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Abstract

Over time the remaining oil prospects are becoming harder to drill and managed pressure drilling is a tool that can be used to reach target depth in depleted reservoirs or similar narrow margin scenarios. In any narrow margin drilling scenario, a critical part of the operation is going to be the tripping in/out along with the ramping of pumps. This thesis investigates the influences of pump ramping schemes during connections of new standpipe on bottom hole pressures by using a simulator called openlabdrilling developed by IRIS.

The case study is conducted by using a matlab interface connected to the openlabdrilling simulator through their API and using a slight modification of the FlowSweep_BHPcontrol code allowed for automatic control of the choke opening with the PI controller that was included in the code bundle from openlabdrilling.

Acknowledgement

Thanks to Dan Sui for being my supervisor and recommending the use of the openlabdrilling simulator, and a thanks to Jan Einar Gravdal for answering my questions regarding the simulator.

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Nomenclature

API	application programming interface
BHP	bottom hole pressure
CBHP	Constant bottom hole pressure
ECD	equivalent circulation density
EMW	equivalent mud weight
FIT	formation integrity test
HPHT	high pressure high temperature
IADC	International association of drilling contractors
IRIS	International Research Institute of Stavanger
KOP	kick off point
LOT	leak off test
LWD	logging while drilling
MPD	managed pressure drilling
MWD	measurement while drilling
NCS	Norwegian continental shelf
NPT	Non-productive time
NRV	non return valve
OBM	oil based mud
OWR	oil water ratio
PID	proportional–integral–derivative
PMCD	pressurized mud cap drilling
PVT	pressure volume temperature
RCD	rotating control device
ROP	rate of penetration
RPM	rounds per minute
WBM	water based mud
XLOT	extended leak of test

Introduction

1 Background

The first chapter will cover some basic concepts of both MPD (Managed Pressure Drilling) and conventional drilling and try to outline some of the differences between the two methods. IADC defines MPD as an "adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. While conventional drilling uses the hydrostatic pressure of the drilling mud to manage pressure in the well, MPD uses a combination of surface pressure, hydrostatic pressure of the mud and annular friction to balance the exposed formation pressure". [24]

The research question of this thesis will be to investigate the impact of several commonly used pump ramp schemes used during MPD connections and the main goal of the thesis will be to determine the best fit scheme for one specific well.

1.2 Drilling margin

1.2.1 Pressures

To avoid issues with wellbore instability when drilling a well, the operators must have a bottom hole pressure that is between the pore pressure and the fracturing pressure of the formation. If the pressure exerted by the drilling fluid is less than pore pressure there is a risk of taking an influx of formation fluids in to the well, and if the pressure is greater than the fracture pressure an outflux may occur, resulting in a loss of drilling fluids. [25]

In figure 1 shows how the pressure envelopes for underbalanced drilling, that aims to have controlled influx of formation fluids, compared to that of MPD that aims to balance the BHP (Bottom Hole Pressure) with the pore pressure. For conventional drilling, there is no quick way to regulate BHP, so the BHP must be kept relatively high above the pore pressure gradient to ensure that influx is minimal. The usual way of regulating BHP in conventional drilling is limited to weighting up the mud, i.e. increasing the hydrostatic head by increase of drilling fluid density. This method could be done rather quickly assuming that the rig has readily available mud to mix in for the density increase, however in most offshore scenarios the deck space on a rig is a valuable resource and a spare pit can't always be used. In the case of not having a spare mud pit, the one method left is for the drilling crew to manually add extra weight, usually in one 25kg bag at a time.

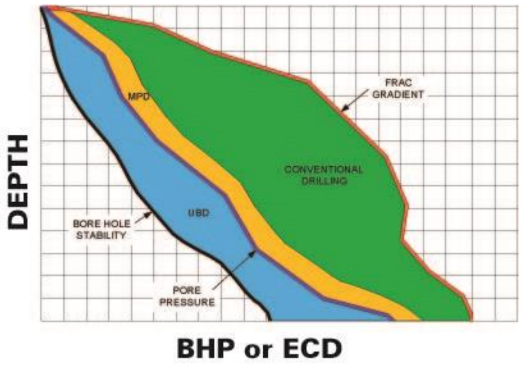

Figure 1 graph of conventional drilling compared to MPD and UBD [1]

Estimating the BHP is usually done using the formula for hydrostatic head: $p = \rho g h$

Where p: pressure, rho: density of mud, g: gravitational acceleration, h: depth (TVD). The formula outputs the pressure as a function of depth, and uniform density of mud is assumed.

The fracture pressure is determined through an LOT (Leak of Test) or XLOT (Extended Leak Of Test), during this test pressure is increased to the point of fracture, this data is used to estimate the fracture gradient for the entire well, along with expert knowledge of the area. [25]

The pore pressure is usually assumed to be a continuous column of seawater, but local variations due to faulting of formation may induce high or low-pressure zones. [25]

1.2.2 Equivalent circulation density

When drilling we also must consider the pressure contribution caused by circulation, this is called ECD, equivalent circulation density and is a measure of BHP with circulation, this is in many ways the real pressure that pushes on the formation. In conventional drilling there is a spike in ECD after a connection have been made, due to stopping circulation, by using MPD these ECD fluctuations can potentially be avoided, or at least have its impact reduced.

The ECD component introduced here is due to friction of mud against the surface of the drill string and annulus. The will be higher for the open hole section of the well due to the rough surface of the drilled formation, and the friction contribution will become especially troublesome for long horizontal wells. [23]

For conventional drilling :$BHP = MW(Mud\ Weight) + ECD$, this is when the well is circulating, for MPD applications an additional term has to be added due to introduction of a backpressure pump, and the equation becomes :$BHP = MW + ECD + Backpressure$. The goal of MPD is to limit fluctuations in the BHP by adjusting choke and pump rates. [2]

In situations where the main pump is not circulating, the static bottom hole pressure may be referred to as an equivalent mud weight, this is because there is going to be a back-pressure component contributing to increased pressure, and thus an apparent increase in mud weight.

1.4 Managed pressure drilling

The main components that separate the MPD system from conventional is the use of a RCD (Rotating control device), a back pressure pump, and a choke. These components allow us to keep BHP constant by utilizing a mix of choke and backpressure. Flow sensors allow us to monitor the in and out flow of the system, making influx or loss detection easier than for conventional method.

The most common variation of MPD is called CBHP and this method is what is referred to throughout the thesis unless something else is specified. Other methods of drilling MPD include pressurized mud cap drilling, this method is usually utilized if it's not possible to continue drilling without big losses due to fractured zones. When drilling using mud cap drilling all the cuttings and mud is effectively injected into low pressure zones and losses are not controlled. The controlled mud level technique is another method used, it involved adjusting mud level in the rise in order to manage BHP, but this thesis will not go into details on this method.

1.4.1 Reactive MPD

When applying MPD in a reactive manner, the MPD equipment is primarily in place to increase the ability to solve spontaneously occurring drilling problems. Reactive MPD is commonly used offshore to provide operators with some extra safety. [3]

1.4.2 Proactive MPD

If the full potential is to be utilized it happens in the form of proactive planning of the entire well with MPD in mind. This is especially useful when trying to achieve the best possible casing program and drilling challenging wells.

1.4.3 Constant bottom hole pressure

This method aims to keep bottom hole pressure constant, as the name implies. The problems arise when we encounter drilling problems like influx, differential sticking, losses, and collapse of borehole. All of these problems can to some extent be mitigated or have the risk of occurrence reduced by implementing the CBHP MPD methods. This method is suitable in environments where the formation is uncertain like exploration wells, but also works great when drilling in HPHT (high-pressure high-temperature) or depleted reservoirs. [3]

During drilling of the Mandarin east well by BG Norway and Weatherford Norway, the CBHP method was used to drill an extreme HPHT well in a relatively unknown environment with great success. Estimations on saving due to using MPD was calculated to be around 7,5 million USD due to using 10 days less than what a conventional method would have used. [5]

There are two main principles to achieve CBHP, the first concept is to manage the annular friction and is mostly used in extended reach wells where the long well will make annular friction a problem. To solve the high annular friction a booster pump is placed in the cased section of the well to help mitigate the friction losses.

The other method is called continuous circulation utilizes an RCD to encapsulate the entire drilling system, in addition a backpressure pump and chokes are installed. This combination of components allows for a constant BHP even when connecting new drill pipe stands, by ramping down mud pump, while simultaneously ramping up the backpressure pump. This MPD technique is especially useful during drilling in narrow drilling windows or when settling of cuttings due to unexpected events is expected to be an issue. [6]

1.4.4 Pressurized mud cap drilling

PMCD is a method that can be applied in areas where large losses are expected to occur, this method have seen extensive use in the Asia pacific, and more recently in Brazil. When drilling PMCD a cheap and expendable fluid like seawater is pumped down the drill string to compensate for the losses, while a heavier mud is pumped down annulus to prevent gas influxes. To use this method the losses must be large enough to ensure that all fluid pumped downhole is lost to formation, if there is any circulation is the well the mud cap will be circulated out and kick protection is lost.

This method makes drilling fractured carbonates, such as the Baturaja and Kujung formations in Indonesia possible to do with less risk of inflating drilling budgets significantly due to NPT (Non Productive Time). [6]

Another variation of PMCD called floating mud cap drilling can be used if the reservoir is below hydrostatic pressure, this means that an annular column of fluid cannot be maintained, and the fluid level in annulus will drop down making it hard to monitor influxes. This method is often described as drilling blind. [6]

1.4.5 Returns flow control

For this method annular pressure is not controlled with choke, but the MPD equipment is instead used to detect influxes earlier that what would be possible in a conventional setup. In cases where there is a risk of getting h_2s in returns this method is an extra safety measure, because returns will be diverted to choke lines if gas is detected. Also having an RCD in place makes it easier to deal with influxes due to being able to move pipe. [6]

1.4.6 Dual gradient drilling

This method is mostly used in deep-water wells were a long riser contributes a significant hydrostatic pressure. The two most common ways of applying the technique is by either have a mud system consisting of two different density muds, a light mud in deep sections of the well and a heavier one at the top section, this method is also referred to as “top kill”. Another approach is to displace the riser fluids with seawater to simulate a scenario of having the rig placed at sea bottom. [6]

1.5 Drilling hazards

Kicks caused by gas influx, consequences can be fatal and costly if an influx is not handled correctly, may develop in to a full blowout.

Well breathing is a situation where drilling induced fractures in the formation absorb drilling fluids, and when the ECD is lowered, due to pump shut down the well fluid trapped in the formation fractures will start to flow back into the well. [16]

1.5.1 Stuck pipe

Several conditions in the wellbore may cause the pipe to become stuck, and stuck pipe can be classified into two groupings, mechanical sticking or differential sticking. Mechanical collapse may be induced by fluctuations flowrates pulling cavings off the wellbore wall. If the well is near vertical there is a risk that cutting beds may form due to insufficient cuttings transport. [27]

Differential sticking occurs when the pressure acting on the drill string wall is larger than the pressure of the formation fluid. The risk of differential sticking increases when drilling with high differential pressure or when the mud cake is thick due to high losses to formation. In an MPD scenario the differential pressure can be controlled to a greater extent, this can in turn reduce the risk of differential sticking. [26]

1.5.2 Wellbore instability

The main reason for wellbore instability is when the hydrostatic pressure exerted by the mud column is of insufficient magnitude to keep the integrity of the wellbore walls. In some scenarios the collapse pressure of the formation may be equal to or even greater than the pore pressure. The problem caused by wellbore instability may be that parts of the wellbore wall may cave in to the well and lead to mechanical pack off that in turn gets the drill string stuck. The dynamic scenario of ramping up and down pumps can create pressure cycles that weaken the wellbore walls, and by using MPD some of these pressure cycles can be avoided by keeping pressures close to constant. [28]

1.5.3 Lost circulation

Lost circulation can occur when the pressure in the well exceeds the formation fracture pressure, it’s prone to occur when pumps are ramped up/down, or during tripping. If fracture pressure is exceeded losses may lead to a loss of fluid to formation, this in turn makes the BHP drop and the risk of taking a kick is increased. Using an MPD system enables greater control of BHP therefore the risk of running into losses can be decreased, and if losses occur the additional flow metering of the MPD system makes it easier to detect early and thus the risk of kick can also be reduced. [29]

1.6 Why MPD

Allows for fine tuning of BHP, this again allows us to plan a well with potentially fewer casing sections, and it allows us to drill wells that have a narrow drilling margin. Other advantages is the ability to use lighter mud weight than conventional, and the greater BHP control makes it easier to minimize kick-loss cycles, detect influx early and manage influx better. [2]

Other benefits with using an MPD system is reduced risk of differential sticking, because of lower differential pressures from borehole to formation.

Can be used to cement in areas with loss issues. One major benefit is the possibility of handling well control issues with less NPT, and the method also allows for dynamic pressure testing.

1.7 Challenges of MPD

MPD is not a technique without flaws and negative aspects, this section explores some of the known challenges and downsides of the method.

An issue that has to be addressed when using MPD is the risk of plugging the choke valve, however this risk is well known, and MPD systems come with contingency chokes in case of main choke failure or plugging. The risk of plugging is present due to choke being placed in front of shale shaker, and the mud passing through the choke will be contaminated with cuttings.

Time must be invested in order to train and educate drilling personnel on how to perform MPD operations. Due to no standard being in place operations may be performed by a crew without the right level of competence, this will in turn increase risk of the complexity of the operation is more complicated than a conventional operation. A good example of an MPD operation that failed due to lack of crew training would be the recent gas leakage that occurred at Gullfaks C on the NCS in 2010, the internal report published by Statoil concludes that risk assessments that were performed in the planning phase were insufficient, and along with insufficient transfer of experience lead to the loss of control in the well. [30]

The cost of implementing the necessary equipment is high. And older rigs may lack the available deck space needed for the RCD, back pressure pump and choke system.

As with any other new technique, the standard for operations may be entirely up to the operator to decide, this can be seen as both a good and bad thing.

1.7.1 MPD on floaters (heave)

When drilling on a floater in heavy weather, the rig tends to move due to waves and in a narrow drilling scenario this poses some difficulty. When drilling in tough weather, the method most commonly used to maintain vertical position of the drill string is called heave compensation, however when a new pipe section needs to be connected, the drill string must be anchored to make the connection, and in this case our draw work can no longer compensate for the wave motions. The sudden vertical motion of the drill pipe can cause pressure fluctuations in the BHP due to surge and swab effects, and in narrow margin drilling this may in a worst-case scenario end up losing the well.

