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| Author:<br><br>Ida Halvorsen Verpe | …………………………………………<br>(Ida Halvorsen Verpe) |
| Faculty Supervisor:<br>Dan Sui<br><br>Co-Supervisor:<br>Olav Gerhard Haukenes Nygaard | |
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# EVALUATION OF THE "COMMAND TAKE-OVER PROCEDURE" IN AUTOMATED WELL CONTROL

# MASTER'S THESIS SPRING 2014


Ida Halvorsen Verpe

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Department of Petroleum Engineering

The Faculty of Science and Technology

University of Stavanger

## SUMMARY

The growing need for new technology in the pursuit of oil is creating new challenges related to well control. Drilling in HPHT (High Pressure High Temperature) reservoirs, arctic areas, and depleted zones might imply that the drilling window between the pore pressure and the fracturing pressure is narrow. This presents challenges in terms of gas influx. As of today kick handling is a manual procedure with the driller in charge.

Automation of well control procedures can be the solution to several problems related to kick detection and kick handling. This thesis introduces theory about conventional well control as well as control theory and automated well control. A part of the work was experimental, and was performed at a simplified rig model at the two-phase laboratory at the University of Stavanger. The results are presented in chapter 6.

The main focus in the experimental part is on the Command Take-over procedure. Several experiments were performed leading to the main experiment. The main principle of this procedure is that the drilling operation is run in MPD (Managed Pressure Drilling) mode with a PI-controller (Proportional Integral controller) on the MPD valve. When a gas kick occurs, the WCV (Well Control Valve) mode is activated with a PI-controller on the WCV. Further the BOP (Blow Out Preventer) is closed and the kick is circulated out of the well through the WCV. After the circulation, the operation is back to MPD mode, and the operation continues as planned.

The results show that the Command Take-Over Procedure is feasible on actual drilling rigs. It is further possible to assume that the procedure is safer, because the procedure is automated, without the dependence of human judgement and ability to make good decisions in well control incidents. However, it is important to have a drilling crew available on the rig in case of mechanical failure. The procedure is also more efficient and time saving since the pump are constantly running during the procedure, and there might not be a need for a new mud with higher density to regain well control after a gas kick.

# PREFACE

This thesis was written as a part of completing a five-year master study in petroleum engineering at the University of Stavanger and is weighted with 30 credits. The last five years have been challenging, instructive, interesting and joyful.

Due to my background in petroleum engineering and my specialization in drilling, I wanted to write a thesis related to well control, preferably an experimental thesis. This thesis combines well control and experiments, as well as cybernetics and control theory. The last two topics were completely unknown to me, and there were a lot of new knowledge to familiarize with.

Regarding the writing of this thesis I have received information and help from several sources. I would like to start by giving a special thanks to my supervisor at the University of Stavanger, Dan Sui, who has been a helpful and important person during this last semester. I appreciate our discussions and her guidance concerning control theory.

I would also like to thank my co-supervisor, Gerhard Nygaard, for presenting this thesis to me and for introducing me to cybernetics and control theory.

Further I would like to thank Alexander Wang for instructing me on how to operate the rig model for the experiments and guiding me through difficulties that occurred along the way.

Last but not least, I want to thank my family for motivating me and supporting me through my five years at the University of Stavanger.

## NOMENCLATURE

A = Area
$\beta$ = Bulk modulus
$\Delta$P = Differential pressure
e = Error signal
F = Friction coefficient
g = Gravitational acceleration
h = Height
K = Gain
k = Constant
l = Length
$\sigma$ = Take-over signal
P = Pressure
$\rho$ = Density
q = Flow rate
r = Reference signal
t = Time
$\tau$ = Adjustable time parameter
u = System input value
V = Volume
w = Width
y = Output value
z = Valve opening

## ABBREVIATIONS

AWCS – Automated Well Control System
BHA – Bottomhole Assembly
BHP – Bottomhole Pressure
BOP – Blow Out Preventer
CTOP – Command Take-Over Procedure
FCP – Final Constant Pressure
HPHT – High Pressure High Temperature
ICP – Initial Circulation Pressure
MPD – Managed Pressure Drilling
NCS – Norwegian Continental Shelf
PI – Proportional Integral
PID – Proportional Integral Derivative
P&ID – Piping and Instrumentation Diagram
PVC – Polyvinyl Chloride
ROP – Rate of Penetration
SICP – Shut-In Casing Pressure
SIDPP – Shut-In Drillpipe Pressure
TVD – True Vertical Depth
WBE – Well Barrier Element
WCV – Well Control Valve
W&W – Wait and Weight

## LIST OF FIGURES

# LIST OF TABLES

# TABLE OF CONTENT

# Part I Theory

# 1 Introduction

One of the most important issues during a drilling operation is safety. Well control is therefore one of the main focus areas. As of today, most of the drilling processes are done manually. This places high demands for the driller's ability to make the right decision in stressful situations. While drilling, challenges can occur along the way, causing dangerous situations like a kick, and even worse, a blowout. If a kick is present, it is the driller's responsibility to assess the situation to decide the best option for the well control procedure. While circulating out the kick, the driller needs to manually control the choke valve while monitoring the pressure gauges. The focus on safety, along with the increasing number of drilling operations in challenging areas, creates a demand of newer technology.

During a drilling operation there are several critical situations that can lead to well control incidents. Drilling into high pressure zones, drilling with too high mud weight, fractures formations etc. can all lead to blowouts if the kick is not detected in time. Due to the manually monitoring of the drilling process, human errors are inevitable. By automating the processes, these problems can be avoided. Automation of well control procedures can give the driller a monitoring role instead of an active role, and also provide a wider overview of the overall situation and the possibility to detect kick warning signs earlier and avoid further problems.

This thesis gives an overview of general well control in conventional drilling and automated well control in automated drilling, and can be divided into three parts:

1. Part I Theory
2. Part II Experiments
3. Part III Conclusion and further work

Part I includes theory about conventional well control procedures, automated well control, reasons for kicks and how to detect them, control theory and the command take-over procedure. Part II includes information on the rig model used for the experiments, different experiment procedures, discussions and results. The last part, Part III, includes conclusions and further work related to the experiments.

# 2 General overview of well control

Well control is the action of maintaining control of the well during unexpected events. It is one of the most important elements in the oil and gas industry, concerning economic aspects, the environment, and most importantly, the safety of human lives. During drilling, it is important to keep the bottomhole pressure stable and prevent any influx from the reservoir. To accomplish this, many factors need to be evaluated; careful planning of the job, experience and proper learning of the drilling crew, the ability of making exact and accurate decision under pressure and execution of the well control operation. According to NORSOK D-010, rev.3 well control is defined as: "Collective expression for all measures that can be applied to prevent uncontrolled release of well bore effluents to the external environment or uncontrolled underground flow [1]."

## 2.1 NORSOK D-010 rev. 3

When it comes to well control, it is important to have structured guidelines concerning what well control is, how it can be performed and so on. The NORSOK standards were developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations in the form of regulations and guidelines. The standard contains definitions, principles, schematics, criteria and designs concerning well integrity in drilling and well operations. NORSOK standard regulates the Norwegian petroleum industry, while other countries have their own equivalent standards [1].

## 2.2 Well barriers

A well barrier is per definition "an envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface [1].” A well barrier is built up of several well barrier elements (WBE), defined as “an object that alone cannot prevent flow from one side to the other side of itself [1].”

Well barriers are furthermore divided into two subcategories:

1. Primary well barrier; the first object to prevent flow from a source
2. Secondary well barrier; the second object to prevent flow from a source

If the first barrier fails to prevent influx from flowing to the surface, the second well barrier serves as a backup barrier. Both primary well barrier and secondary well barrier is required to be completed on the Norwegian Continental Shelf (NCS) [1]. The main purpose a well barrier is to avoid or reduce the damages caused by an unintentional influx of fluid into the wellbore. The term includes mainly technical barriers, but also human barriers. NORSOK D-010 defines primary and secondary WBE in different situations. During drilling, the primary barrier is the fluid column providing pressure given by the weight of the mud.

## 2.3 Blow Out Preventer (BOP)

During drilling, the blow out preventer (BOP) functions as a secondary well barrier. The BOP is installed subsea on floating rigs, and topside on fixed rigs and platforms. It is a device consisting of several valves and rams, which function is the maintain control of the wellbore after a kick. On the NCS, a BOP is required during all drilling operations, including completions and interventions. Acting as a secondary well barrier, the BOP is intended to stop the influx if the primary well barrier fails. There are three different sets of rams in a BOP; blind rams, shear rams and blind shear rams. The blind rams are heavy steel components that are able to close off the well when there are no pipes in the well and seal it. Shear rams are hardened steel rams, which can cut through the drillstring or the casing. The blind shear ram is a combination of the two previous mentioned rams. It has the ability to cut through the drillstring as the rams close off the well.

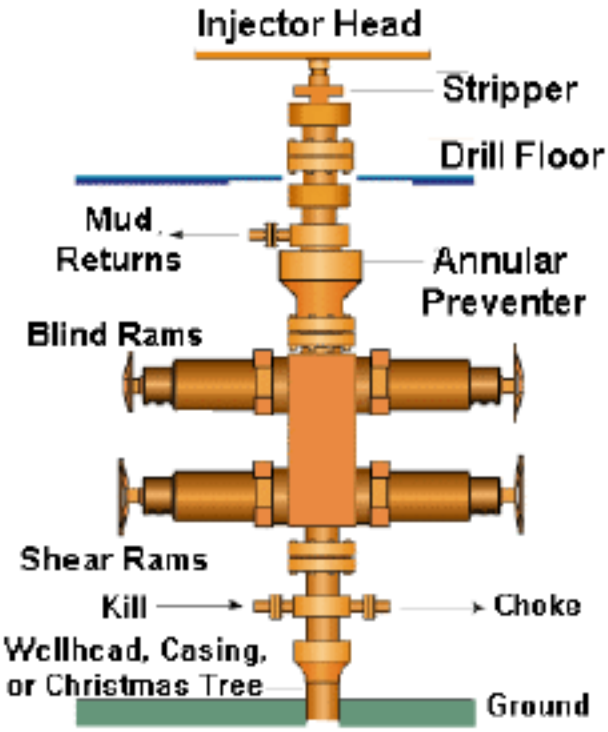

Figure 1: Blow Out Preventer [2]

There are two inlets/outlets on a BOP; the kill line and the choke line, see figure 1. The kill line is a high-pressure pipe leading out from BOP stack to the high-pressure rig pumps. During normal well control operations, kill fluid is pumped through the drillstring and annular fluid is taken out of the well through the choke line to the choke.

### 2.4 Kick

A kick is defined as "unintentional inflow of formation fluid from the formation into the wellbore [1]." A kick can lead to disastrous consequences, both economic, environmental and the risk of losing human lives, and should by all means be avoided. If a kick occurs, the BOP is used to shut in the well and the influx is circulated out through the choke line. Once well control is maintained and the kick is circulated out of the well, the drilling may continue as planned. If the drill crew for some reason is not able to gain control of the well, a worst-case scenario is that the kick can lead to a blow out.

### 2.4.1 Reasons for kick

There are three conditions that must be present for a kick to occur:

1. The pressure in the formation must exceed the pressure in the wellbore
2. The permeability in the formation must be high enough for the formation fluid to flow into the wellbore
3. The formation fluid must have low enough viscosity to be able to flow into the wellbore

The main reason for a kick is that the pressure in the formation exceeds the pressure in the wellbore. The fluid will choose the path of least resistant and thereby flow into the well. Another physical parameter that contributes is the porosity, the measure of void space in a substance. To notice a kick, large amounts of fluid is required, and thereby also a high porosity. A kick taken by a formation with high porosity and high permeability can cause a lot more damage than a kick taken by a formation with low porosity and low permeability. Several well situations can lead to a kick[3]:

1. Insufficient mud weight/insufficient bottomhole pressure
2. Failure to keep the hole fill while tripping
3. Swabbing during tripping
4. Lost circulation

**Insufficient mud weight**

As mentioned previously, the fluid column is the primary barrier during drilling. The bottom hole pressure is given by the weight of the column

$$P = \rho g h \qquad (2.4.1.1)$$

Where:

$P$ = Pressure

$\rho$ = Density of the drilling fluid

$g$ = Gravitational acceleration, 9,81 m/s$^2$

$h$ = Height of the drilling fluid column

There are high demands related to the mud weight to have sufficiently high pressure in the well to prevent influx from the formation. However, the mud weight must not exceed the pore pressure, causing the formation to fracture, which leads to fluid loss.

**Failure to keep the hole full while tripping**

Tripping is a critical operation regarding kicks. Tripping is the act of pulling the drillpipe out of the wellbore, then running it back in. When the drillpipe is pulled out of the well, the fluid level in the well will sink due to the volume displacement from the drillpipe. This decrease in bottom hole pressure may be enough to cause a small kick, and it is therefore important to closely monitor tripping operations. To avoid a kick, mud is refilled to the well from the trip tank.

**Swabbing during tripping**

When pulling the drillpipe, a negative pressure is created, called swabbing. Due to the volume replacement from the drillstring the bottom hole pressure will decrease. The void space needs to be filled with mud in order to maintain high enough pressure. If the pump rate of the mud is too low, swab will occur. If the reduction in bottom hole pressure caused by swabbing is below formation pressure, a kick will occur.

**Lost circulation**

Lost circulation is when the mud disappears into the formation. Several reservoir conditions can cause lost circulation:

1. Formations that are naturally fractured, cavernous, or have high permeability
2. Improper drilling conditions, too high mud weight
3. Induced fractures caused by excessive bottomhole pressure and setting intermediate casing too high

Due to lost circulation, the mud does not return to surface, and the level in the mud pits decreases. Mud can be very expensive, and lost circulation can lead to huge economic losses, and in worst case, a kick due to low bottom hole pressure caused by insufficient amount of mud in the well.

Natural fractures, high permeability and cavernous formations make it impossible to avoid lost circulation. However, there are several methods to prevent it. The most common methods are [4]:

1. Maintaining proper mud weight and adjusting with lost circulation materials if necessary
2. Minimizing annular-friction pressure losses during drilling and tripping in
3. Adequate hole cleaning
4. Avoiding restrictions in the annular space
5. Setting casing to protect upper weaker formations within a transition zone
6. Updating formation pore pressure and fracture gradients for better accuracy with log and drilling data

In addition, it is possible to perform tests to minimize the possibilities of lost circulation situations. The two most common tests are Leak-off Test and Formation Integrity Test.

### 2.4.2 Detection of kicks

The drilling process is closely monitored by the drilling crew to detect early signs of a kick to avoid severe consequences. The most common warning signs are [3]:

1. Flow rate increase
2. Pit volume increase
3. Flowing well with pumps off
4. Decreasing pump pressure and increasing pump strokes
5. Improper hole fill-up on trips
6. String weight change
7. Drilling break – e.g. when drilling into an open hole which increase the ROP (Rate Of Penetration) significantly

It is important to state that these signs may not always lead to a kick. Careful and proper training of the drill crew is therefor important to evaluate the situation.

**Flow rate increase**

The pump rate is kept constant while drilling a well. An increase in the flow rate is therefore one of the most important kick indicators. The increase is caused by the formation fluid flowing into the wellbore.

**Pit volume increase**

When the formation fluid enters the well it will mix with the mud and flow up the annulus and back to the rig, through the shale shaker and back to the mud pit. Due to the fluid displacement of the reservoir fluid, the mud volume in the mud pit will increase.

**Flowing well with pumps off**

Occasionally during drilling the pumps are stopped. This implies that the well flow stops because there is no pump rate forcing it up the well. If there is a continuing flow up the well, it could be a kick in progress. There are two ways of confirming that the well flow has stopped; by reading data off a flow meter, and performing a flow check where rig personnel visually checks the return flow line.

**Decreasing pump pressure and increasing pump strokes**

Initial fluid entry intro the well may cause the mud to flocculate and temporarily increase the pump pressure. As the flow continues, the low density formation fluid will displace heavier mud, and the pump pressure may begin to decrease. The mixture of the light formation fluid and the heavy mud in the annulus will lead to a less dense fluid in the annulus, and the mud in the drill pipe tends to fall. Due to this, the pump speed may increase.

**Improper hole fill-up on trips**

While tripping, the fluid level in the well will decrease due to the displacement of the volume of the removed drill pipe. As mentioned in 2.4.1.2, the lost volume needs to be filled with mud from the trip tank. If the well does not require the calculated volume of mud to bring the mud level back up to the surface, it might because an influx of formation fluid has already displaced the volume from the tripped drill pipe.

**String weight change**

The drill string is under normal drilling conditions floating in the mud due to buoyant forces. This will reduce the actual weight of the string supported by the derrick. The buoyancy force will increase with increasing mud weight. After an influx, the density in the well will decrease, and following also the buoyancy effect on the drill string. At surface this is detected by the increasing weight of the string.

**Drilling break**

The term drilling break is used to describe an abrupt increase in bit penetration rate, and is an abnormal-pressure-detection indicator. A sudden increase in rate can imply a change in rock type. In some cases, this new formation may have a kick potential. When a drilling brake is recorded it is recommended practice to drill another 3 to 5 ft into the new formation and stop to check for flowing formation fluids. However, the industry practice is to only stop and check for flow if drilling has been progressing for some interval in a formation with a potential to seal or one that is slow drilling.

### 2.4.3 Kick tolerance

Kick tolerance is per definition the maximum volume of a kick that is possible to successfully shut the well in and circulate the kick out of hole without breaking formation strength at shoe depth or overcoming the weakest anticipated fracture pressure in wellbore. In order to calculate the kick tolerance, the kick intensity needs to be known. Kick intensity is the different between the maximum anticipated formation pressure and planned mud weight. On order to calculate the kick tolerance, the kick needs to be separated into two cases: gas at the bottom of the well, and gas right below the casing shoe, which is the weakest point in the well. The kick tolerance depends on several reservoir conditions, such as pore pressure, kick volume, safety factor, density of the mud, and kick distributions.

## 2.5 Conventional well control procedures

After a well is shut-in, the primary well barrier is lost and action needs to be taken right away to re-establish well control. This is achieved by replacing the original mud with a higher density kill mud. It is the drilling crews responsibility to take decisions to minimize the kick and regain control to proceed the drilling. Below there is a general description on shut-in in a well [5] [6]:

- Kick detection
- Rotation of the drillstring and pumps are stopped
- Close the BOP
- Monitor shut-in pressure
- Determine the appropriate kill method
    - Driller's method
    - Wait and weight (W&W)
    - Bullheading
    - Volumetric method
- Open choke line and circulate the kick out through the choke line to the separator or to flare. (Driller's Method and W&W)
- Open and close the well during the kill procedure to stay between the formation pressure and fracture pressure. (Volumetric method)
- The kill line can, if needed, be used as a secondary choke line or to pump fluid into the well

### 2.5.1 Driller's Method

The Driller's Method is a widely used method to kill wells [7]. The main concept of the method is to kill the well under constant bottomhole pressure (BHP). The method is sometimes referred to as the Two-Circulation Method because it requires two complete and separate circulations. A criteria for the Driller's Method is that the drill bit needs to be at the bottom of the well. This is because the mud needs to be circulated from the bottom to the top in order to fully displace the well.

