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Limiting Factors for the Ability to Achieve Accurate Pressure Control in Long Wells

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Abstract

Extended-Reach Drilling (ERD) with narrow pressure margin or uncertain geo-pressure is a challenge with respect to accurate pressure control. The back-pressure Managed Pressure Drilling (MPD) method has been widely used in drilling operations with the aim of controlling annulus pressure within safe bounds, and may also be applicable for ERD wells. However, the ability to control the pressure accurately is limited by several factors. Some of which are related to back-pressure MPD operations in general and some of which are more specific to ERD wells. In this paper, a study is presented on how pressure control is affected and sometimes limited by the actual data availability and quality, equipment, hydraulic models, control algorithms, and downhole conditions during an MPD operation in an ERD well. By using a transient well flow model, the theoretically obtainable MPD performance can be simulated. The benefit by utilizing real-time downhole pressure measurements transmitted by a wired drill pipe is demonstrated by simulations. It is shown quantitatively how variations in delay of measurement and bandwidth will influence the ability to control downhole pressure accurately in an ERD well. Benefit by this approach is a more accurate prediction of what is obtainable with MPD and how various factors may influence the ability to control downhole pressure.

Keywords: Managed Pressure Drilling, Extended Reach Wells, Flow Modeling, Pressure Control

1 Introduction

Extended Reach Drilling (ERD) is defined as drilling wells with a horizontal length more than twice the vertical depth. As new drilling technologies and methods are introduced, together with improvements in drill bits, rotary steerable, mud systems and instrumentation, drilling an ERD well is often preferred to drilling a well from a template closer to the reservoir. In some reservoirs, especially those that are depleted, the pressure conditions are challenging since the window between fracture pressure on the high side and the pore or collapse pressure on the low may be very narrow. To improve pressure control while drilling in such reservoirs Managed Pressure Drilling (MPD) is often preferred to conventional drilling. MPD has become widely used the last decade and is often preferred to Underbalanced Drilling because of the cost and sometimes also available space on the rig, Hannegan and Fisher (2005). The most common MPD technique today is the so-called back-pressure MPD, Malloy et al. (2009) where a rotating control device seals around the drill pipe and the return flow is directed through a choke valve. By actively changing the opening of the choke valve, creating a back-pressure, the pressure in the entire wellbore will be changed rapidly compared to conventional drilling.

However, there are several challenges with MPD that are augmented and thus becoming more important in ERD wells compared to wells with short open hole sections:

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- Oil based or synthetic based mud is often preferred because of its high lubricant properties. However, these muds are highly compressible and thus complicate pressure control in long wells because of time delay and large pressure transients.
- There is a relatively long distance from downhole pressure sensor(s) to the zone which is most critical with respect to hole collapse, influx or lost circulation. Unless a wired drill pipe is used with along-string measurements, there may be several kilometers of open hole from the sensor to the weakest zone.
- Hole cleaning and wellbore stability are in general more challenging in long horizontal sections than in other wells. To maintain sufficient hole cleaning, the flow rate needs to be high enough to transport cuttings, which in turn causes larger pressure variations during connection.
- Transmission of downhole measurements through mud pulse telemetry suffers from low bandwidth, and typically becomes less reliable in long wells.
- Depending on the geothermal profile, heating of the mud may be significant in a long horizontal section during connection or during a long-time period with low or no circulation. This has a large impact on the ability to control pressure when resuming circulation since temperature affects both the density of the mud and the rheological properties.
- Estimation of downhole pressure is challenging. The above-mentioned effects can be modeled, but real-time calibration of the model is difficult because of the sparse information from downhole and the absence of steady-state conditions. In addition, other effects such as gelling, which are more difficult to calculate accurately, may have a larger impact in a long well.

Managed Pressure Drilling (MPD) is defined by the International Association of Drilling Contractors (IADC) as “an adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore. “The objectives of MPD are “to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly.”

However, the ability to control wellbore pressure “more precisely” for a specific drilling operation is limited by several factors. When planning and executing back-pressure MPD in long wells, it is important to know the limitations of what can be achieved in terms of accuracy and robustness for a given MPD setup. In this paper, we describe factors that influence pressure control during MPD in ERD wells, and point at some key challenges that need to be accounted for in the planning and execution of the operation. Three factors are then studied more detailed by simulations; changing the operating procedure when ramping pump during connection, delay in downhole pressure measurements, and sampling interval.

2 Factors that Influence Pressure Control

In this paper, we have categorized the factors in the following groups:

- Surface and downhole equipment
- Drilling mud
- Wellbore geometry
- Measurements
- Well flow models
- Downhole conditions
- Performance of operating procedures
- Pressure control method

2.1 Surface and downhole equipment

In general, neither the drilling equipment of a typical onshore or offshore rig nor the downhole tools are designed particularly for the purpose of MPD. As an example, a piston pump does not allow a smooth ramping down to zero flow rate, but usually a step from 5-6 strokes per minute to zero. This is a challenge for the MPD systems, since the rheological properties of the drilling mud result in a significant reduction of Equivalent Circulation Density (ECD) even for small rates, and must be compensated accurately by increase in back-pressure. Another example is the MPD choke valves where the design is not yet optimized with respect to MPD. There are challenges with the speed and accuracy of the chokes that highly affect the ability to control back pressure. In addition, downhole tools, such as hole openers and circulation subs, are also affecting the ability to control pressure since the influence on flow, and resulting in change in ECD, is not easily instrumented.

2.2 Drilling mud

In back-pressure MPD it is the change in pressure loss through the MPD choke which is used to actively increase or decrease the pressure in the entire wellbore. It is therefore important to understand the relation between the applied back-pressure at the choke and the corresponding pressure change in the well. For shorter wells, and when using drilling mud with low compressibility, a change in back pressure results in an almost immediate and equal change in downhole pressure. The pressure pulse travels with the speed of sound, which is a function of compressibility, and the pulse is attenuated by viscous forces. Also, the process related to viscosity-compression interaction, and moving of fluids during pressure changes, depends on the length of the well. For short wells with water based mud the transmission time is therefore relatively low compared to the time of e.g. ramping the main pump down before the connections. One can expect that any change in back pressure is directly transferable to the same change in downhole pressure. Downhole pressure can therefore be controlled using the anticipation that any change to surface pressure will give an immediate and equal change to downhole pressure. ERD wells are typically drilled with oil based or synthetic based mud (OBM/SBM) because of its lubrication capabilities, and reduced mechanical friction. Although low viscosity mud is preferred in long wells, and especially when the geo-pressure window is narrow, the ECD may be significant for long $8\frac{1}{2}$” sections and narrower. The combination of a drilling fluid with relatively high compressibility (like OBM/SBM) and a long well with high frictional pressure loss, results in long propagation time for pressure waves to travel through the well. This may be a challenge for accurate pressure control, especially if changes happen quickly (e.g. when loosing rig pump power or suction, or in case of twist-off or any sudden change that affects downhole pressure). Another issue with long wells, when using OBM/SBM, is the gelling properties of the mud (from additives, to prevent sagging) and the resulting pressure peak that occurs when resuming circulation. In practice, this effect is difficult to handle for the MPD system due to its complexity. However, well flow models that calculates pressure propagation when breaking circulation have been developed and might be useful in the MPD control system.

