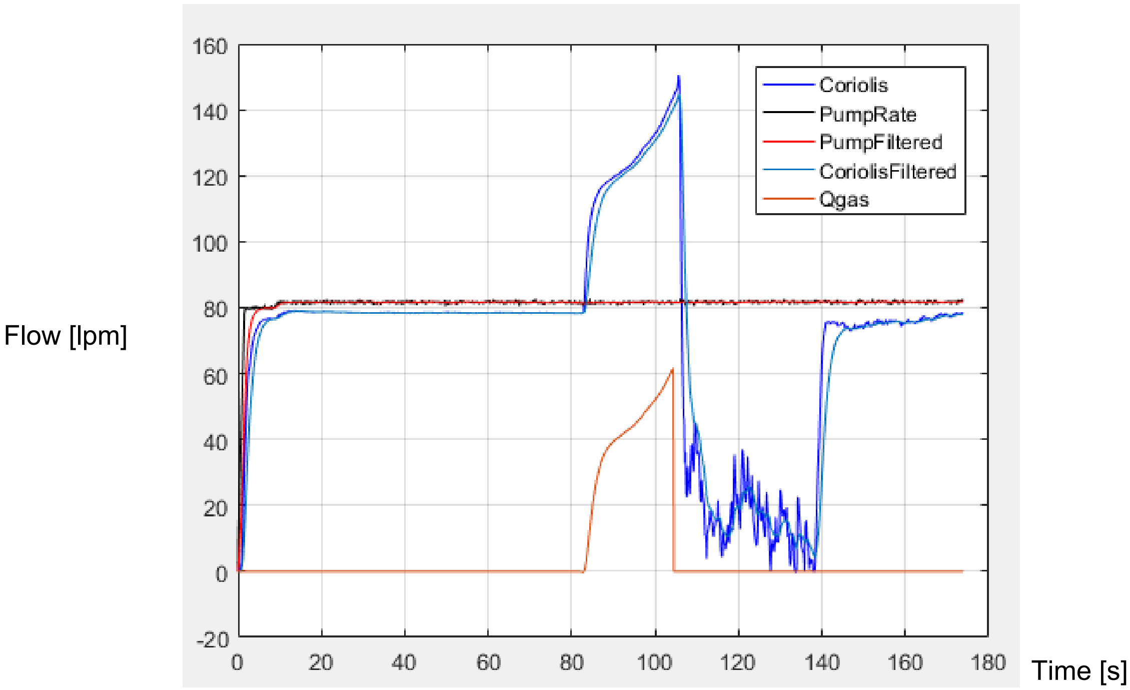


Figure 21 Figure 1 generated by Matlab Script, large volume

To be able to calculate the mass of the gas by using the calculated volume, one first has to calculate the density of air. As air is a highly compressible fluid, one has to calculate the density by using the ideal gas law. The injection pressure can be read using the manometer at injection inlet. This is constantly 3 barg. We can calculate the mass of the gas from the source, which simulates a reservoir. A summary of the results can be found in Table 4.

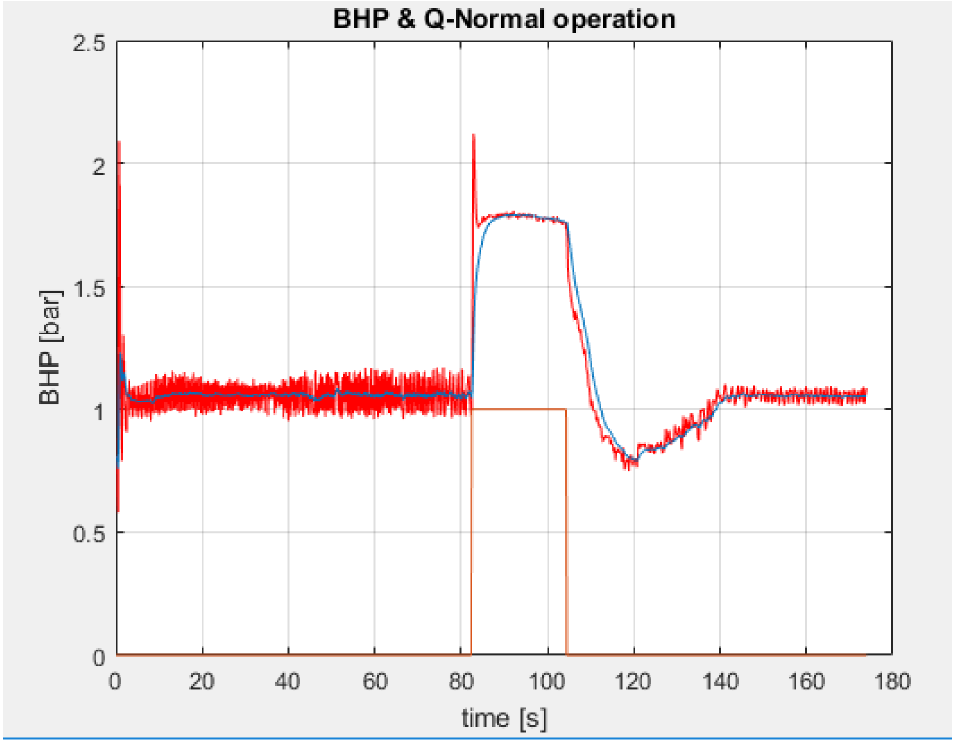


Figure 22 Figure 2 generated by Matlab Script, large volume

Figure 22 shows the generated BHP plot. The low-pass filter is applied to the BHP as well, due to the sensor measuring lots of noise. The results shows a smooth and elegant, filtered plot.

Below is a summary of the results generated by the Matlab script:

Parameter	Value	Unit
BHP before gas injection	1.06	Bar
BHP after gas injection	1.76	Bar
ECD before gas injection	2.51	s.g.
Pump flowrate	81.61	Lpm
Time injection	22.04	Seconds
Gas Volume	14.7	Liters
Gas Mass (Reservoir)	71.0	Grams

Table 4 Test results for large kick size

5.3. Calculating a small kick size

In addition to calculating the volume of a large volume as in Chapter 5.2, a simulation is also done on a small kick size. To be able to inject a small volume, one simply injects air at a shorter time period. The results are shown below.

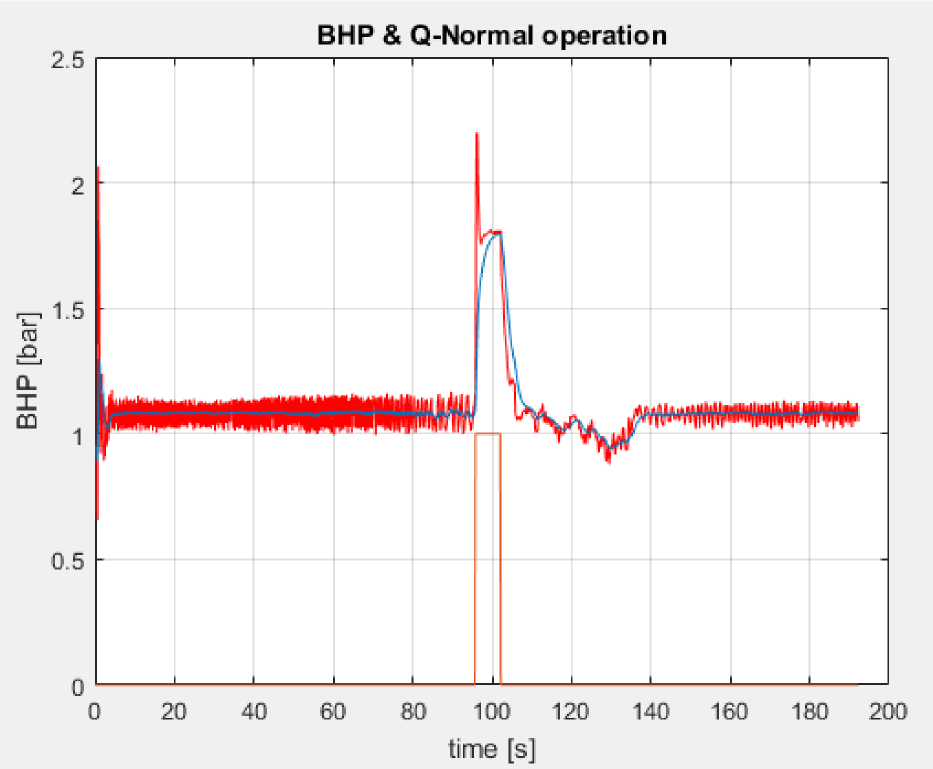


Figure 23 Figure 2 generated by Matlab Script, small volume

The same BHP trends as for the large volume are seen on the small volume. The maximum BHP value is similar to the large kick size. Due to injecting a smaller volume, there is a time period between injection stop, and until the gas reaches Coriolis. BHP starts to decrease as soon as injection stops. There is still the same trend of BHP going under its initial value after going through Coriolis.