The main purpose of the first circulation is to circulate the influx out of the well with the original mud weight to re-establish the primary well barrier. After the well is shut-in and the influx is trapped, calculations are done to ensure a safe and effective circulation. To maintain a constant BHP, a remotely controlled choke is used to control the choke line backpressure. It is important to keep the BHP constant above the reservoir pressure, but not higher than the fracture pressure. To achieve this, the mud pumps need to be synchronized with the choke.

A column of the original mud weight remains in the wellbore after the influx is circulated out of the well. It is not sufficient to hold back the formation pressure, and a new kick might build up. Therefore, the mud needs to be replaced by a heavier mud, called kill mud. The new mud density is calculated based on the shut-in drill pipe pressure (SIDPP), which is the pressure on top of the drillstring:

$$\rho_{killmud} = \frac{SIDPP}{TVD * 0{,}052} + \rho_{mud} \qquad (2.5.1.1)$$

Where:

$\rho_{killmud}$= The density of the kill mud
$SIDPP$ = Shut-in drill pipe pressure
$TVD$ = True vertical depth
$\rho_{mud}$ = The density of the original mud

In the second circulation the kill mud is pumped down the drillstring and up the annulus. A constant pressure is also required in this circulation. A FCP (Final Constant Pressure) is set constant on the top of the drillstring. Similarly to the first circulation, the choke is regulated in interaction with the kill mud being pumped into the annulus volume in order to maintain a constant BHP. The well is killed when the annulus in filled with the kill mud. The valves may be re-opened and the drilling can proceed as planned.

The Driller's Method is a kill method that requires manual evaluation of the kick situation. Various calculations need to be done; the new kill mud weight, the pump rate, and manipulation of the choke. Kill sheets are used to maintain constant BHP during the second circulation. During this method, the well is exposed to high pressures, and for this reason certain durability demands are required to the equipment and casing shoes. Time can be a critical factor. Due to the two required circulations this method can be time consuming and the well is under maximum pressure over a long period of time. However, this method can be initiated immediately after an influx detection without having to weigh up the kill mud.

### 2.5.2 Wait and Weight Method

The Wait and Weight Method (W&W) was introduced after the Driller's Method as a counter reaction to the two circulations. The principle of the W&W is that one circulation is sufficient to kill the well. For this reason it is sometimes referred to the One-Circulation Method, and even the Engineering Method because of all the needed calculations [7].

After a kick is detected, the well is shut-in. While the well is kept shut-in, allow the well pressure to stabilize and record stabilized shut-in casing pressure (SICP), initial shut-in drill pipe pressure (SIDPP), and pit gain. The new kill mud weight is calculated based on these recordings. The new mud is pumped down the drillstring and preplaces the wellbore in one circulation. Due to the increased mud weight, the drillpipe pressure will consequently decrease. In order to maintain a constant BHP, a drill pipe pressure schedule must be developed and followed until kill mud weight to the bit. Once the mud comes out of the bit, the mud weight inside the drillpipe and in the annulus will be the same. Therefore, to maintain a constant BHP, drill pipe pressure must be maintained while displacing the kill mud.

The well is successfully killed when the original mud is displaced by the kill mud and the fluid column manages to hold back the formation pressure. If the new mud weight is not sufficient, another circulation is needed in order to re-establish well control.

### 2.5.3 Volumetric Method

The Volumetric Method differs slightly from the previously mentioned method in the way that it is used in situations where there are no possibilities of circulating out the kick. This method is suitable in situations where the drillstring is pulled out of the well or where the bit is not at the bottom of the well, and constant bottomhole pressure methods are not possible. This may happen during swabbing. The first priority is to try to trip the drillstring back into the well. If this is not possible, the Volumetric Method is the best option.

This method is based on that the influx in the well is gas [7]. Once the gas enters the well, the mud density decreases and the gas migrates up the annulus. If the valves at the top of the well are open, the gas volume will increase and the mud will flow out at the drill floor. On the other hand, if the valves are closed, the pressure in the well will increase due to the buoyancy of the gas.

The principle of this method is to allow the gas to expand and thereby reduce the gas pressure in the wellbore. The pressure increase at the top of the well is bled off by opening the choke valve. It is still desirable to keep the pressure approximately constant. In the two methods above, the well are killed by displacing with heavier mud. Since there is no drillstring in the well when the Volumetric Method is used, this is not possible. To regain control of the well when performing this method, one needs to allow all the gas to enter the well and bleed it off. The drillstring is brought back into the well once all the influx is removed, and the drilling can proceed as planned.

## 2.6 Automated well control

The petroleum industry is constantly in development, and there is thus a need for new technology associated with challenges to this development. The demand for more oil, higher oil recovery and high costs related to today's technology pushes the limits for the drilling operations. Drilling in deep water and arctic areas place higher requirements for drilling equipment, drilling stability, formation pressure conditions, and knowledge of the drilling crew etc. [8]

During a drilling operation, the main priority is to drill and complete the well with maximum safety for the crew and the environment and in a minimum of time. Managed Pressure Drilling (MPD) was introduced to improve pressure control during drilling, involving new pump systems and choke valves. The improved pressure control is obtained by controlling the backpressure while drilling [9]. A rotating control device seals the top of the annulus, and the mudflow from the well is routed through the choke manifold. This applies an additional backpressure to the annulus [10]. To provide additional control of the backpressure in the case of low mudflow from the pumps, a backflow pump is installed to boost the flow through the choke. MPD makes is possible to drill with a BHP close to the pore pressure, and still maintaining well control. MPD is controlled manually and the crew still needs to make decisions in critical situations and operate the pumps and chokes manually.

To achieve more effective and safer drilling operations, there is a need for automated well control. There is currently being done a lot of research on automated drilling procedures, including automated coordinated control of the drilling process, pump rates, chokes and drilling fluid properties. The though behind automated drilling is that the operations can be controlled by personnel sitting onshore using different computer programs. The core in automation is that algorithms control the process and detect changes quickly and prevent problems early on.

Automated well control has proven to be especially effective when it comes to taking gas kicks and circulation out the influx. A well control method called the Command Take-Over Procedure is an automated method under development that has proven to be able to replace conventional well control methods such at the Driller's Method and the Wait and Weight Method. This method is described further in chapter 5.

# 3 Automated control algorithms

Control system is a concept based on that a device, or set of devices, that can manage, command, direct or regulate the behavior of other device(s) or system(s) [11]. Control systems play an important part in automated well control as they make the processes automated.

A key feature of a control system is that the output is a desired parameter. In order to get the desired outcome, the system needs correct input. Transfer functions are commonly used to characterize the input-output relationship of components or systems that can be described by linear, time-invariant, differential equations [12] [13].


Figure 2: Open loop control system [14]

Figure 2 above shows an open loop control system. There is no way to compensate for variations in the open loop system. To account for changes, and to improve the efficiency of control systems, closed loop systems are introduced. There are two types of closed loop systems; feedback control and feedforward control.

### 3.1 Feedback control

A feedback control system is a system that maintains a prescribed relationship between the output and the reference signal by comparing them and using the difference as a means of control [15]. In closed loop control, the output, $y$, is measured by a sensor. The measured output, $y_m$, is compared to a reference signal, $r$, often the desired state. An error term, $e$, is generated and then fed through a controller where the error is converted into a system input value, $u$ [12] [13]. Figure 3 below demonstrates the concept of feedback control.

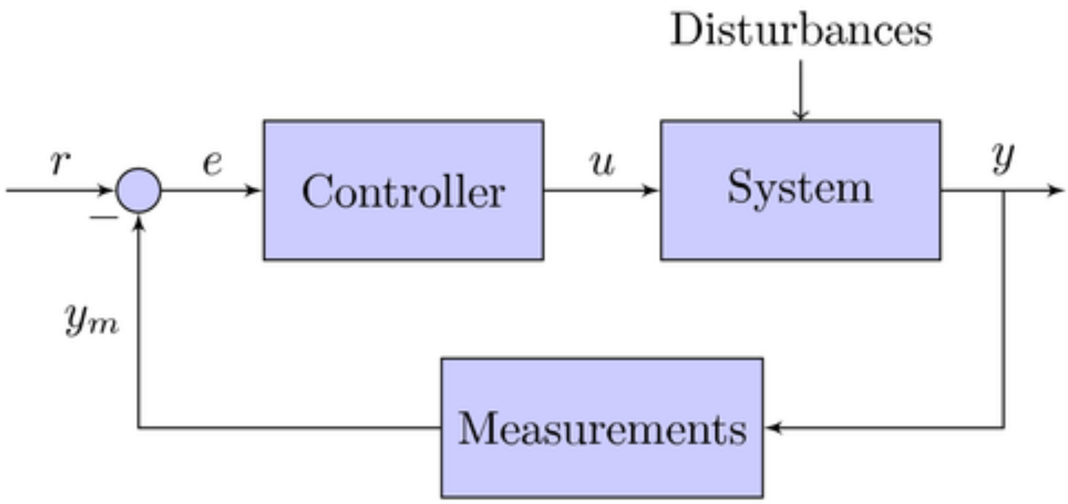


Figure 3: Feedback control [16]

The control system runs the loops several times, until the error term matches the reference signal. The disturbance on the system is a non-controllable input variable that affects the output and is therefore undesirable.

In order for the feedback control to work desirably, it must be clear what the reference signal is. The system behaviour mode must be measured and controlled to work properly. A system model is introduced to get an overview of the control system and its purpose.

There are two types of feedback control, negative and positive. Briefly, negative feedback is when a change in some variable results in an opposite change in a second variable. Oppositely, positive feedback is when a change in a variable results in a subsequently similar change in a second variable.

### 3.1.1 Control functions

A widely used feedback control mechanism is PID control (Proportional Integral Derivative control). Similarly to the feedback control, the PID controller generates an error term and compares it to the required reference signal. The controller attempts to minimize the error by adjusting the process control outputs [12] [13].

The PID-controller was introduced as an even more effective control method. As the name implies, the PID-controller consists of three parameters, the proportional, the integral, and the derivative values, respectively P, I and D. P depends on the present error, I on the accumulation of past errors, and D is a prediction of future errors.

The next subchapters deal with simplified version of the PID-control and how to develop the final PID-controller.

### 3.1.1.1 Proportional control

The simplest mode in PID-control is the proportional mode. As mentioned previously, the objective in control theory is to reduce the error signal to zero where [12] [13]

$$e(t) = y_{SP} - y_m \qquad (3.1.1.1.1)$$

Where:

$e$ = Error signal

$y_{SP}$ = Set point, previously referred to as reference signal

$y_m$ = Measured value of the controlled variable

$t$ = Time

For proportional control, the controller output is proportional to the error signal. For an ideal proportional controller, the following applies

$$u(t) = u_0 + K_p e(t) \qquad (3.1.1.1.2)$$

Where:

$u(t)$ = Controller output

$u_0$ = Nominal input value

$K_p$ = Proportional gain

Based on this equation, the proportional gain can be adjusted to make the controller output changes as sensitive as desired to deviations between set point and controlled variable.

### 3.1.1.2 Integral control

The integral control is slightly more complicated than the proportional control, and the controller output depends on the integral of the error signal over time [12] [13]

$$u(t) = u_0 + K_i \int_0^t e(\tau)\ d\tau \qquad (3.1.1.2.1)$$

Where:

$K_i$ = Integral gain given by $\frac{K_p}{T_i}$

$T_i$ = Integral time

$\tau$ = Adjustable time constant

Again, this equation implies for an ideal integral controller. An important characteristic of integral control is that it eliminates the offset. For this reason, an integral controller is often combined with a proportional controller, a PI-controller, given by

$$u(t) = u_0 + K_p\, e(t) + K_i \int_0^t e(\tau)\ d\tau \qquad (3.1.1.2.2)$$

The result of combining these two controllers is that the error signal decreases over time, shown in figure 4 below.

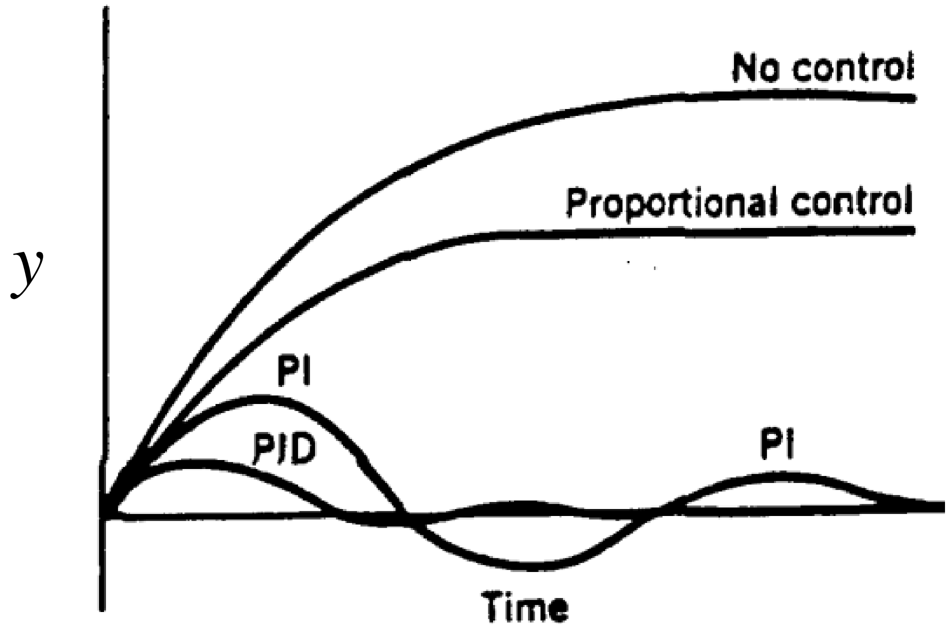


Figure 4: The result of adding controllers to a process [17]

It is the integral term in the PI-controller that is essential. Assume that $e$ is positive. As long as $e$ is higher than zero will the integral term and the total input value increase due to a positive value of the time interval. This implies that the integral term provides zero static offset.

### 3.1.1.3 Derivative control

The derivative control is the last branch in the PID-controller and it anticipates the future behavior of the offset by considering its rate of change. By adding the derivative control to the PI-controller, faster control is achieved for the system. For an ideal derivative controller, the following implies [12] [13]

$$u(t) = u_0 + K_d \frac{d}{dt} e(t) \qquad (3.1.1.3.1)$$

Where:

$K_d$ = Derivate gain given by $K_p T_d$

$T_d$ = Derivative time

By providing anticipatory control action, the derivative mode tends to stabilize the controlled process.

### 3.1.1.4 PID control

Adding all the control functions gives the final PID-control given by [12] [13]

$$u(t) = u_0 + K_p e(t) + K_i \int_0^t e(\tau)d\tau + K_d \frac{d}{dt} e(t) \qquad (3.1.1.4.1)$$

Assume that the offset is increasing. In other words, the offset´s derivative is positive, and the derivative term will contribute positively to the input value.

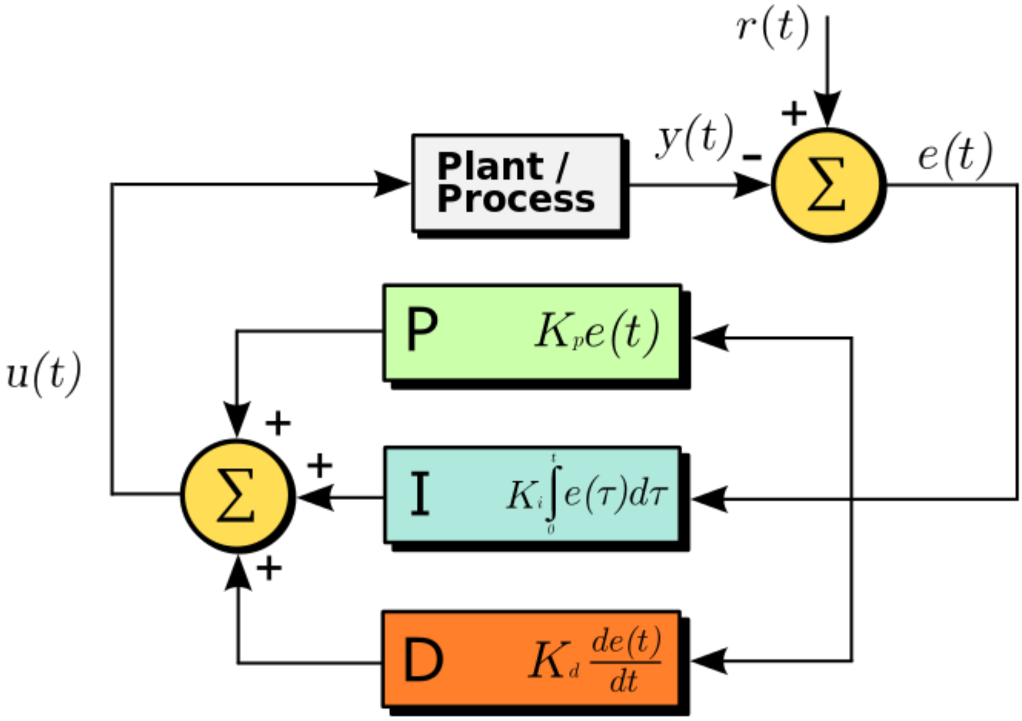


Figure 5: PID controller [18]

Figure 5 above shows a block diagram of a PID controller in a feedback loop. A convenient feature of the PID-controller is that it is possible to downgrade the controller to a P-controller or a PI-controller. By setting $T_i$ to a very high value and $T_d$=0, the PID-controller returns to a P-controller. PI-controller is possible to get by setting $T_d$=0.

### 3.1.1.5 Ziegler-Nichols

The Ziegler-Nichols method is a heuristic, experience based problem solving, PID tuning rule that attempts to produce good values for the three PID gain parameters [19]:

- $K_p$
- $T_i$
- $T_d$

The method was introduced to deal with challenges regarding the aspect of tuning of the gains required for stability and good transient performance.

By using only proportional feedback control, the controller parameters are determined by the following steps [19]:

1. Reduce the integrator and derivative gains to 0.
2. Increase *Kp* from 0 to some critical value *Kp=Kc* at which sustained oscillations occur
3. Note the value *Kc* and the corresponding period of sustained oscillation, *Tc*
4. The controller gains are now specified as follows:

Table 1: PID gain parameters

| **PID Type** | $\mathbf{K_p}$ | $\mathbf{T_i}$ | $\mathbf{T_d}$ |
|---|---|---|---|
| **P** | $0.5K_c$ | $\infty$ | 0 |
| **PI** | $0.45K_c$ | $T_c/1.2$ | 0 |
| **PID** | $0.6K_c$ | $T_c/2$ | $T_c/8$ |

Figure 6 below shows how the applied Ziegler-Nichols method determines $T_c$, the period of sustained oscillation. This particular graph show the determination of controller settings by reading the time period of a temperature cycle for a proprotinal control action.