2.3 Wellbore geometry

A wide annulus gives lower velocity of the drilling mud and therefore lower friction pressure loss compared to a narrow annulus. Especially for ERD, where low viscosity mud is often used, this has some implications. ECD may be an issue in the 8 $\frac{1}{2}$ inch section or narrower, but moderate in a wide annulus. E.g. as low as two bar per 1.000 meter for a WARP mud in 13 3/8 inch casing. However, the lower end of the recommended operational range for the MPD choke may be as much as 20 bar. Therefore, when drilling a long 12 $\frac{1}{4}$ inch section, the back pressure may dominate the total friction pressure, and the uncertainty of the MPD pressure control will be of the same order as the pressure loss. On the other extreme are wells with narrow geometry over a long distance, for example through tubing drilled wells where around 10 bar per 1000 meter all the way up to the BOP has been seen. Then for a long well the difference between static and dynamic surface pressure may exceed 50 bar, and very accurate determination of well pressure is required to achieve the small requested downhole pressure variations.

2.4 Measurements

The performance of an MPD operation relies heavily on the measurements. However, it is important to understand that it is not only the quality of the data that is affecting pressure control, but also the placement of the sensors and the awareness of what is measured. These problems have been addressed in Cayeux et al. (2013).

One problem is that pump rate latency has a significant effect if pump rate is calculated from stroke count, especially at low pump rates. With strokes counted once each revolution it may take up to 24 seconds to record two consecutive strokes at 5 strokes per minute, which is a normal pump rate when starting pumps from zero. Figure 1 shows the actual measured flow rate and pump pressure from an MPD drilling operation. The result was that the choke opened too late, causing the 10 bar pressure increase seen in Figure 2.

There is a fairly simple way to remedy this problem by using the measurements of the rotational speed of the pump engine for calculation of flow rate rather than the stroke counter. It is important to be aware of this prior to the operation and plan for it. Alternatively Stand Pipe Pressure (SPP) could be used to detect pump start, but this is vulnerable to sensor failure and to changes in SPP from other causes, and SPP alone does not tell what the accurate pump rate is. In addition, problems with feeding mud to the suction side of the rig pump are seen from time to time. Actual flow rate through the rig pump may be less than the rate calculated from strokes or rotational speed of the pump engine, and either a flow meter or a robust use of SPP measurement is needed to handle this automatically.

Another problem is related to the hook load measurement which does not measure the weight at the top of string, which is the boundary for the torque &

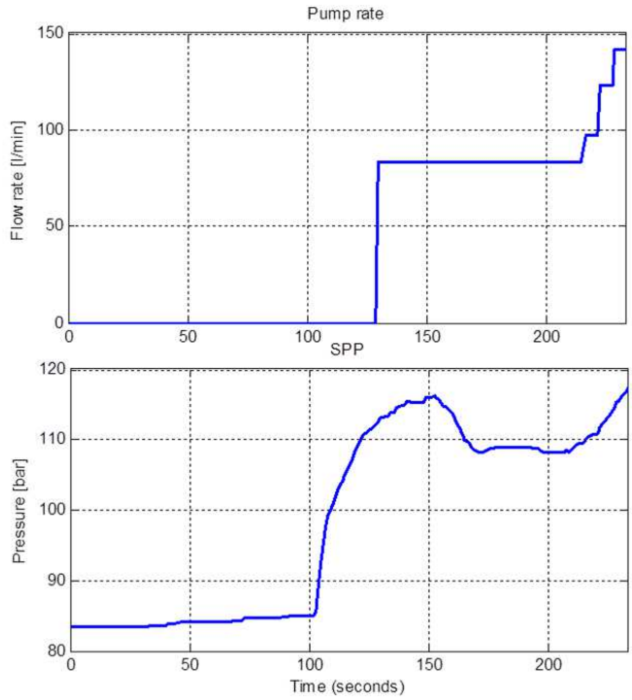

Figure 1: Measured flow rate and pump pressure when ramping up main pump. The pump started at the time when the increase in SPP started, but the pump rate signal was from strokes and therefore delayed.

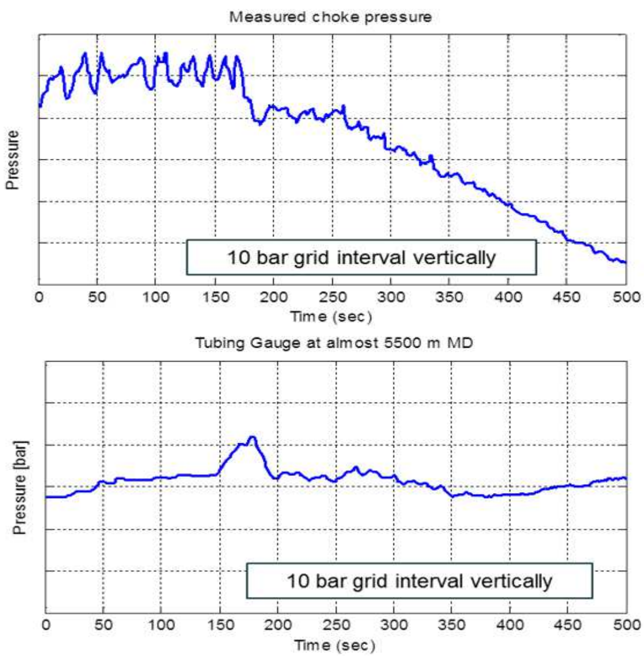

Figure 2: Measured choke pressure and downhole tubing pressure shortly above the open hole.

drag models, but the tension in the dead line anchor. This means that both sheave friction, weight of mud in pipe and weight and dynamic position of mud hose will change the measured hook load, based on the height of the top drive and the speed and direction of the lines.