1.7.2 Cost associated with MPD operations

The main argument for investing in an MPD system is that the system enables drilling of narrow margins, with a reduced risk of NPT compared to the same operation performed with a conventional drilling system. Using an MPD system makes in wells or areas where high losses due to depleted reservoirs will enable a lot more of the rig time to be utilized for actually drilling the well, instead of spending days on stuck pipe and losses. The casing program could also potentially yield some cost savings, due to the enhanced pressure profile control fewer casings could be used compared to conventional drilling.

Investing in an MPD system makes a lot of sense in cases where the drilling is expected to be problematic, where ROI is high as a consequence of lowered NPT. In addition to the equipment cost the drilling crew training is essential in order to properly utilize the system, this cost also have to be considered.

The reason for the cost associated with drilling operations can be contributed to the day rate of the rigs being high, using MPD may help lower the cost of operation by reducing the time spent on common well issues. In an article from 2004 that investigates the most common causes for downtime during the drilling operation, the areas that MPD systems can contribute to help solve are responsible for approximately 600 out of 17641 days of NPT. [18]

2 Equipment used in CBHP drilling

2.1 Rotating control device

In many ways the difference in rig equipment between conventional drilling and MPD is not big. To go from a conventional setup to MPD, the rig will have to be fitted with an RCD, this component is what allows for pressure to be applied to the annular while making connections or during other potential halts in drilling. In simple terms the RCD puts a cap on the well, while simultaneously allowing drill pipe to rotate.

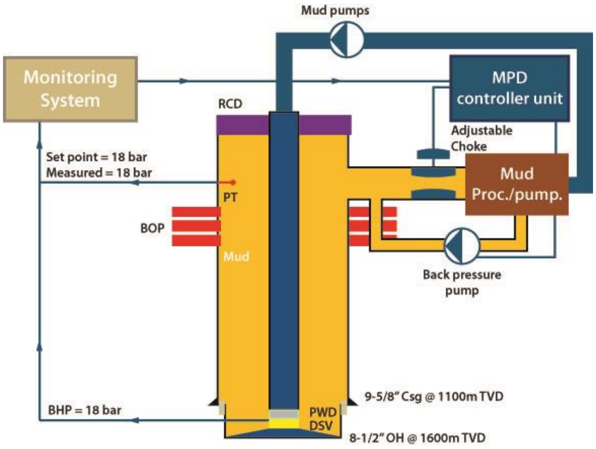

Figure 2 a simple conceptual figure of an MPD drilling system [7]

The RCD diverts flow through the choke, and by adjusting choke opening either manually or by automated control methods we can increase BHP. When a new section of pipe needs to be connected to continue drilling, the backpressure pump ramps up, and mud pump ramp down, thus BHP is still maintained.

The rotating control device is the component that enables drilling with a backpressure, the device usually consists of a stripper rubber that is a smaller dimension than the drill pipe, causing it to seal at zero pressure difference, but due to the conical shape of the element, higher pressures will push the sealing element against the pipe reinforcing the seal further. Since the stripper rubber is in direct contact with the drill pipe this piece of equipment will eventually wear down, during replacement of the stripper rubber the BOP could be engaged to maintain the annular backpressure.

2.3 Choke system

The choke plays an important part in regulating BHP, by adjusting the choke opening return flow is constricted, and this in turn increases the BHP. The choke system can be mounted by itself, but most vendors provide solutions in a modulated form, meaning each module contains a handful of relevant flowmeters, pressure gauges, chokes and some also include control systems to automatically adjust components.

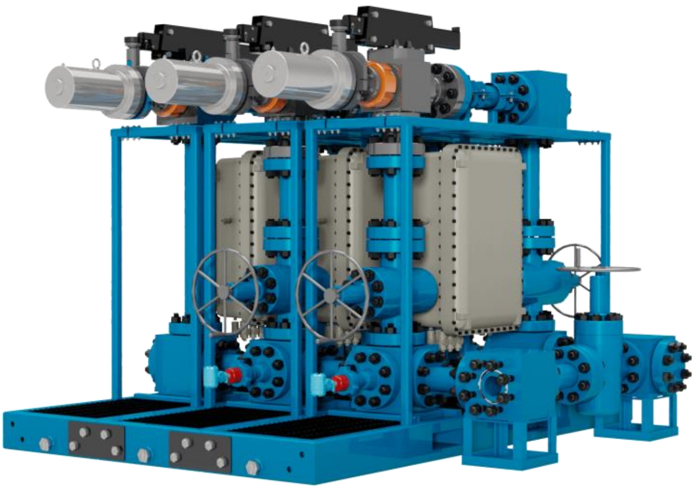

Figure 3 image of an MPD choke manifold module by pruit [8]

2.4 Mud pumps

There are normally two mud pumps in action when drilling with MPD, the main pump is used to circulate mud through the drill string down to bottom. The most common pump used for mud circulation is the triplex pump, and it is usually made up of three pistons attached to crankshaft much like a regular in-line petrol engine. This pump is popular due to its modular nature that allows for easy modification of the pump rate range by changing the piston and cylinder to alter the stroke volume. Using a stroke pump also allows for greater control of flowrates, due to the fixed volume pumping, flowrate will be directly linked to the RPM that the pump is set to run at, this allows for precise control of small flowrates. Although the triplex pump is by far the most common in the industry today, there are other configurations on the market, such as duplex or hex configurations. The benefit of adding more pistons to the pump will be a smoother pressure delivered from the pump, and this will reduce the noise on readings conducted by downhole equipment.

2.5 Non-return valve

Because of the added backpressure added to the annulus when drilling MPD, it is essential to fit a non-return valve (NRV) in the drill string to prevent mud flowing back when applying backpressure. The drilling mud contains cuttings and can plug the pipe or cause significant damage to sensitive MWD equipment. The NRV may also be referred to as a float valve, and the most basic NRV is similar to that of an engine valve, or a flapper type which is a disc that cover the cross section of the pipe.

The immediate advantage of using a flapper type valve is that it will not be an obstruction when the valve is in open position, thus making it possible to run wireline in the string. When operating with an NRV operators need to ramp up pumps in order to get a shut-in pressure reading in the case of a kick situation. [9]

2.6 Kick response and influx management

In conventional drilling the principles are simple, monitor your mud pit and if there is an increase or drop shut in the well and let everything come to rest. This is the way kicks have been handled for a long time, but this method is mainly used due to not being able to precisely monitor the flow of the well. With the introduction of MPD the drilling system is fitted with flow gauges and pressure monitoring this may enable earlier kick detection and faster kick handling perhaps without shutting the well. This section is based on a study published in SPE in 2010 that looked at ways to handle kicks in an MPD environment. [10] The study consisted of two parts, the first one was strictly done in a simulated environment, using hydraulic models to predict results, the second part was a practical experiment on a full-scale rig, were the objective was to determine whether the methods that were successful in the simulations would be possible to implement in practice.

2.6.1 Shut-in response

The study tested ten alternative methods of initial kick responses for a wide range of kick scenarios on three different well geometries but did not manage do determine a general initial response that could effectively cover all scenarios. However, the study did find four responses that could be applied, under varying conditions. The most applicable method was to simply shut in the well, with no extra equipment needed it successfully stopped all simulated influxes. The shut-in methods downside is the risk of increasing losses due to pressure fluctuations caused by ramp up and ramp down of pumps, and the extra difficulty in monitoring the drill pipe pressure due to the NRV.

2.6.2 Pump shut down with choked flow check and shut-in

This method involves shutting down the mud pump in steps, while keeping the choke pressure constant during the shutdown, followed by a shut-in. the method confirms a kick if the choked flow check exceeds expected values during pump shutdown. The disadvantage with this technique is the risk of having large gains during pump shut down, because it maintains underbalance during the pump shutdown.

2.6.3 Rapid increase in choke pressure

Of the circulating methods the most applicable was the rapid closing of the choke, it was effective for most kick scenarios and it resulted in a generally lower pressure at the casing shoe than shut-in and slower methods of choke pressure increase. Its downside is the need for a precise measurement of the Qout flowrate, to determine if an influx has stopped, something that proved to be difficult during low rate kicks and large gas influxes.

2.6.4 Stepwise increase in Qin

This method aims to set Qin and Qout equal with constant choke pressure by stepwise ramping Qin, and by doing this the pressure and losses at casing shoe are minimized. This method is the one out of the four that has the smallest window of applicability, seeing as it can not be used for large diameter bore holes and precise measuring of Qout is essential. This method can likely make matters worse as the required pump rate may not even be possible with the available pumps, and the increase in circulations accelerate the gas influx.

2.7 Dynamic estimation of pore pressure

Having a good estimation for the pore pressure of the formation is critical for any drilling operation, but in problematic or depleted zones the estimation is harder to get right due to local variations in pressure. The classic way of estimating pore pressure is to use LWD data or seismic data and then calibrate using a drill stem test or a repeat formation tester. [19]

The dynamic estimation of pore pressure allows for less NPT, without sacrificing any operational safety. The estimation is done by initiating a stepwise decrease in BHP this is repeated until an influx is taken, this pressure will be the minimum pore pressure of the exposed open hole formation, so compared to a other methods that may only get the pore pressure of local regions, the dynamic method using MPD systems is able to more correctly estimate pore pressures over longer sections of formation for each run of the test. An FIT can also be run by stepwise increase in pressure. [19]

3 Hydraulic system simulations

3.1 open lab hydraulic model

This section is based on a paper published by IRIS, the paper describes the formulas and principle used to make the simulator. [21] To make an accurate model capable of simulating the transient mechanics of a flowing well, IRIS has used a high fidelity transient model. The model takes into account mass, momentum and energy balances for two phases in one dimension. Gravity and wall friction are important factors in describing the well pressure behavior. The mass conservation equation can be written:

$\frac{\partial}{\partial t}(\alpha_k A \rho_k) + \frac{\partial}{\partial s}(\alpha_k A \rho_k v_k) = 0, k = l, g$, where l,g are the liquid and gas phase, t is the time variable, α is the volume fraction, A is the cross-sectional area, ρ is the density, s is length of the well and v is fluid velocity.

When the momentum conservation equations are added together the equation becomes: $\frac{\partial}{\partial t}A(\alpha_l \rho_l v_l) + \frac{\partial}{\partial s}A\left(\alpha_l \rho_l v_l^2 + \alpha_g \rho_g v_g^2\right) + A\frac{\partial}{\partial s}p = -A(K - \rho_{mix} g sin\theta)$, where p is pressure, K is a friction pressure-loss term, θ is the well inclination and $\rho_{mix} = \alpha_l \rho_l + \alpha_g \rho_g$ is the mixture density. The equations stated above are not sufficient to properly explain the real dynamics of a well, since there are more unknowns than equations. To solve this problem empirical closure relations are used, and due to this the model may be slightly inaccurate for wells that don't coincide that well with these relations. Summarized the drilling simulator consists of a set of fully integrated numerical models [21]:

- A transient hydraulic model that solves momentum and mass balance in order to estimate the pressure distribution in the wellbore. This model will take into account dynamic effects such as drill-string movements, pump acceleration, the presence of multiple formation fluids in the well and gelling effects.
- A transient cutting transport model that estimates the distribution of the cuttings inside the annulus and determines whether the cuttings are suspended or if they accumulate as a cuttings bed. Transport of cuttings by bed erosion is also simulated.
- A torque and drag model that computes the tension and torque distribution along the drill-string.
- A heat transfer model, which computes the temperature evolution inside the wellbore as well as in the near formation. Forced convection, heat conduction, and convective heat transfer are accounted for in the simulations.

All the models mentioned in the paper are in the simulator interconnected and impact each other, this is illustrated in the figure below.

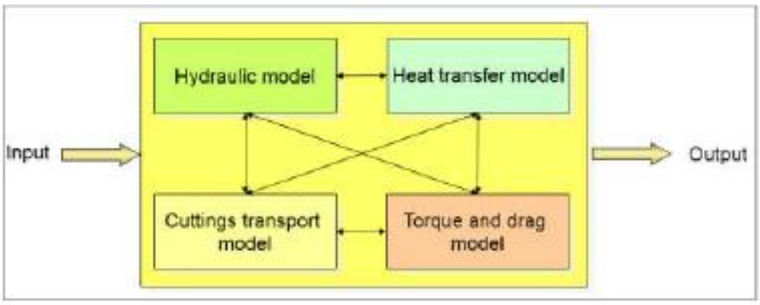

Figure 4illustration showing interaction of models [21]

3.1.2 Rheological model

For determining rheological properties in the simulations, the Roberson stiff model is used. This is a model that uses three parameters to determine the rheology.

$\tau = A(\gamma + C)^B$, where A, B and C are the model parameters. The A and B parameters can be compared to the parameters k and n of the power-law model. The C parameter is used as a correction factor to the shear rate, and the bracketed term $(\gamma + C)$ is considered the effective shear rate. Compared to the usual Bingham and power-law models the Robertson and Stiff model has proved to be a lot better, but due to the difficulty in evaluating a three-parameter model it has not seen a lot of use in the oil industry. [20]

3.1.3 Transient cuttings model

The transient cuttings model used to determine the transport of cuttings during dynamic situations in the drilling process. This model was used to monitor two wells drilled on the NCS, and the model was able to predict the locations of cutting-beds, this was confirmed when the drill-string experienced overpull at the predicted locations in the well bore. This model has also been used to determine if the well has issues with hole cleaning, by comparing the cuttings that is taken in return to the model prediction the operator now has an indication of poor well cleaning. The model takes into account drill string mechanics such as rotation and helps the operator possibly detect cuttings-bed build up earlier. [22]

3.2 Openlabdrilling drilling software (interfaces)

The openlabdrilling simulator MPD system consists of two separate pumps, one mud pump that is active when the rig is drilling, and one back pressure pump that is ramped up whenever there is a situation that requires the circulation through drill pipe to stop. The simulators web interface allows for easy manipulation of various rig parameters, such as water depths and it allows for high degree of customization in terms of accurately representing a real well configuration.

In the configurations tab, the simulator provides an easy way to set up the wellbore by either typing in the path or by importing, this allows for dogleg severity to be included in the simulation, something that can be useful when studying the cuttings transport capacity of the wellbore. The hole selection tab allows the user to select the appropriate casing program for the well.

For drill fluid selection the fluid can be modified by selecting the right density, PVT, gelling and rheology. For users that have access to a mud lab, or a selection of premade muds this means that any mud in stock could easily be implemented into the simulator.