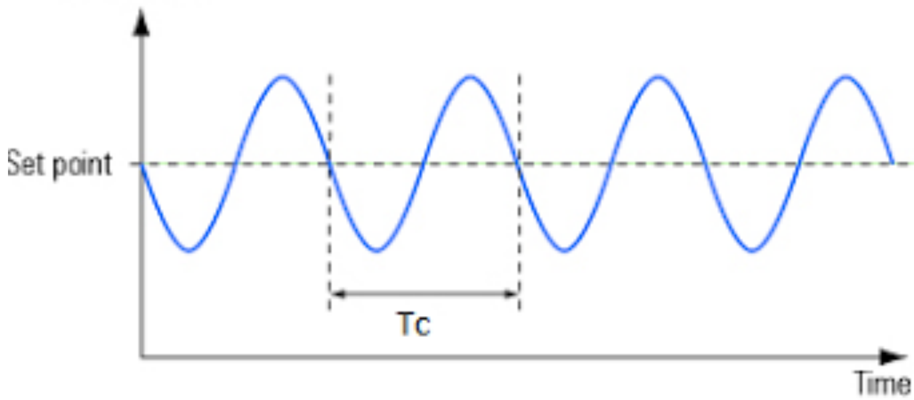


Figure 6: Determination of $T_c$ [20]

### 3.2 Feedforward control

Feedforward control is another branch within control systems [12]. Similarly to the feedback control, it is a closed loop system, but it differs slightly in certain areas. The feedforward control measures the disturbances and references in the system and compensates for them before the controlled variable deviates from set point. A control system that has only feedforward behavior responds to its control signal in a pre-defined way without responding to how the load reacts. Unlike a feedback system, the feedforward system´s control variable adjustment is not error-based. Instead it is based on knowledge about the process in the form of a mathematical model of the process and knowledge about or measurements of the process disturbances. Figure 7 below displays the layout of a process with feedforward control.

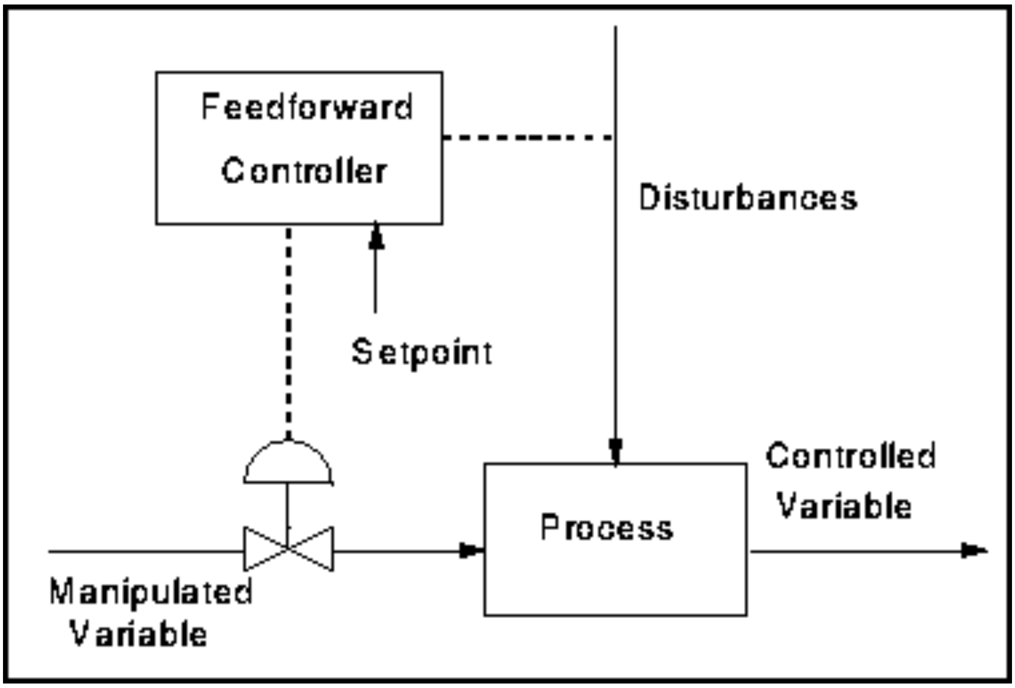

Figure 7: Feedforward control[21]

Feedforward and feedback control are often combined to eliminate the offset. One of the purposes of feedback control is to compensate for the fact that feedforward cannot calculate perfect input value.

### 3.3 Tank example

All the information on control theory above can be illustrated by an example of a water tank. The water level in the tank, $h$, is described in terms of the water inlet, $q_{in}$, and the valve opening, $z_c$. Figure 8 below describes the dynamic model of the water level in the tank system [22].

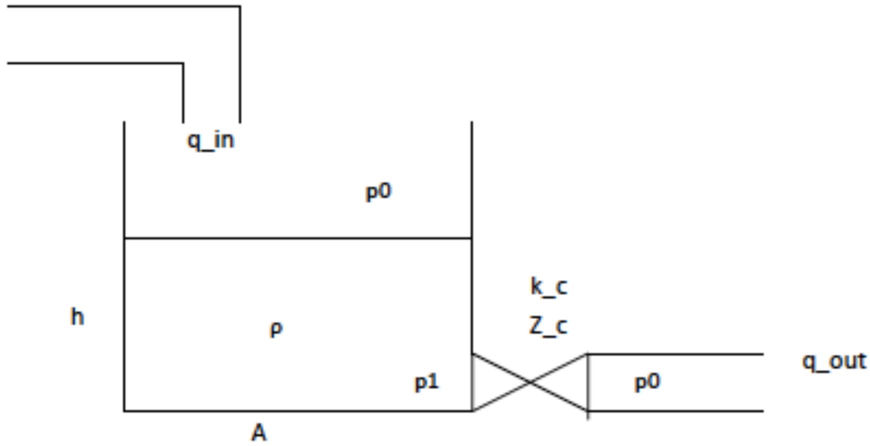


Figure 8: Water tank example [22]

The tank in figure 8 has a width of *w* meters, a length of *l* meters, and a height of *h* meters. The area of the tank can the be given as

$$A = wl \qquad (3.3.1)$$

The tank is filled with liquid to a level of *h* meters. The volume of the liquid in the tank is given by

$$V = Ah \qquad (3.3.2)$$

The valve at the bottom of the tank is a choke valve that can be adjusted to the desired opening. The pressure *P1* is given by the overlying fluid column

$$P1 = \rho g h + P0 \qquad (3.3.3)$$

Where:

$\rho$ = Density of the water, 1000 kg/m$^3$

$P0$ = External pressure, given by the amount of water drained through the valve

The flow rate through a choke valve, $q_c$, can be modeled by the valve equation given by

$$q_c = z_c k_c \sqrt{\frac{\Delta P}{\rho}} \qquad (3.3.4)$$

Where:

$z_c$ = Choke valve opening

$k_c$ =Valve constant

$\Delta P$ = Differential pressure across the valve

By applying control theory to the system one can control variables in the tank system. The liquid volume dynamics in the tank can be modeled as

$$\frac{dV}{dt} = q_{in} - q_{out} \qquad (3.3.5)$$

The level dynamics of $h$ in the tank is then given by

$$\dot{h} = \frac{1}{A}\left(q_{in} - q_{out}\right) \qquad (3.3.6)$$

The flow through the valve when $P0$ is the atmospheric pressure can then be given by

$$q_c = z_c k_c \sqrt{\frac{\rho g h}{\rho}} \qquad (3.3.7)$$

A dynamic model of the tank can then be expressed as

$$\dot{h} = \frac{1}{A}\left(q_{in} - z_c k_c \sqrt{gh}\right) \qquad (3.3.8)$$

When simulating the level in the tank, the Euler's method is used, giving

$$h(t_{k+1}) = h(t_k) + \left[\frac{1}{A}\left(q_{in} - z_c k_c \sqrt{gh}\right)\right] dt, x(t_0) = 0 \qquad (3.3.9)$$

The water level in the tank can be simulated by using MATLAB, and the MATLAB script can be found in Appendix B. The graph below simulates the water tank level using a PID controller. According to the theory behind PID controllers, it minimizes the error in the tank level, and regulates the actual tank level to be as close to the reference level as possible [22].

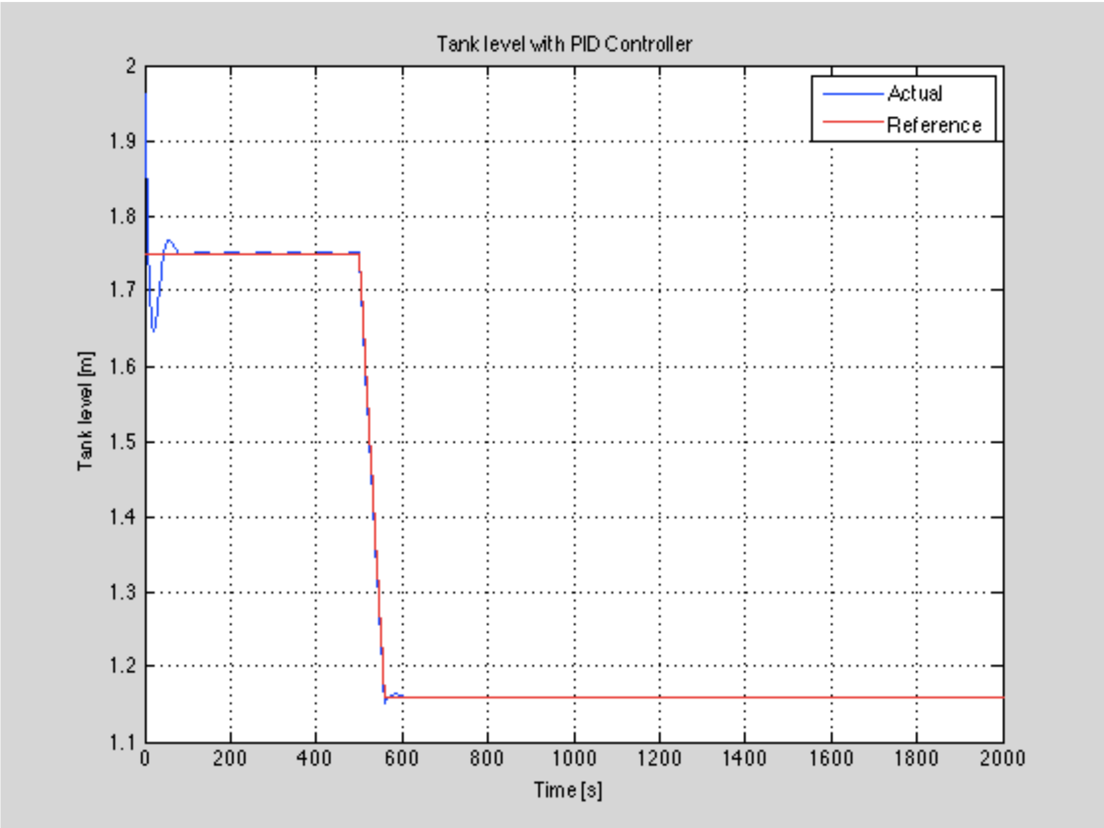


Figure 9: Tank level with PID controller

The tank model includes both feedback and feedforward control. To maintain a steady level of water in the tank, the valve opening needs to be regulated in correlation to the flow into the tank. An increase in $q_{in}$ will increase the measured water level. This will be detected by a sensor in the tank, and the valve opening will consequently increase to lower the water level back to the reference level. In the opposite case, if the valve opening is increased, the system will compensate by increasing the flowrate into the tank. Figure 10 below displays the choke opening as a fraction between 0 and 1 over time.

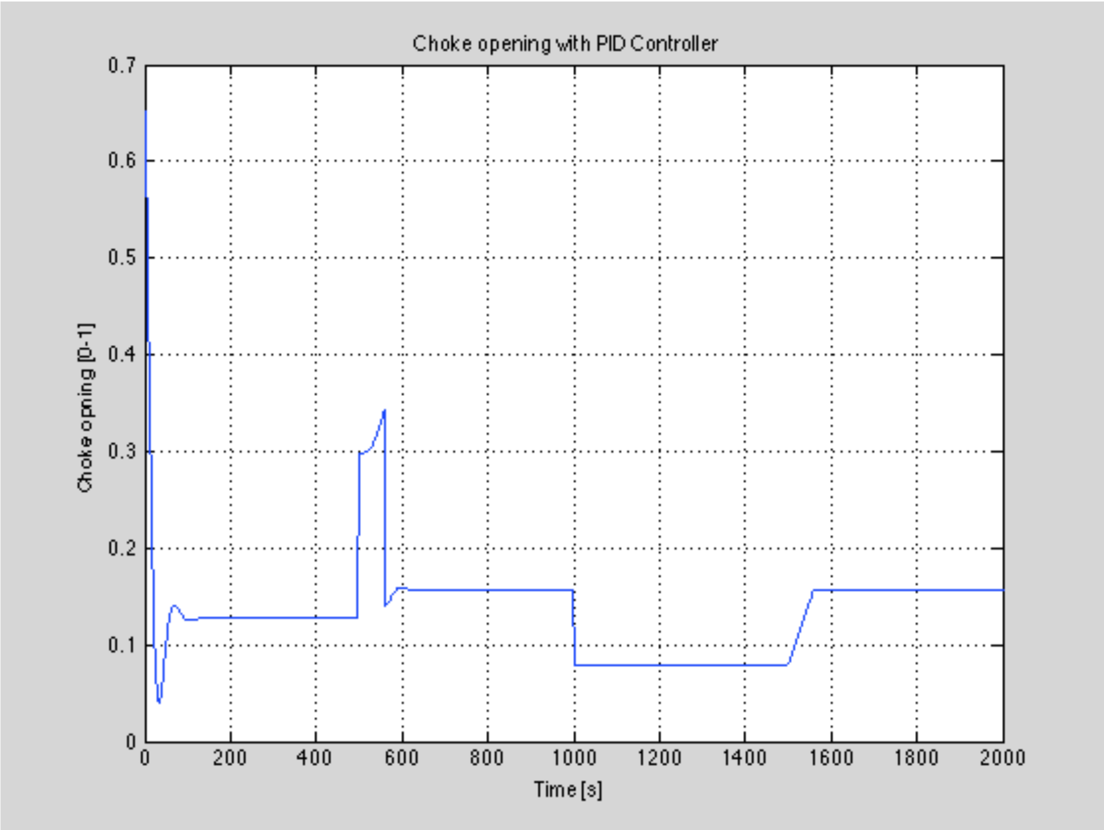


Figure 10: Choke opening with PID controller

As the choke opening varies, so will $q_{in}$ and $q_{out}$. This is shown in the figure 11 below. The correspondence between the choke opening and the flowrate can be seen by comparing figure 10 and 11.

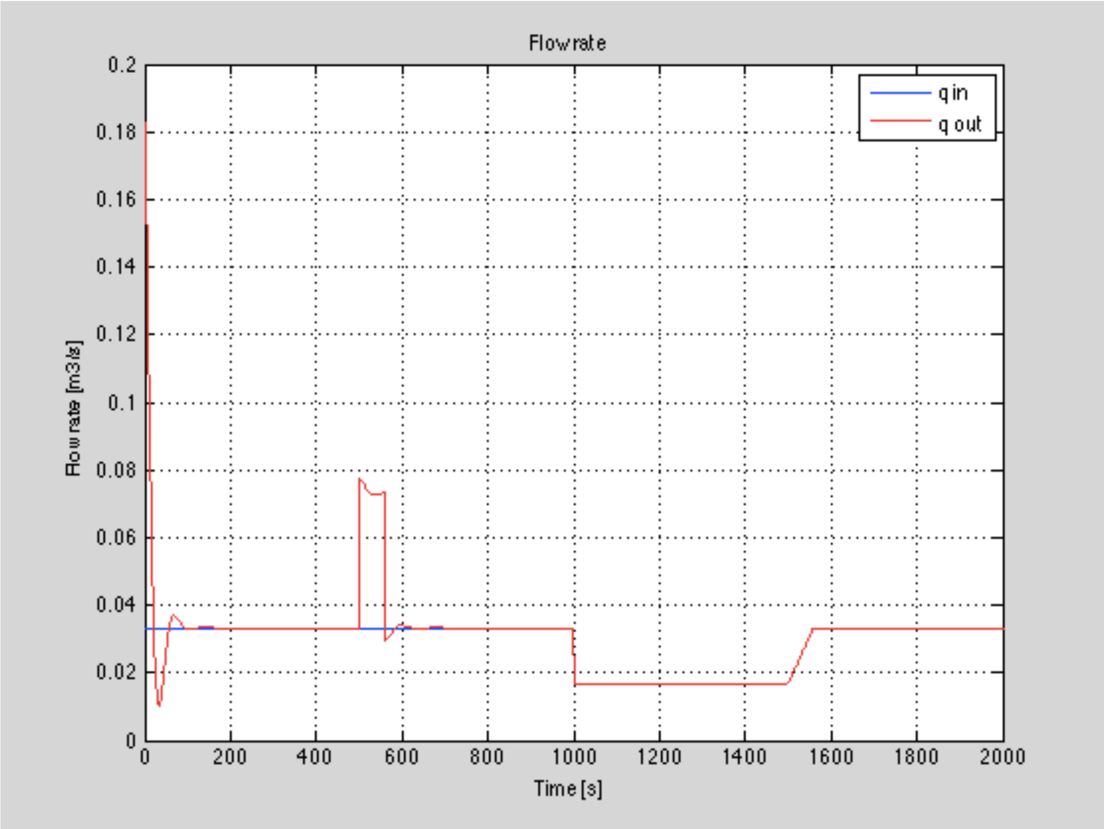


Figure 11: Flowrate

The water inflow can be seen at as disturbance to the system. Feedforward control ensures that the error signal is reduced by designing the input value relative to the disturbance. Since it is possible to measure and adjust $q_{in,}$ it will in principle be fairly easy to control this system in terms of maintaining a steady water level.

# 4 Automated well control

Automation is a well-known technology and has been used in aircraft and cybernetics for a long time. However, automation in the oil and gas industry is not yet widely distributed. There are several reasons for this: The main reason is considered to be the cooperation between companies in a drilling operation. The operations are performed partly by oil companies, drilling contractors and service companies. The split division of responsibilities means that neither party gets an overall view of the operation, and therefore not the need for automation of drilling processes. Another reason for the lack of automated processes is that the oil and gas industry has not yet reached a point of cost constraints. Automation was introduced to other industries due to economic reasons. An increase is automation offshore leads to less demand of personnel working offshore. This will affect the industry, especially the service companies, the providers of equipment and service offshore [23].

The automation of well control appears at different levels from where the whole process is controlled automatically; to where some parts are automatic while other parts are still controlled manually. The automation includes pressure control with automatic choke adjustments, pump rates and the MPD valve. The automated well control system, hereinafter referred to as AWCS, is divided into five phases [24]:

1. System identification/calibration
2. Kick detection
3. Shut-in
4. Circulation
5. Displacement

**System calibration**

It is important that the system is calibrated at all times, especially while identifying circulation pressure loss at various pump rates. Calculations of volumes, kill mud weight and initial circulating pressure (ICP) are performed automatically, but the crew should confirm that the calculations are correct.

**Kick detection**

The AWCS is only monitoring during kick detection, due to the absent need for pump or choke valve control. The system will monitor the pump, pit tank volume and flow rate out, and an alarm will go off if a kick is detected.

**Shut-in**

Similarly to the previous phase, the AWCS is only monitoring. The rig crew operates the BOP, the pump and the choke. If the system has a float valve, it must be opened when the pressure has stabilized after shut-in. This is to record the SIDPP, and is done by starting the pumps at a low circulation rate. It is desirable to fully automate the shut-in process in the future and control it by a computer system.