2.4.1 Downhole measurements

Downhole pressure measurements using mud pulse telemetry for real time transfer to surface has its clear limitations:

- Data is only transferred when pumping above a threshold, and at a low bandwidth. This may be sufficient for adjusting pressure while drilling, but gives little help to accurate tuning of pressures during connections.
- It is possible with some tools to send a package with static pressure data (ESD) after the pumps have ramped up after connection. This may be very helpful, but also deceptive because it does not distinguish between a narrow peak and pressure being high or low over a longer time. Accordingly, it may be hard to determine the best adjustments. Also, such pressure data packages may be excluded due to lower priority than other data types, given the low bandwidth of mud pulse telemetry.
- Pressure sensors may drift or fail due to very harsh environments, and with one or two sensors the chance of this happening may be significant. Also, if one of two sensors drifts it may be difficult to tell which is correct.
- Mud pulse telemetry may be unreliable in long wells since the pressure pulses are more diffused than in shorter wells, and because of the higher compressibility in OBM/SBM that are commonly used in long wells.

Pressure measurements transmitted with wired pipe telemetry is more expensive in terms of direct cost, but remedies many of the problems listed above for pulse telemetry, especially if more than two downhole pressure sensors are used. Wired pipe telemetry adds the possibility of distributed sensors, which opens possibilities for

- More accurate control of pressure and drill string vibrations
- More accurate tuning of simulation models for downhole pressure, temperature and trill string mechanics
- More accurate and reliable detection of anomalies like kick, loss, pack-off, leakage, etc.

However, there is a risk of losing the wired telemetry, and then adequate fallback options will be needed in addition to traditional mud pulse, especially if in the middle of drilling a reservoir section. One option is to run a high fidelity real time model which is accurately calibrated to match wired pipe data, and let the model take over and serve as an artificial “sensor”.

2.4.2 Uncertainty in wellbore positioning

Another factor related to measurements during the drilling operation is that the actual wellbore position differs from the planned and estimated trajectory. The estimated wellbore position is derived from indirect measurements of the inclination, the azimuth and the length of the drill string at each measurement point. These angles and length measurements can be biased by systematic errors that can result in a miscalculation of the position of the well. An over or under estimation of the actual vertical depth of the well may introduce discrepancies in the estimation of the downhole pressure. A study has been performed on this topic by Lande (2013). From his conclusions “. . . Wellbore position uncertainty has been shown to have significant impact on the wellbore pressure, at least in longer wells. Magnitude of the experienced variations is systematic and a direct result of depth (TVD) uncertainty of the wellbore. Significance of pressure variations in shorter wells has not been discussed, however in longer and more complex wells with narrow pressure margins, these uncertainties will have to be considered.”

However, it should be noted that information collected during the drilling operation (e.g. from formation integrity tests, leak-off tests, pressure measurements and inflow checks) will have the same bias. The relative error may therefore be smaller than the absolute error, and thus have a positive effect on pressure control despite the error in wellbore position.

2.5 Well flow models

Accurate pressure control is an essential target for any MPD operation, and the accuracy of the results obtained by model simulations play a key role both in the planning and execution phase. In the planning phase, the intention is to predict if, and how, the pressure in the well can be maintained within the requested bounds given by the geo-pressure margins. The planned trajectory, string, bottom hole assembly (BHA), mud, and operational parameters are then used to predict the pressure profile during the different stages of the operation. Steady-state well flow models are typically used in this phase. In the execution phase, the drilling engineers will update these estimates based on the new information obtained during drilling and the actual choice of drilling parameters. Also at this stage steady-state models are typically used.

However, MPD needs to control pressure also during transient sequences. Fast changing pressure transients are caused by changes in flow rate or when changing string rotation or axial speed. Transients are also caused by unexpected impacts affecting the mud flow, such as twist-off, pack-off, plugging (typically bit nozzles or the back-pressure choke) or because of influx or lost circulation. Slower changes in the wellbore pressure are caused by operational changes in mud properties (density or rheology), temperature effects, the amount of cuttings in suspension, barite sag, building or erosion of cuttings beds and hole enlargement (by hole opener or unintended).

There are always unplanned changes in trajectory, tally, mud and operational parameters, and these changes may affect the pressure significantly, and also influence the ability to control pressure. In a work by Gravdal and Siahaan (2012) the most relevant factors that influence the annulus pressure are thoroughly described.

2.5.1 Configuration (Data gathering)

For all utilizations of well flow models the configuration of the models is critical. This has been emphasized e.g. in Toft (2013). Before running the model one needs to enter the trajectory, well geometry, tally and the mud properties. If any interaction with the formation is included in the model, the geo-pressure profiles and the geothermal temperature gradient are also needed. Some models also require description of the entire flow line on the rig to the mud pit. The number of parameters varies largely from the simpler models to the most advanced models.

For accurate pressure calculations it is important that the input is properly quality controlled. It should be stressed here that accurate fluid properties at surface and downhole conditions are very important, and it is recommended to make the best available data available for MPD vendors as part of any fluid delivery, and obtain accurate and timely measurements of inlet fluid properties.

2.5.2 Calibration of well flow models

Calibration of well flow models consists of changing (estimating) model parameters in such a way that one or several key output variables match the corresponding measurements. In practice, this is a very complicated task, since there are far more model parameters than measured variables, Bjørkevoll et al. (2010). Today, in commercial available software, the mandatory parameters that are estimated are:

- A fudge factor for the friction pressure loss in the drill string
- A fudge factor for the friction pressure loss in the annulus
- A possibility of tuning static pressure
- Linear weight of the drill pipe element
- Mechanical friction factor between drill pipe and wellbore.

In practice the parameters listed above need to be estimated during a steady state situation. Except for the friction pressure loss in the drill string the calibration is performed when the system is in a quasi-steady state situation since completely steady state is not obtainable during drilling, and especially not in ERD. Calibration can be done manually or automatically. Automatic calibration requires a way of detecting the right time where it is allowed to estimate model parameters.

2.5.3 Realistic model

When using well flow models in today's MPD operations one typically disregards the interaction between liquid flow and drill string mechanics, except for the surge and swab effects during axial movement and effects on frictional pressure loss from changes in Revolutions Per Minute (RPM). However, there are several effects that should be accounted for, in particular; drill string vibrations and dynamic eccentricity.

Better approximation of in situ (local) placement and movement of the drill pipe in the annulus has a large influence on well pressure. Today, one assumes homogeneous movement of the drill pipe from rig floor to the bit. If more realistic behavior is modeled, better estimates can be given on;

- Transition between laminar and turbulent flow.
- Friction pressure loss.
- Surge and swab pressures.
- Cuttings transport.

For long wells, the effect on downhole pressure may be significant when considering the highly compressible mud and the long drill string interacting with a long inclined well.