The simulator can be run directly in most web browsers, and it allows for changing a large amount of input parameters. When staring a new simulation the user can decide to run the simulation in real-time, with the option to fast forward the simulation, or a sequence could be made to run a predetermined set of input changes.

3.3 sensors in MPD system

3.3.1 Flow rate monitoring

The MPD system is usually fitted with a flowmeter in order to determine accurate flow out values. These measurements are normally performed by leading the return flow through a Coriolis flow meter. Having an accurate measurement of flow out, allows for early kick detection, and it enables accurate estimation of the wellbore breathing during fingerprinting.

The flowmeter is usually used to provide real-time data that is analyzed by the drilling software in order to detect emerging issues and can enable automatic alarms when an issue arises.

Using two flowmeters can enable real-time data on the cuttings taken in return, giving a good indication on how well the hole is cleaned.

Using a Coriolis flow meter several important factors can be calculated, such as mass flow, density and volumetric flowrate. The calculated parameters can be used to optimize hole cleaning and ROP. [17] To be able to accurately determine the velocity, pressure and temperature of gasses in the return flow highly accurate ultrasonic sensors can be used.

3.3.3 Pressure monitoring

When using an MPD system the ability to compare the BHP from simulations with the actual well will be beneficial. PWD tools are essential to any operation where the allowable pressure margin is narrow, so utilization of PWD tools will increase along with the difficulty of the well. Wired pipe technology enables the monitoring of local pressure build up due to having several pressure sensors placed down the drill string.

3.5 PID controllers

This section is based on the Wikipedia article on PID controllers, and sub references of the article have been controlled to verify validity of the content. [11]

To maintain a constant BHP in the well, it is necessary to employ some kind of controller to manipulate choke opening. The most common controller used is usually some variant of a PID controller, p is proportional, I integral and D is a derivative term. A PID controller will in this case monitor the current BHP and compare this value to that of a preset set point, if the values are different the error function will be either negative or positive, and this tells the system whether the choke should be opened or closed.

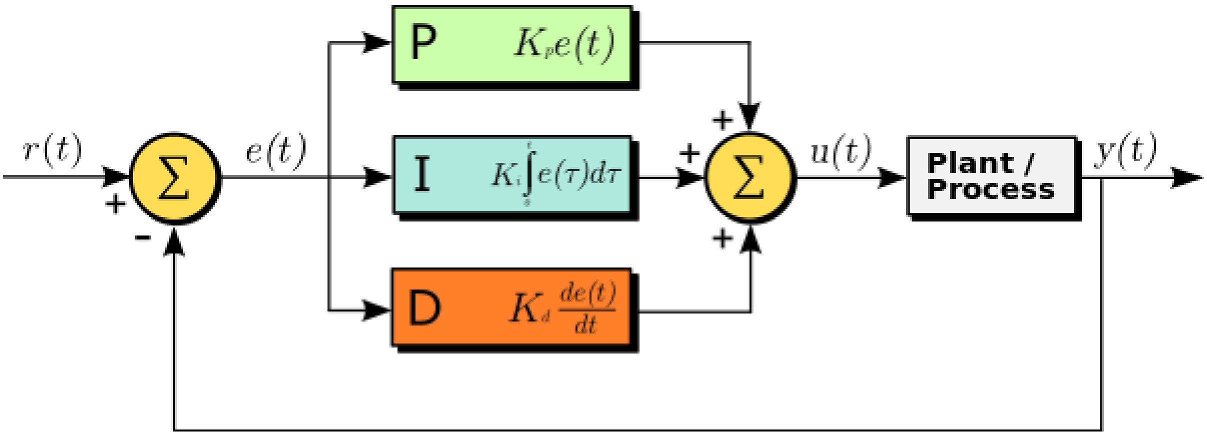

Figure 5a block diagram of a PID controller with a feedback loop [11]

The concept is to create an error function, to get the difference between set point and measured values

$$e(t) = y_{sp} - y_m$$

Where, t is time, y_{sp} is the desired set point value and y_m is the measured value from the system.

The proportional gain tries to correct the error by adjusting the system with a proportional parameter, meaning that a large error will induce a large correction by a factor k

$$u(t) = u_o + k_p * e(t)$$

Where, u_o is the input value of the system, k_p is the proportional gain parameter, $u(t)$ is the output of the controller and $e(t)$ is the error function.

The integral component works by integrating the error function over a certain time frame to get closer to set point. This works nicely in pair with the proportional part, because the effect of proportional gain is diminishing as the error function approaches zero, so if there is any fine-tuning left, the integral component grows and eventually corrects for this small error.

$$u(t) = u_t + k_i \int_0^t e(\tau) dt$$

$$k_i = \frac{k_p}{T_i}$$

Where, k_i is the integral gain, T_i is the integral time and τ is an adjustable time constant.

Both the integral gain and the proportional gains needs to be tuned to the specific system to prevent the controller from exhibiting unstable behavior, like oscillations or overshoots.

k_d is the derivative of the error function, meaning that a fast increase or decrease in error will make the k_d term larger. The derivative term is mostly used in processes where a large overshoots would be problematic.

$$u(t) = u_0 + k_d \frac{d}{dt} e(t)$$

Where, k_d is the derivative gain as a function of k_p and t_d (derivative time).

The derivative term is the term that is most often left out, because of the derivative terms susceptibility to system noise, meaning that noise produced from various sensors in the system may make the system unstable. [11]

Adding all the control terms together we get the equation for a PID controller

$$u(t) = u_0 + k_p e(t) + k_i \int_0^t e(t) d\tau + k_d \frac{d}{dt} e(t)$$

But in order to make the controller useful the gains must be tuned for the specific system it is applied to, this can be done automatically, but for smaller plants iterative tuning is also a viable option.

4 pump pressure manipulation during connections literature study

Chapter 1 briefly mentioned on some of the general issues that can handled by MPD and also touched on to some areas that are still being developed in order to utilize MPD systems on floaters. This chapter will go into more in to detail on the specific issue of maintaining a constant BHP during a pipe connection.

4.1 Literature study of connections research MPD

The area that MPD techniques really excels at is the ability to keep BHP constant, however the MPD system and the PI/PID controller will have a hard time during dynamic phases of operation. Under a pipe connection or perhaps under a well control situation there may be a need to stop rotating the drill string and stop mud pump circulation. In this situation our flow path is changed from that of figure 6, to that of figure 7. The consequence of this change in flow path will manifest itself in the form of a lowered BHP, assuming all other parameters stay equal. The reason for this change in BHP is due to the fact that fluid is no longer circulating through the annulus of the well, so the annular friction factor part of the ECD equation goes to zero making effective bottom hole pressure decrease.

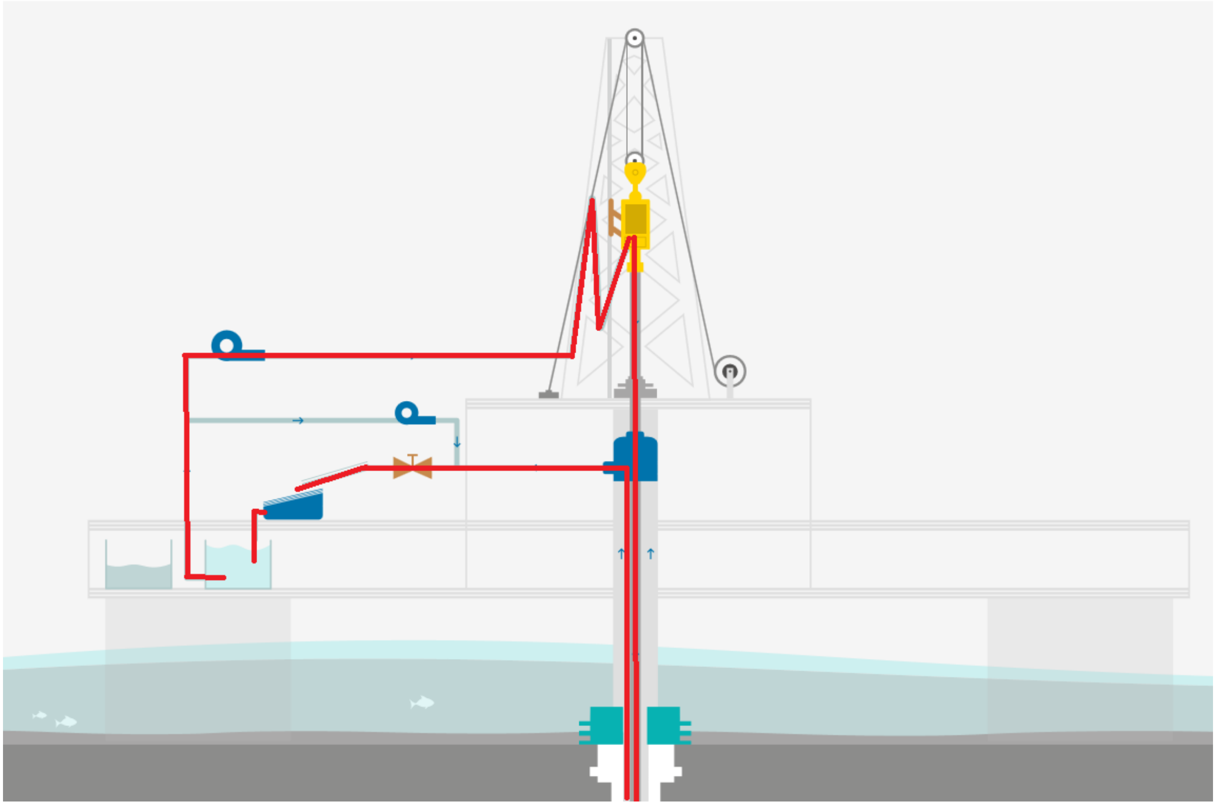

Figure 6 the figure illustrates the mud flow path during drilling [13]

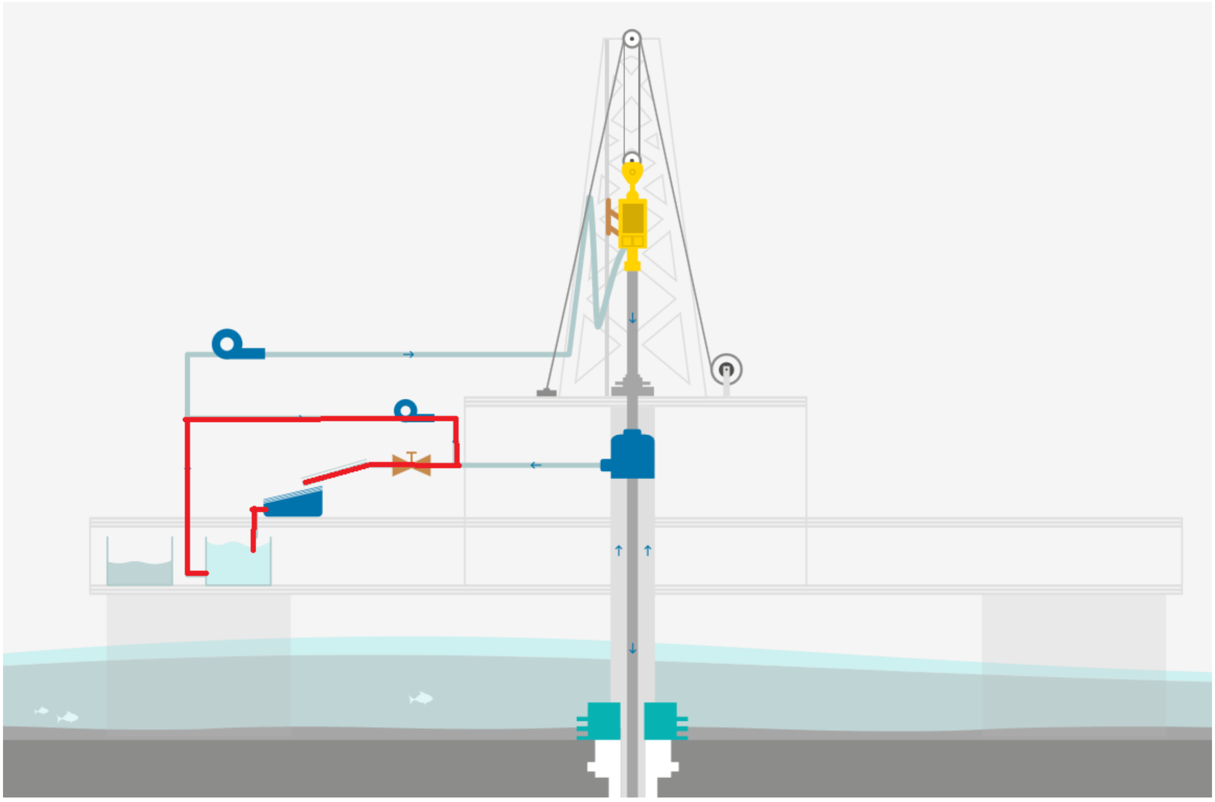

Figure 7 the figure illustrates the mud flow path during circulation using the back pressure pump [13]

In a SPE article written by Denney, D it's stated that a common misconception is that an automatic MPD system will be effective at regulating BHP during all aspects of a drilling operation, but the automatic systems show some weaknesses during massive changes being made to the system, like ramping up and/or down the pumps during a connection. Some of the observed issues are the fact that the choke regulation can become unstable during rapid pressure fluctuations, and if these fluctuations occur there is a risk that well breathing could become an issue. [12]

Another aspect that is critical to the BHP behavior is the drilling fluid that is used, it is crucial to realize that during the drilling process the temperature profile of the drilling fluid will constantly be changing. After drilling for some time the drilling fluid will reach a thermal equilibrium and no longer change with respect to time.

Any challenging well with narrow drilling margin should be carefully planned and simulated to determine the best approach for the specific well. Utilizing high fidelity simulations in the planning of troublesome wells will allow the operator to cut cost. By already having drilled the section in a simulator and thus gathered experience that could be applied to the actual operation.

In [14], the method used to build back pressure is a stepwise increase in BPP flowrate, while simultaneously ramping down the flowrate of the rig pump. This is at least the conceptual idea of how the pump swap should be performed, and this paper show the stepping plan over an arbitrary time period.