**Circulation and circulation**

It is the driller's decision whether to run the circulation manually or automatically. If it is run automatically, there are different automatic control levels to choose from. The procedure for the AWCS is as following:

1. Start circulation
2. Circulate kick
3. Change to kill mud
4. Circulate kill mud in drillstring
5. Circulate kill mud in annulus

## 4.1 The Kaasa Model

The Kaasa model is a mathematical model developed by Glenn-Ole Kaasa, and is based on dividing the drilling system into two control volumes: one for the drillstring and one for the annulus. This is because when modeling fluid flow during a drilling operation, it is assumed that the flow pattern in the drillstring is uniform along the whole length of the drillstring, and likewise, the flow pattern in the annulus is uniform in the whole length of the annulus [22]. Figure 12 below shows a simplified schematic of the two control volumes.

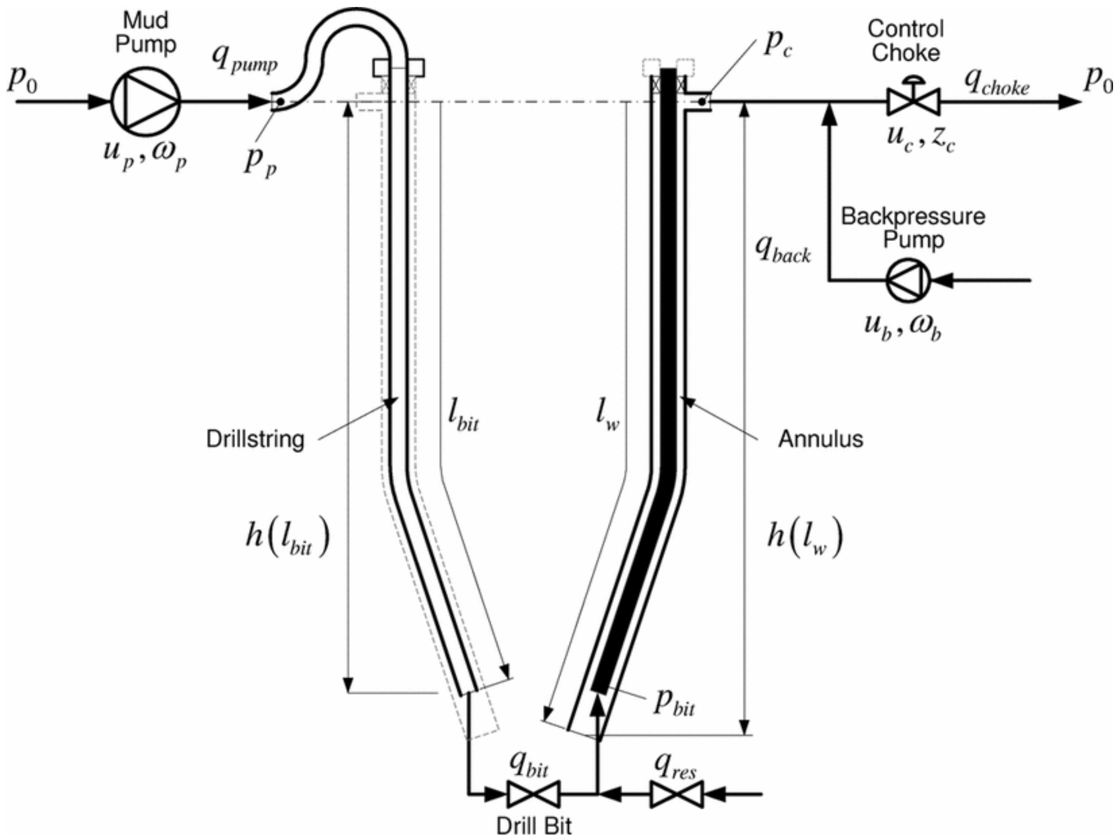


Figure 12: Simplified schematics of the drillstring and the annulus [10]

The dynamics of the mud pump pressure in the drillstring, $P_p$, and the choke pressure in the annulus, $P_c$, is given by [10]

$$P_p = \frac{\beta_d}{V_d}(q_{pump} - q_{bit}) \qquad (4.1.1)$$

$$P_c = \frac{\beta_a(t)}{V_a(t)}(q_{bit} + q_{res} + u(t) + V_a) \qquad (4.1.2)$$

Where:

$\beta_d$ = Bulk modulus of the drillstring

$V_d$ = Volume of the drillstring

$\beta_a$ = Bulk modulus of the annulus

$V_a$ = Volume of the annulus

$u(t)$ = The control input, given by $u(t) = q_{back}(t) - q_{choke}(t)$

Both $P_p$ and $P_c$ are measured, and the bottomhole pressure, $P_{bit}$, is calculated from these parameters. This can be done in two ways, either by considering the pressure differences through the annulus, given by

$$P_{bit}(t) = P_c + \rho_a(t)gh + F_a {q_{bit}}^2 \qquad (4.1.3)$$

or the pressure difference through the drillstring, given by

$$P_{bit} = P_p + \rho_{mud}gh - F_d {q_{pump}}^2 \qquad (4.1.4)$$

Where:

$\rho_a$ = The density of the fluid in the annulus

$F_a$ = The friction coefficient for the annulus

$\rho_{mud}$ = The density of the mud

$F_d$ = The friction coefficient of the drillstring

# 5 The Command Take-Over Procedure

The Command Take-Over Procedure is an automated well control method that can be implemented on a drilling system with an MPD choke manifold and annulus pump, which control the bottomhole pressure. The idea behind the procedure is that an implemented controller automatically attenuates a kick without shutting down the main pump. There are two modes of operation; a normal operation, where the bottomhole pressure is kept constant at a set-point, and a kick operation, where the controller is switched to pure flow control mode [25].

While drilling with MPD, the bottomhole pressure is kept slightly higher than the pore pressure in the reservoir. Due to the uncertainties in the reservoir conditions when using MPD, the pore pressure may exceed the bottomhole pressure, resulting in an influx of reservoir fluids. Automation of the drilling operation provides earlier kick detection, which is crucial for MPD.

## 5.1 Controller design

The controller design for the Command Take-Over procedure is deduced by using the

Kaasa Model presented in subsection 4.1. By differentiating equation (4.1.3) with respect to time and inserting it into equation (4.1.2), the dynamic model for $P_{bit}$ is obtained by [10]

$$\dot{P}_{bit} = \frac{\beta_a(t)}{V_a}\left(q_{bit} + q_{res} + u(t)\right) + \dot{\rho}_a(t)gh \qquad (5.1.1)$$

A simple control law can be proposed from (5.1.1):

$$u = -k_p\sigma(t)\left(P_{bit}(t) - P_{ref}\right) - \hat{q}_{bit} \qquad (5.1.2)$$

Where:

$k_p$ = Positive tunable constant

$\sigma(t)$ = Take-over signal

$\hat{q}_{bit}$ = An estimate of $q_{bit}(t)$

The take-over signal is given by

$$\sigma(t) = \begin{cases} 1 \\ 0 \end{cases}$$

Where:

1 = No reservoir influx

0 = Kick

Mode 1 and 0 represents the two modes of operation, the normal operation and the kick operation respectively. While drilling, the controller runs in normal mode and the take-over signal is chosen as 1 and $k_p$ is set to a desired level. This will regulate the bottomhole pressure to the reference pressure. A kick may occur while drilling as a result of drilling into a gas pocket, swabbing, lost circulation etc. After detecting the kick, the controller is set to kick handling mode by setting the take-over signal to 0. The controller reduces to a pure flow controller, giving the closed loop a self-regulating property. By doing this, the kick is attenuated and the reservoir influx is converged to zero.

During drilling, the control is in Mode 1, meaning in MPD-mode. A PID controller controls the bottomhole pressure. If the bottomhole pressure changes, the PID-controller will regulate the output value to the reference value. However, if a kick is detected, the controller will switch from Mode 1 to Mode 0. The drilling operation is no longer in MPD-mode, but now in WCV-mode (Well Control Valve). The MPD-valve closes by closing the BOP and the WCV opens to circulate out the kick. When well control is regained, the controller is switched back to normal mode, and the drilling operation continues. The Command Take-Over Procedure introduces kick handling without having to stop the pumps. This eliminates all problem related to pump start up in conventional well control.

### 5.2 Controller take-over logic

The take-over logic itself is divided into three parts [10]:

1. A kick detection algorithm that estimates reservoir influx and governs switching from normal mode to kick handling mode.
2. A reservoir pore pressure estimator for computing a new pressure set point.
3. A timer that governs switching from kick handling mode back to normal mode.

# Part II Experiments

# 6 Results and discussion

The laboratory experiments were performed at the two-phase laboratory at the University of Stavanger. The experiments were performed on a rig model designed and developed during fall 2010 by Tormod Drengstig, Magnus Tveit Torsvik and Alexander Wang.

The appendix contains information of the equipment used in the experiments, and additional experimental results.

## 6.1 The rig model

The rig model is a simplified implementation of a pressure managed drilling process where the buttonhole pressure is controlled by the pump and different valves [26] [27]. The pumprate is given as a fraction between 0 and 1 of the maximum motor speed at 50 Hz. 50 Hz corresponds to a maximum pumprate of 1400 liters pr. hour. However, the maximum limit pump rate on the pump is set to 0,45 as a safety setting.

The model is built up by 50 meter of PVC (Polyvinyl Chloride) pipes with a diameter of 32 mm coiled around a scaffolding to simulate a well. The rig model is following equipped with a BOP, a Managed Pressure Drilling valve (MPD valve) and a Well Control Valve (WCV). The BOP takes approximately 10 seconds to go from fully open to fully closed. The WCV and MPD valve openings are given as a fraction between 0 and 1. This can be done automatically or manually.

A water tank is placed next to the scaffolding and connected to the pump. To simulate an influx from the reservoir, air pressure from the University's air pressure system is injected through an electrical valve connected to a reducing valve at the bottom of the rig model. The reducing valve is implemented between the gas inlet and the electrical valve, providing the possibility to regulate the gas supply automatically. In addition, a simple valve is implemented for manually controlling the gas inflow.

A computer with MATLAB and Simulink is connected to the rig model, and all the experiments are performed using these programs. Figure 13 below shows the Piping and Instrumentation Diagram (P&ID).

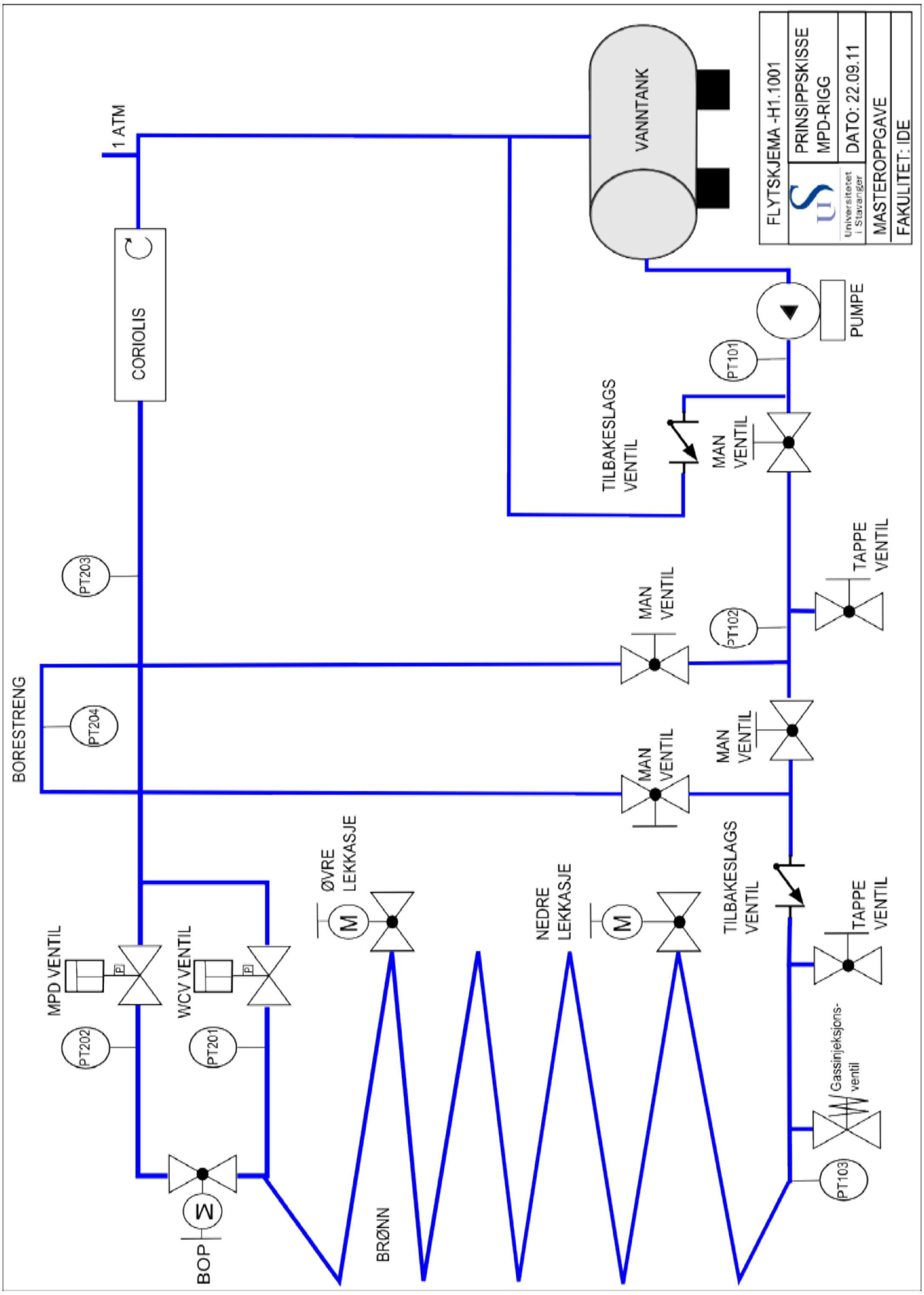


Figure 13: The P&ID of the rig model [26]

Table 2: Explanation to the pressure sensors

| Pressure sensor | Equivalent pressure |
|---|---|
| PT103 | Pore pressure |
| PT202 | MPD choke pressure |
| PT102 | Pump pressure |
| PT204 | Stand pipe pressure |

The simulations on the drilling rig represents the drilling process after the mud is pumped through the drill bit and up the annulus to the topside. The water is therefore pumped from the water tank, passing PT102, through the flowloop topside passing PT204, and thence through the backflow valve and into the well passing PT103. The water will further be pumped up the well to the BOP, WCV and MPD valve. Thence the water is pumped through a coriolis flowmeter and returns to the water tank.

### 6.2 Conventional drilling

Various experiments were carried out as feasibility tests to finally carry out the main experiment, the command take-over procedure. The experiments that were carried out prior to the main experiments were carried out to get a broader physical understanding of automated drilling and the command take-over procedure.

The experiments in the subsections 6.2.1 and 6.2.2 are done with the MPD choke fully open to provide an image of a conventional drilling operation.

#### 6.2.1 No influx

The flowrates are functions of the pumprates, and the pressure responses to different flowrates are shown in figure 14 and 15 below.

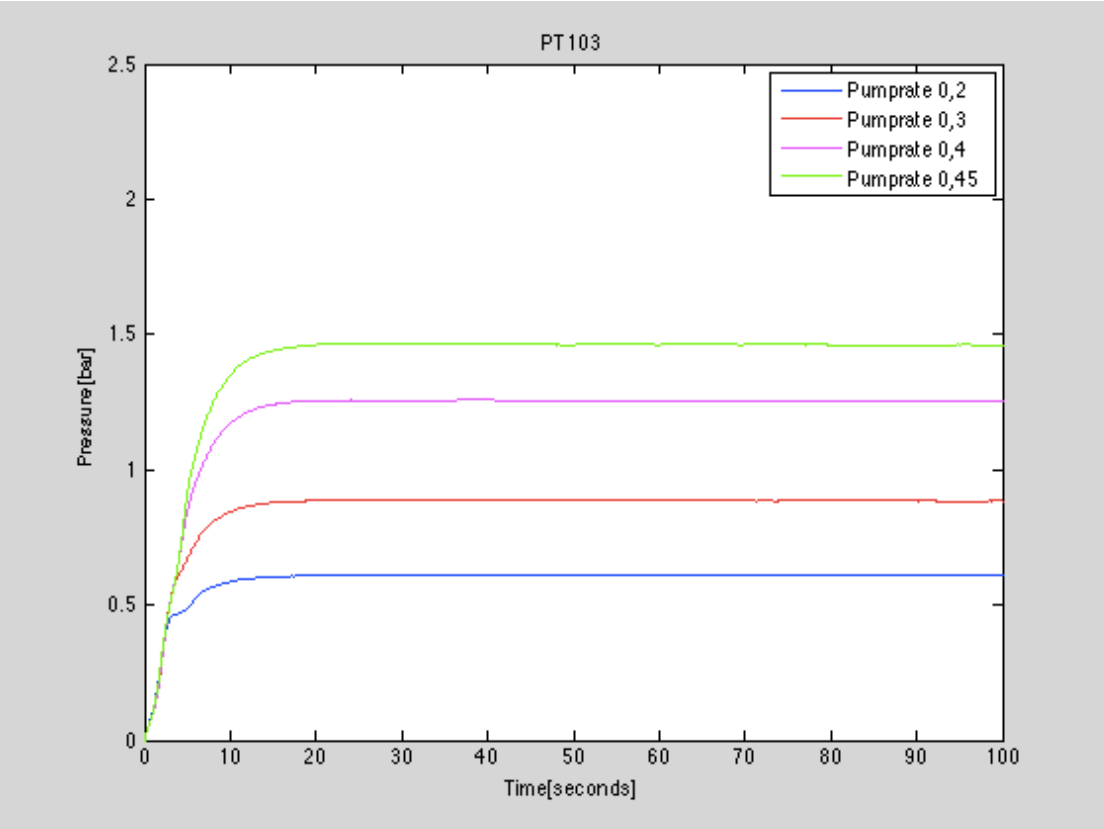


Figure 14: Downhole pressure as a function of pumprate

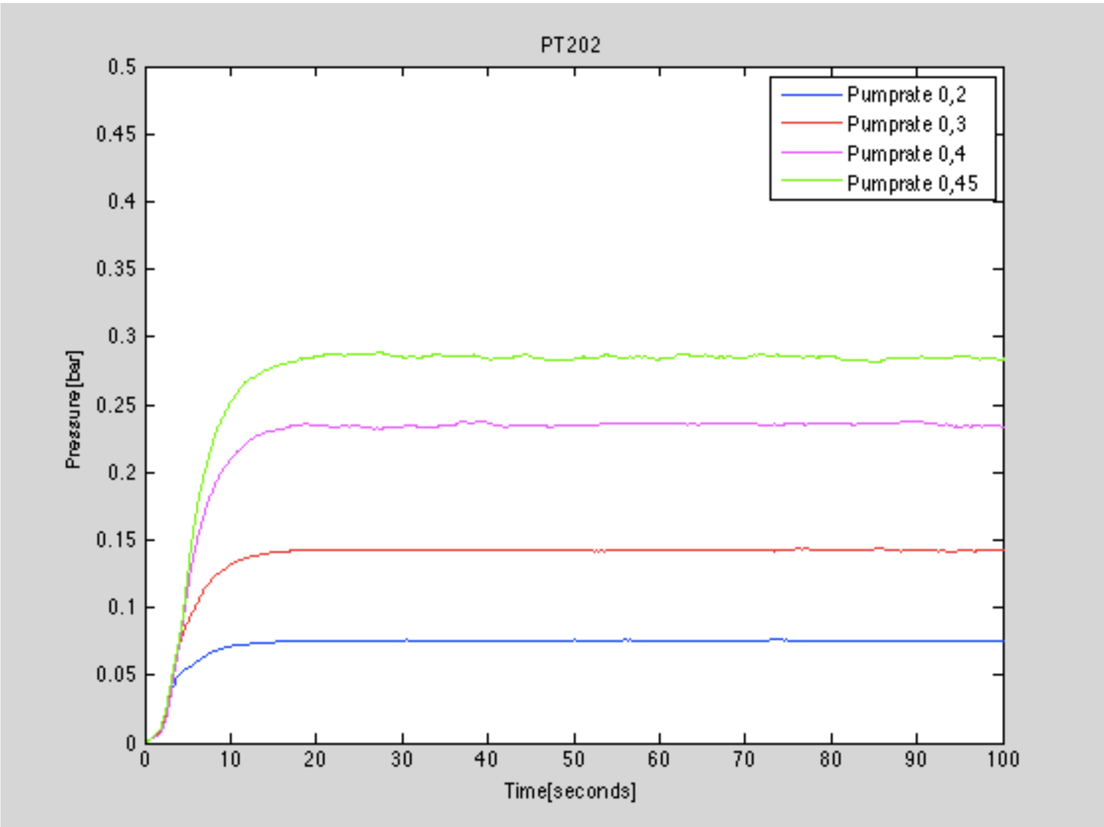


Figure 15: Topside pressure as a function of pumprate

Figure 14 and 15 show different pressure responses to different flowrates. As the flowrates increase, so will the pressure, due to increased frictional forces.