2.6 Downhole conditions

There are many physical processes that affect the ability to control pressure precisely. Some are related to the fact that the properties of the fluid(s) in the annulus are highly dynamic, and influenced by the surroundings. Others are related to changes in flow path caused by expected or unexpected events. Especially far away from any pressure sensor, these processes will affect the ability to achieve accurate pressure control. In addition, forward simulations will have less value if these processes are not modeled correctly. The processes that are most relevant are:

- Dynamic temperature
- Barite sag
- Cuttings transport
- Pack-off tendencies
- Lost circulation
- Kick
- Plugging
- Hardware failure (such as twist-off and leakages in valves)

Some of these processes are included in advanced flow models for real-time calculations, such as dynamic temperature, barite sag and cuttings transport. I addition flow models for kick and transport and mixing of formation fluids are available. These effects can therefore be accounted for to some extent. The other processes can also be modeled.

2.7 Performance of operating procedures

In addition to changes in pump rate and pressure changes because of movements in drill string there are several other operating procedures that need to be handled by the MPD system and that requires special precautions.

2.7.1 Running liners and cementing

Running liner and cementing is normally done without downhole pressure readings, and although model calculations have been accurately tuned while drilling and circulating, this may the reduce accuracy of for several reasons:

- String geometry is normally very different from the geometry of the drilling string.
- The fluid in the well may not be the same when breaking circulation with the liner in the hole as when drilling the hole.

- Even with the same fluid its properties are more uncertain and probably less homogeneous now because the fluid has been static for a long time.
- The temperature profile is different after the long static period.
- Displacements are always uncertain because the new fluid has not been circulated down the well for a long time.
- Knowledge of fluid properties at downhole conditions for spacer and cement is normally very inaccurate.

In addition, large pressure spikes are seen when pumping balls and darts for various purposes:

- Release running tool
- Set liner-hangers
- Track cement front and end
- Set liner-packer.

Many of these spikes are large compared to given pressure boundaries for the MPD operation, and may damage the formation. The short duration of the peaks helps. When landing the dart or ball following the cement flow will stop immediately into the annulus and sufficient pressure must be trapped quickly to avoid a long period in under-balance, Bjørkevoll et al. (2008). A way to reduce this effect is to ramp down pumps gradually as low as possible shortly before the flow stops.

2.7.2 Circulation of Lost Circulation Material (LCM)

The addition of LCM is made to strengthen the formation and thus prevent lost circulation, at the cost of adding extra challenges for the MPD system. It has been seen that the drilling fluid becomes more sticky and inhomogeneous after adding LCM, causing larger choke pressure fluctuations and problems with, for example, back-pressure pump after it has turned off a couple of hours filled with LCM contained drilling fluid. It is therefore recommended to consider tuning and testing with LCM particles added before drilling out of the shoe.

2.7.3 Fluid displacements

Accurate pressure control is challenged by the new fluid being inhomogeneous with properties different from target values. A deviation between measured and calculated static fluid pressure of about 10 bars has been observed, and required both good measurements and extra attention from operators throughout the displacement operation. Inexperienced operators may struggle with interpreting and handling a situation like this.

Frequent inlet density measurement during first part of displacement is recommended if continuous data from accurate sensors is not available.

2.8 Pressure control method

Back-pressure MPD can be performed by manual operation of the MPD choke, or automatic controlled choke by a control algorithm. Manual control has been used in the past but has its clear limitations because of the complexity of the system to be controlled, and the risk of human error. Today, MPD is therefore usually associated with automatic control. Different control strategies exist, usually dependent on the level of instrumentation, and the complexity of the well to be drilled. The details of the commercial available technologies are typically not published. To our knowledge only Proportional-Integral-Derivative (PID) control algorithms have been used commercially, with varying methods to define the back-pressure set point as described e.g. in Godhavn (2010), Saeed et al. (2012) and Reitsma and Couturier (2012). One of the most appealing features of PID control is its simplicity of structure and ease of implementation. However, a PID controller needs a good tuning of its parameters. Moreover, variation in the system requires the tuning being conducted from time to time since a typical good set of parameters only works on a certain drilling operation as the set tends to work well locally. Indeed, it is not surprising if the performance of closed loop system using PID worsens when there is a change in the dynamic properties of the well, such as tripping or connection, if the parameter is badly tuned. Many tuning approaches for PI/PID in drilling application has been reported in the literature. A mass-balance model which gives the relation among choke level, choke pressure and flow rates is used to tune the PID in Godhavn (2010). An internal model control design can also be used to tune the PI for well control situation, Carlsen et al. (2008). Another approach is by tuning the PI/PID based on data-driven measurement instead of a model, Siahaan et al. (2012).

2.9 Simulation case on uncertainties in sensor delay and bandwidth

To exemplify one of the limitations with back-pressure MPD in a long well, we focus on the uncertainties in sensor delay and bandwidth associated with downhole telemetry. The example also illustrates the effect

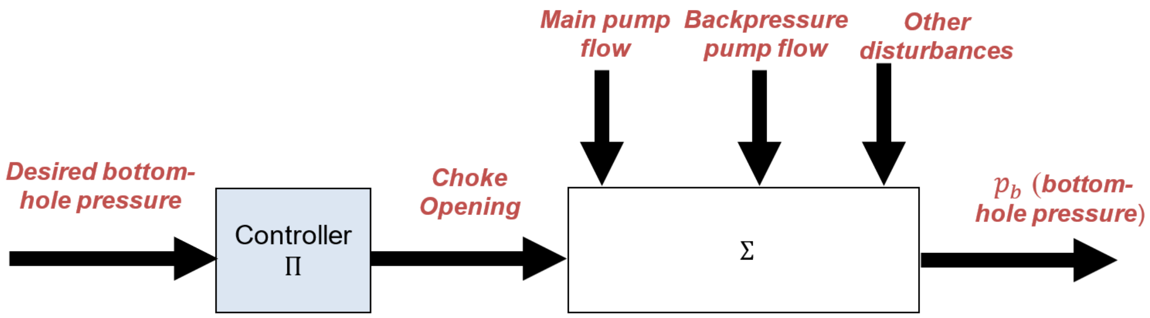

Figure 3: Controller structure for the connection phase during drilling.

of change in operational procedure (ramp down time) during connection.

We assume that downhole pressure measurements are transmitted through a wired drill pipe, which are typically seen as a promising enabler of improved pressure control during MPD. However, as the results show, it is important that the users are aware of the consequences of delay in measurements, and of the bandwidth capacity.

Table 1: Well geometry and fluid data.