An example of how MPD systems can be useful in narrow margin drilling was presented by a group of engineers from shell in Nigeria 2017. [15] The paper states that the operator had problems with a highly permeable reservoir with high fluid mobility, and a drilling margin between 0.4 - 1.6 ppg. Due to the high risk it was decided to use an MPD system to keep the bottom hole pressures from going outside the safe pressure regime. One of the highlighted areas of concern was the risk of losing well control due to pressure fluctuations initiated by the starting and stopping of the mud pump and back pressure pump, in total 11 MPD connections were successfully made during the drilling of the exploration well. To be able to accurately determine bottom hole pressure during the operation a highly accurate pressure while drilling tool was deployed, this enabled the drilling team to determine and continuously improve the pump rate scheme during connections.

Before commencing the operation, a full calibration of the MPD system was initiated to determine the pump scheme and to optimize the connection procedure, this exercise is called fingerprinting and the idea behind doing such a test is to compare the simulated scenario to the real system. The fingerprinting exercise is performed before drilling the shoe out of casing, and once more immediately after drilling the casing shoe. During fingerprinting the MPD system is circulated with differing pump rates to determine the correlations between the simulated well and the real operation. The amount of well breathing that is to be expected from the formation can be safely explored right after drilling the casing shoe, as illustrated in figure 8. [16]

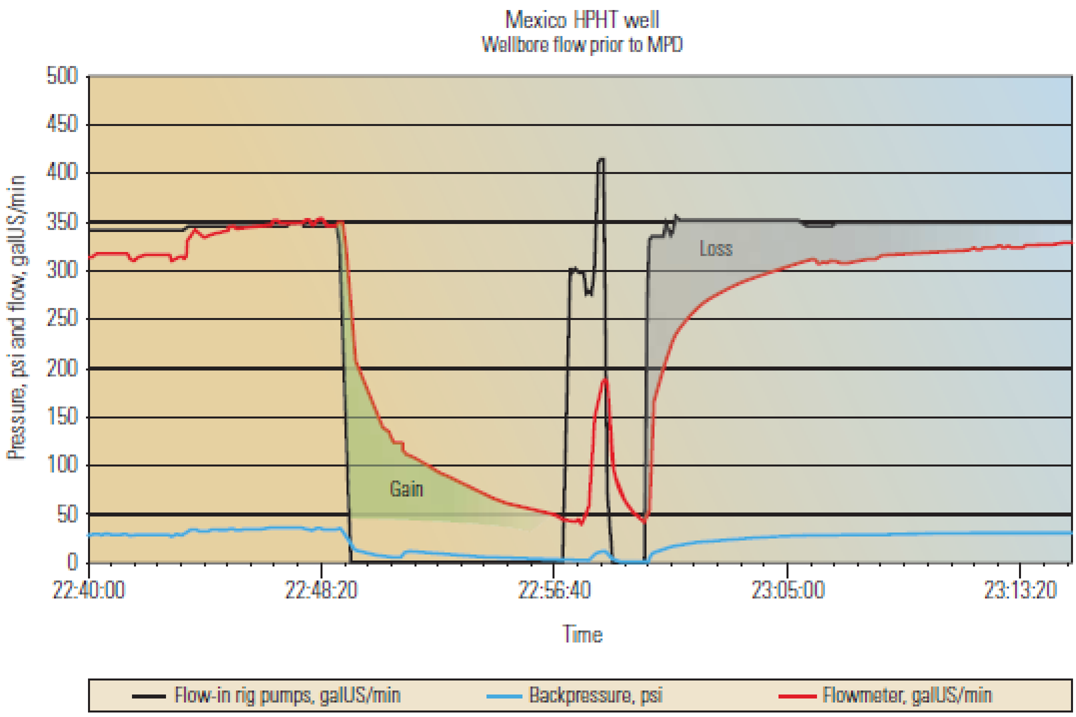

Figure 8 fingerprinting exercise before employing MPD system [16]

Figure 9 illustrates the pump scheme used prior to initiating the pipe connection for pump rates lower than 160 gpm. From figure 10 we observe that the time spent on making this specific connection was around 40 minutes. The MPD configuration used in the drilling of the x1 well is similar to the configuration available in the openlabdrilling simulator.

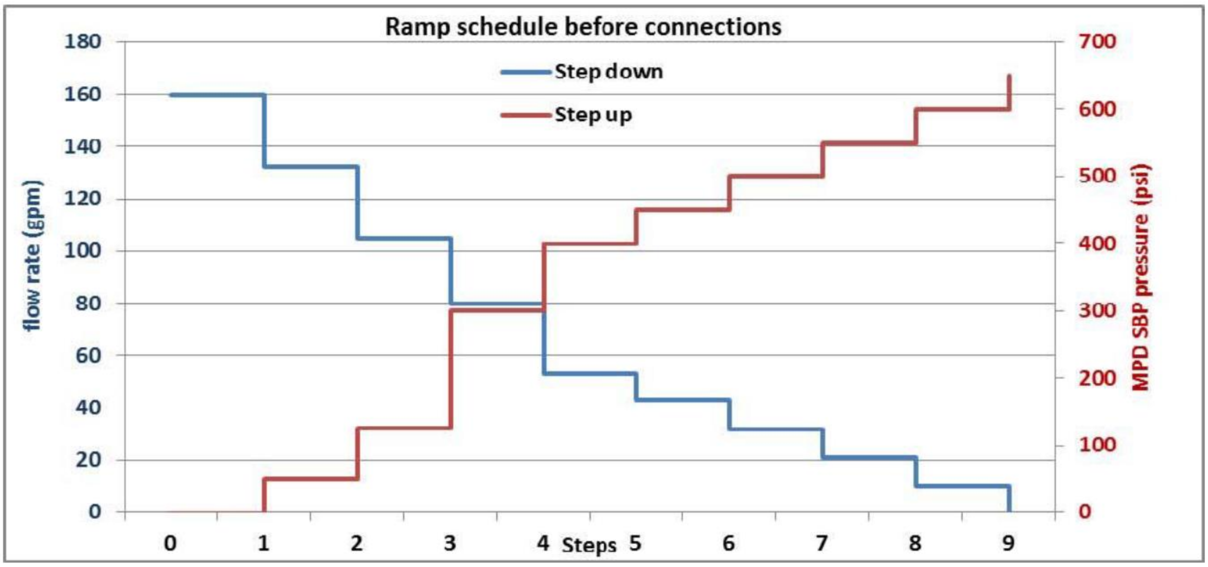

Figure 9the pump scheme used by shell drilling HPHT exploration well in the Niger Delta [15]

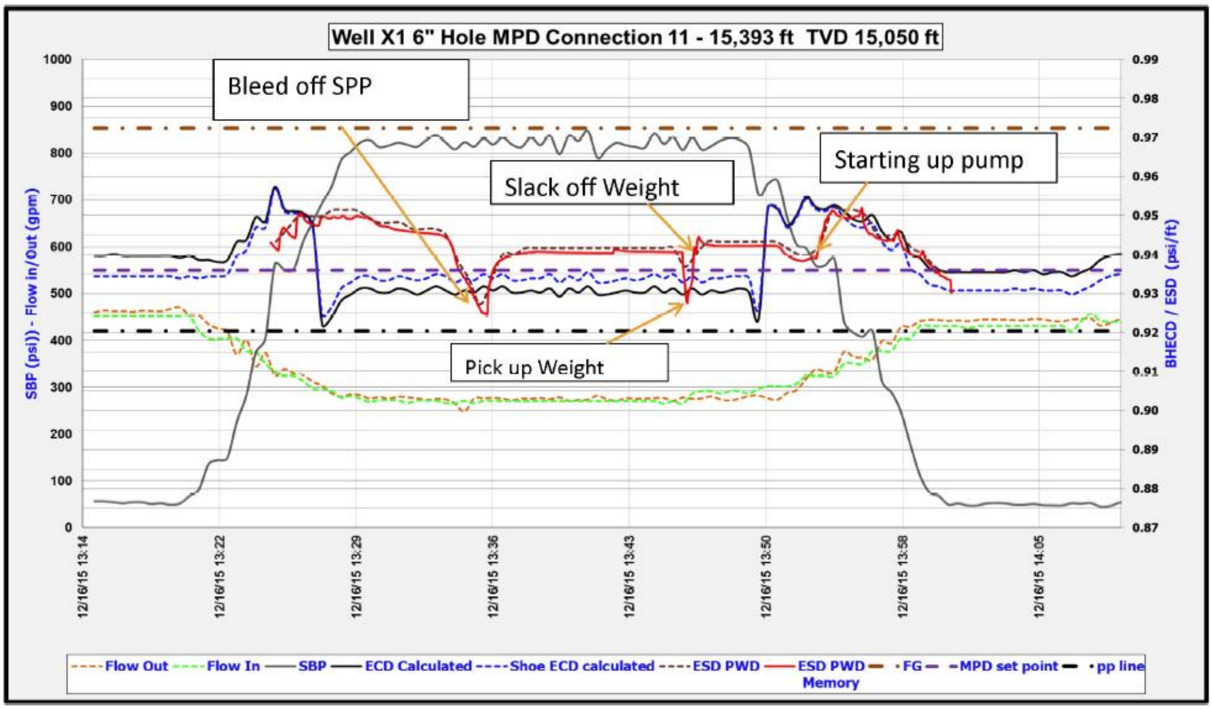

Figure 10 MPD connection 11 on the x1 well in the Niger Delta [15]

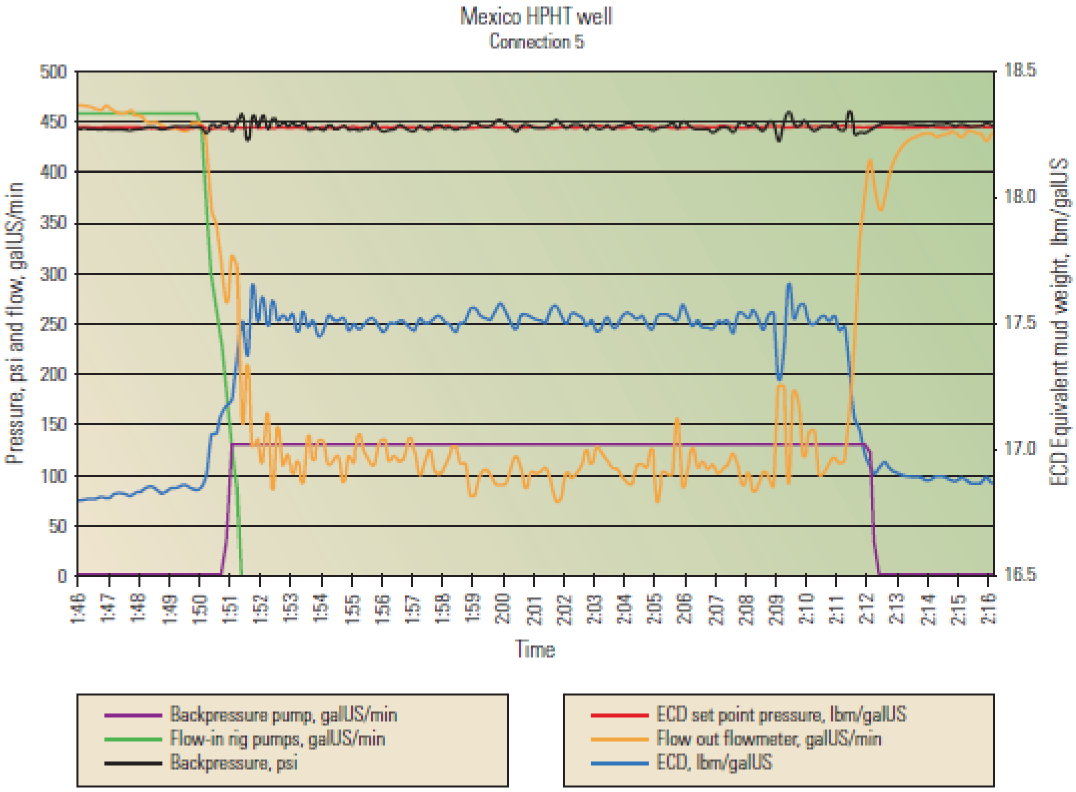

Figure 11 20 minutes spent making connection [16]

4.2.1 Case study: Well configuration

The configuration used for the case study is the premade well called inclined well 2500 m, the goal of the case study will be to look at different pump ramp schemes and try to distinguish the differences between them and possibly determine a best fit scheme. The expected results from swapping the pumps around is expected to make pressure fluctuate in the period where one pump is taking over for the other, and in the second phase gel strength is expected to develop in the annulus due to no circulation. Breaking the gel strength is expected to result in a high spike in ECD value. The industry standard for any bottom hole regulating system is considered to be an envelope of ±2,5 Bar from the set point, the simulations take aim at getting any pressure fluctuation within this envelope.

The well path is vertical down to KOP at 700 meters, and angle is first built to ~30 degrees, and after second KOP at 1300 meters angle is kept between 40-47 degrees as shown in figure below.