### 6.2.2 Influx

These experiments were performed with an enforced gas influx. The control algorithm in Simulink is programmed to inject gas as long as the PT103 pressure is above a threshold value. The kick size is determined by the pressure margin and the influx time. The following experiments were performed with air pressure 4 bar and a constant pumprate of 0,3:

1. Influx time 10 seconds
2. Influx time 8 seconds
3. Influx time 5 seconds
4. Influx time 3 seconds

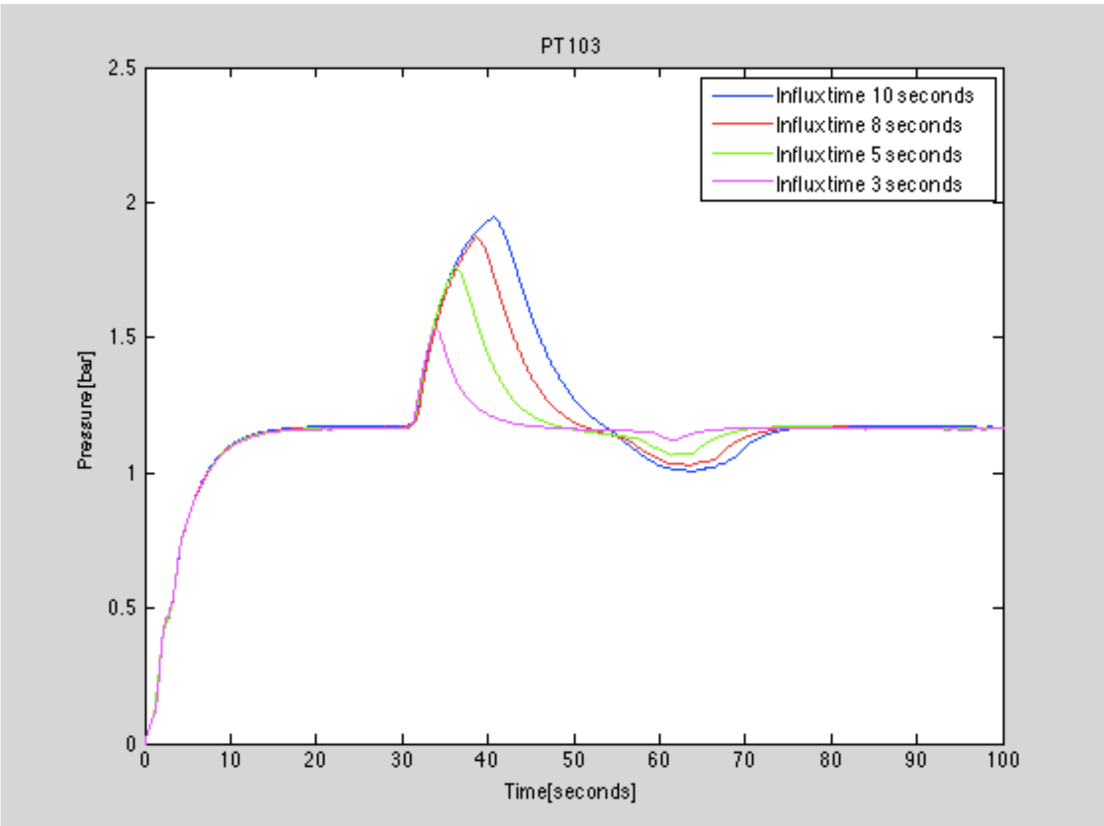


Figure 16: PT103 response to different kick sizes

- t=0 s: The pump and simulation was started
- t=15 s: The pressure was stabilized
- t=30 s: The kick was initiated

From figure 16 it is clear that the different kick sizes have very different impact on the pressure. After the kick is stopped, the pressure experiences a drop before it reaches the same value as before the kick was initiated. This is due to a combination of the following effects:

1. Increased velocity due to the gas will result in a higher frictional pressure loss
2. Decreased density due to the gas will reduce the hydrostatic pressure
3. The gas bubbles will expand as they flow up in the pipe
4. The viscosity will change as a result of the gas influx

The next four figures show different pressure responses and the flowrate response to the same experiment.

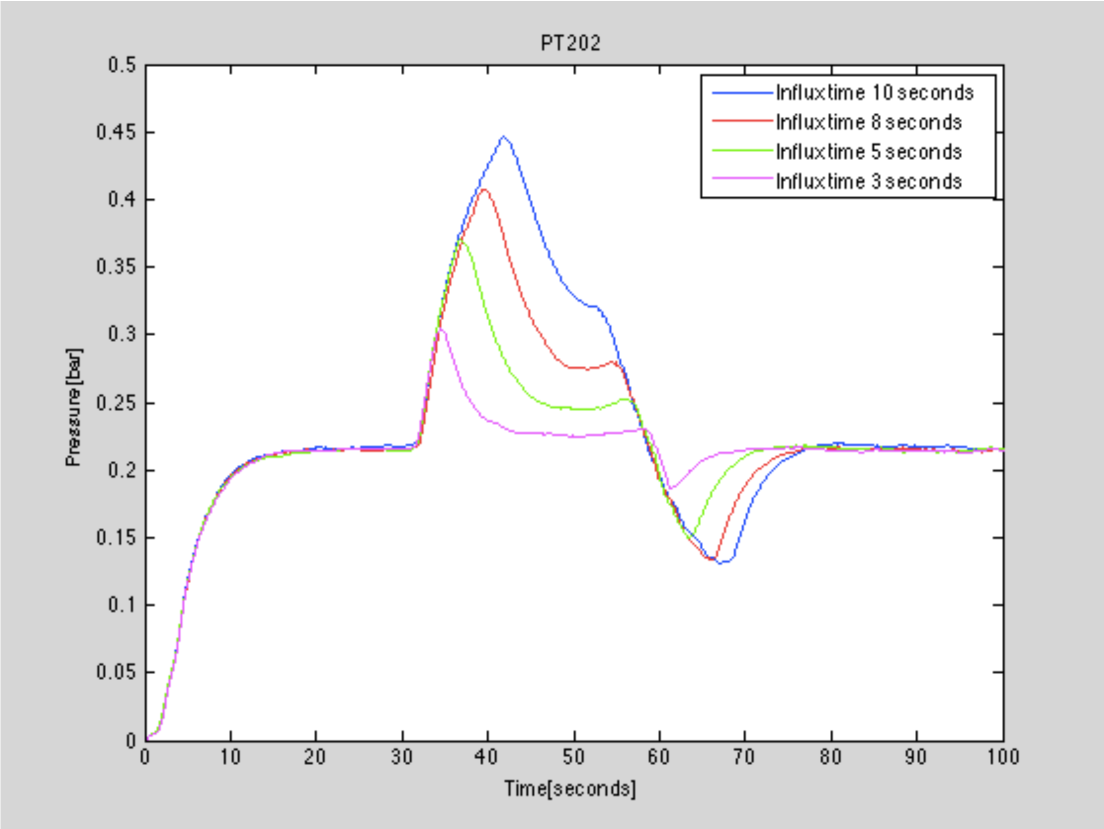


Figure 17: MPD choke pressure response to different kick sizes

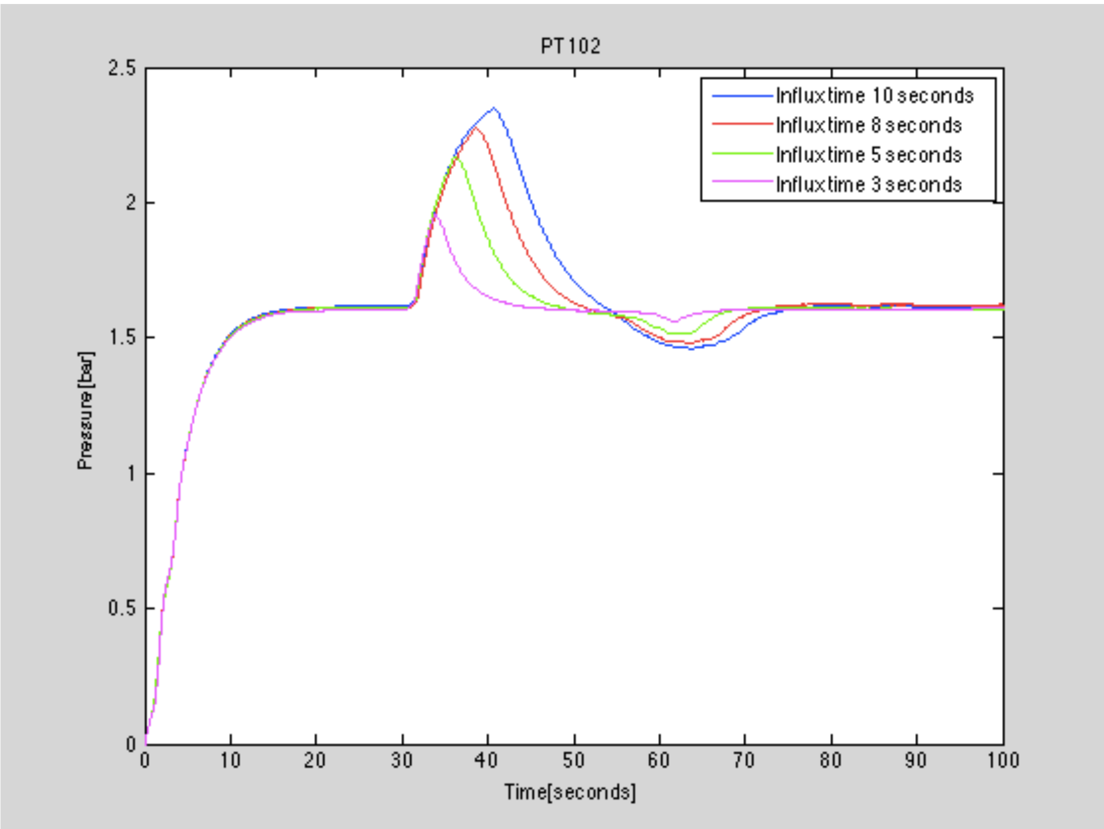


Figure 18: Pump pressure response to different kick sizes

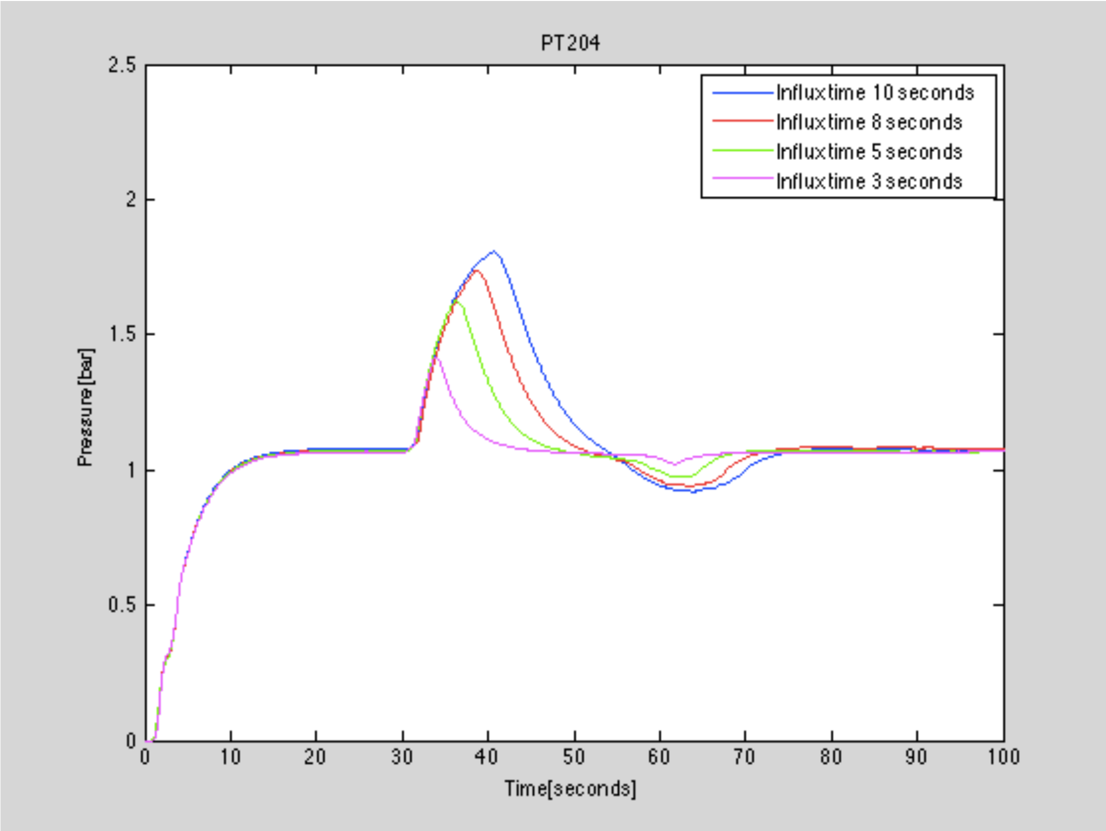


Figure 19: Standpipe pressure response to different kick sizes

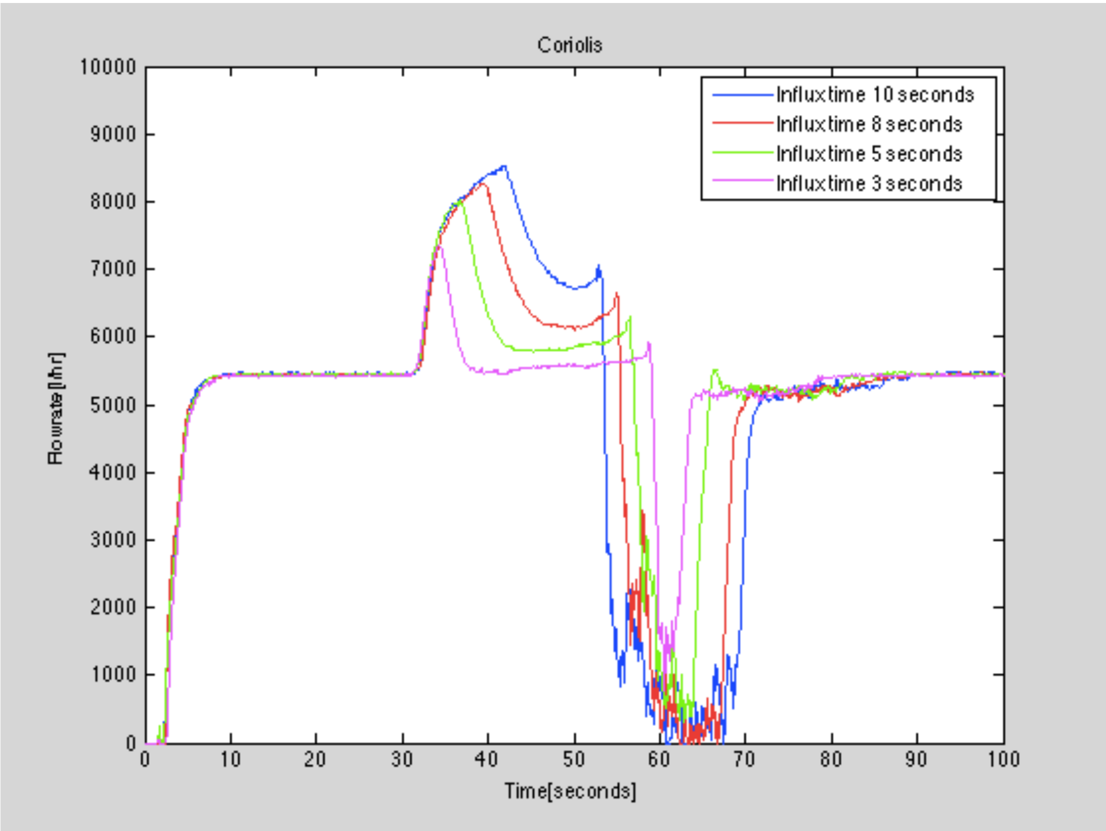


Figure 20: Coriolis flowrate to different kick sizes

The coriolis flowmeter measures mass flow in [kg/hr], but since the experiments are done with fresh water, the unit for the flowrate is given in [l/hr]. The coriolis can only measure single flow, so when the gas enters the well, the measurements are no longer valid. However, the coriolis is a helpful indicator to see how the flowrate changes to pressure changes and when the gas is circulated out of the well.

### 6.3 Automated drilling

This subchapter involves controlling the MPD valve using a PI-controller to obtain the preferred pressure value. Both simulations are started in MPD mode with valve fully open and a constant pumprate of 0,4. The tuning parameters for the PI-regulator are $K_p$=-0,1 and $T_i$=3.