Parameter	Value
Well length	6700 m
Casing inner diameter	$12\frac{13}{32}$ in
Drill string outer diameter	$5\frac{1}{2}$ in
Drill string inner diameter	$4\frac{25}{32}$ in
Oil density	0.805 sg
Water density	1.000 sg
High gravity density	4.200 sg
Oil-water ratio	3.160
Drilling fluid mixture density	1.670 sg

Simulations are carried out using the in-house well simulator WeMod, Lorentzen et al. (2014) and Lage et al. (2003), developed in IRIS. The simulator employs a drift flux model, Lorentzen and Fjelde (2005). Various simulation parameters which represent an offshore drilling operation in the Gyda field are shown in Table 1. The drilling fluid used in the simulations is an oil-based mud with density 1.53 sg with rheological data as shown in Table 2.

2.9.1 System Structure

We consider a representation described in Figure 3 for the connection in drilling with a typical controller structure. The representation describes the choke, the main pump flow, the backpressure pump and other variables affecting the pressure in the bit (p_b). Here, the choke is manipulated by a control system Π while the main pump flow and the backpressure pump flow are manually operated. The main pump flow and the backpressure pump flow are regarded as measured disturbances to the control system. The other variables are regarded as unmeasured disturbances. We divide the connection phase into two periods described as follows.

- The first period is during stopping the main pump flow from full rate into full stop. At the same time, the backpressure pump is ramped up until it reaches full rate accordingly.

- The second period is during starting up the main pump flow into full rate, while at the same time, stopping the backpressure pump from full rate into full stop accordingly.

In this paper, we only present simulation results for the first period as we want to focus on the role of feedback and feedforward control in MPD instead of the problem of control design. We therefore assume that we have done control design beforehand. Our study is to investigate the role of uncertainties which degrade control performance and how to suppress the effect of uncertainties in a better way. Throughout the simulations, the aim of controller is to maintain the bit pressure p_b around the set-point $r_b = 700$ bar.

2.9.2 Feedback (PI Control) for Connection Phase

To get a better insight, we perform various simulations with PI feedback control using a set of controller parameters. This set of parameters is chosen such that it gives the best response of the bottom-hole pressure from exhaustive simulations of different sets of parameters. This set of controller parameter is referred to as nominal parameters, unless otherwise stated. The problem of obtaining good PI parameters is not discussed for this occasion. The literature on tuning

Table 2: Stress from Fann reading.

Temp (°C)	Press (bar)	Stress at 3 rpm (lb/100 ft^2)	Stress at 6 rpm (lb/100 ft^2)	Stress at 30 rpm (lb/100 ft^2)	Stress at 60 rpm (lb/100 ft^2)	Stress at 100 rpm (lb/100 ft^2)	Stress at 200 rpm (lb/100 ft^2)	Stress at 300 rpm (lb/100 ft^2)	Stress at 600 rpm (lb/100 ft^2)
20.00	1.0	5.6	8.7	14.3	20.0	27.0	37.9	53.4	78.5
20.00	300.0	6.1	8.9	15.8	20.9	28.9	39.1	56.3	82.0
20.00	600.0	6.5	9.4	16.5	21.7	29.7	40.1	57.7	83.9
80.00	1.0	2.6	3.8	6.2	8.6	11.3	15.6	19.4	31.4
80.00	300.0	3.1	4.4	7.5	9.8	13.1	17.1	22.1	34.7
80.00	600.0	3.4	4.8	8.1	10.5	13.9	17.9	23.4	36.3
160.0	1.0	1.4	2.3	3.7	5.1	6.7	8.9	9.8	17.1
160.0	300.0	1.8	2.8	4.7	6.2	8.3	10.3	12.1	19.8
160.0	600.0	2.0	3.1	5.2	6.8	9.0	11.0	13.2	21.1

the PI parameters is very extensive. However, it remains an open problem which method is best suited for drilling applications. In this paper, the good parameters are obtained by exhaustive simulations.

As shown in Figure 4 the response is better for longer period of ramping down the main pump. The overshoots in the pressure response occur after the flow rate starts to change and after the flow rate comes in full stop.

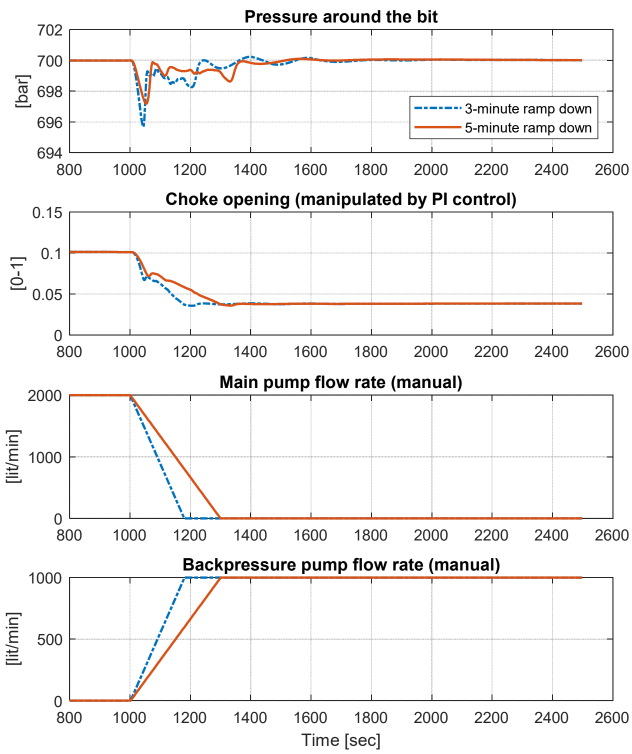

Figure 4: Pressure response while stopping the mud circulation.

For the next simulation, we try a softer change of flow rate in the beginning and in the end of stopping the circulation. Here, softer means that the flow is smoothly and slowly decreased during the beginning and the end. The flow is decreased with maximum rate during the period in between. The result in Figure 5 using softer change of flow rate shows that the overshoot in the beginning is improving, but it is worsening in the end.