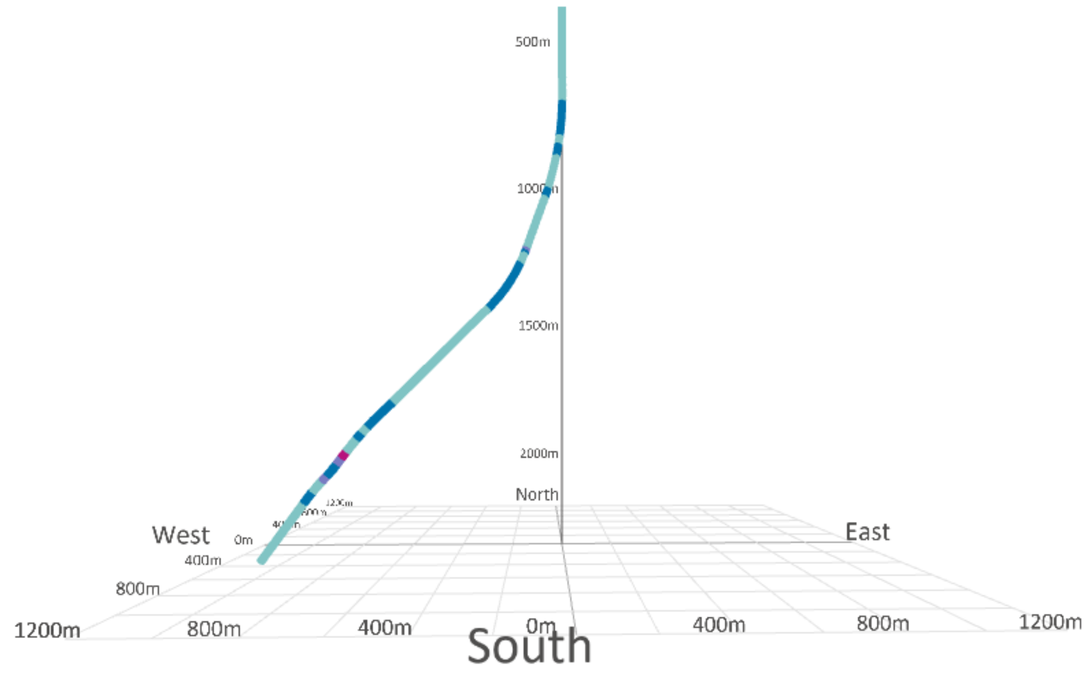

Figure 12 side view of the well

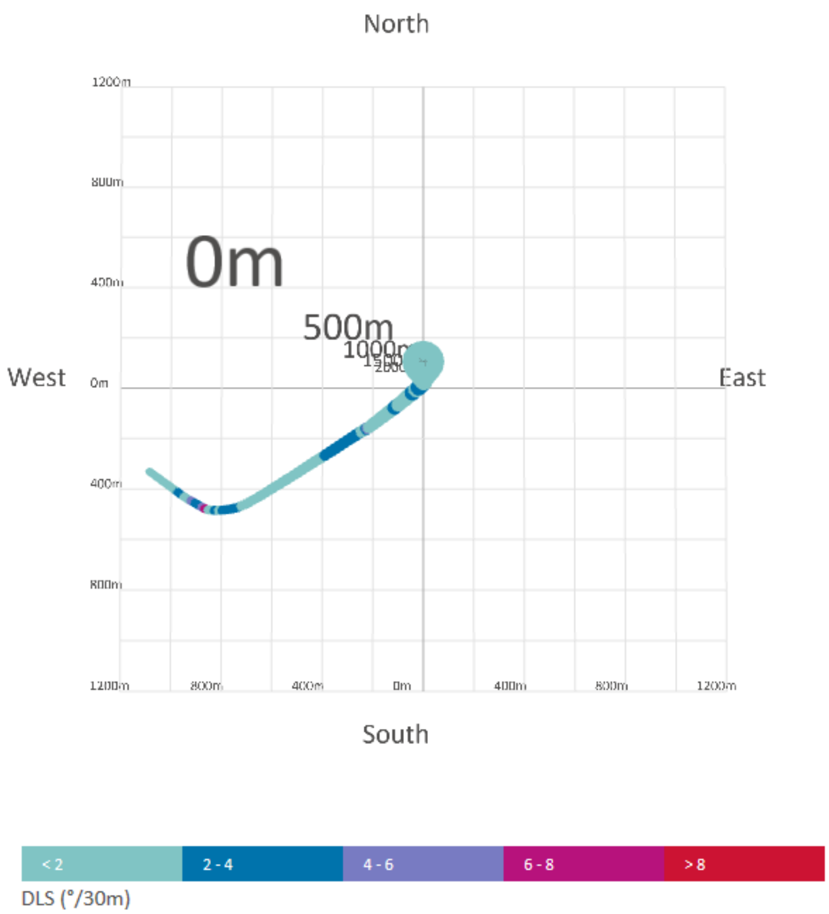

Figure 13 top down view of the well path used for simulations

For rheology the standard fluid called generic OBM 1 was chosen, this has a 56,92% volume fraction of base oil, 18,97% of water and 24,11% of barite and an OWR of 75/25. The mud has a specific gravity of 1,65 and the 10 second is 6 Pa and the 10 minute gel strength is 9 Pa. The simulations take into account the PVT properties of the base oil in the mud, and there is a table describing the effects of temperatures under different pressures.

The pump configuration used for the simulations is a setup with a main mud pump, that is responsible for circulation when drilling, and an MPD pump that can be used when connections are made or tripping. Parameters like choke and pump acceleration is left on the standard, for the pumps this is 200 l/min/s for both main and MPD pump, and the choke acceleration is set to 20%/s.

The simulations were run from a matlab interface, by using a modified sweep scheme that was provided in the matlab package, this was done in order to utilize the prebuilt PI controller that is included in the code bundle on the openlabdrilling website. The PI controller will enable the choke to be controlled automatically during the connection. The Figure below is from one of the first simulation runs that was done with the PI controller enabled, the gains that were initially in place were causing a lot of instability and consequently the Kp gain had to be slightly reduced. In every simulation there are 100 time steps that are used to ramp up pumps, and after the 100 time step the PI controller kicks in and starts to regulate choke opening, but the initial choke opening was set to a value close to what was needed to maintain the target BHP of 380 Bar. After time step 100, some time was spent letting the PI controller get closer to set point before initiating the connection procedure.

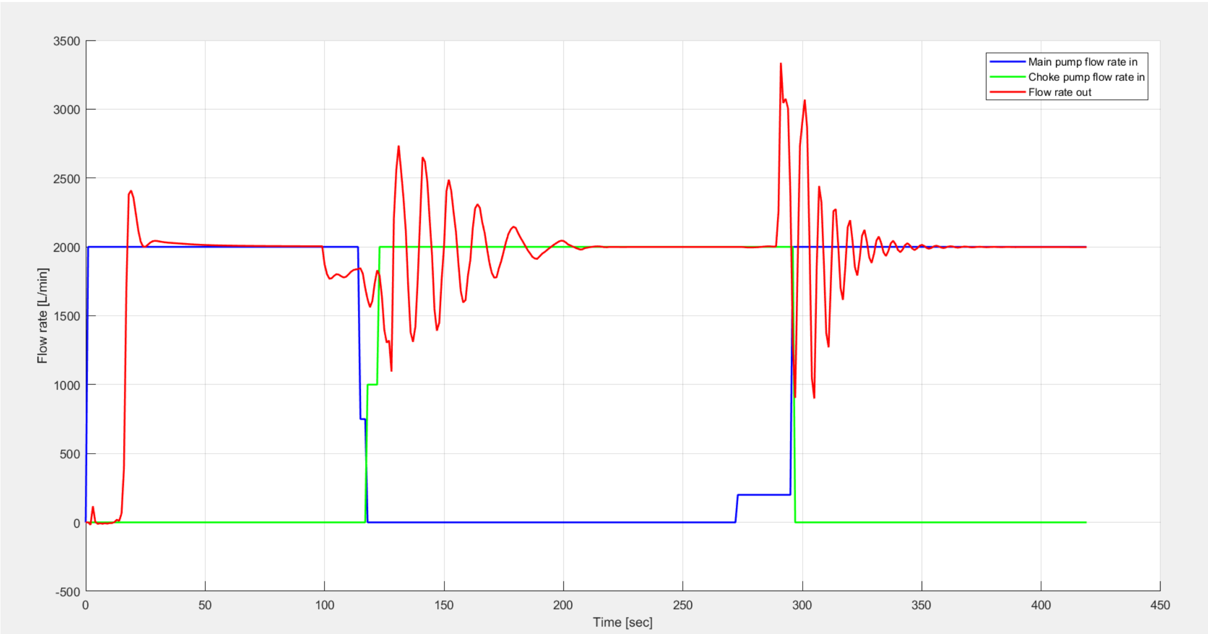

Figure 14 example showing instability due to high Kp gains

The first few iterations where spent on tuning the PI controller, but at the controller was initially tuned according to, so only minor adjustments were made. The tuning was done by trial and error, because the initial gains showed instability. From the literature study it was concluded that the time spent on making the connection was widely differing with each well, some wells used 40 minutes others as little as 10 minutes, however to be able to do an adequate number of simulations the time spent making the connection was set to be 3 minutes, this is the time from disconnecting the top drive, until the top drive is reconnected, total connection time will be larger due to the time spent ramping up and down pumps.

For the entirety of the case study, the ramping up and down will be referred to as phase 1 and phase 2, phase one being the step when main mud pump is ramped down, and MPD pump is ramped up. Phase 2 is the reverse of phase 1, meaning that main mud pump is ramped up and MPD pump is ramped down. This is illustrated in figure below.

4.3.1 Scheme 1 simulation 1 swapping pumps in the same time step

The first scheme is to increase/decrease pump rate in one step with varying gradient and pump offset. The result in figure under shows that flow out increases as the MPD pump is engaged, this is to be expected, because for this scheme in the set point where pump rates are set to change we run in to a situation where the main pump is 2000 lpm and decreasing , while the MPD pump is 0 lpm and increasing both at equal gradient, intuitively one can assume that this equates a constant flow out of 2000 lpm at all times, however due to the difference in length of flow path this is not the case. It is observed that flow out will continue to rise until the main pump reaches a flow rate of 0 lpm, then flow out can start to stabilize around 2000 lpm, but due to our choke adjustments we get a slight undershoot directly followed by an overshoot around time step 150. In phase 2 it is observed that flow out is highly correlated with the ramp down of the MPD pump, this is most likely due to the fact that the mechanism for ramp up of main pump needs to build pressure before any flow can go through the no return valve. This combined with the longer flow path of the main pump makes flow out drop rapidly when MPD is ramped down, the flow out starts to recover in time step 329, but due to large fluctuations the choke is now completely shut, and when flow initiates the PI controller is way too slow to handle the rapid changes, causing large fluctuations in flow out, as the choke desperately tries to regain control.

The matlab graph is not entirely correct in cases like this, this is due to the graph not displaying the correct values for the pump rates, but rather it displays the pump rate set point, for the schemes that have a gradient differing from maximum acceleration the matlab plots are correct.

If compared with the graph from the web client this phenomenon is clear.

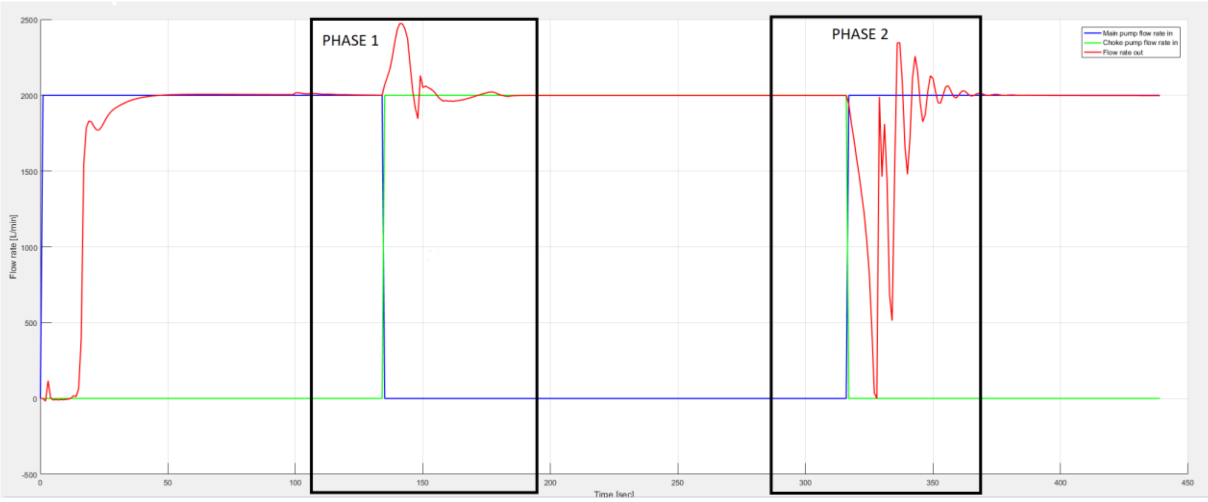

Figure 15 scheme number 1, swapping with max acceleration

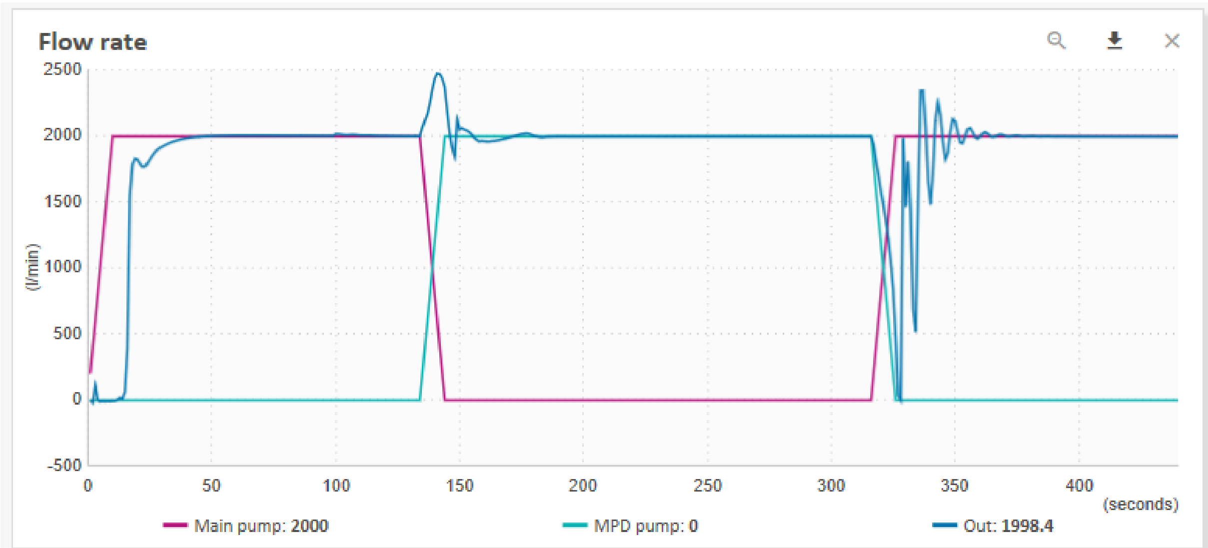

Figure 16 figure from the openlabdrilling web client includes the accurate pump rate gradient

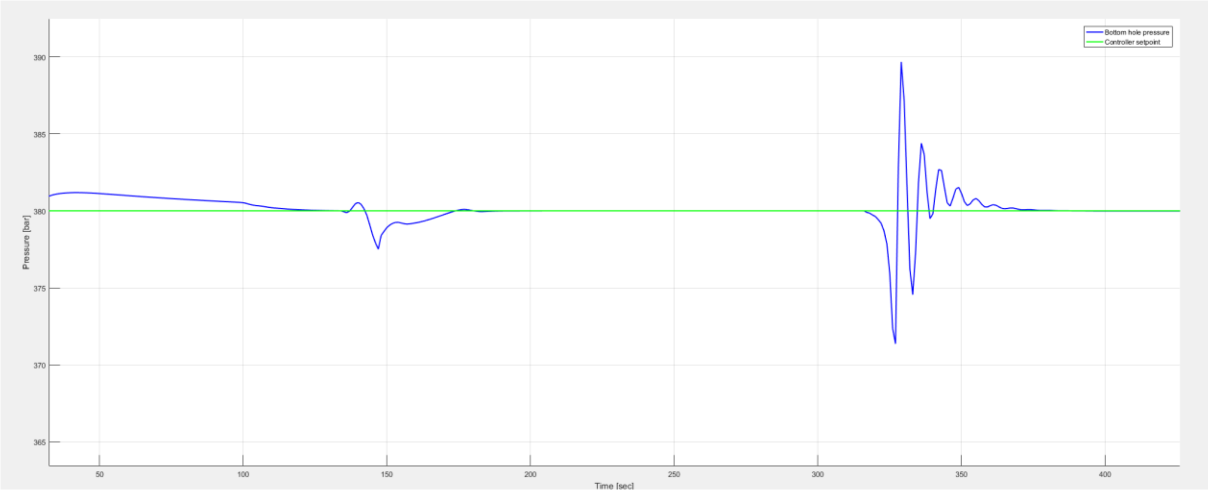

Figure 17 bottom hole pressure scheme 1

The bottom hole pressure for scheme 1 is marginally within the industry standards specifications for phase 1, however phase 2 is extremely unstable and reaches max pressure of 389,66 Bar and a minimum pressure of 371,36 Bar, this is way too high of a deviation, and this kind of pressure scenario would in a narrow drilling window result in fracturing of the reservoir followed by a potential influx, with a high risk of losing the well.