#### 6.3.1 PI-control on the MPD valve using PT202 control without influx

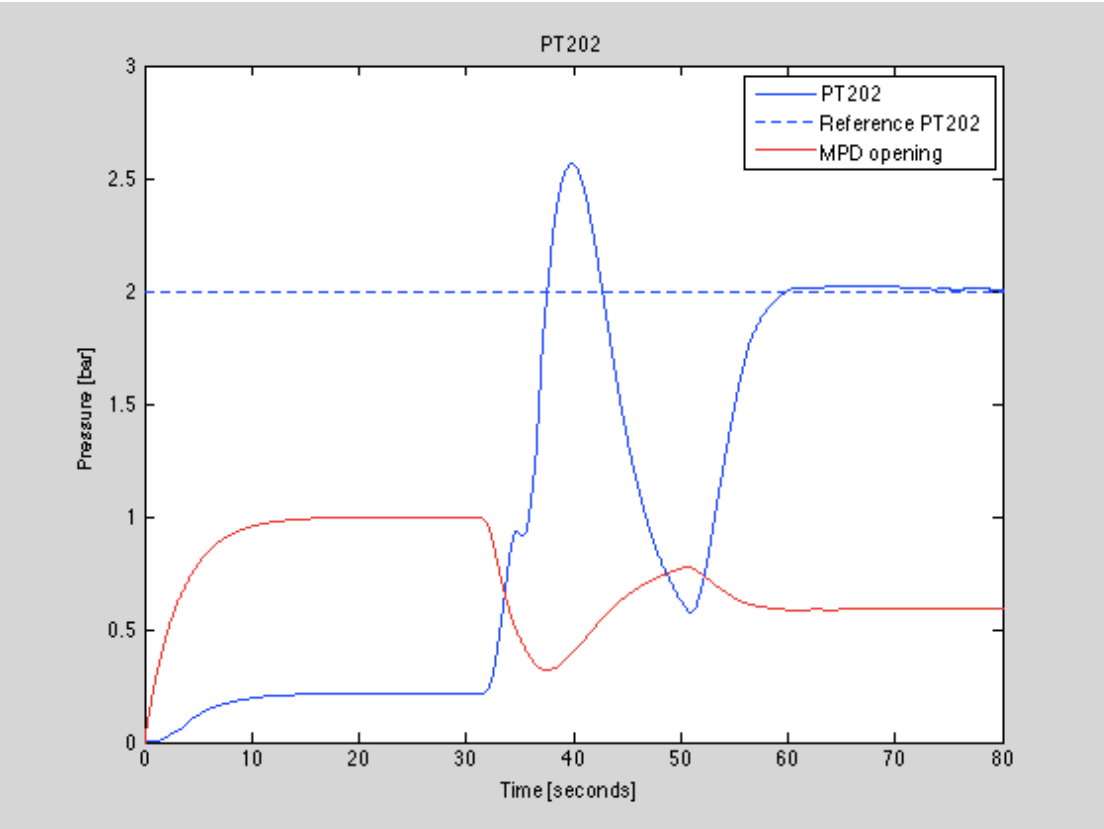


Figure 21: PI-control on the MPD valve using PT202 control without influx

- t=0 s: The pump and simulation was stared
- t=30 s: The PI-controller was activated

The PI-controller was activated after 30 seconds with a reference value of 0,2 bar, which was increased to 2 bar after the activation. The reason for this is that the reference value needs to be close to the actual value for the activation of the PI-controller. If the reference value is too far from the actual value, the pump will automatically shut off. After the PI-controller activation, the pressure experiences an increase, and the MPD valve opening decreased to correspond to the increasing pressure. As the pressure decreased, the valve increased the opening. The pressure stabilized at the reference value after 90 seconds, and the valve opening and pressure value was kept at a constant value.

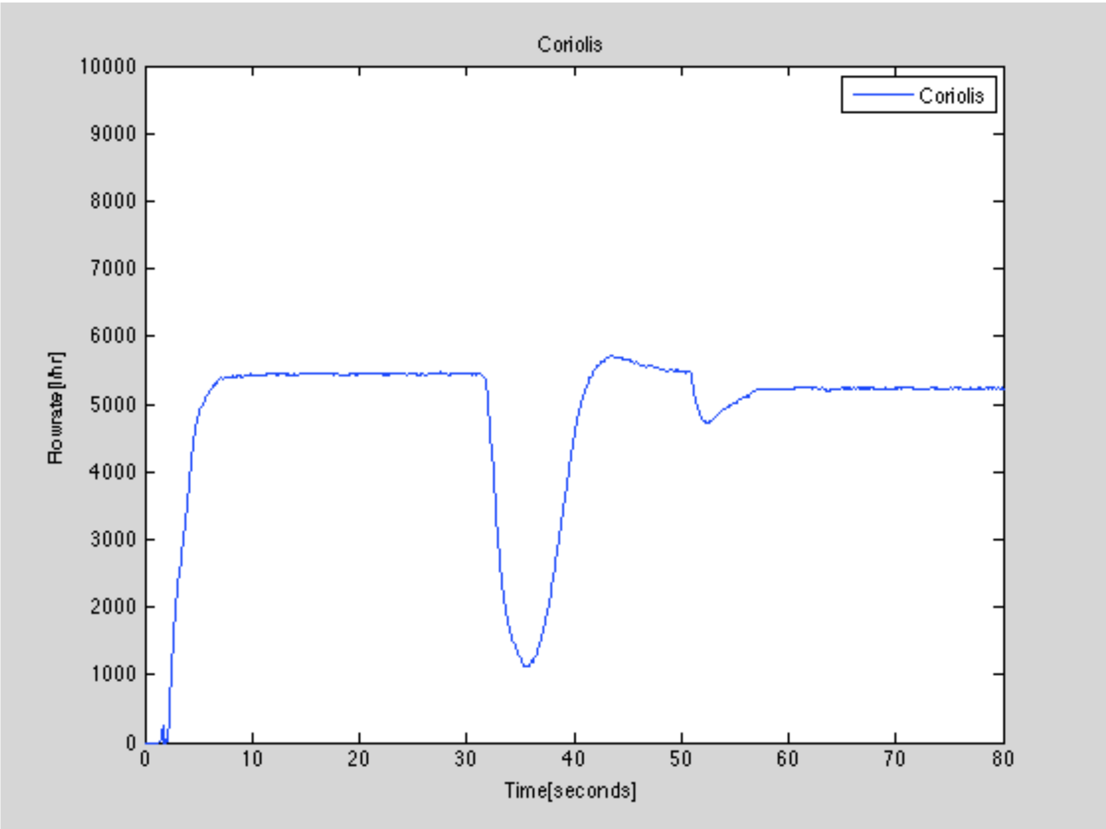


Figure 22: Coriolis flowrate

### 6.3.2 PI-control on the MPD valve using PT103 control without influx

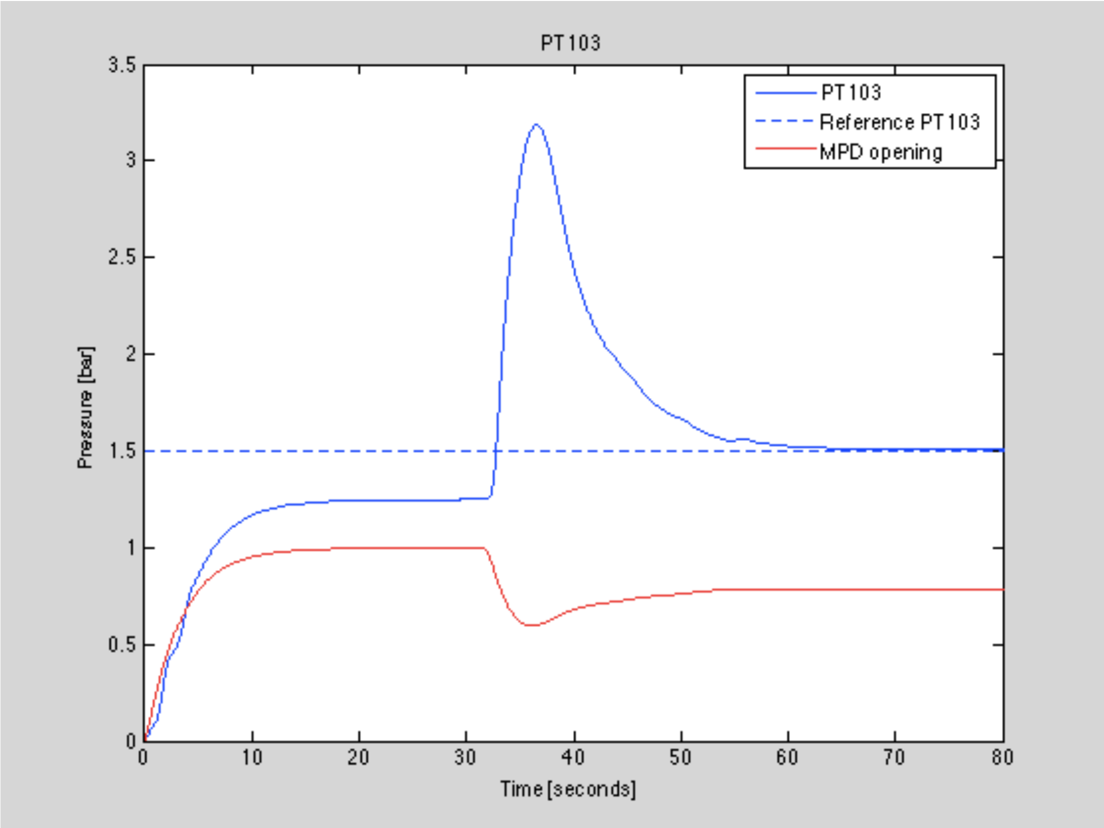


Figure 23: PI-control on the MPD valve using PT103 control without influx

- t=0 s: The pump and simulation was stared
- t=40 s: The PI-controller was activated

Figure 23 shows the same pattern as figure 21. The controller was activated after 30 seconds with a reference value of 1,0 bar, which was increased to 1,5 bar after the activation. The MPD valve opening corresponded immediately to the pressure changes to keep the measured PT202 pressure at the reference value.

### 6.3.3 PI-control on the MPD valve by choosing reference based on measurement of PT202

**Case 1** Activate influx

1. Keep the MPD valve in PT202 control and record the pressure readings of PT103
2. Select a pore pressure just below the PT103 value
3. Set the gas influx control to be 0,1 bar below the pore pressure value
4. Reduce the reference of PT202 control with 0,2 bar
5. Verify gas influx and an increase in the frictional pressure in the annulus

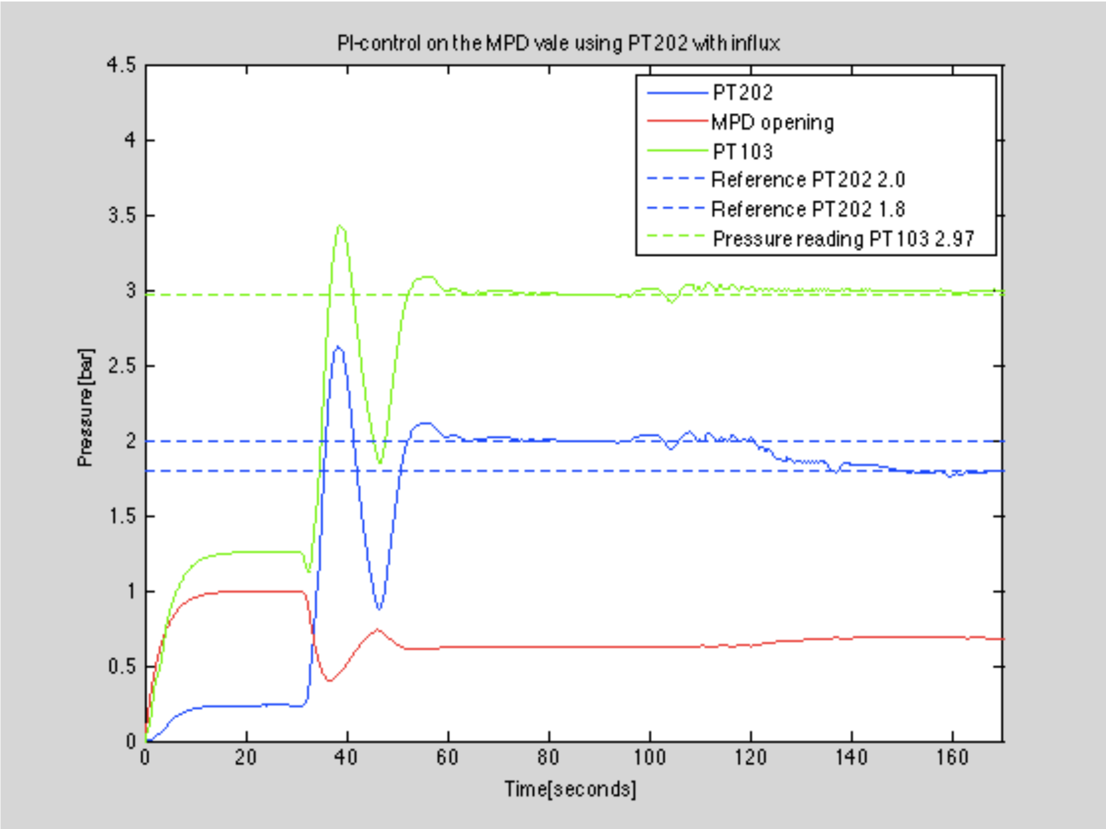


Figure 24: PI-control on the MPD valve using PT202 with influx

- t=0 s: The pump and simulation was started
- t=30 s: The PI-controller was activated in PT202 control. The reference was first set to 0,2 bar before it was increased to 2,0 bar
- t=60 s: PT202 has stabilized at the reference value. The value of PT103 was recorded to be 2,97 bar
- t=95 s: The threshold for the gas injection was set to 2,87 bar and the reference for PT202 was reduced to 1,8 bar to enforce an influx
- t=140 s: PT202 stabilizes at the new reference value

After the PI-controller is activated, the pump stops for a few seconds before it starts again. This result in the pressure drops that PT202 and PT103 experience after the activation. The coriolis flowmeter in figure 25 supports this. The pump stop is probably built-in a safety mechanism. An observation in this experiment is that when the reference of PT202 was lowered by 0,2 bar, the PT103 pressure was still constant. The reason for this is that there were gas in the well at that time. The bottomhole pressure before the gas influx is given by

$$BHP = \rho_0 gh + P_{f1} + P_{c1} \qquad (6.3.3.1)$$

Where:

$BHP$ = Bottomhole pressure

$\rho_0$ = Drilling fluid density before the gas kick

$P_{f1}$ = Frictional pressure loss before the gas kick

$P_{c1}$ = Choke pressure before the gas kick

The frictional pressure is a function of flowrate, density, viscosity, area and length. From the observation that the bottomhole pressure did not change after the gas influx it can be concluded that the bottomhole pressure after the influx is given by

$$BHP = \rho_1 gh + P_{f2} + P_{c2} \qquad (6.3.3.2)$$

Where:

$\rho_1$= Drilling fluid density after the gas kick

$P_{f2}$ = Frictional pressure loss after the gas kick

$P_{c2}$ = Choke pressure after the gas kick

The gas influx results in changes in the flowrate, density and viscosity. Thus, there were changes in the density and the frictional pressure loss. Because the bottomhole pressure and the choke pressure were the same in the two situations, the new equation is given by

$$\rho_0 gh + P_{f1} = \rho_1 gh + P_{f2} \qquad (6.3.3.3)$$

From this equation it is reasonable to ascertain that when the density decreases, the frictional pressure loss increases. It is because of this that PT103 is not lowered with 0,2 bar even though the PT202 reference is lowered.

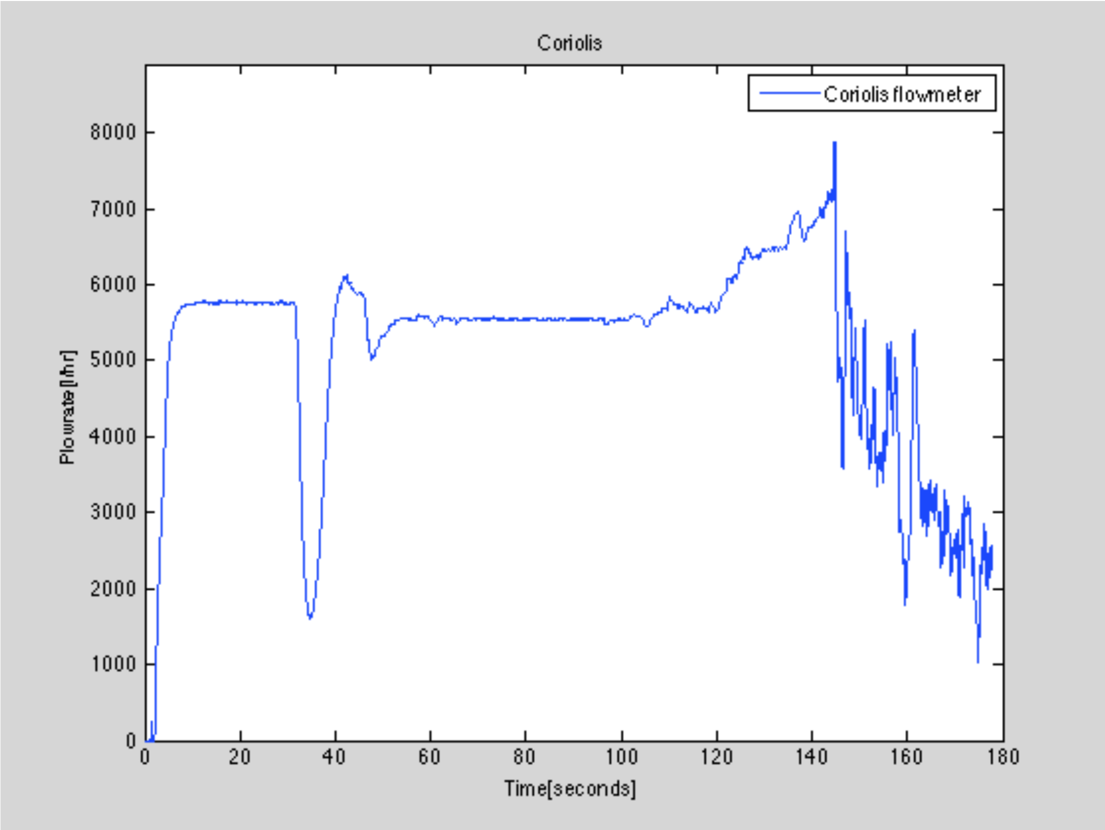


Figure 25: Coriolis flowrate

**Case 2** Stop the influx

1. Keep the MPD valve in PT202 control and record the pressure readings of PT103
2. Select a pore pressure just below the PT103 value
3. Set the gas influx to be 0,1 bar below the pore pressure value
4. Reduce the reference of PT202 control with 0,2 bar
5. Verify gas influx and an increase in the frictional pressure in the annulus
6. Update the reference with 0,5 bar
7. Verify that the influx has stopped

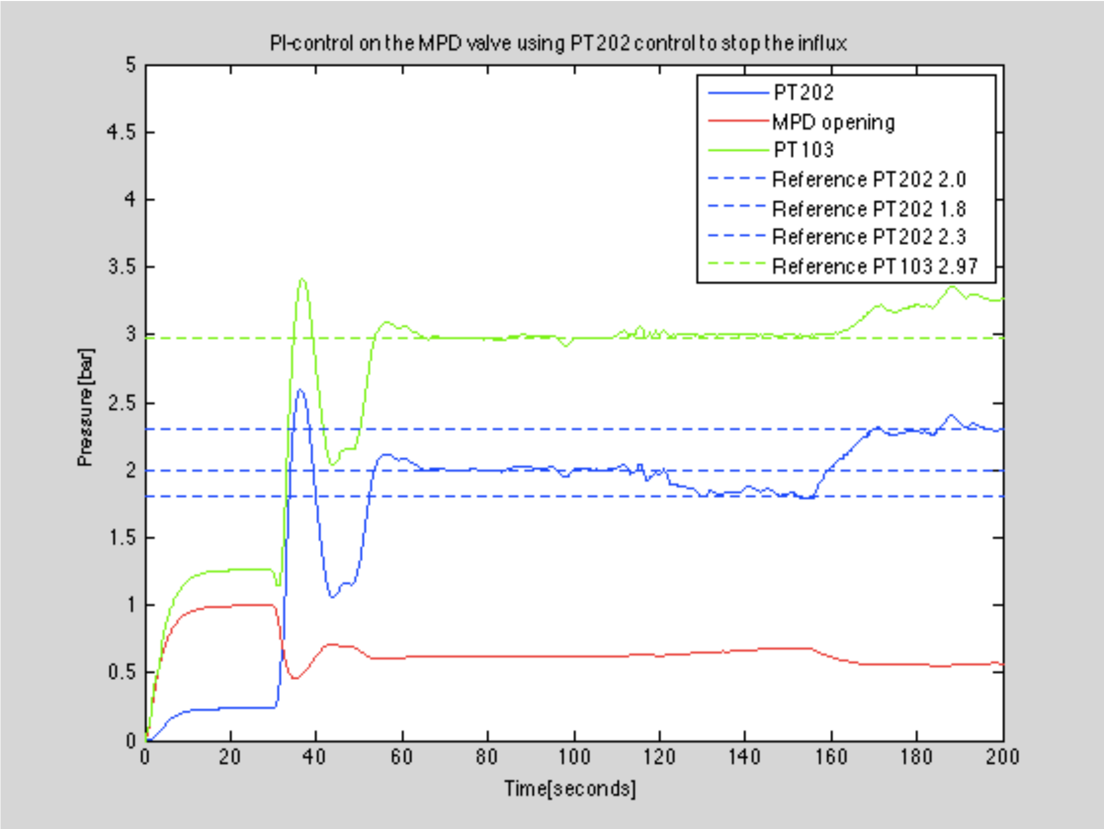


Figure 26: PI-control on the MPD valve using PT202 control to stop the influx

The same observation as in the last experiment is observed here. When the PT202 reference was lowered by 0,2 bar to 1,8 bar, PT103 did not follow the pressure decrease. The reason for this is stated in the subsection above. However, when the reference was increased by 0,5 bar to stop the influx, PT103 was increased by 0,3 bar. The reason for this is that when PT202 reached the original reference pressure at 2 bar, the influx stopped. The values for density, viscosity and flowrate went back to the original values from before the kick. PT202 increased further with an additional value of 0,3 bar to reach the set reference value, and PT103 increased with the same additional value.