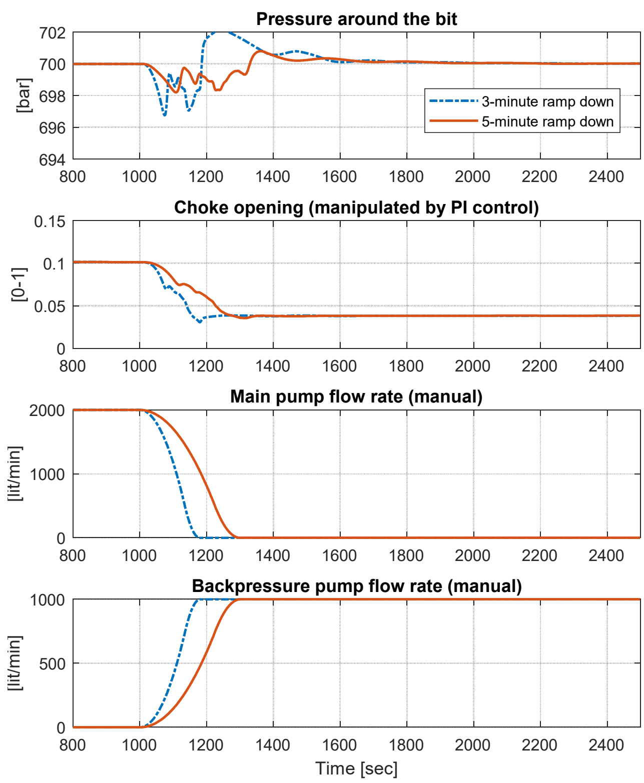

Figure 5: Pressure response while stopping the mud circulation with soft changes in the beginning and in the end of stopping circulation.

This result brings us to the next simulation where we impose softer change in the beginning, while we keep the rate at maximum until it is full stop. The

Figure 6: Pressure response while stopping the mud circulation with soft changes in the beginning of stopping circulation.

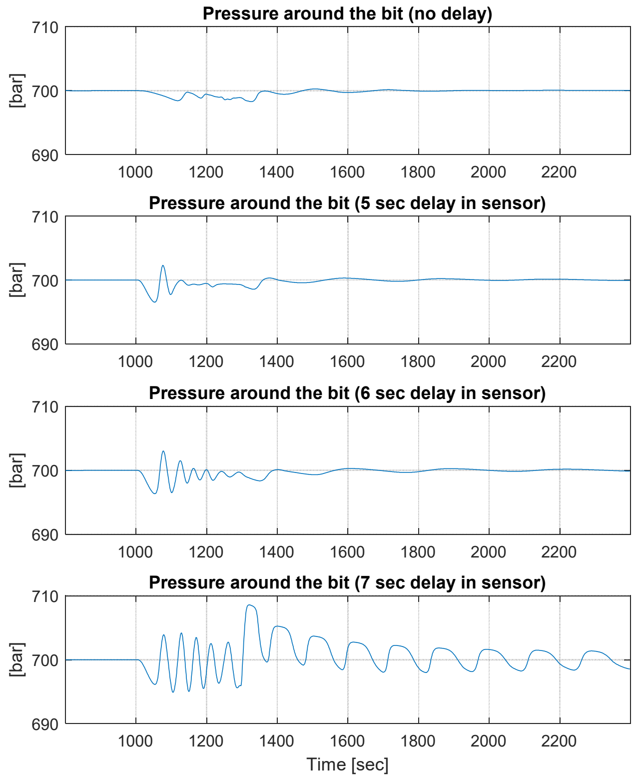

Figure 7: Pressure response due to delay in measurement.

result in Figure 6 shows that this strategy is better than presented in Figure 4 and Figure 5.

So far, the controller has to control p_b and manages to keep a small margin of deviation (+/- 3 bars) from the set-point r_b. This PI controller parameter is referred to as nominal parameter. In the following, we will see how a certain type of uncertainty can affect the performance. We use the PI and the scheme related to Figure 6 with ramping down the main pump in 5 minutes as our default control structure for simulation with uncertainty.

2.9.3 Delay in Sensor

Here, we include a class of uncertainty in the sensor where the measurement of bottom-hole pressure to the default control structure is delayed for some reason. For wired pipe telemetry there is no latency in the transmission in the drill string itself, but latency may occur in the data gathering and distribution at the rig. This will indeed affect the PI as it reacts with respect to the history of pressure instead of current state of pressure. For delay of less than 5 seconds, the PI control can still maintain satisfactory performance. However, for delay of more than 5 seconds, the response of the bottom hole pressure exceeds the margin of +/- 3 bars and starts to oscillate, as shown in Figure 7.

2.9.4 Sensor Bandwidth

Another type of uncertainty from the sensor is due to bandwidth capacity. As the wellbore length is increasing, the bandwidth can be lower which means that the pressure measurement is updated less frequently (longer sampling time). In all of our previous simulations, the control structure receives measurement update from the sensor every one second (sampling time of one second). Here, we simulate the response of the bottom-hole pressure for different sampling rates. Figure 8 shows that there is little effect of longer sampling time when there is no delay in the sensor. However, when we include transmission delay, even one second different in sampling time affects the response considerably, Figure 9.

2.9.5 Robust Feedback Controller

Uncertainties can degrade the performance of a feedback controller. Indeed, feedback control system can be designed such that it achieves a small margin of deviation from the set-point of the bottom-hole pres-

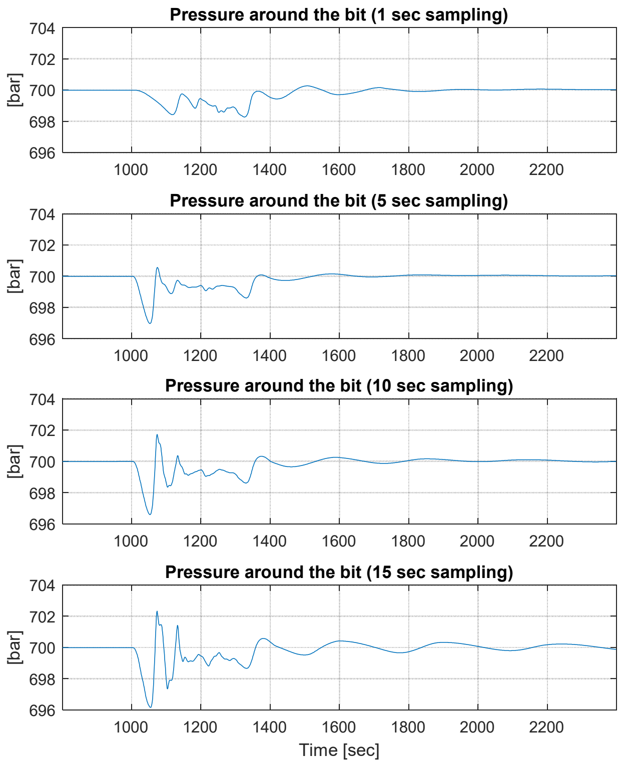

Figure 8: Pressure response due to different sampling times.