4.3.2 Scheme 1 simulation 2 increased gradient for pumps

Scheme 2 followed the same principals as scheme 1, ramping both pumps in the same time step, but this time the pump gradients were slowed down so that ramp time would be 20 seconds.

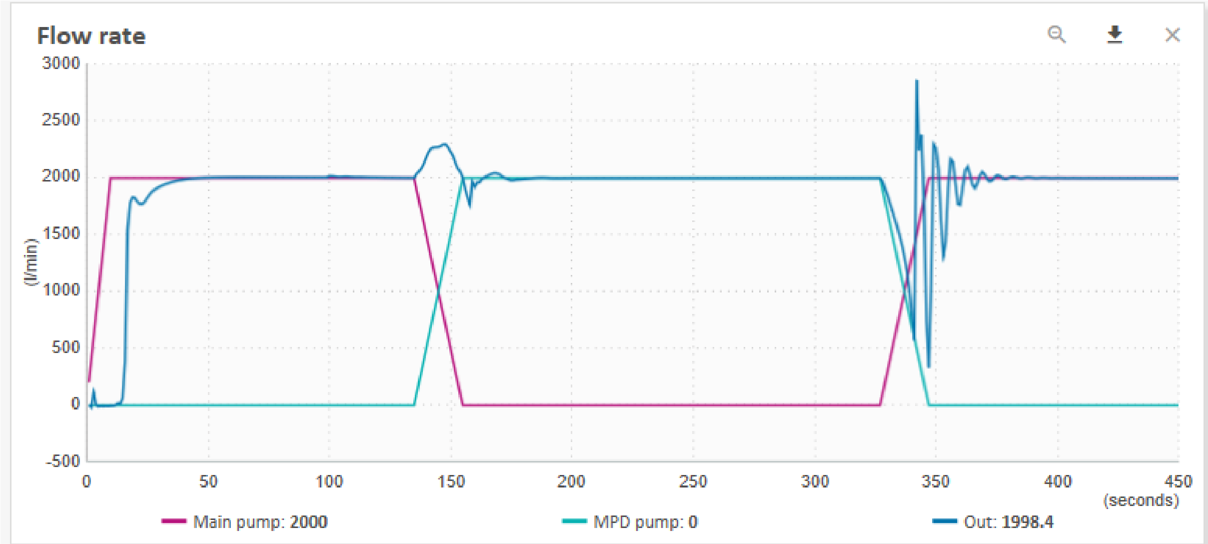

Figure 18 ramping done over 20 seconds

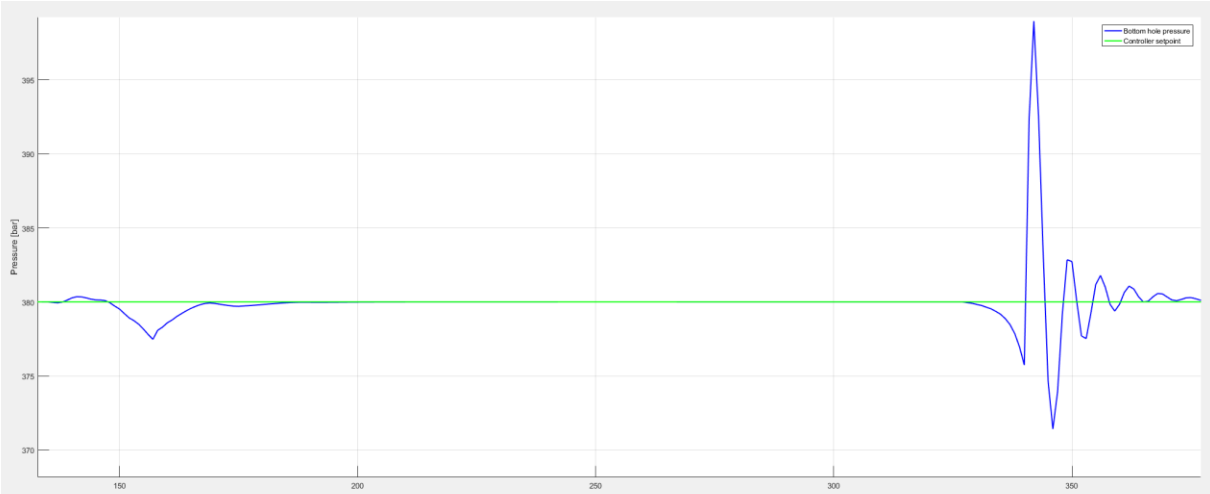

Figure 19 bottom hole pressure 20 second ramping

The increased time frame allowed the PI controller to better fit the BHP curve with set point during this scheme, but in phase 2 the same problem still persists. As seen in the BHP plot in figure 15 the pressure in phase one dips just below the goal of $\pm$2,5 Bar, as for phase 2, the choke instability still causes massive pressure fluctuations. In order to smoothen out the spikes that occur in phase 2 a delay is introduced, meaning that in phase 2 the main pump will start ramping up slightly before starting the ramp down of the MPD pump, this is to compensate for the elongated flow path of main pump compared to the MPD pump.

4.3.3 Scheme 1 simulation 3 introducing offset on pumps

In this iteration the BPP is initiated four time steps earlier in phase 1, and the main pump is initiated 3 time steps earlier. This iteration showed that the initial offsets were a bit exaggerated, and as a result dropped the flow out in phase 1 way to low, causing pressure to go outside of the $\pm$2,5 Bar envelope.

Figure 20 introducing some offset on the pumps

For phase 2 the flow out drop was somewhat alleviated, but still not to an extent that would allow the controller to smoothly regulate BHP.

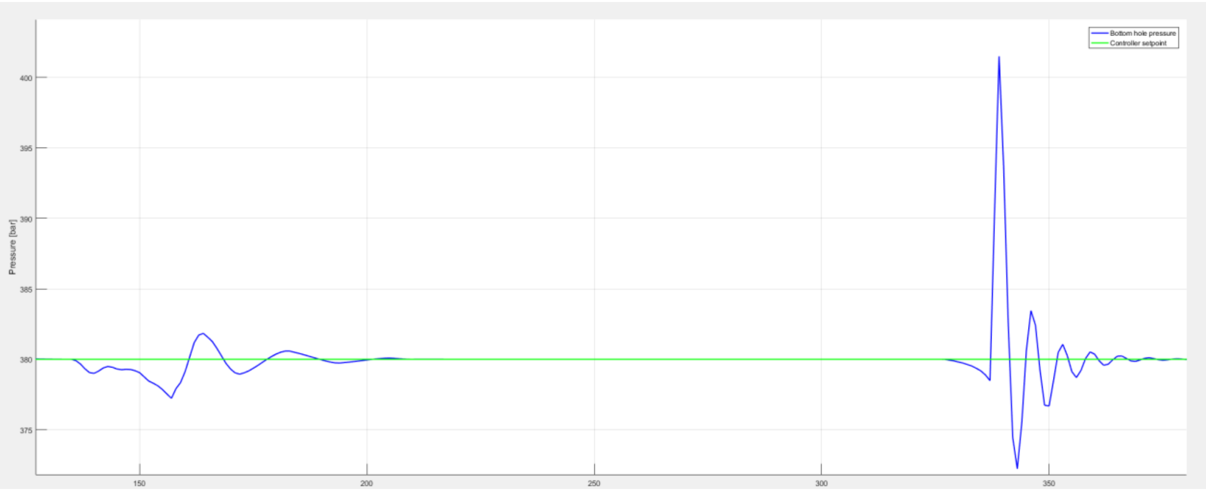

Figure 21 BHP with introduced pump offset

4.3.4 Scheme 1 simulation 5 – 17 summary

Due to the results in phase 2 being so high all of these schemes were trial and error, with the intention of smoothing the flow out curve. The logic behind this approach would be that a less abrupt change in flow out values would require less abrupt changes to choke opening, resulting in lower pressure deviation and hopefully little instability. All of these schemes had in common that the pump rate was increased or decreased in one step, and the slowest gradient was a total ramp up/down in 200 seconds. Most of these simulations consisted of changing the ramp time steps of both pumps by one or two for each iteration, despite phase 1 seemingly having relatively low deviation during all these simulations, the phase 2 was never able to get remotely close to the specified industry standard of ±2,5 Bars. Scheme 1 was abandoned after simulation 17, this was by far the best result from scheme 1 but pressure deviation and instability issues prevailed, even for the simulations using 100 and 200 seconds on ramp the only noticeable improvement observed was for phase 1, using 200 seconds on ramping the maximum BHP deviation was reduced to less than 1 Bar.

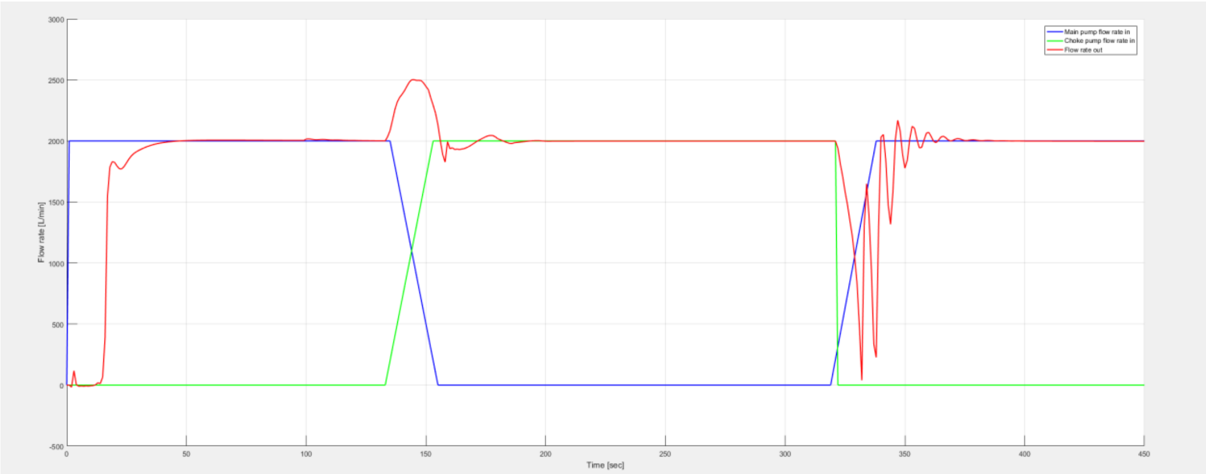

Figure 22 Flowrate simulation 15, abrupt ramp down of BPP

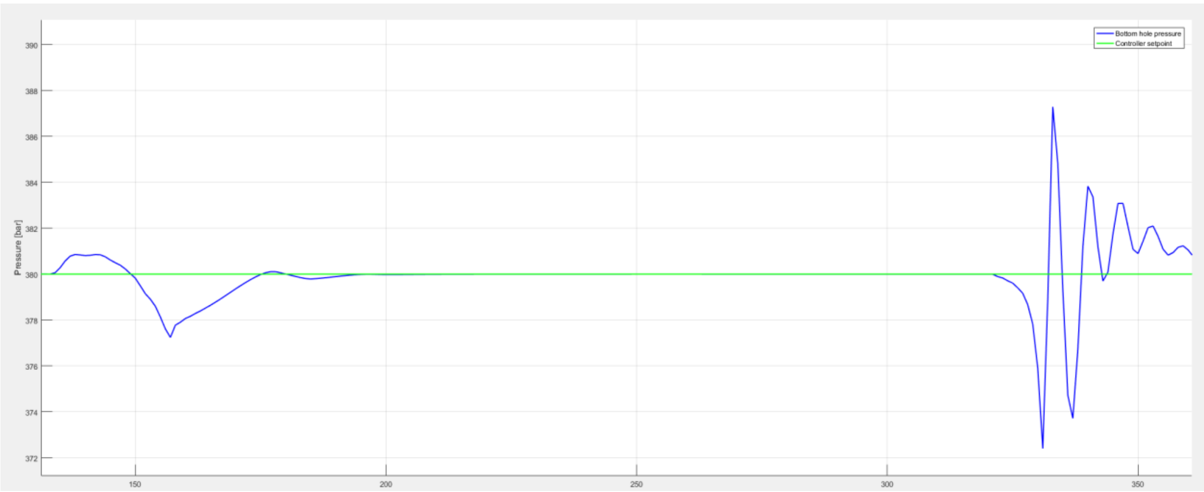

Figure 23 simulation 15 BHP

4.4 Scheme 2 staircase stepping summary

The second scheme is one that is mentioned in [14], because it involves a predetermined set of steps it is the preferred method to use in a manual control scenario. The first iterations used 5 time steps before initiating a new step, this induced some slightly growing oscillations in phase 1 and it seemed that the PI controller was struggling with adjusting fast enough, so the stepping duration was increased to 10 seconds, this resulted in a total time spent ramping of