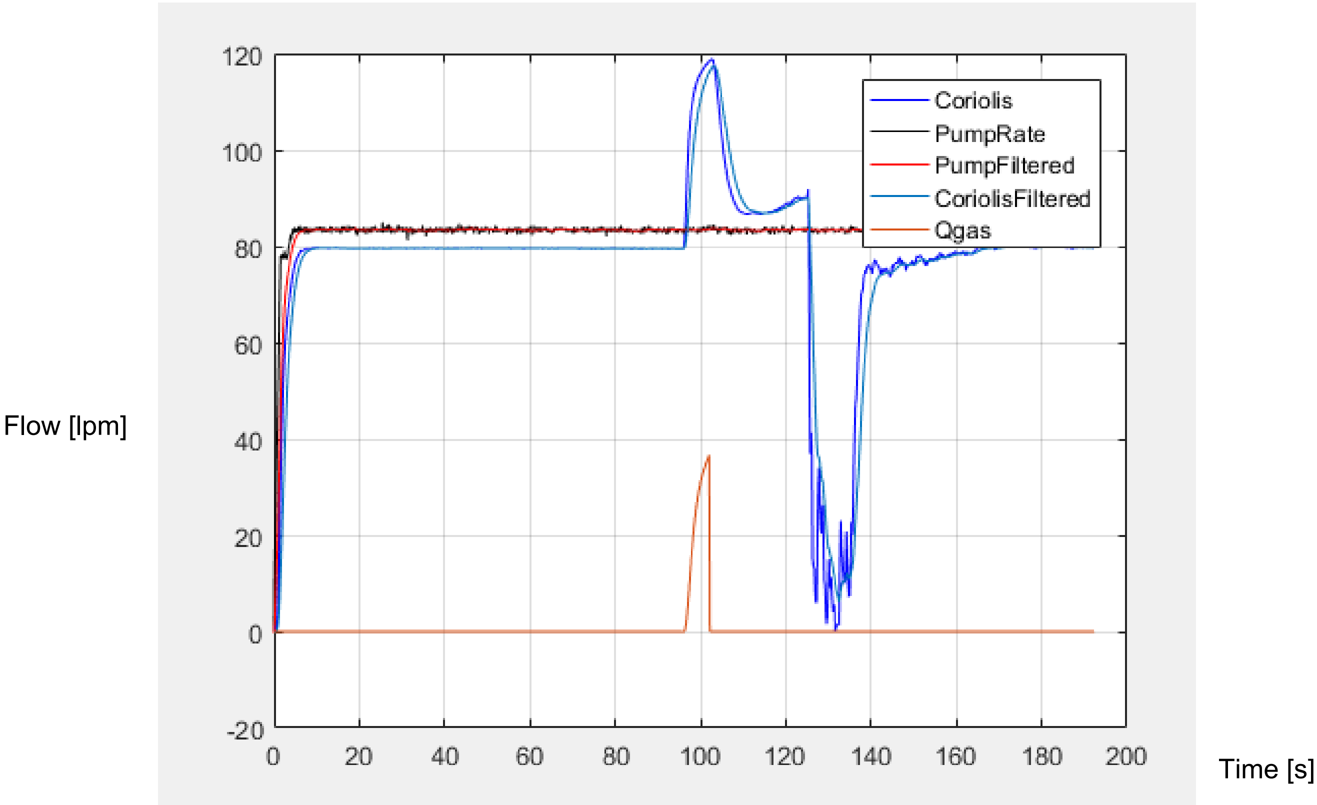


Figure 24 Figure 2 generated by Matlab Script, small volume

Due to a smaller volume of gas is injected to the system, the flow does not peak at the same point (≈120lpm) as for the large volume (≈150lpm). The plot is also subject to the time period before gas reaches Coriolis. The table below provides a summary of the calculated variables:

Parameter	Value	Unit
BHP before gas injection	1.08	Bar
BHP after gas injection	1.77	Bar
ECD before gas injection	2.56	s.g.
Pump flowrate	83.44	Lpm
Time injection	6.37	Seconds
Gas Volume	2.24	Liters
Gas Mass (Reservoir)	10.83	Grams

Table 5 Test results for small kick size

5.4. Circulating out a kick

In this experiment, a kick is taken during circulation. Initially, we have MPD valve opening of 75% and flow of 42 lpm, which gives a BHP equal to ~0.7bars. We then take a gas kick at t=38 seconds. We immediately recognize this as a gas kick, due to the increase in BHP and flow rate. This is shown in Figure 25 below.

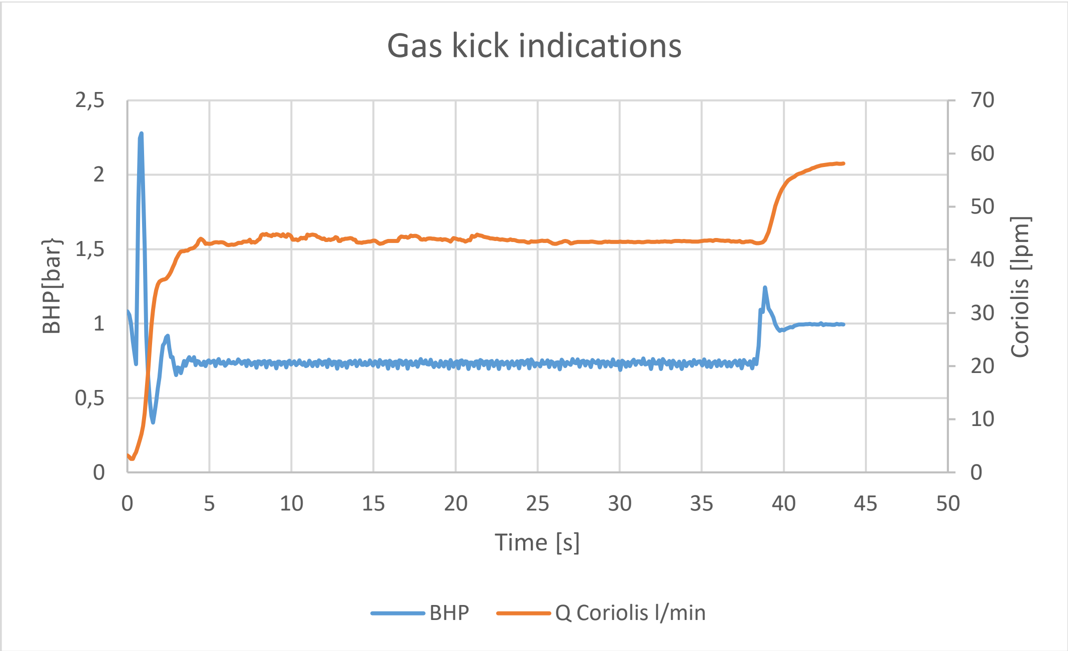


Figure 25 Gas kick indications

To be able to circulate out the kick safely, we use the **soft shut-in method** (Chapter 3.5.2). We follow the procedure below for shutting in, and circulating out the kick:

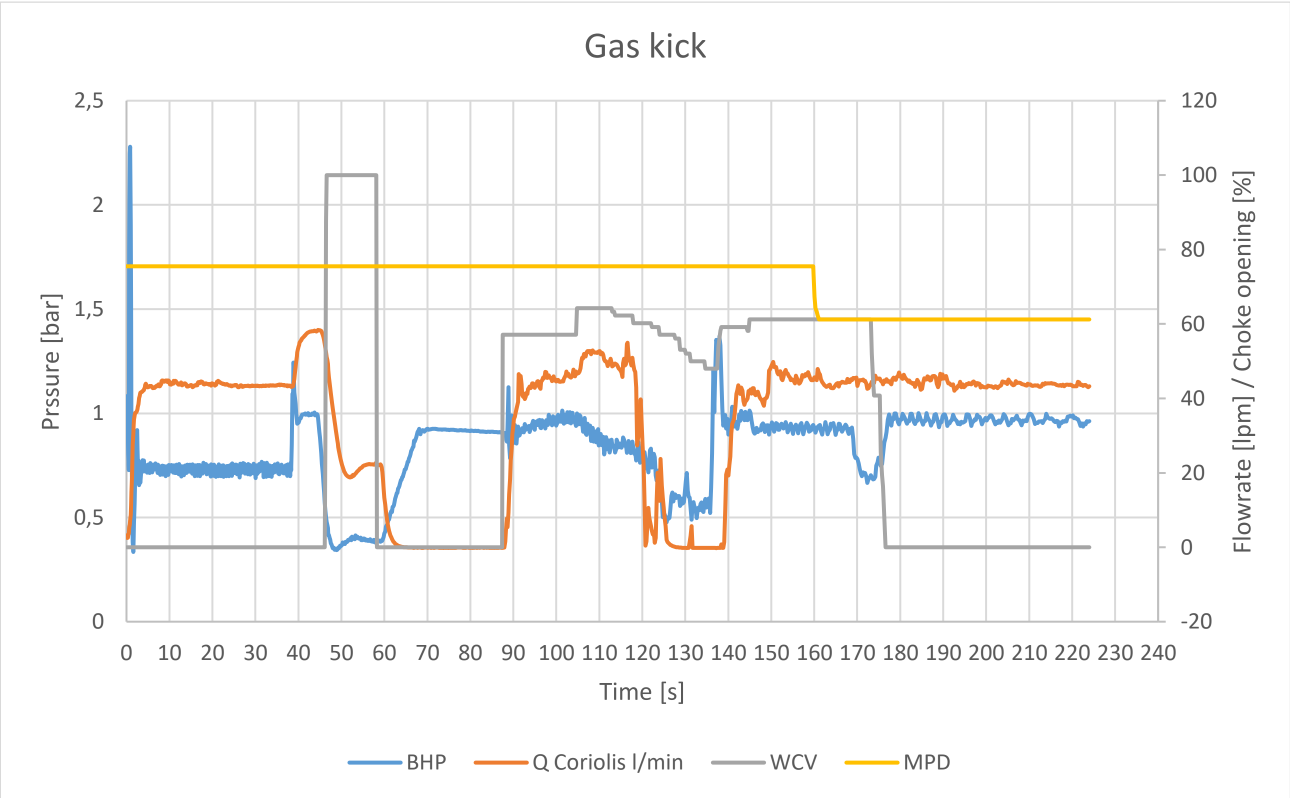
1. WCV stays closed during circulation.
2. Gas kick is taken
3. Stop pump
4. Open WCV
5. Close BOP
6. Close WCV
7. Gas influxes stops. Note BHP where influxes stops (= P_s).
8. Open WCV
9. Start pump. Manipulate WCV opening to keep BHP above P_s.
10. Circulate out kick while maintaining BHP avove P_s.
11. When stable BHP is reached, set MPD opening equal to WCV.
12. Open BOP and close WCV. Continue circulating.

The influx will keep flowing after the well is shut in, until the pressure in the well is large enough to stop the influxes. In LabView, we cannot set pore pressure properties. We therefore manually stop the gas injection. In this case, we stop the gas injection at BHP ≈ 0.9 bar. This means that we need to keep the BHP above 0.9 bars for the coming circulations.

After shut-in and when the well has been stabilized, we have to open the WCV and start the rig pump to circulate out the kick. When doing so, we have to keep the BHP above 0.9 bars. This can be done by manipulating the WCV opening. This proved to be hard on the simulator rig, as we are operating at such a small dimension.

After kick is circulated out, and a stable BHP is obtained, we can open the BOP again to continue drilling. To avoid having fluctuations in BHP when opening BOP, we mirror the MPD choke opening to the WCV opening. By doing this, we can open the BOP and close the WCV without seeing a drop in BHP.