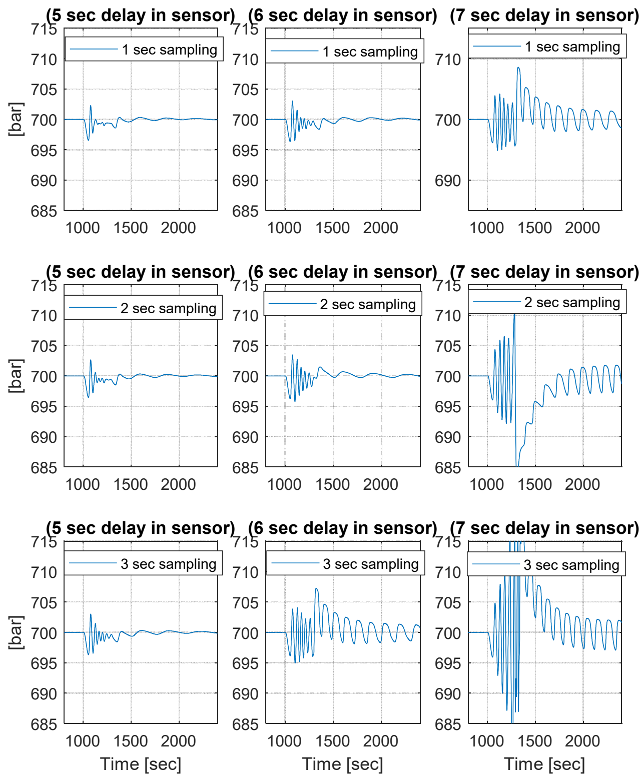

Figure 9: Pressure response due to delay in measurement and different sampling times.

sure. However, it is important to realize that, in reality, drilling operations are subject to a more severe uncertainty than the type of uncertainty shown in this paper. A control system which is designed to achieve as close as possible to the set-point might be fragile towards uncertainty which is not captured during the design and the test of the control system in a simulator platform. Therefore, design of a feedback controller which is robust towards uncertainties should also be taken into account. The performance of a robust feedback controller in a ‘world free of uncertainty’ might not be as good as the original one using nominal parameters which can bring the smallest margin of deviation of the bottom-hole pressure from the set-point, but it can suppress the effect of uncertainty better.

As an example, consider another set of PI parameters which gives worse performance than the original one (nominal parameters) when there is no uncertainty, Figure 10. The PI control using nominal parameters can bring the bottom-hole pressure within the margin of less than 2 bars from the set-point while the other parameters (call it robust parameters) drives the bottom-hole pressure up to 5 bars from the set-point. Next, we perform similar simulations like in Figure 9 where we use the robust parameters. Figure 11 shows that although the robust parameters perform worse when there is no uncertainty, they are better for handling delay and longer sampling time. The pressure response is much better than using nominal parameters.

It is important to point out that we need to take robustness into account whenever we design a feedback controller. Indeed, the performance of feedback control system can be pushed towards achieving a small margin of deviation from the set point of bottom-hole pressure. However, the resulting closed loop system can be fragile towards uncertainty. In this case, we should be aware about the tradeoff between tight performance and robustness. Moreover, in drilling, we are subject to a more severe uncertainty than the type of uncertainty shown in this paper. Therefore, a feedback control system which is claimed to be able to achieve pressure response within a very tight margin (for example, +/- 3 bars) still needs to be verified and tested against uncertainties.

2.10 Feedforward for Connection Phase

The performance of our designed feedback controller (PI control) can be improved further. So far, the controller must control p_b subject to all kind of disturbances. Though a feedback control can be robust

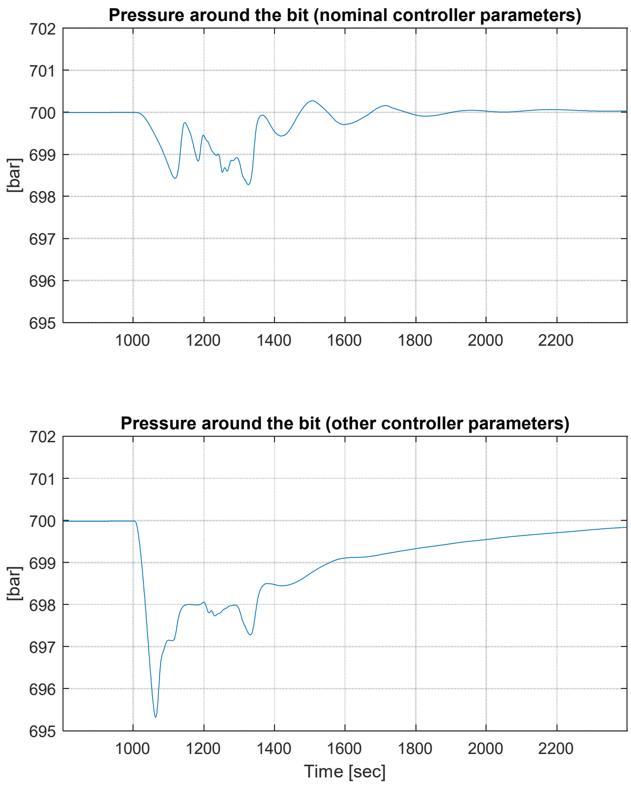

Figure 10: Pressure response using nominal and other (robust) controller parameters.

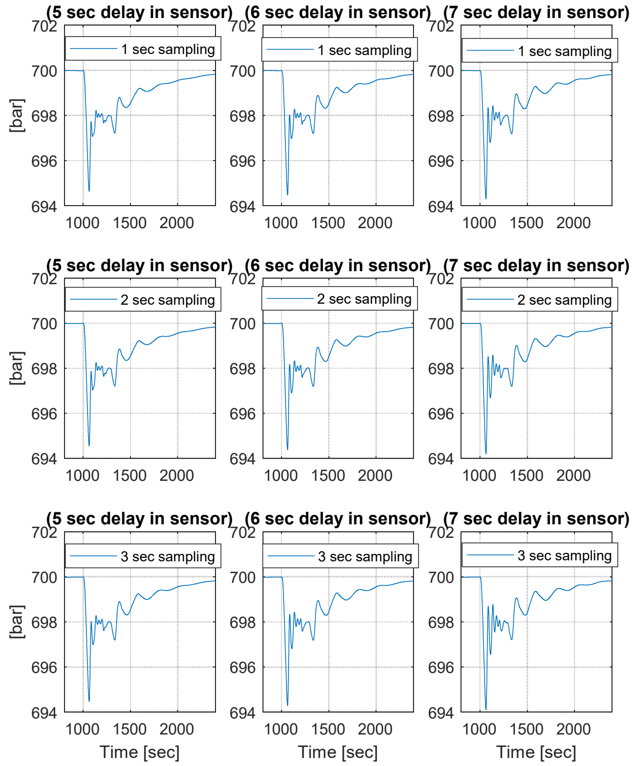

Figure 11: Pressure response which is robust w.r.t. delay in measurement and different sampling times (using other (robust) controller parameters).

against some disturbances if it is properly tuned, the performance can still degrade due to other class of disturbance. The more information we have about a class of disturbance (for example, the model of disturbance, the magnitude of expected disturbance, the stochastic property, etc.), the better we can enhance our controller performance by adding a feedforward term which has the information of the disturbance. In this case, we help the feedback controller to ease its burden to 'face' all sorts of disturbances.