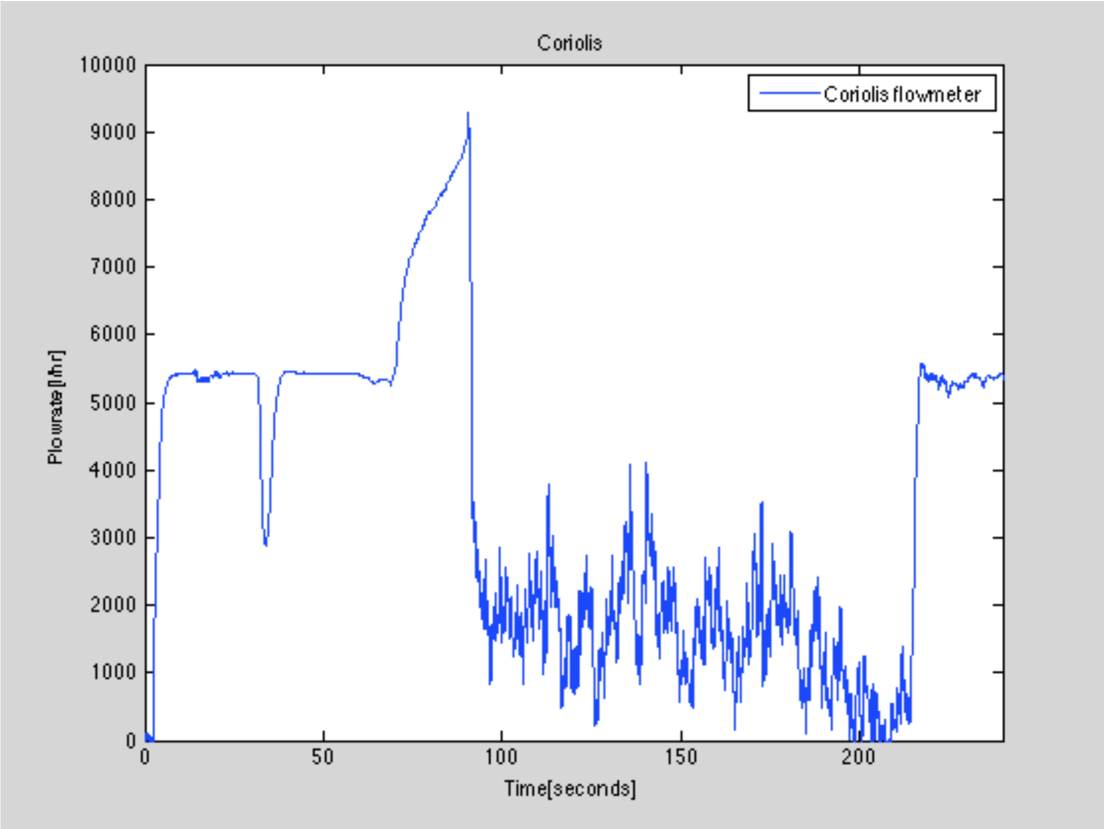


Figure 27: Coriolis flowrate

### 6.4 The Command Take-Over Procedure

The main steps in the implementation of the command take-over procedure (CTOP) is explained below:

1. Start the measurement and the pump, and run in MPD control mode
2. Reduce the reference value to trig a gas influx
3. Verify gas influx and activate the WCV and set it to the current PT201 pressure (in front of the WCV)
4. Close the BOP

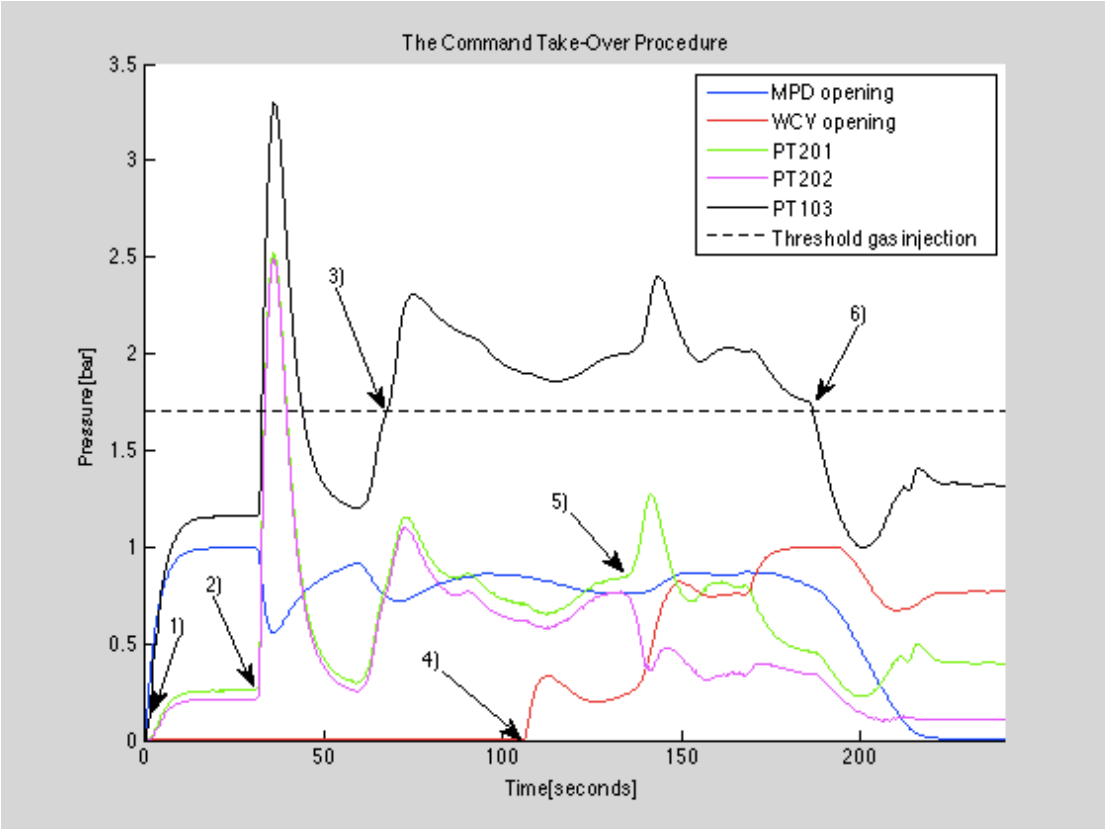


Figure 28: Different pressure responses and valve openings in the CTOP

The general timeline for the CTOP:

1) t=0 s: The pump and simulation was started
2) t=30 s: The PI-controller was activated
3) t=68 s: Gas influx initiated
4) t=105 s: The WCV was activated
5) t=130 s: The BOP was closed
6) t=185 s: Influx stopped

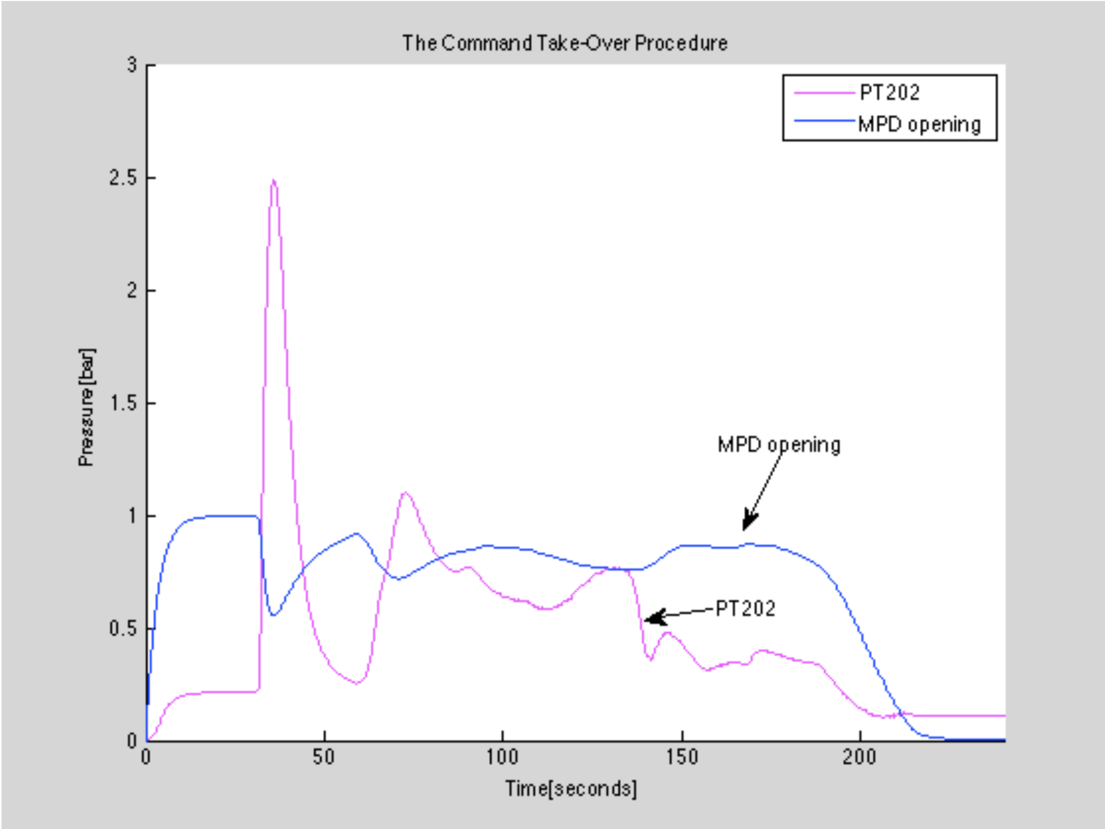


Figure 29: Pressure response in front of the MPD valve in the CTOP

This experiment was performed with a constant pumprate of 0,38. The first part of the experiment was run in conventional mode with a manual control on the MPD. The PI-controller was activated after 30 seconds, and from this point, the experiment was in automated control. After the activation, the PT202 followed the same pattern as described in subchapter 6.3.1. To get a gas influx, the threshold for the gas injection was lowered from 3,0 bar to 1,7 bar and the reference of PT103 was increased from 1,0 bar to 2,0 bar. The gas influx occurred at t=68 seconds, and resulted in pressure decrease in PT202 and increased opening of the MPD valve due to increased velocity, decreased density, expansion of gas bubbles and viscosity changes. After t=105 seconds, the experiment was changed to WCV mode, and the MPD valve was no longer used to regulate the pressure. PT202 experienced a pressure drop due to the closing of the BOP, which takes approximately 10 seconds to go from fully open to fully closed. This is because PT202 is the pressure in front of the MPD valve, and is closed off the flowloop when the BOP is closed. After the BOP was closed, the influx was stopped by recording the PT201 pressure and decreasing the reference value. The kick was circulated out through the WCV, and the MPD was opened.

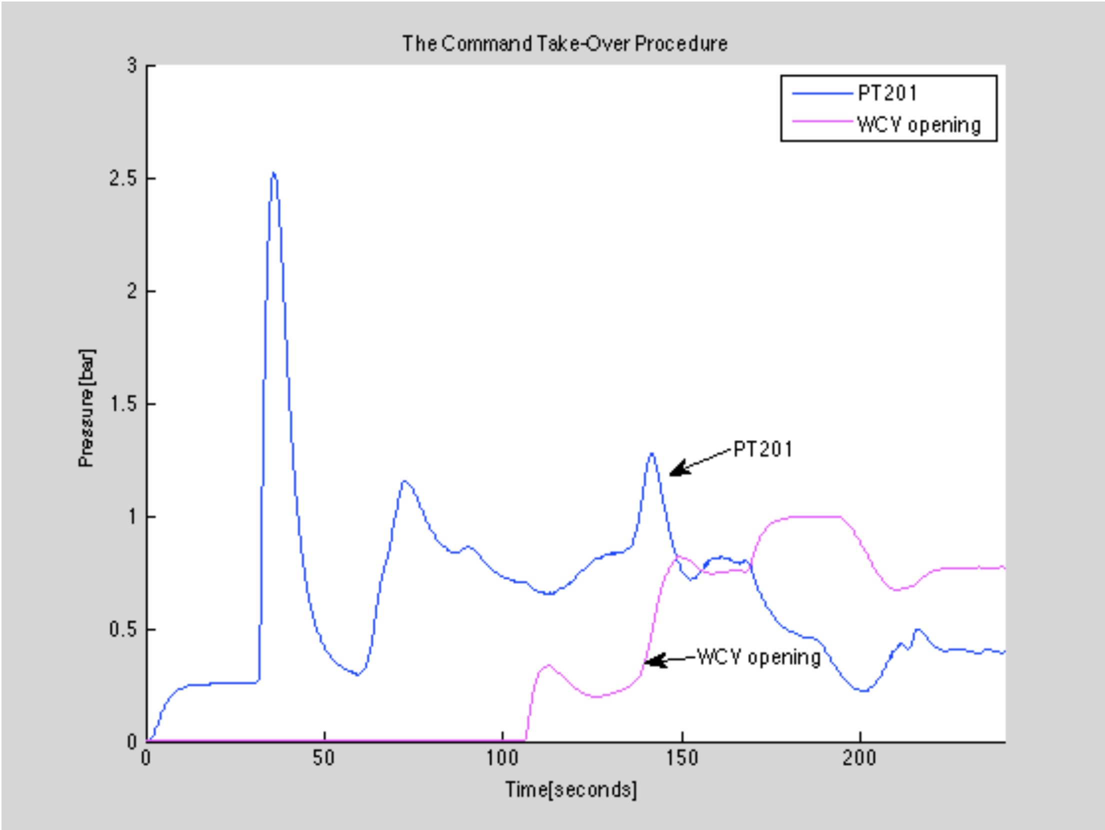


Figure 30: Pressure response in front of the WCV in the CTOP

Figure 30 above shows the correlation between the WCV opening and the PT201. PT201 behaves corresponding to PT202 in figure 29 up to the point where the BOP is closed. The reason for this is that both PT201 and PT202 are located parallel at the topside of the rig model. After the closing of the BOP, the flowloop to the MPD valve is closed off, forcing the fluid to flow through the WCV, resulting in a pressure increase on PT201. After t=105 seconds, the WCV was activated and run in PT201 control, with the reference is set to the PT201 value recorded after the influx reached topside, recorded to 0,8 bar. To stop the influx, the PT201 reference value was lowered to 0,4 bar to manipulate PT103 to a value below 1,7 bar. After the influx was circulated out of the well at t=200 seconds, the WCV opening was decreased to keep PT201 at the reference value 0,5 bar.

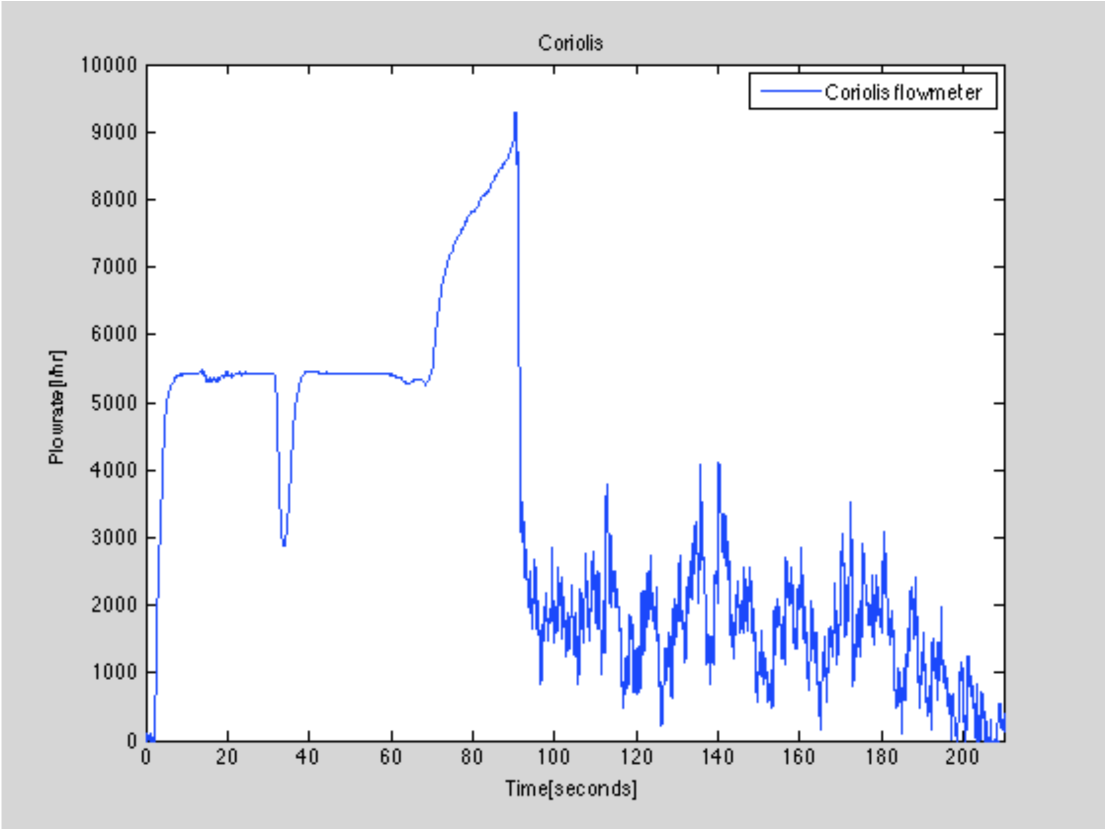


Figure 31: Coriolis flowrate response in the CTOP

Figure 31 above shows the flowrate response to the pressure changes in the CTOP. The flowrate experienced a rapid decrease when the PI-controller was activated. This is because the pump ramps down during the switch to automated mode. The reason for this is unknown, but it is assumed that it is a safety factor. At t=68 seconds gas started to flow into the well, resulting in the increase in flowrate due to higher frictional pressure loss. As the gas reached the coriolis flowmeter at t=90 seconds, the flowrate dropped, and the measurements are no longer valid due to two-phase flow. This is because the gas mixes with the water, and it is no longer possible to differentiate the liquid flowrate and the vaporous flowrate.