The result is as follow:



Time [s]	Action	Comment
38	Gas injection start	We see increase in BHP and flow
45	Pumps are shut off	To react to the kick, we shut off the pump. Drop in BHP & flow.
46	WCV is opened	We open WCV as a part of the soft shut-in method
47	BOP is closed	We close BOP as a part of the soft shut-in method
58	WCV is closed	We close WCV as a part of the soft shut-in method
87	Open WCV	After influx stops, and well is stable, one can start to circulate out kick
87-160	Manipulate WCV	Manipulate WCV to keep BHP above 0.9 bars
160	Set new MPD opening	The new MPD opening set equal to the WCV opening that keeps a stable BHP after kick is circulated out
167	BOP is opened, and WCV is closed. Pump starts.	Continue circulating with new BHP = 0.9 bar

Table 6 Kick shut in and circulation time history

First of all, the dimensions of the operating window is very small compared to a real life drilling rig. When the pump is shut off at t = 45s, the BHP reduces to ~0.4 bars. This is something we cannot compensate for. Ideally, we could have a backpressure pump, which could compensate for the drop in BHP.

After t = 87 seconds, the kick is circulating out of the well. The WCV is used to manipulate the BHP, to try to keep it above 0.9 bars. This is not easy to do when the dimensions are so small, which is why the BHP is so low in the timeframe t = 110 – 140. Circulating out a kick while manipulating the choke is something that requires experience. Drilling contractors have training with regards to handling a kick, which is why this circulation is not quite as good as it could have been. One proposal is to implement a fully autonomous shut in and circulation procedure on the rig.

The circulation is similar to the Drillers Method (Chapter 1.4.5). The method states that the well should be killed afterwards with a kill mud. On this rig, we do not have the possibility to change the density of our drilling fluid. We therefore use the MPD valve to set the new BHP after kick is circulated out of the well.

Chapter 6 - Simulink

6.1. How to use Simulink to automatically operate the rig

Simulink is a software integrated in Matlab, which uses graphical objects to program and simulate dynamical systems. It uses block diagrams to link inputs and outputs, which makes it simple and user-friendly. Analog signals are recorded and input in the program, where the block diagrams links the signals with automation algorithms. Two PID controllers are in place. One regulates the BHP, and one regulates the flow rate.

To be able to run the program, take the following steps:

1. Close Labview if open.
2. Open C:/rigg/Oppstart_utgangspunkt.m, or use the desktop shortcut. This will open the Matlab script.
3. Inside the script, one initially has to decide if one wants to active kick and/or leakages situations during automation simulations.
    - BronnspartLekkasje = 1 activates kick and loss simulations
    - BronnspartLekkasje = 0 deactivates kick and loss simulations
4. Select either 'MPD' or 'DG' to select which mode one wants to run the rig.
5. If BronnspartLekkasje = 1, select the parameters for kick and loss simulations.

Variable name	Definition
LekkasjePaaOver	Fracture pressure [bar]. At which pressure does the leakage valves open.
LekkasjeAvUnder	Closing pressure [bar]. At which pressure does the leakage valves close.
LekkasjePulseringDrift	Leakage happens in pulses (1=on, 0=off)
LekkasjePeriodeTid	Time period per pulse [s]
LekkasjeDriftssyklus	Percentage [%] of operating cycle maximum on-time
BronnsparkPaaUnder	Pore pressure [bar]. Under which pressure should air injection activate.
BronnsparkAvOver	Determines at which pressure the influxes stop. This is usually slightly larger than Pore Pressure
BronnsparkPulseringdrift	Air injection happens in pulses (1=on, 0=off)
BronnsparkPeriodeTid	Time period per pulse [s]
BronnsparkDriftssyklus	Percentage [%] of operating cycle maximum on-time

Table 7 Matlab variables

6. Run the script by selecting ‘run’ at the toolbar at the top. This needs to be done prior to running the automation script in Simulink.
7. Run MPD.slx or DG.slx from the left hand side window
8. Follow Figure X to maneuver through the Simulink program.

6.2. Simulink interface

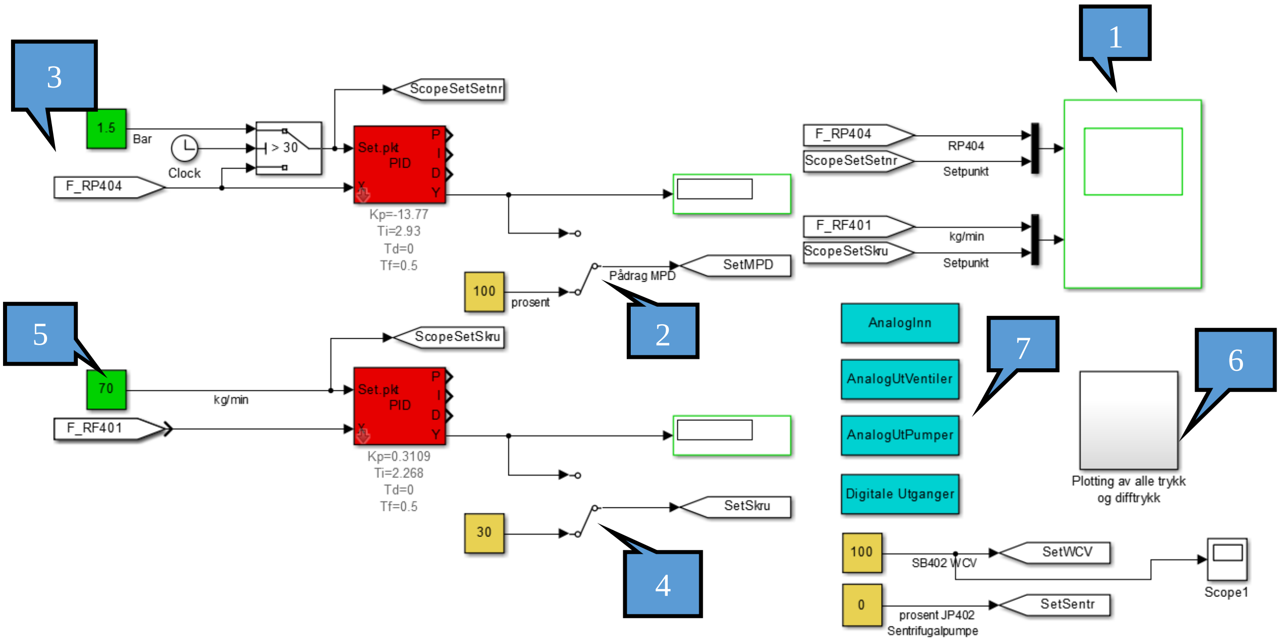


Figure 26 Simulink interface

1. Double click to view graph for RP401 and set point.
2. Switch to run MPD in automated mode or manual mode. In manual mode, one selects valve opening (%). In automated mode, one uses the PID controller to regulate to set point, 3.
3. Set point for BHP
4. Switch to run pump in automated mode or manual mode. In manual mode, one selects pump gain. In automated mode, one uses the PID controller to regulate to set point, 5.
5. Set point for flow in kg/min
6. Double click to view an extended graph with all pressure sensors.
7. By opening these boxes, one can view all the inputs and outputs, as well as studying the code.

The code is written by Tor Bonham-Forus og Otto Drangeid [2]. To be able to get other graphical output values, one can insert blocks and connect them with the *Scope* (6 in Figure 26). This makes it possible to export the values one wants to study. This is done to study the performance of the PID-controller for MPD regulation, as one suspected bad performance at high BHP.

6.3. Tuning the PID by using Skogestads method

There are several methods for PID tuning available. Ziegler-Nichols is an old and proven method, which is widely used in the process industry. In addition, software tools exists, which can tune PID controllers accurately. One could also tune PID controllers manually, by trial and error. However, this requires experienced personnel, which not always are available.

The Skogestad method is a model-based tuning method, where the PID parameters are calculated directly from the transfer function model of the process. The control system is assumed to have a transfer function similar to Figure 27.

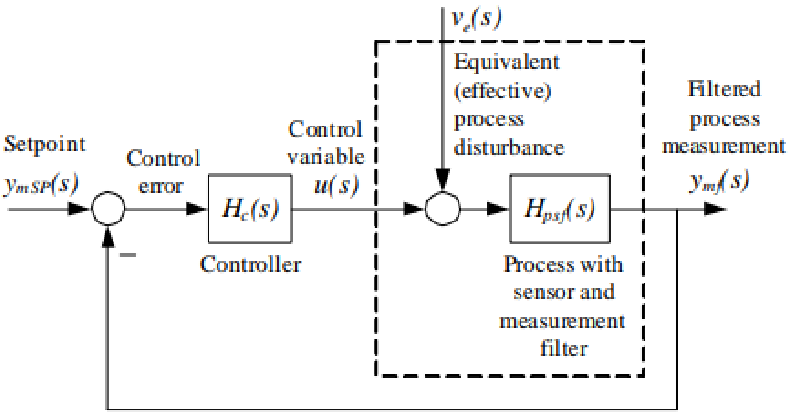


Figure 27 Block diagram Skogestad [23]

Skogestad presents the following equations for calculations of the PI(D) variables:

Process type	$H_{psf}(s)$ (process)	K_p	T_i	T_d
Integrator + delay	$\frac{K}{s}e^{-\tau s}$	$\frac{1}{K(T_c+\tau)}$	$c(T_{C+}\tau)$	0
Time-constant + delay	$\frac{K}{Ts+1}e^{-\tau s}$	$\frac{T}{K(T_c+\tau)}$	$\min[T, c(T_{C+}\tau)]$	0
Integr + time-const + delay	$\frac{K}{(Ts+1)s}e^{-\tau s}$	$\frac{1}{K(T_c+\tau)}$	$c(T_{C+}\tau)$	T
Two time-const + delay	$\frac{K}{(T_1 s+1)(T_2 s+1)}e^{-\tau s}$	$\frac{T_1}{K(T_c+\tau)}$	$\min[T_1, c(T_{C+}\tau)]$	T_2
Double integrator + delay	$\frac{K}{s^2}e^{-\tau s}$	$\frac{1}{4K(T_c+\tau)^2}$	$4(T_{C+}\tau)$	$4(T_{C+}\tau)$

Table 8 Skogestads equations for PID selectio

Definition of variables:

K_p - Gain regulator

T - Time constant

K - The gain of the process

τ - Time delay

c - Scaling factor. Recommended is c = 1.5 for quicker disturbance compensation

T_C - Specific time-constant.