As an example, we have access to the measured disturbances which are the main pump flow rate and the backpressure pump flow rate. We can benefit from this information to improve our controller performance by including the measured disturbances to our controller. This can be achieved by assigning

$$chokelevel = u_{PI} + u_{ff} \tag{1}$$

where u_{ff} is the feedforward term which accommodates the information from the measured disturbances. In this paper, we consider two classes of feedforward controller as illustrated in Figure 3:

- feedforward using static damping model
- feedforward using dynamic step response model

and compare both classes for our benchmark case.

2.10.1 Static Damping Model

Consider the choke equation which gives approximation to the flow rate through the choke given by

$$q_c \approx k_c z_c \sqrt{\frac{p_c}{\rho}}$$

where z_c is the level of choke opening which is in the range value between 0 (fully close) and 1 (fully open), p_c is the pressure drop along the choke, ρ is the density of the fluid and k_c is the choke constant. The feedforward given by

$$u_{ff} = \frac{q_c}{k_c \sqrt{\frac{p_c}{\rho}}}$$

is an estimate of the choke opening based on the choke equation. The feedback u_{PI} is then correcting the modeling error from the choke equation by correcting the mismatch between p_b and its set-point r_b.

The feedforward using static damping model needs information of the flow rate out of the choke (q_c). In case it is not available, we can approximate it by

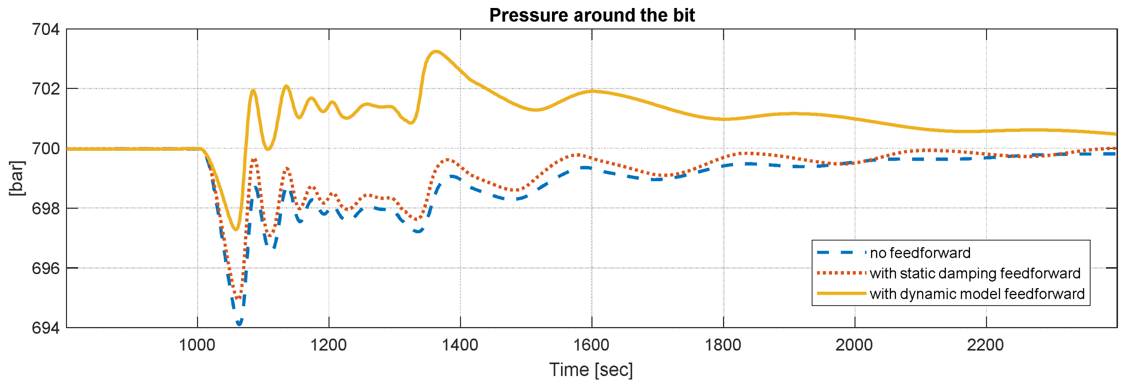

Figure 12: Pressure response with no feedforward and with feedforward (using robust controller parameters and subject to 7 sec measurement delays and 3 sec sampling time).

$$q_c \approx q_m + q_{bpp}$$

where q_m is the main pump flow rate and q_{bpp} is the backpressure pump flow rate. However, for a long well, this approximation can be misleading as there is a significant delay of q_m reaching the choke.

2.10.2 Dynamic Model

Alternatively, we can consider a dynamic model which describes the relation between the Controlled Variable (CV) and the Manipulated Variable (MV). There are different approaches to obtain a dynamic model, ranging from a simple first order linear differential equation to a complex nonlinear partial differential equation with empirical relations. In this paper, we consider first order linear differential equations as the dynamic model to be used for constructing the feedforward term. Consider the following model

$$p_b \approx G\,(d/dt)\, z_c + G_{d1}\,(d/dt)\, q_m + G_{d2}\,(d/dt)\, q_{bpp}$$

where d/dt is the differential operator. The model (G, G_{d1}, G_{d2}) is constructed based on the snapshot of data which represents the response of p_b due to the step changes in z_c, q_m and q_{bpp}. The feedforward is then given by

$$u_{ff} = -G^{-1}\left[G_{d1} q_m + G_{d2} q_{bpp}\right]$$

which is a cancelling effect of measured disturbances in the model. The closed loop is then given by

$$p_b \approx G\,(d/dt)\, u_{PI}$$

where the measured disturbances have been cancelled out. The two classes of feedforward are compared in simulation for 5-minute ramping down the main pump flow rate with 7 seconds delay in measurement and 3 seconds sampling time using robust controller parameters. Figure 12 shows the performance using the dynamic step response model is better than that using static damping model.

3 Conclusions

Back-pressure MPD in ERD wells is challenging compared to shorter wells and calls for special precautions. It is important to know the limitations of what can be achieved in terms of accuracy and robustness for a given MPD setup when planning and executing an operation. In this paper, we have systematically described important factors that influence the ability to control pressure precisely:

- Surface and downhole equipment
- Drilling mud
- Wellbore geometry
- Measurements
- Well flow models
- Downhole conditions
- Performance of operating procedures
- Pressure control method

It is important to understand that there are physical constraints on what can be achieved with respect to pressure control, and also the consequence if any of the factors above are changed.

By simulations we show the effect of using improved downhole instrumentation, through wired drill pipe, the effect of change in operational procedure (ramp down time) during connection, and the effect of choosing different choke control strategies.

Although the focus of this article is ERD wells, many of the factors that influence pressure control are related to back-pressure MPD in general and we hope the readers will find it useful also when planning non-ERD wells.

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Abbreviations

CBHP	Constant Bottom Hole Pressure
CCD	Continuous Circulation Device
CV	Controlled Variable
ECD	Equivalent Circulation Density
ERD	Extended Reach Drilling
ESD	Equivalent Static Density
LCM	Lost Circulation Material
LPM	Litres per Minute
MPD	Managed Pressure Drilling
MV	Manipulated Variable
OBM	Oil Based Mud
PI	Proportional Integral
PID	Proportional Integral Derivative
RCD	Rotating Control Device
RPM	Revolutions per Minute
SBM	Synthetic Based Mud
WBM	Water Based Mud

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