90 seconds for each phase. The second iteration done with the 10 second steps and no offset showed promising results for phase 1, allowing the PI controller to keep BHP within a range of ±2,0 Bars, however phase 2 still had major stability issues reaching a peak pressure of over 392 Bar.(figure below)

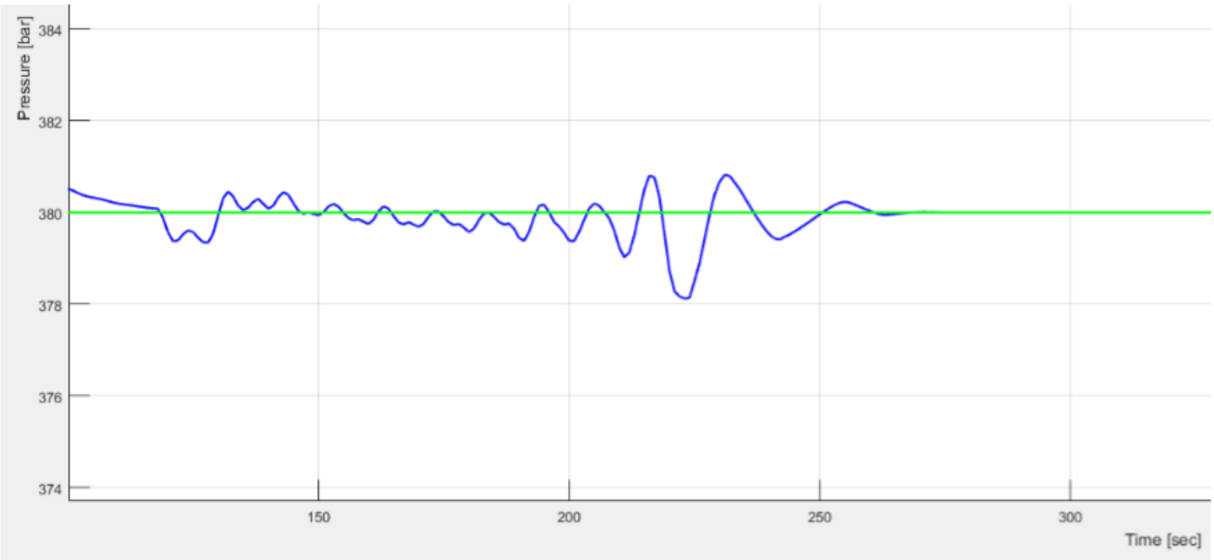

Figure 24 BHP in phase 1 of the second itteration using 10 second plateau

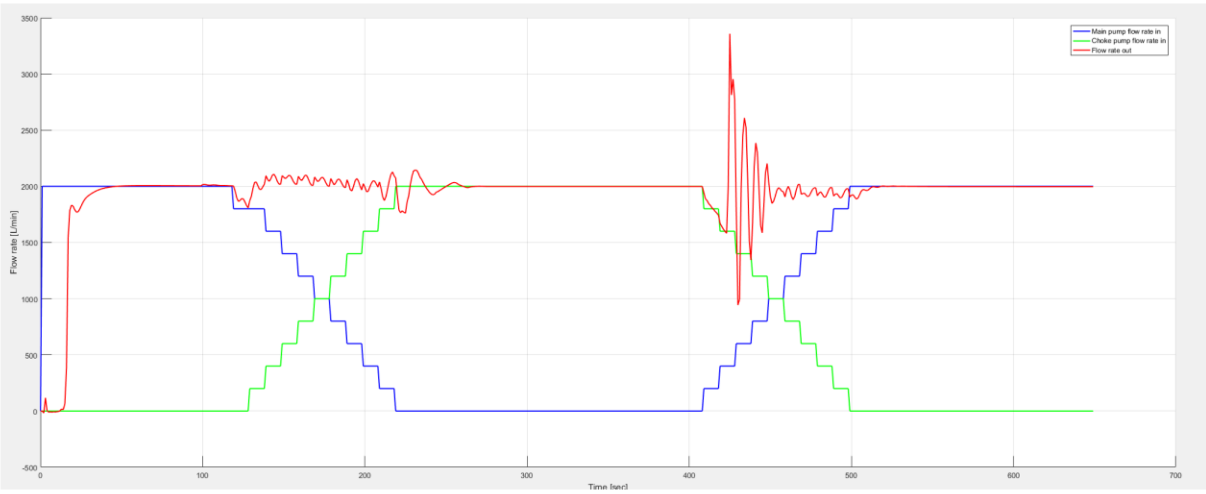

Figure 25 high correlation between flow out and BHP in phase 1 is observed

After many iterations a ramps scheme that would somewhat negate the massive pressure deviations in phase 2 was found. The scheme has significantly fewer steps than the first iterations, especially in the ramp down of the choke pressure pump.

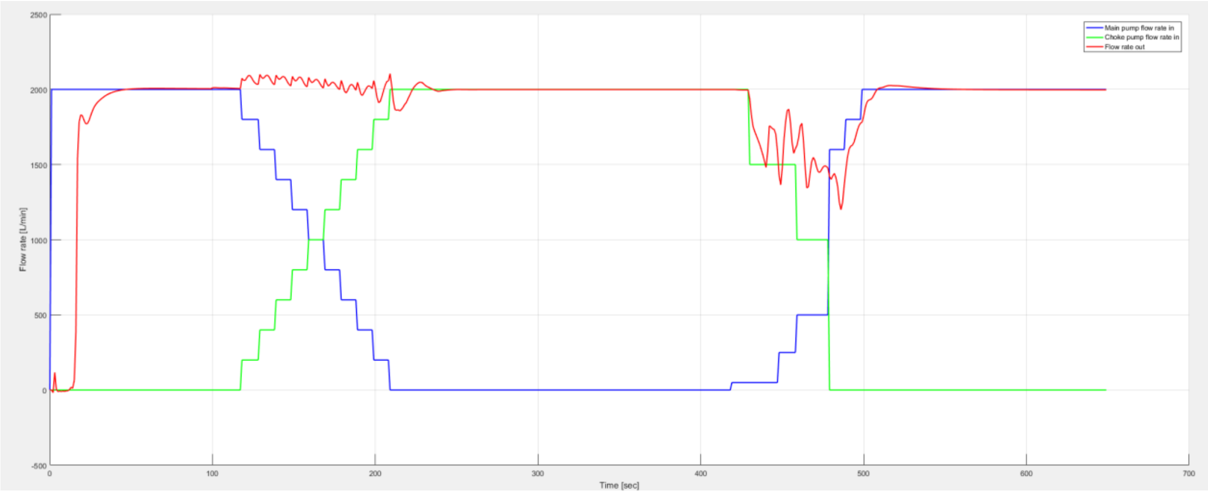

Figure 26 best result from staircase scheme

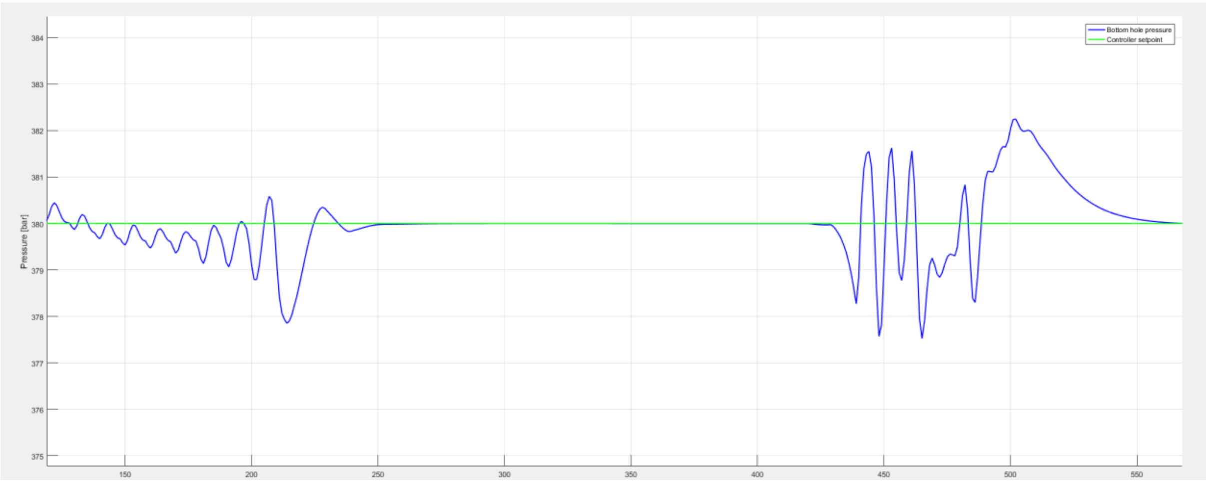

Figure 27 pressure deviations within ±2,5 Bar deviation

In order to get within the envelope some adjustments had to be done to the PI controller, these changes did not account for extremely large changes in behavior but helped to reduce the pressure spikes slightly.

```
% Controller settings
Kp = -0.008; Ki = Kp/12; Ts = 1;
ReferenceBHPPressure = 380 * 1E5; % [Pa]
InitialChokeOpening = 0.15; % [closed: 0, open: 1]
PI = PIcontroller(Kp, Ki, Ts, ReferenceBHPPressure,InitialChokeOpening); % Create PI controller object, pressure in [Pa]
```

Figur 1 Kp gain reduced from -0,012, and Ki increased from kp/10

4.5 Scheme 3 Statoil method summary

The pump scheme used by Statoil in MPD operations consist swapping pumps in one step for phase 1, and in phase 2 main pump is ramped to a low flowrate for a while, before ramping to full flow in one step. 120 rpm of rotation was added to try and get within specs, without rotation, the scheme would not have been successful.

The first iteration showed high initial pressure spikes, due to high flow out with pressure in phase 2 reaching a max value of 390 Bar, and under pressure of 5 Bar. The next iterations tried to equalize flow in and flow out.

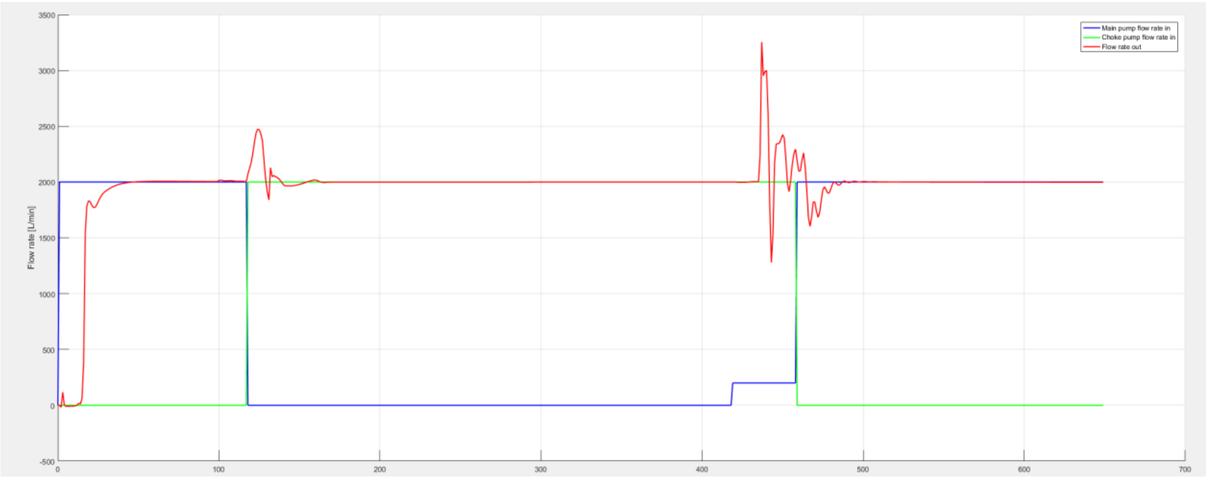

Figure 28 flowrate simulation 1

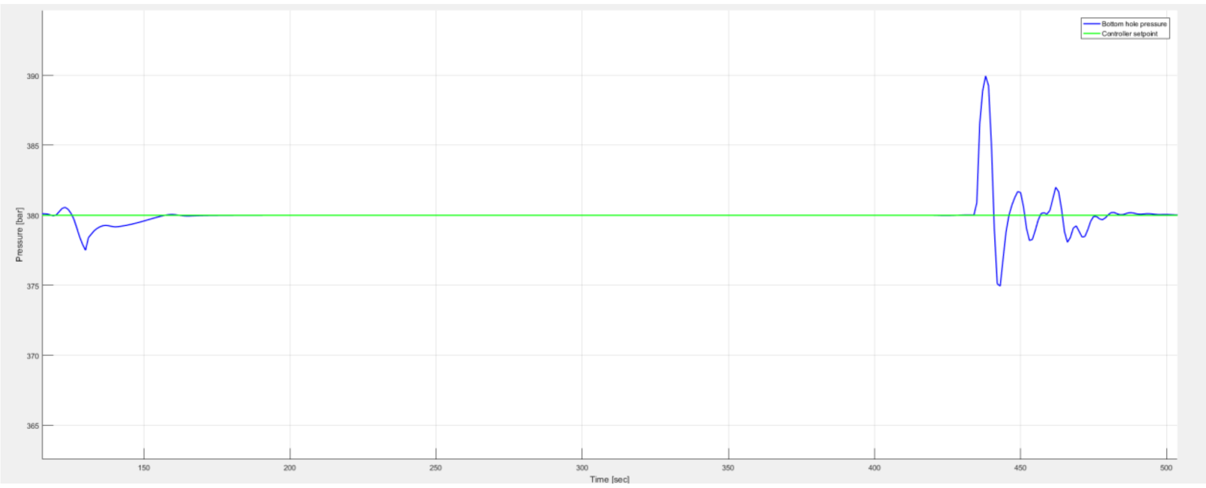

Figure 29 BHP simulation 1

By reducing the gradient of the pumps flow was smoothened out substantially compared to the first iteration, but the pressure values where still overshooting by a couple of Bars.