To get the variables, the MPD valve properties are recorded. The time delay and time constant is recorded two times. First by recording a negative gain, changing the valve opening from 60% to 55% open, followed by a positive gain, opening the valve from 55% to 60%. The BHP change is recorded as well when doing this. This data is recorded when circulating with 77 LPM.

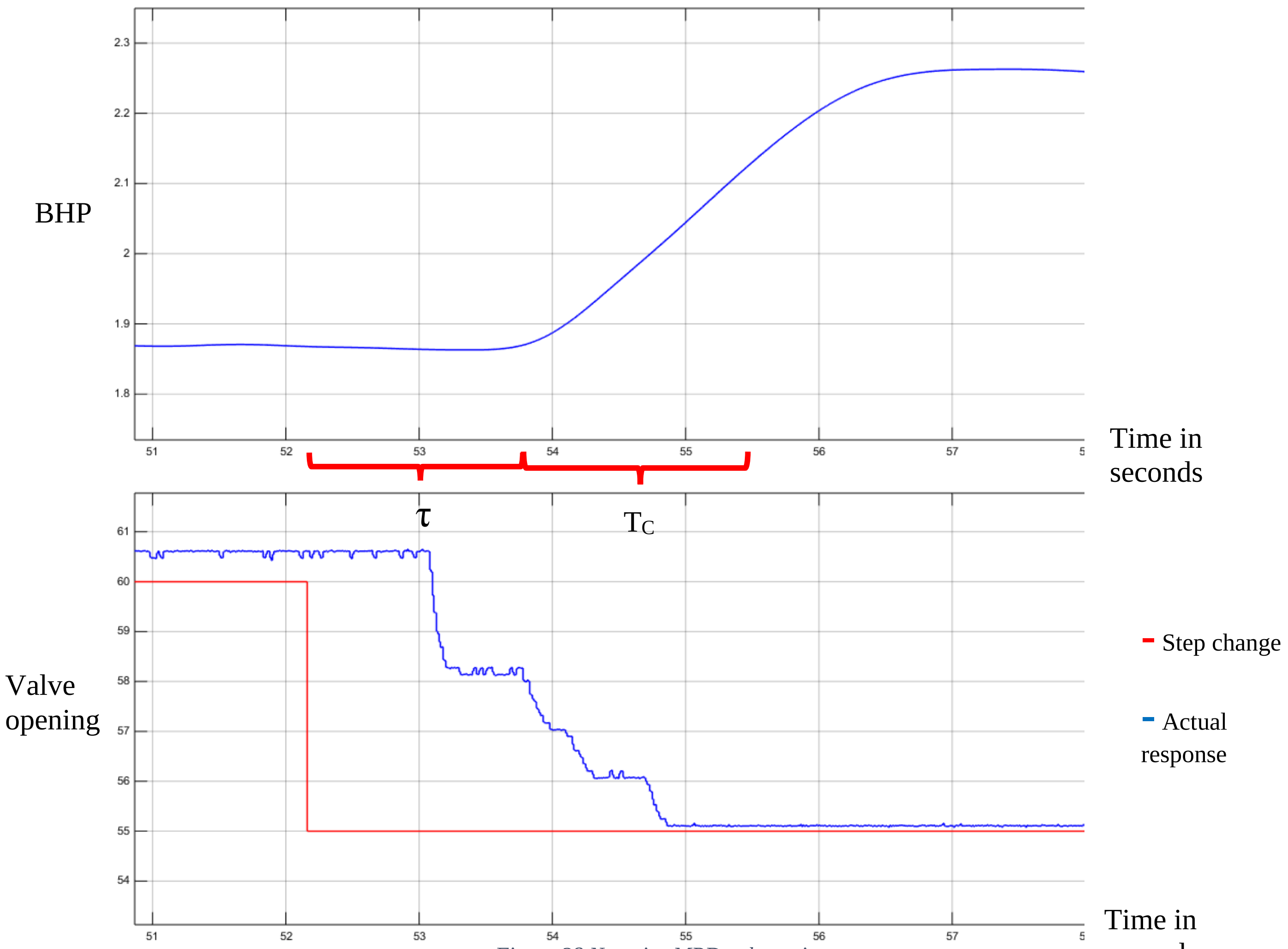


Figure 28 Negative MPD valve gain

After inputting a new valve opening value, there is a time delay before it actually reacts. This is defined as the time delay (τ). Skogestad also defines the constant T_C, which is the time from the end of the time delay, until 63% of the set point. Both values are shown in red in the figure above.

To be able to identify the process type for the system is challenging, and requires experience and advanced methods. Therefore, process identification is not part of this thesis. The "Time-constant + delay" process from Table 8 is selected. This is based on the equation including time-delay, and not including a derivative term, which as we stated in Chapter 2.2.3 can lead to an unstable controller.

We calculate the following parameters:

- Time delay (τ) = 1.34 seconds
- Time constant (T) = 2 seconds
- K = 0.395 / -5 = -0.079

Skogestestad suggests using Tc = τ [23]. We use these parameters to calculate the proportional and integral term:

$$Kp = \frac{T}{K(Tc+\tau)} = \frac{2}{-0.079 * (1.34 + 1.34)} = \mathbf{-9.446} \tag{25}$$

$$Ti = \min[T, k1(Tc + \tau)] = \min[2, 1.5 * (1.34 + 1.34)] = \mathbf{2} \tag{26}$$

We conduct the same calculations, but with a positive gain. We increase the opening from 55% to 60%, and export the data into graphs:

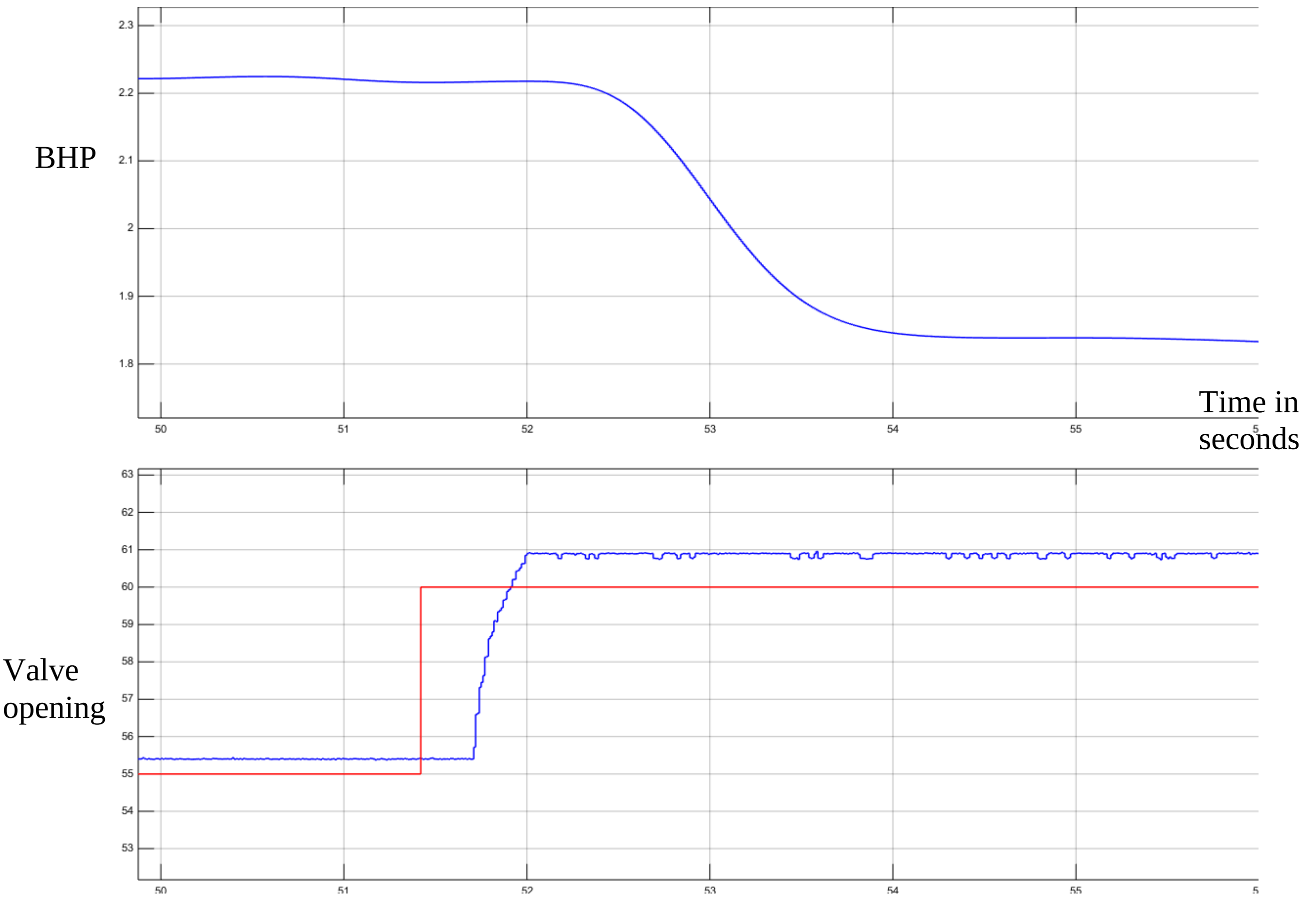


Figure 29 Positive MPD valve gain

Time in seconds

We calculate:

- Time delay (τ) = 0.73 seconds
- Time constant (T) = 1.03 seconds
- K = 0.395 / 5 = 0.079

We notice that the valve is quicker to open, than to close. Again, we calculate the proportional and integral terms:

$$Kp = \frac{T}{K(Tc + \tau)} = \frac{1.03}{0.079 * (0.73 + 0.73)} = 8.93 \tag{27}$$

$$Ti = \min[T, k1(Tc + \tau)] = \min[1, 1.5 * (0.73 + 0.73)] = 1 \tag{28}$$

Having two sets of proportional and integral terms makes room for selection, since we cant have different paramters for closing and opening. Therefore, we base our selection on Skogestads theory [23], and we select the largest absolute Kp value, and lowest Ti value. Since we initially have an fully open valve (100%) when running the Simulink script, we need to have a negative gain. We then concludes with the following values:

- Kp = -9.446
- Ti = 1

6.4. Simulink PID performance

Simulink tests are performed to capture the error for the PID controller when regulating the BHP with the help of the MPD choke valve (SB401). We first set a set point, and study how the PID controller reacts. We then increase the set point, having in mind the maximum pressure we can impose the system to. It is suspected that the BHP oscillates between the set point and the BHP more as the set point increases. The goal of the tests is to find a trend that can help us with finding the source of the bad PID performance.