# Part III Conclusion and further work

# 7. Conclusion and further work

The rig model cannot be fully compared with real life drilling rigs. All the parameters are significantly lower on the small-scale rig, like the pipe size, the temperature, the depth, the pressures, the pump rate etc. The size of the rig leads to faster pressure change detections that at an actual drilling rig. Disturbances and noise in the laboratory, in the form of noise, might have interrupted the measurements in a negative way.

After these experiments it is clear that it is possible to introduce the command take-over procedure on drilling rigs offshore. When the kick comes into the well it is immediately detected by looking at the pressure sensors and the coriolis flowmeter. Kick handling mode is initiated and the BOP is closed. In this manner the kick is being circulated out of the well while pressure control is released. By regulating the reference value on the controller on the WCV to a desired value, the bottomhole pressure will follow the same regulation. This provides the ability to increase the bottomhole pressure, and hence stop the influx. The operation is switched back to MPD mode and the drilling continues as planned.

The fact that the pump is running throughout the whole operations is a major advantage in well control situations. The conventional well control procedures require pump stop and shut-in in order to gain well control and circulate out the kick. The CTOP avoid problems related to mud sag, cutting falling to the bottom of the well and blocking the drillbit, time issues, and extended costs related to time delays. Another observation from the experiment done on the procedure is that there is no need for kill mud, the same mud weight can be used during the circulation and for further drilling.

In terms of safety, the CTOP is safer than conventional procedures. Since the whole process is automated, there is no longer the same pressure on the driller to make quick and good decisions. The driller gets a monitoring role, and a better overview of the situation, and can therefore be better prepared for unexpected events. Even though the process is automated it is important to have the drilling crew available offshore to fix mechanical issues related to the pump or other equipment.

The rig model has been at the lab for several years, and will probably be there for many years to come. It is therefore room for improvements on the controller logic, experiment performance and so on. Further work needs to be done in order to improve the regulators performance when there is gas in the well. For these experiments, it was not possible to lower the pressures by lowering the reference of the PI-controller. A feedforward controller may be added in Simulink to include the Kaasa model to the experiments.

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# APPENDIX A

### Control valves

The two control valves implemented in the rig model, the MPD valve and the WCV, are of the brand Bürkert 8630.

### Coriolis flowmeter

A flow meter is a device that measures mass flow rate of the fluid travelling through a tube. The coriolis massflow meter implemented on this rig model is of the type Promass 80F and is produced by Endress+Hauer.

### Pump

The water pump is fabricated PCM, draws 11 A and supplies 400 V. It provides a maximum pump rate of 9 bar.

### Emergency stop

In the case of an emergency, an emergency stop button is implemented on the rig model. If activated, the pump stops immediately. Twist the button to reactivate the pump.

### BOP

The BOP is an ER10 valve placed on top of the rig, in front of the MPD valve. The valve is an electrically actuator controlled on/off- valve that takes 10 seconds to close.

More information on the instrumentation can be found in Magnus Torstveit´s master thesis "Laboratory model of well drilling process. Construction, instrumentation, startup and regulation.

# APPENDIX B

## Matlab script

### Tank example in subchapter 3.3

```
clear all; clc;
close all;

Ts=1; %Time step
Ti=2.5; %Initial time
Tf=2000; %Final time
qinn = 0.03333;% Flow inlet[m3/s] (2000 l/min)
h=2;% Height [m]
A=4;% Area [m]
rho=1000; %Density [kg/m^3]
Kv=0.002; %Valve constant
g=9.81; %Gravitational acceleration
z=0.12; % Valve opening
delta_z=0; %Change in valve opening
e=0; %Error
Kp=3.0; %Proportional gain
%Kp=0.25;
%Ki = Kp/Ti;
%Ki = 0.05;
Ki = 0.3; %Inetrgal gain

qut=Kv*sqrt(rho*g*h); %Flow outlet


h_setp = 1.750;
h_setp_old = h_setp;

%min and max values
h_max = 2;
h_min = 0;
z_max = 1;
z_min = 0;
qinn_max = 0.04;
qinn_min = 0;


h_ar =[];
h_setp_ar =[];
z_ar =[];
y_ar =[];
u_ar =[];
ufb_ar =[];
uff_ar =[];
ufr_ar =[];

qinn_ar = [];
qut_ar = [];
zff_ar = [];
zfr_ar = [];
```

```
uff = 0;
ufr = 0;

for i=1:Ts:Tf

    %Update reference
    if (i > 0.25*Tf) && (i < (0.25*Tf)+60)
        h_setp = h_setp - 0.01;
    end

    %Update disturbance
    if (i >= 0.5*Tf)&&(i < 0.75*Tf)
      qinn = 0.01667;% [m3/s] (1000 l/min)
    end

    if (i >= 0.75*Tf) && (i < (0.75*Tf)+60)
      qinn = qinn+ 0.0002777;% [m3/s] (ramp up by 1000 l/min in one
minute)
    end

    if i >= ((0.75*Tf)+60)
      qinn = 0.03333;% [m3/s] (2000 l/min)
    end
    % calculate z feed forward disturbance
    zff = qinn/(Kv*sqrt(rho*g*h));
    %calculate z feed forward reference
    zfr = (A*(h_setp_old-h_setp))/(Kv*sqrt(rho*g*h));
    h_setp_old = h_setp;
    %scale process variables to controller
    r = ((h_setp-h_min)/h_max)*100.0; % reference
    y = ((h-h_min)/h_max)*100.0; % controlled variable
    u = ((z-z_min)/z_max)*100.0; % manipulated variable
    uff_new = ((zff-z_min)/z_max)*100.0; % manipulated variable
    ufr_new = ((zfr-z_min)/z_max)*100.0; % manipulated variable
    %--
    %uff = 0; % turn off feedforward disturbance
    %ufr = 0; % turn off feedforward reference
    ufb = u-uff-ufr;
    %Store previous values
    last_e = e;
    e=y-r;
    %Controller
%     delta_u=Kp*(e-last_e)+((Kp*Ts)/Ti)*e;
    delta_u=Kp*(e-last_e)+(Ki*Ts)*e;
    ufb=ufb+delta_u;
    %ut=0;
    uff = uff_new; % comment update if ff dist is off
    ufr = ufr_new; % comment update if ff ref is off
    u = ufb +uff + ufr; %( feedback + ff dist + ff ref)
    if u<=0
        u=0;
    end
    if u>100
        u=100;
    end
    %--

    %scale controller variables to process
    z = z_min + z_max*(u/100.0);
    %--
```

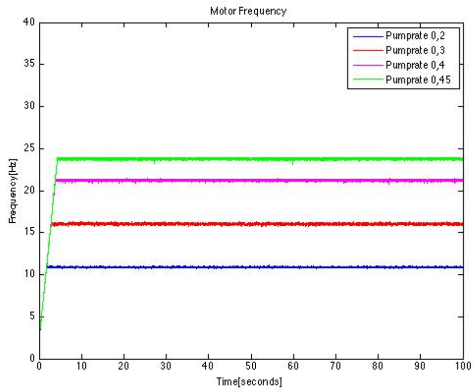
```
    %simulere med ny regulatorsetting (z)
    qut=z*Kv*sqrt(rho*g*h);
    deltah=(1/A)*(qinn*Ts-qut*Ts);
    h=h+deltah;
    % verify min,max levels in tank
    if h<=0
        h=0;
    end
    if h>2
        h=2;
    end


    %store to arrays
    h_ar =[h_ar h];
    h_setp_ar = [h_setp_ar h_setp];
    z_ar =[z_ar z];
    zff_ar = [zff_ar zff];
    zfr_ar = [zfr_ar zfr];
    y_ar =[y_ar y];
    u_ar =[u_ar u];
    ufb_ar =[ufb_ar ufb];
    uff_ar =[uff_ar uff];
    ufr_ar =[ufr_ar ufr];
    qinn_ar =[qinn_ar qinn];
    qut_ar =[qut_ar qut];

end
figure;
plot(1:Ts:Tf,h_ar,'b',1:Ts:Tf,h_setp_ar,'r');
legend('Actual','Reference');
xlabel('Time [s]');
ylabel('Tank level [m]');
title('Tank level with PID Controller');
grid on;

figure;
plot(y_ar);
xlabel('Time [s]');
ylabel('Tank level [%]');
title('Tank level with PID Controller');
grid on;

figure;
plot(z_ar);
xlabel('Time [s]');
ylabel('Choke opning [0-1]');
title('Choke opening with PID Controller');
grid on;

figure;
plot(zff_ar);
xlabel('Time [s]');
ylabel('Feed forward  disturbance choke opning [0-1]');
title('Feed forward choke opening direct');
grid on;
figure;
plot(zfr_ar);
xlabel('Time [s]');
ylabel('Feed forward reference choke opning [0-1]');
```

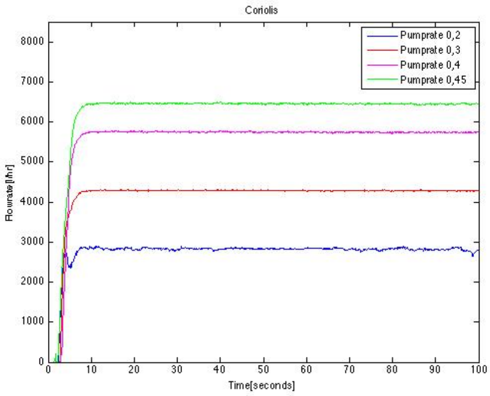
```
title('Feed forward choke opening direct');
grid on;

figure;
plot(u_ar);
xlabel('Time [s]');
ylabel('Choke opning [%]');
title('Choke opening with PID Controller');
grid on;
figure;
plot(ufb_ar);
xlabel('Time [s]');
ylabel('Choke opning feedback only [%]');
title('Choke opening with PID Controller');
grid on;
figure;
plot(uff_ar);
xlabel('Time [s]');
ylabel('Choke opning ff dist only[%]');
title('Choke opening with PID Controller');
grid on;
figure;
plot(ufr_ar);
xlabel('Time [s]');
ylabel('Choke opning ff ref only[%]');
title('Choke opening with PID Controller');
grid on;

figure;
plot(1:Ts:Tf,qinn_ar,'b',1:Ts:Tf,qut_ar,'r');
legend('q in','q out');
xlabel('Time [s]');
ylabel('Flow rate [m3/s]');
title('Flow rate');
grid on;
```

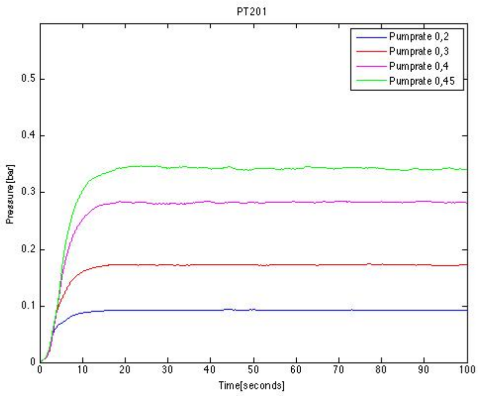
# APPENDIX C

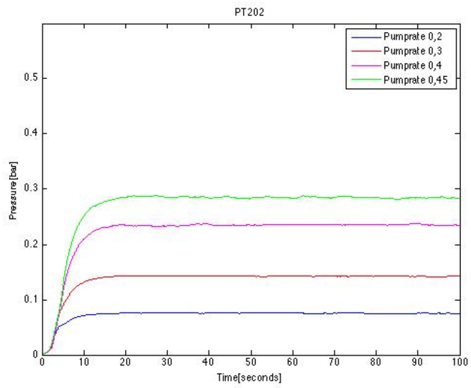
## Experimental plots

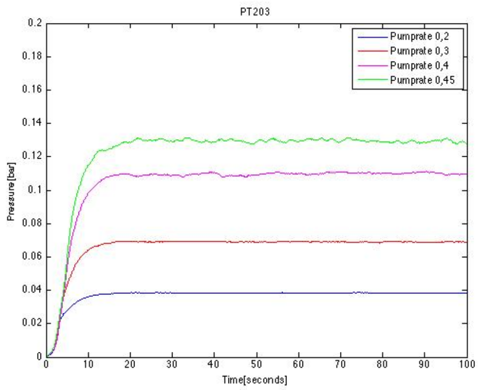
### 1) No influx

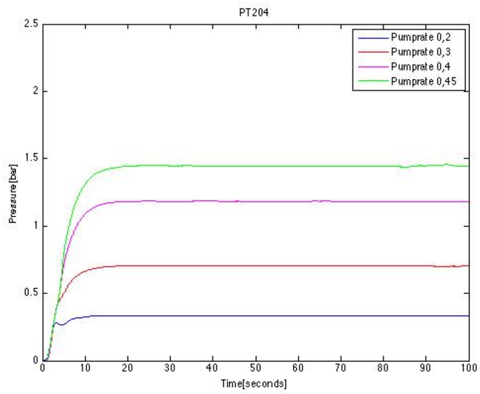


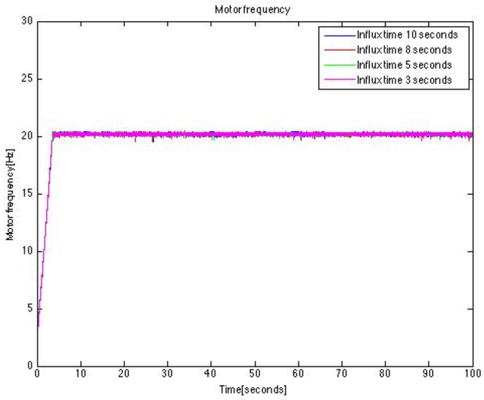



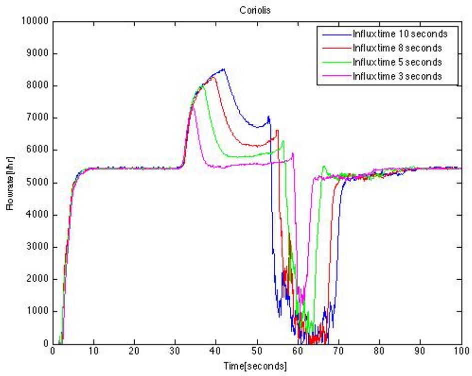



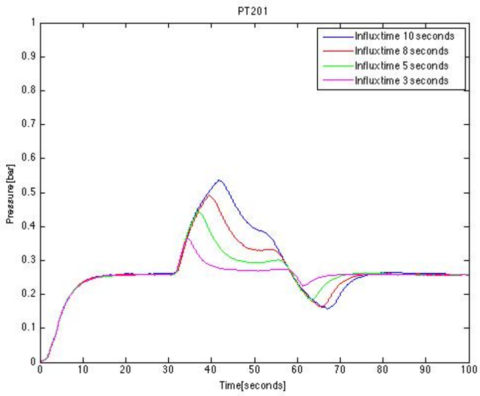



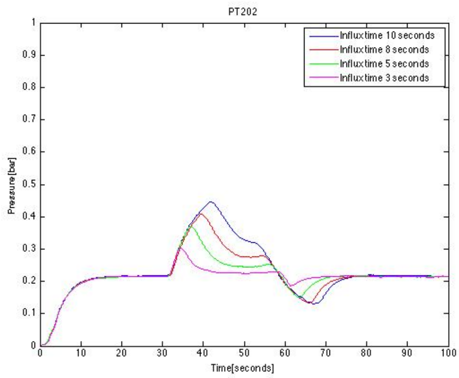



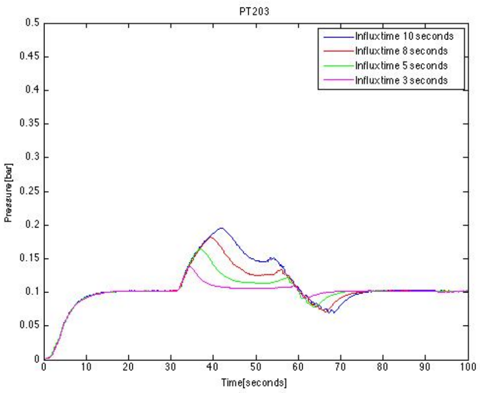
## 2) Influx

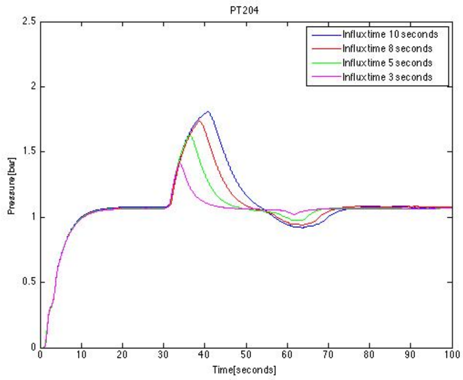

Motorfrequency
Influxtime 10 seconds
Influxtime 8 seconds
Influxtime 5 seconds
Influxtime 3 seconds
Motor frequency[Hz]
Time[seconds]


Coriolis
Influxtime 10 seconds
Influxtime 8 seconds
Influxtime 5 seconds
Influxtime 3 seconds
Flowrate[l/hr]
Time[seconds]


PT201
Influxtime 10 seconds
Influxtime 8 seconds
Influxtime 5 seconds
Influxtime 3 seconds
Pressure[bar]
Time[seconds]


PT202
Influxtime 10 seconds
Influxtime 8 seconds
Influxtime 5 seconds
Influxtime 3 seconds
Pressure[bar]
Time[seconds]


PT203
Influxtime 10 seconds
Influxtime 8 seconds
Influxtime 5 seconds
Influxtime 3 seconds
Pressure[bar]
Time[seconds]


PT204
Influxtime 10 seconds
Influxtime 8 seconds
Influxtime 5 seconds
Influxtime 3 seconds
Pressure[bar]
Time[seconds]

### 3) The Command Take-Over Procedure