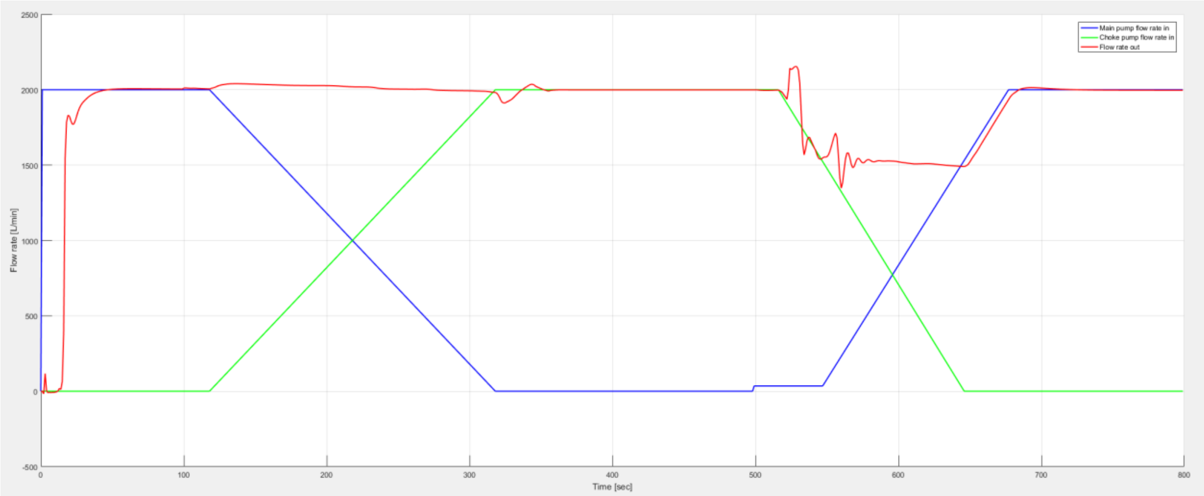

Figure 30 Simulation 2 with lowered pump gradients

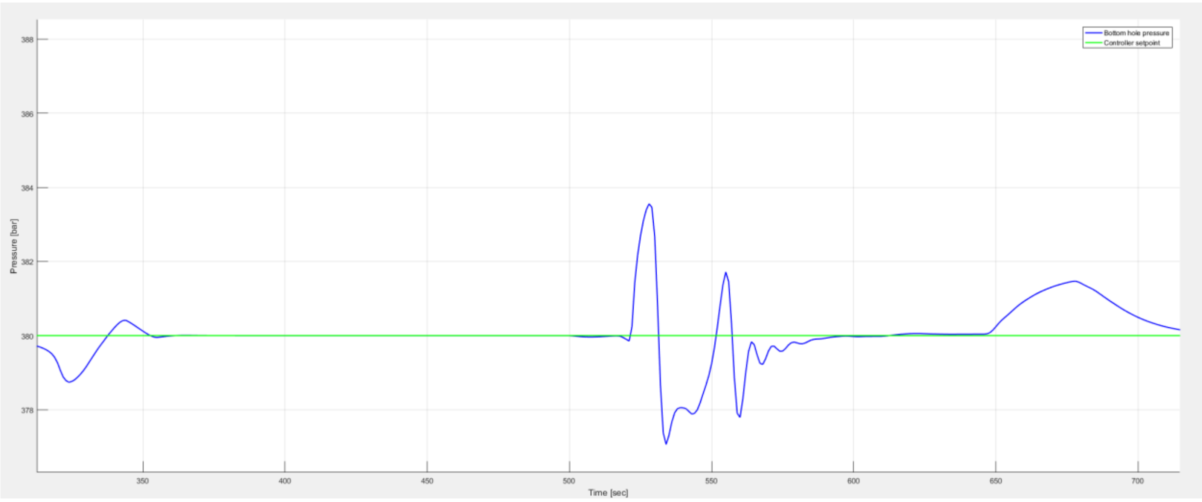

Figure 31 BHP is almost within ±2,5 Bar deviation for simulation 2

For scheme 3 the gains were reset to the initial settings of $k_p = 0{,}012$ and $k_i = \frac{k_p}{10}$, but when the iterations were starting to look promising it was clear that the gains would benefit from being tuned to the same values as scheme 2, however this was not entirely sufficient, so additional means had to be taken to get values within specifications. 120 RPM of rotation was added from time step 500 to 700, and this almost enough to get pressure spikes just below the ±2,5 Bar deviation limit.

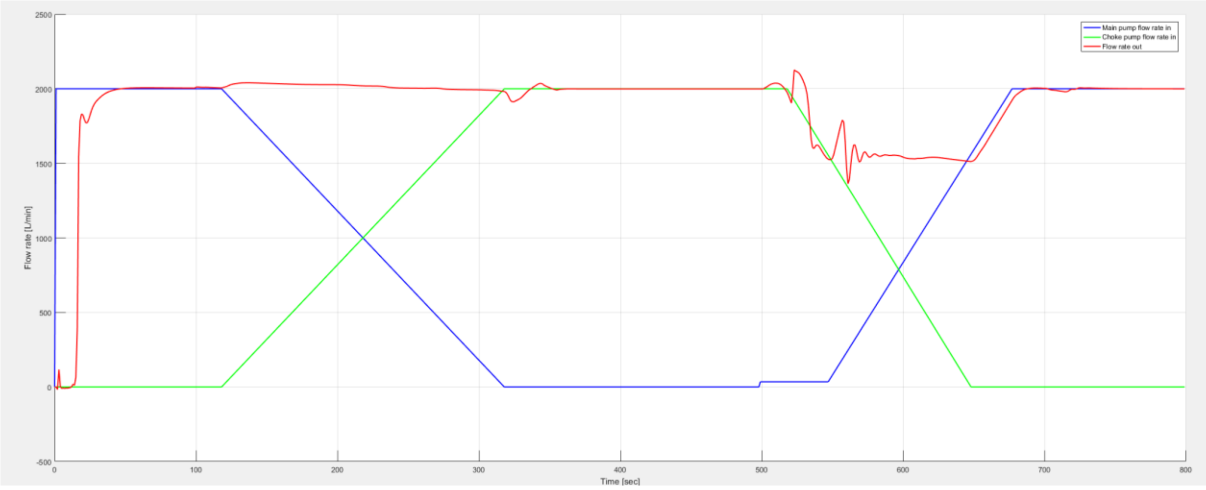

Figure 32 Flow rate with 120RPM rotation

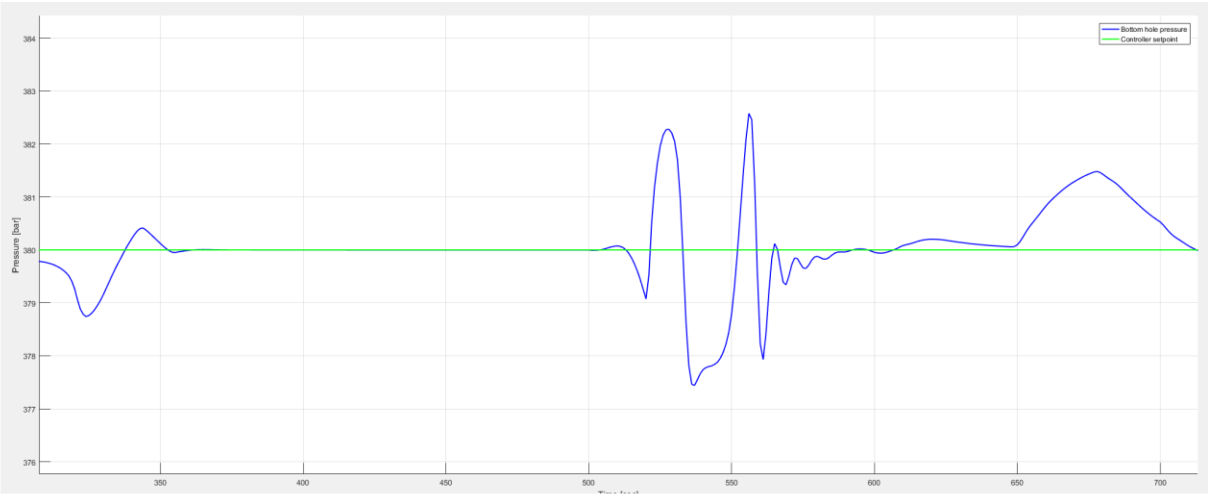

Figure 33 BHP pressure with added 120 RPM rotation

Increasing rotation with small increments until pressures are within the limit. The rotation necessary to get within scope turned out to be 138 RPM.

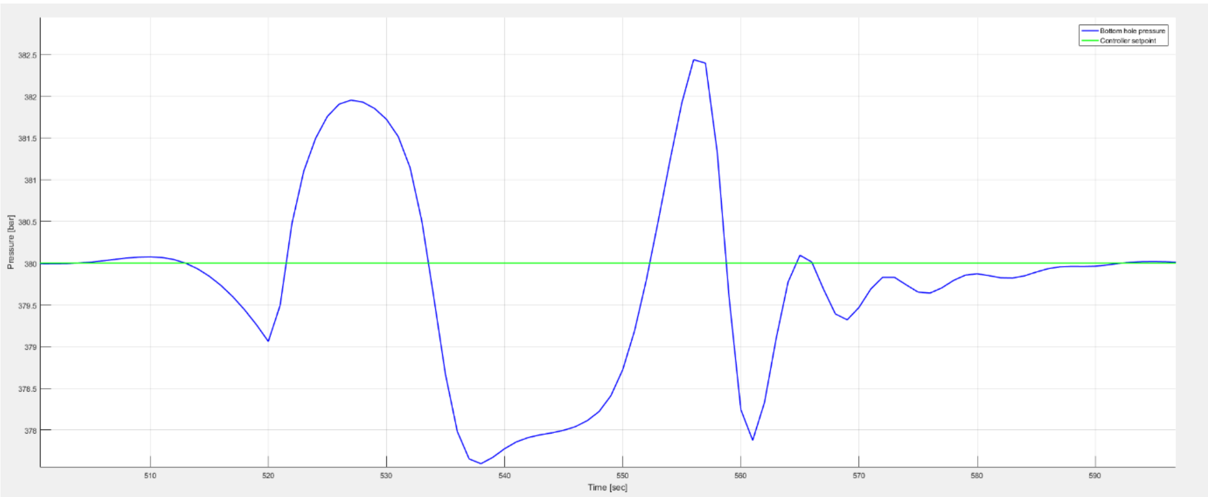

Figure 34 phase 2 BHP deviation with 138 RPM rotation

4.6 Discussion

The simulator provides good accuracy when it comes to pressure behavior downhole, but there are certain factors that may have an impact on pressure behavior that have not been taken into account. In the start of each simulation the temperature of the drill string increases to around 50 degrees Celsius, this means that our mud is at roughly 50 degrees C when simulation is started, but the temperature profile of the wellbore follows the geothermal gradient of the formation. Over time the temperature of the well will increase, and as a consequence the density of the drilling fluid will decrease slightly over time, however this effect should not be significant because the PI controller will subsequently adjust choke opening slightly down to account for this change.

Since the simulator did not allow doing an actual connection there are some elements regarding the connection procedure that are not accounted for, one of the most critical being the standpipe bleed off. In the literature study figure 10 shows a pressure drop due to stand pipe bleed, this pressure drop was measured to be in the 300-400 psi range, meaning that the exclusion of this element potentially could make the phase 1 go out of bounds if this was to be included in the simulation.

Regarding the fact that a new stand is never connected, one can question the accuracy of the phase 2 pressure graphs, due to an added section of pipe there would have been a minor increase in friction, however this friction would be from internal drill pipe walls so most likely the increase in friction pressure drop would be of insignificant magnitude. Although the friction pressure drop most likely would have been very small, one aspect that could throw off the pump schemes is the increase in flow path. The extra flow path would potentially require the start of phase 2 to be pushed back slightly, but there is no reason to assume that this would impact downhole pressure behavior greatly.

Due to the iterative nature of the experiment, the time spent on connections is significantly shorter than what the literature study shows is the case in troublesome wells. The literature study shows connections taking up to 40 minutes to complete, the most time consuming simulation done in the case study lasted roughly 13 minutes so if the simulations were run for a longer duration, it is possible that fluctuations could be smoothened out more. It was easy to spot that a longer ramp time correlated to less pressure fluctuations in phase 1 of the second scheme, however a similar correlation was hard to determine for phase 2.

The time spent on making the connection is estimated to be 180 seconds, this may be bit of an optimistic estimate due to not considering the potential need to slowly bleed of the standpipe pressure. This optimistic estimate in turn leads to less gel strength build up, and may compromise the validity of phase 2 pressure deviations.

Each simulation was done without having any cuttings in the annular, mainly due to cut down time spent per simulation. The implication of not having cuttings in the annular may reduce the accuracy of the pressure responses, because the fluid with cuttings suspended have slightly altered properties. The fact that mud with cuttings have a higher density would most likely not be a major issue in a steady state seeing as this is a slow process that will be regulated by choke. If simulation was run with cuttings present in annular it is possible that it would have had some effect on the mud viscosity and gel strength build up, especially in phase 2 where the gel strength properties are critical

4.7 Conclusion

Starting with scheme 1, this scheme performs within the industry specifications for the first phase if the ramp gradient is large, meaning that delta t is around 100 seconds long. The main issue of scheme 1 in phase 2 is the lack of a low initiating flowrate to break the gel strength without hitting a large pressure spike. Scheme 1 was discarded after more than 17 iterations, because no amount of change in ramp gradient or pump offset change would reduce the initial phase 2 pressure spike enough, it is still possible that this method could function if a fluid of lower gel strength build up properties was used.

Scheme 2 is the technique that allows for the highest amount of customization, and it is possibly the best suited method with safety contingency in mind, seeing as it allows for easy manual control with few rapid steps, rather than continuous regulation as would be the case in a gradient ascent/descent situation. Although the pressure spike tops are within specifications the fluctuations have a high frequency, this may be avoidable with a more sophisticated gain tuning method.

Scheme 3 show the best results in terms of having the smallest amount of pressure deviation compared to the second scheme. However, it was necessary to add rotation to get the third scheme within the pressure envelope, this ultimately means that the third scheme probably would not be suitable if a mud that has a more aggressive gel strength buildup were to be used.

In conclusion the second scheme seems to better regarding contingency, if transition to manual mode is required. Although the second scheme has a more unstable behavior than the third scheme, it has more headroom for a wider range of fluids and well paths considering the fact that scheme 2 was able to get within the industry standard specification without adding rotation to the drill string and at the same time spending 30 seconds less to complete phase 2 compared to scheme 3.

4.8 Further work recommendations

One way to get around the issue of increased BHP pressure in the well for the phase 2 ramp up could be to implement a feed forward into the PI controller, making it possible to predict the sudden pressure spike initiated by the breaking of mud gel.

This issue could potentially also be solved by having an algorithm that accounted for the increase in pressure after pump ramp up, and it would have needed to be calibrated using the results from fingerprinting.

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