Three different tests are performed, where the different tests have different volume flow rate defined by the mud pump (JP401).

PID parameters:

- Kp = -9.446
- Ti = 1
- Td = 0

6.4.1. Test #1 – 60 LPM

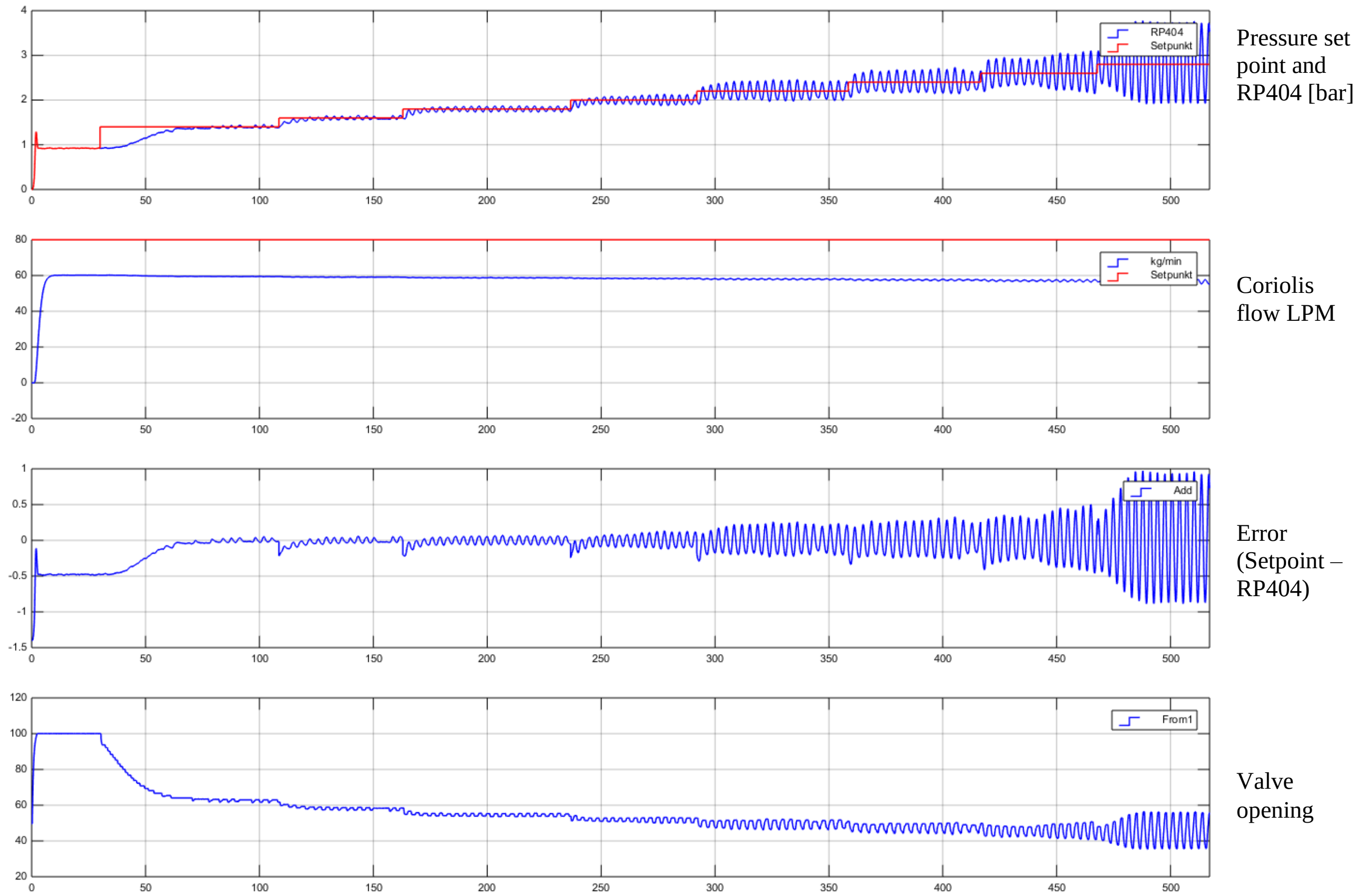


Figure 30 Test #1 - PID performance

We set the flow at 25.7 %(60 lpm). The first graph shows the set point and the actual BHP reading. We also create a basic equation for calculating the error between the set point and the pressure. This is exported, and shown in the third graph from the top. We confirm our suspicion of bad PID performance at high BHP. The maximum error is close to 1bar, which is relatively much, considering the system we are running the tests on.

BHP setpoint	Valve opening average	Error (Max – setpoint)
1.4	63	0.039
1.6	58	0.044
1.8	55	0.066
2.0	51	0.125
2.2	49	0.261
2.4	47	0.330
2.6	45	0.502
2.8	44	0.972

Table 9 Test #1 summary

6.4.2. Test #2 – 70 LPM:

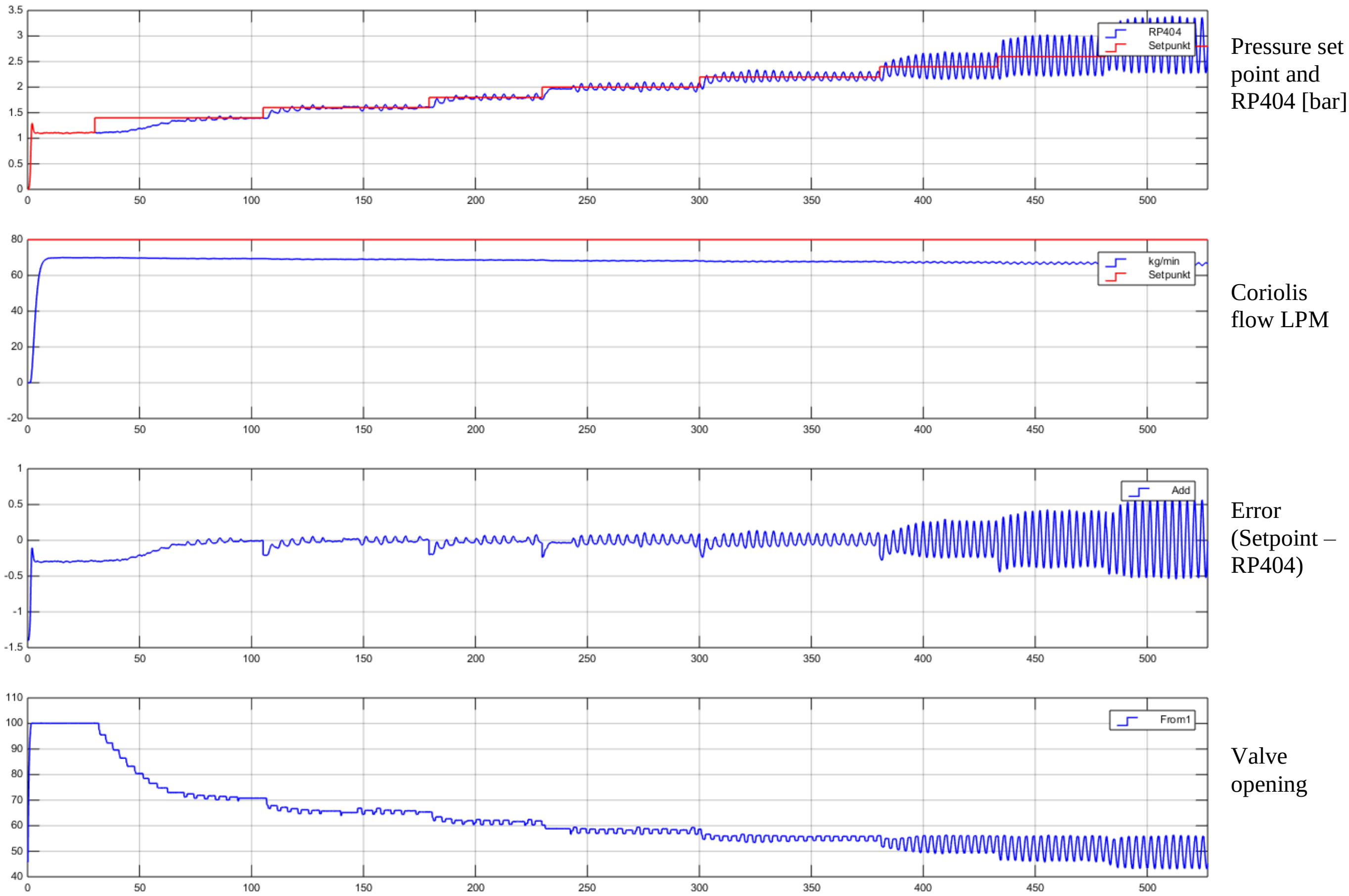


Figure 31 Test #2 - PID performance

In this test we set the flow at 30%, which corresponds to 70 lpm. We notice once again the same trend as in the first test. However, the parameters below shows that the BHP error is smaller than in the first test.

BHP setpoint	Valve opening average	Error (Max – setpoint)
1.4	71	0.033
1.6	66	0.061
1.8	61	0.080
2.0	58	0.108
2.2	55	0.141
2.4	53	0.297
2.6	51	0.427
2.8	49	0.595

Table 10 Test #2 summary

6.4.3. Test #3 – 90 LPM

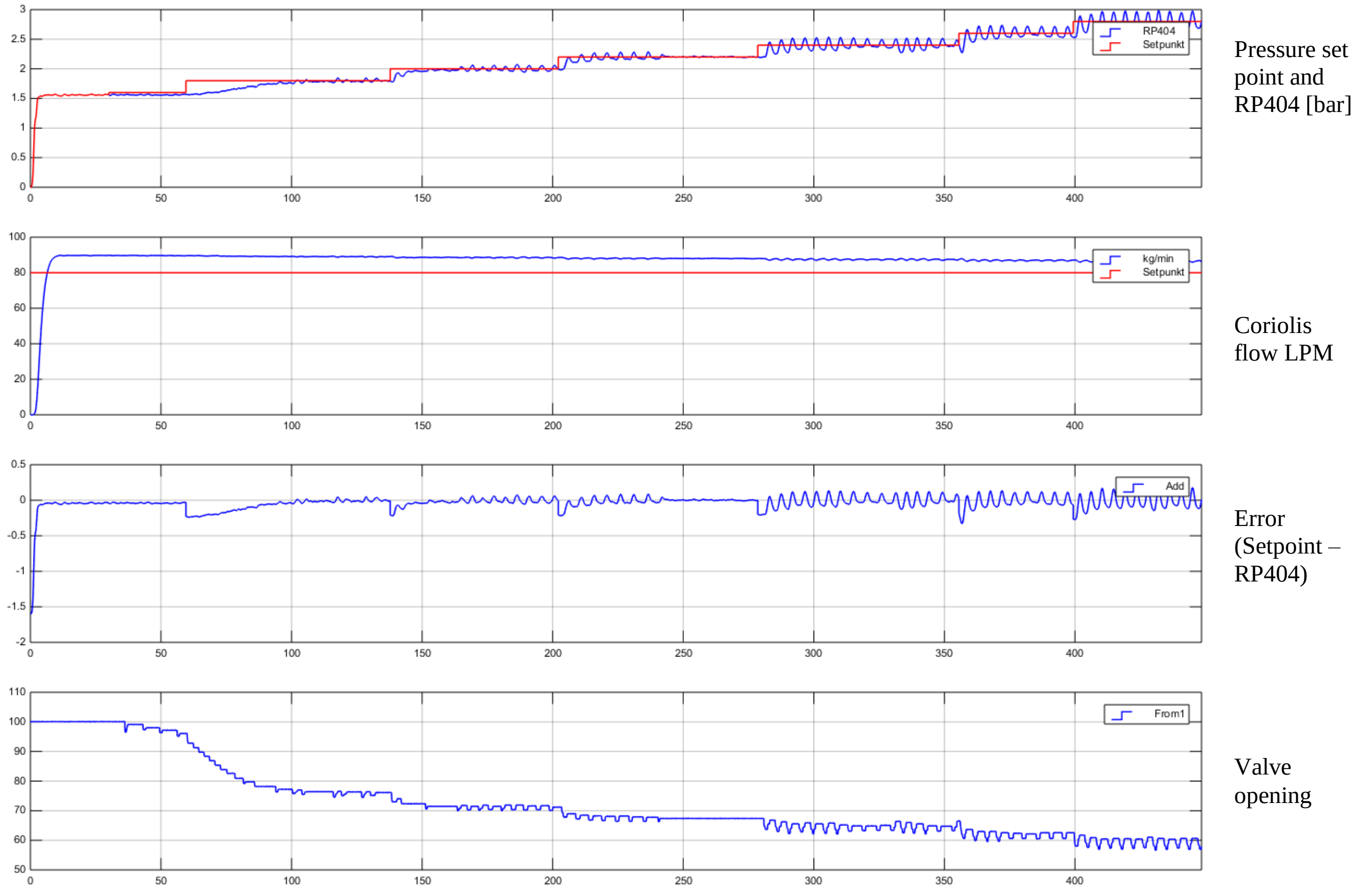


Figure 32 Test #3 - PID performance

Below are average values form test #3. Again, we see that the error decreases when flow is larger. We do not have values for 1.4 and 1.6 BHP, as the flow itself causes larger BHP than 1.6 bar.

BHP setpoint	Valve opening average	Error (Maks – setpoint)
1.4	-	-
1.6	-	-
1.8	76	0.047
2.0	71	0.075
2.2	67	0.086
2.4	65	0.125
2.6	62	0.122
2.8	59	0.186

Table 11 Test #3 summary

6.4.4. Summary of PID tests:

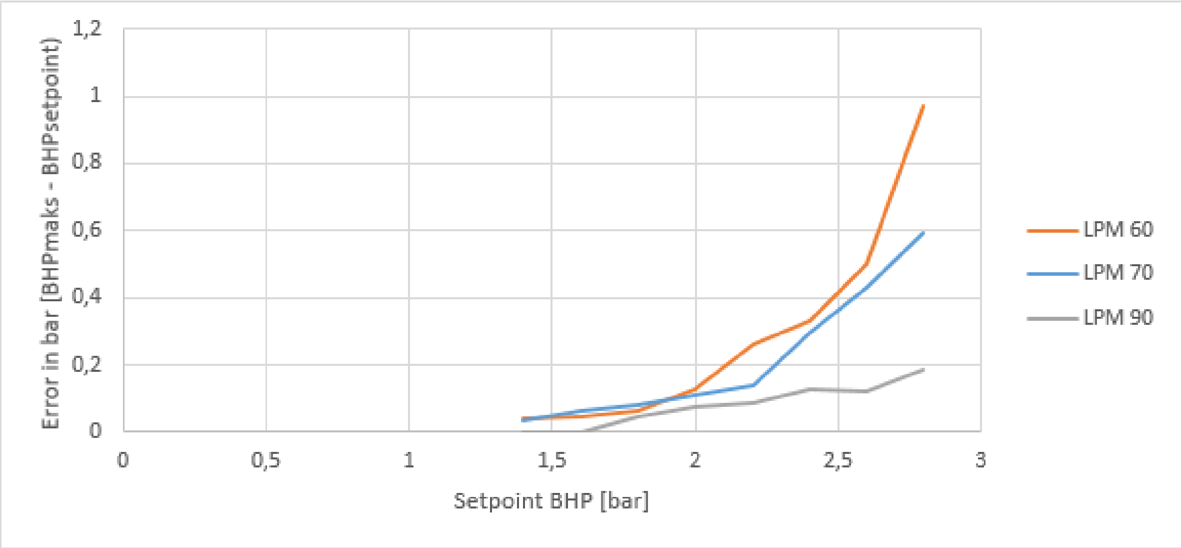


Figure 33 PID test summary

The graph above shows a trend between the volume flow and the regulator error. It looks like a relative slow volume flow from the pump makes it harder for the pneumatic MPD choke to level out at the set point. And on the other hand, a flow of 90 lpm performs good. Even though we still have an error at 90 lpm, it is significantly better than for 70 lpm. One could maybe think that 90 lpm creates more noises, which could make the controller perform badly. This is not the case.

Looking at the choke opening window, the choke operates in a window between 59 and 76% for the 90LPM test, and between 44 and 63% for the 60 LPM test. An additional theory for the error trend can be that the choke operates better in a more open position.

6.4.5. RP404 filter

Even though the PI-controller was tuned with parameters, the performance was not ideal. A suspicion on Simulinks signal processing caused a further investigation. By accessing the Simulink script, one could see a high-order smoothing filter being applied to the RP404 signal. This is the signal the PI-controller uses to regulate with. If the filter is not properly designed, or not being applicable for the signal, the signal will be very sensitive to noises, which will further make the PI-controller sensitive for noises.

It was therefore experimented with different first order signals instead, and by substituting Equation 29 below, the PI controller's performance was massively improved

$$Y(s) = \frac{1}{5s + 1} \tag{29}$$

PID performance after tuning and new filter:

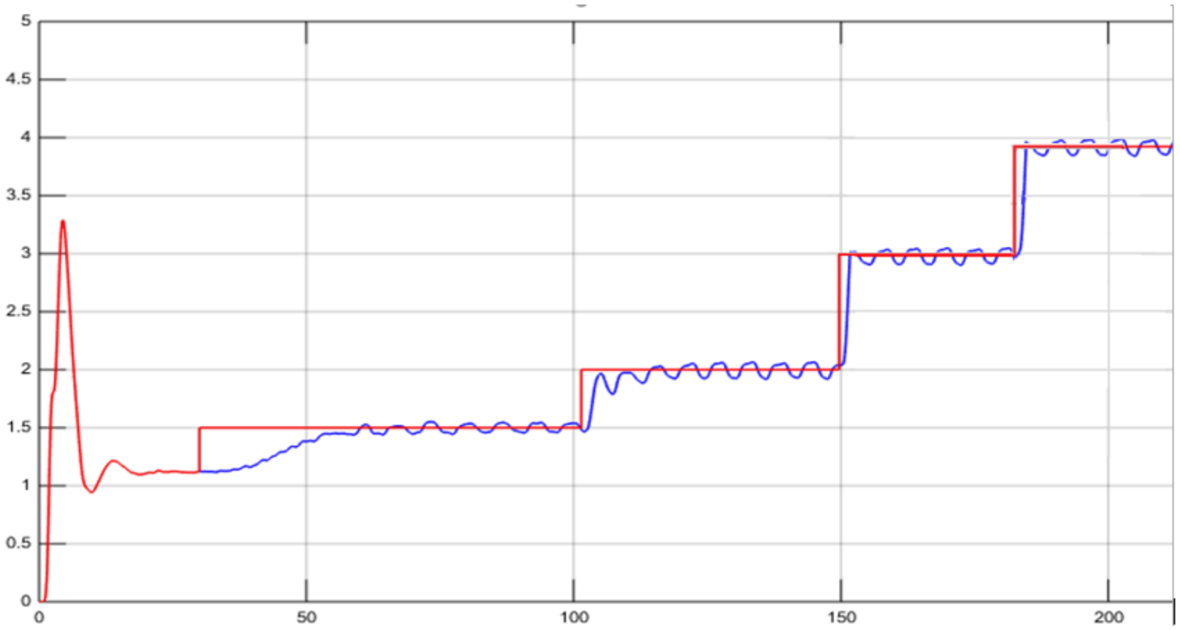


Figure 34 PID performance after tuning and new filter

As one can see from the figure above, the PID performance is tremendously better than previously (See Figure 30 for comparison). There are still improvements that can be done. Such as the initial step change, which has a slow build up. There are also still fluctuations, though not as severe as the original performance.

Chapter 7 - Post discussion

The simulator has several weaknesses that has been addressed. First of all, the rig has been exposed to pressure, and several leakages has been observed. This are now fixed, but it is important that one careful with pressure spikes. Meaning that rapid gain changes to MPD valve and pump rate should be avoided.

Increase in BHP when taking a kick is a result of increased friction across the MPD choke. During conventional drilling, we usually see a slight drop in BHP when taking a kick. However, as we for MPD systems have a closed loop, the BHP increased instead. This is seen on the simulators BHP output. The BHP max pressure when injecting air is irrelevant of injection time: The BHP observed is a function of flow rate and MPD valve opening.

If one compares the simulator with a standard drilling rig, everything is considerable smaller. There are both negative and positive sides with this. First of all the simulator does operates in a window between 0-5 bars. This makes it a significantly safer operating window, compared to e.g. a HPHT well. Shutting in the well, circulating out a kick, getting a stable well etc. are all operations that is much quicker on the simulator.

Due to the small dimensions, it is hard to do an accurate well control procedure without going below the pore pressure. As the PID controller now is tuned, implementing a fully autonomous kick removal procedure is sought after. The kick control was done in Labview for manual operation. However, as Simulink already has PID regulation towards BHP setpoint, creating an autonomous procedure for kick detection and well control is proposed as a future thesis topic.

To sum up ideas for thesis research:

- Implement an autonomous kick handling procedure. One should have the possibility of setting a kick injection start pressure, and a kick injection stop pressure. Where the stop pressure is slightly higher than the start pressure. The first step to the algorithm should be a kick detection script, which initiates the procedure. Then the BHP should be increased in steps, until the injection stops. This should be new BHP set point for further drilling.
- If one does not want to circulate out the kick through MPD valve, one can write an autonomous script following the steps in Chapter 5.4. This involves implement a PID regulator for the WCV, to be able to circulate out the kick through this with a constant BHP. One is also shutting off the pump in this scenario.
- In kick handling procedure in Chapter 5.4, one had a relatively low flow rate. One could also look into what the output would be for a larger flow rate and BHP. By doing this, one is able to study the kick tolerance. By having a large BHP, does shutting off the pump lead to a too large drop in BHP? Is it possible to implement a back pressure pump do the system?

Chapter 8 - References

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Chapter 9 - Appendix

Appendix A. Matlab scripts

A.1 Calculate gas kick volume

```
clear all
close all
clc

%data import
Size = size(xlsread('InjectionTest_SmallVolume_2.xls'));
RowsExcel=Size(1)+1;
PPump = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('A2',':','A',num2str(RowsExcel)));
STP = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('B2',':','B',num2str(RowsExcel)));
BHP = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('C2',':','C',num2str(RowsExcel)));
PChoke = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('D2',':','D',num2str(RowsExcel)));
PCori = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('E2',':','E',num2str(RowsExcel)));
Time = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('H2',':','H',num2str(RowsExcel)));
Q = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('F2',':','F',num2str(RowsExcel)));
Switch = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('I2',':','I',num2str(RowsExcel)));
PumpFlowrate = xlsread('InjectionTest_SmallVolume_2.xls','Sheet1',
strcat('G2',':','G',num2str(RowsExcel)));

H_RP406 = 4.57; % Height in mTVD, Also applies for RP407
H_RP404 = 1.12; % Height in mTVD
ro_water = 1; % sg
g = 0.0981; %Gravitational constant

BHP_average_stable=mean(BHP(100:300));
```

```
STP_average_stable=mean(STP(100:300));
PChoke_average_stable=mean(PChoke(100:300));
PPump_average_stable=mean(PPump(100:300));
PCori_average_stable=mean(PCori(100:300));
Q_average_stable=mean(Q(100:300));
Pumpflowrate_average_stable=mean(PumpFlowrate(100:300));

AnnFric_average_stable = BHP_average_stable - PChoke_average_stable -
(g*ro_water*(H_RP406-H_RP404)); % calculates friction in annulus
ECD_average_stable =  ro_water + (AnnFric_average_stable/(g*(H_RP406-
H_RP404))); % ECD in sg

no_of_samples=length(BHP);
time_of_experiment=max(Time);
BHP_new=BHP-mean(BHP);
dt= time_of_experiment/no_of_samples;
sr=1/dt;% sampling rate
timeConstant = 1/0.8903;
BHP_Filtered = lowpassFilter(BHP,dt,timeConstant)';
PumpFlowrate_Filtered = lowpassFilter(PumpFlowrate,dt,timeConstant)';
Coriolis_Filtered = lowpassFilter(Q,dt,timeConstant)';
Coriolis_stable = mean(Coriolis_Filtered(100:300));

Qgas_new=[];
injection_time=[];
for j=1:length(Coriolis_Filtered)
    if Switch(j)==1
        Qgas(j)=Coriolis_Filtered(j)-Coriolis_stable;
        Qgas_new=[Qgas_new;Qgas(j)];
        injection_time=[injection_time;Time(j+1)-Time(j)];
    else
        Qgas(j)=0;
    end
end

Time_Switch = sum(injection_time);

TotalGasVolume1=0;
for i=1:length(Qgas_new)
    TotalGasVolume1=TotalGasVolume1+Qgas_new(i)*injection_time(i)/60;
end
```

```
InjPressure = 4; % bars
M = 28.9647; % Molar mass of air in g/mol
Z = 0.998794; % Coefficient of compressibility
R = 8.3144598*10^-5; % Gas constant, m3 bar K^-1 mol^-1
T = 273.15 + 16; % Temperature in Kelvin

Ro_Gas = (InjPressure*M)/(Z*R*T*1000); % Density of gas in g/l

TotalGasMass1 = TotalGasVolume1*Ro_Gas; % Mass gas in grams

figure(1);
plot(Time,BHP,'r')
hold all
plot(Time,BHP_Filtered)
plot(Time,Switch)
grid on
xlabel('time [s]')
ylabel ('BHP [bar]')
title('BHP & Q-Normal operation')

figure(2);
plot(Time,Q,'b')
hold all
plot(Time,PumpFlowrate,'k')
plot(Time,PumpFlowrate_Filtered,'r')
plot(Time,Coriolis_Filtered)
plot(Time,Qgas)
grid on
legend('Coriolis','PumpRate','PumpFiltered','CoriolisFiltered','Qgas')
```

A.2 Matlab code for lowpass filter

```
function y =lowpassFilter(x,dt,timeConstant)

alpha = dt / (timeConstant + dt);

y(1) = x(1);
n=length(x);

for i=2:n
    y(i) = alpha .* x(i) + (1-alpha) .* y(i-1);
end

end
  % alpha = 1/1+n
  %then n =time constant / Sampling time

  %time constant = -(sampling time)/ln(1-alpha) or approximately time
constant=1/alpha

  %And the cut-off frequency will be:
%FC = -ln(alpha)*(sampleRate/2*pi) (FC is -3dB cut-off frequency in Hz)
```

Appendix B. Rig maintenance

B.1 Replacing three-way valve

During rig simulations, a leakage was detected close to the RP403 pressure sensor. At this location, there had been installed a three-way pipe. The part is pictured to the left in Figure 35 below. It is used to connect standpipe and drill pipe. However, the third path way was sealed off, due to not being in use. This is where the leakages started. Instead of trying to seal the leakages, it was decided to replace it with a two-way (ref. pipe on the right in Figure 35), and removing the risk for future leakages.

Figure 35 Replacing three-way pipe

However, it was decided to use PP-pipe, as it was available at the lab. Also, plastic glue from Biltema was used to connect the PVC connections with the PP-pipe. After replacement, the connection failed during a rig simulation, leading to a water spill at the lab. After inspection of the failed part (Figure 36), it was obvious that the glue was not sufficient. The materials PP and PVC pipe are not safe to glue together. A proper risk analysis was not conducted together with lab engineers prior to replacement.

Figure 36 Failed pipe

As a result of the incident, it was purchased 40 mm PVC pipe, together with new PVC connections. Furthermore, it was acquired PVC glue and cleaner. Everything was acquired through Ahlsell. The PVC glue and cleaner are provided by Tangit, and are designed for gluing together PVC parts which are subject to pressure. The instructions for applying glue and connecting the parts are provided with the packaging.

Links for buying from Ahlsell:

- Tangit PVC glue (Product number 2445732N5)
  https://www.ahlsell.no/33/forbruksmateriell/kjemisk-teknisk-og-hygiene/lim/teknikklim/2445732n5/
- Tangit KS Cleaner (Product number 9510185)
  https://www.ahlsell.no/33/forbruksmateriell/kjemisk-teknisk-og-hygiene/hygiene/rengjoringsservietter/9510185/
- 40 mm OD PVC transparent pipe. This was ordered through a third party supplier named GPA.

After installing the new PVC connection, a proper pressure test was conducted, in order to test the strength of the connection. Due to the replacement pipe being close to the SPP sensor, this was monitored. The rig pump was first used to manipulate the pressure, followed by MPD valve manipulation. The test was proven successful, as the connection managed to hold several pressures over a time period. See Figure 37 for pressure test.

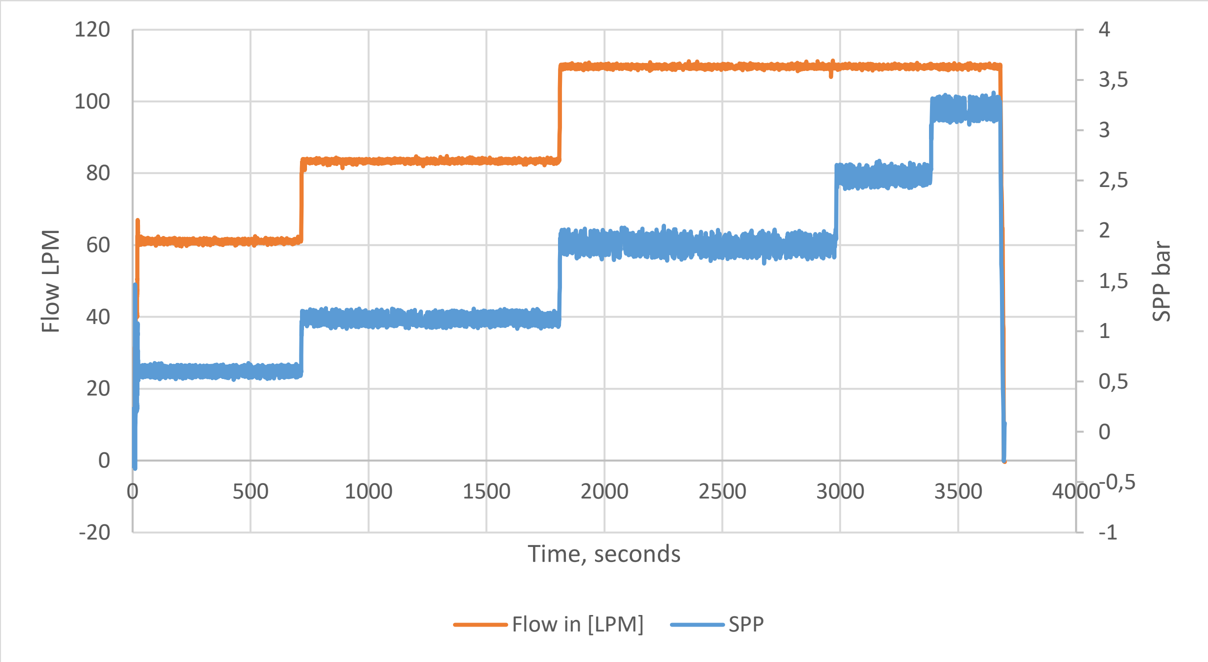

Figure 37 Pressure test for new PVC connection

B.2 Replacing pipe #2

Another incident occurred while running the simulator. A PVC pipe after the pressure relieve valve (QO401) cracked, leading to leakages when operating the rig above 3 bars BHP. It was decided to replace this as well, as the crack had a risk of growing. The rig had originally a flexible rubber pipe connecting the 40mm pipe from tank with the 40mm pipe to the standpipe. The rubber pipe had an ID larger than the PVC pipe's OD. Because of this, the solution for connecting this was by using lots of glue, and clamps. This in the leakage. Original setup is shown in Figure 38 below, where the leakage is numbered **1**.

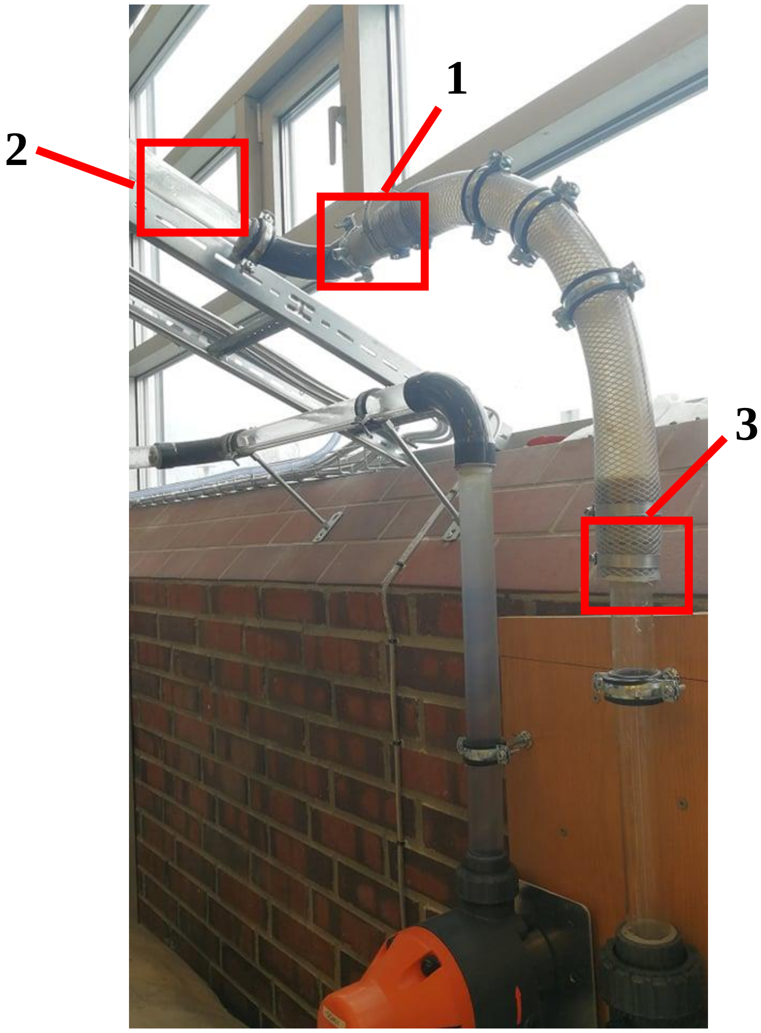

Figure 38 Leakage #2 Original

As everything is glued together, and not screwed together, the replacement became challenging. One decided to try to replicate the solution which originally was in place, replacing the big flexible rubber bend with a new one, and also by providing new transparent PVC pipe.

Due to not being able to detach the PVC parts due to glue, one had to make a cut at mark **2** and **3** in Figure 38. A union was mounted on the pipe in mark number 2, which is used to installed new pipe on. This was bought from Ahlsell as well.

After installation of the new parts, the new system looked like in Figure 39. The solution was the same as the original setup, with a large flexible bend.

Figure 39 New pipe for leakage #2

This was also pressure test, but failed when reaching above 2 bars BHP. The large bend was not properly sealed. The fault was equal to the original leak; a misfit between ID and OD connection was not properly sealed. The pressure test is showed in the figure below.

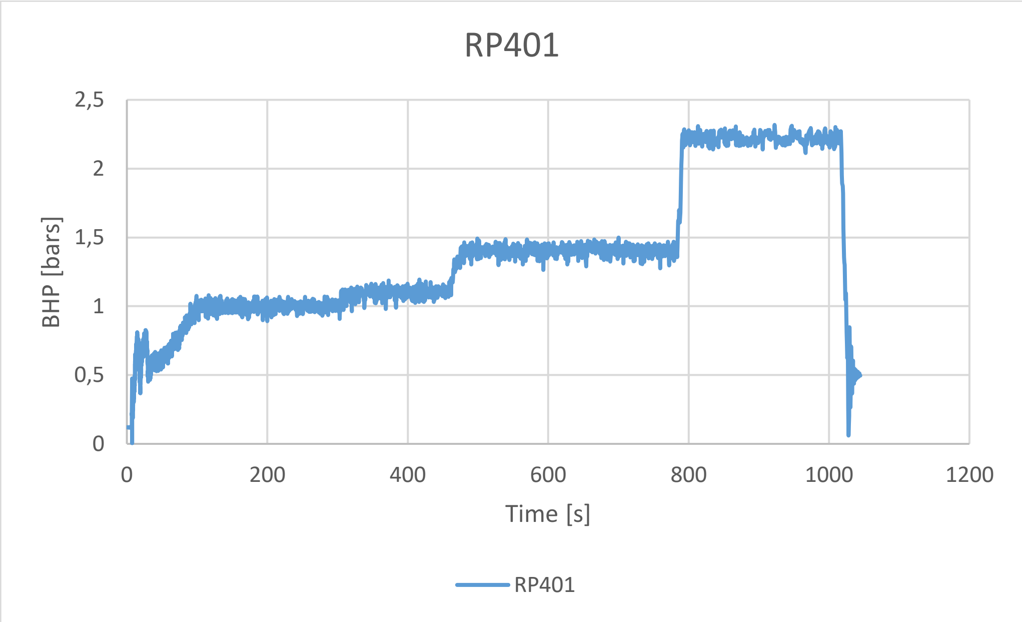

Figure 40 Pressure test leakage #2

It was then decided to find another solution than the large rubber bend. There are not documentation on why it was decided to use this, instead of PVC pipes likes the rest of the rig. One theory is that the flexible pipe creates a large bend, which absorbs lots of the vibrations from the flow exiting the pump. However, due to the potential leakage source, one decided to mount a small PVC bend instead. This is shown in Figure 41.

Figure 41 New setup for bend near pump output

A pressure test was done on the new setup in order to determine if no leakages occurred during flow. The pressure test proved to be successful. One was skeptical to removing the large bend due to vibrations near the pump. However, this theory proved to be wrong, as the water was flowing just as fine with the new setup. The pressure test is provided in Figure 42. At time ≈ 1250 seconds, the pressure drop is due to reducing the flow, rather than the MPD opening. This was a blunder when running the pressure test, rather than a leak occurring.

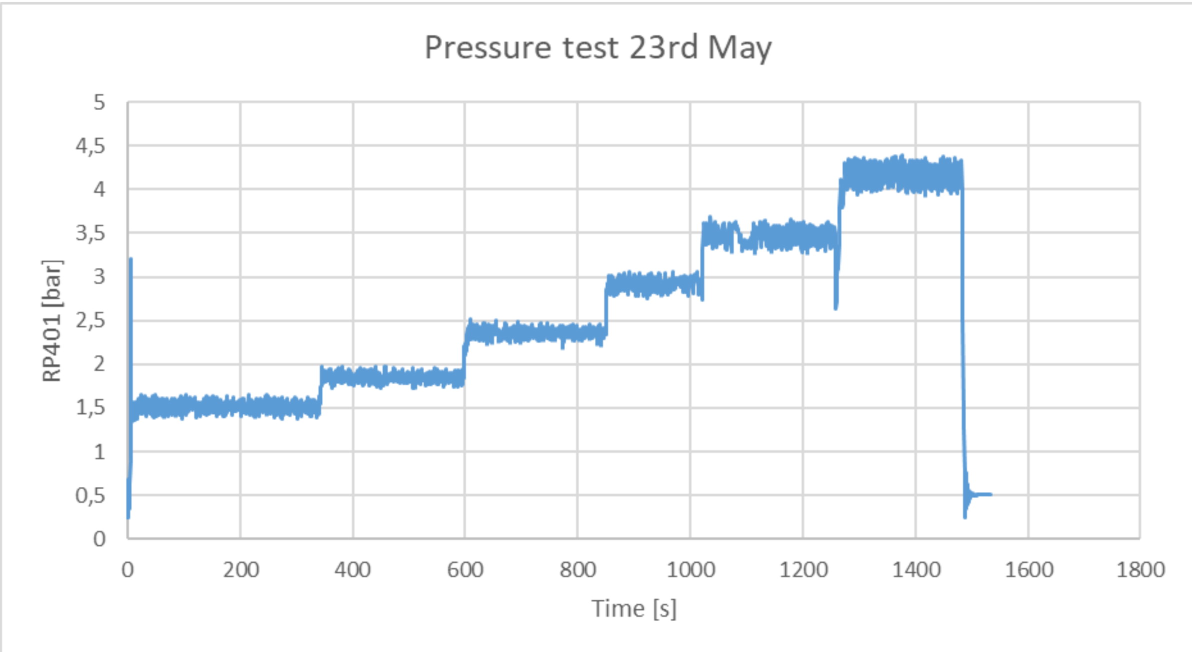

Figure 42 Presure test newest bend from leakage #2