MODELING AND CONTROL EVALUATION OF MANAGED PRESSURE DRILLING OF OIL WELLS

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Abstract. *The drilling of oil wells involves basically the same technology since the 19th century. The fluid pumped through the interior of the drillpipes not only is responsible for bringing the cuttings to the surface, but it also compose the primary barrier against influxes from the well, and is responsible for stabilizing the walls of the open hole. The difference between the minimum and maximum pressure allowable for a given depth is called the operating window. Being the pressure in the well within the operating window, problems with influxes and hole stabilization are not expected. Some new oilfields as well as some depleted fields are experiencing severe operational restrictions due to small operational windows. The open hole pressure variation due to friction losses on the annular in some cases is greater than the operational window, inhibiting the perforation of the well. Managed Pressure Drilling (MPD) is an alternative technology to conventional drilling. In order to achieve proper control of surface pressure and downhole pressure, the modeling and control of the MPD system must be accurate and fast enough to face operational needs. Therefore, their evaluation is important to identify key points of this new technology, as detailed in this work*

Keywords: *MPD, Control, Modeling, Drilling*

1. INTRODUCTION

The oil well drilling is an activity performed worldwide. The characteristics of the formations crossed in the well trajectory define the minimum and maximum possible pressure at each depth of the well. The difference between the minimum pressure and maximum pressure required for a given depth is called operating window. Geomechanical studies and pore pressure estimates serve as a reference for setting the number of stages and the well coatings project.

Fragile formations or reservoirs with advanced depletion usually presents smaller operational windows for drilling. During drilling with conventional technology, the pressure in the well at each depth is defined as the sum of the hydrostatic pressure at the depth to the pressure losses seen from the depth up to the return on surface. During connections, the mud pumps aligned to the string are stopped and the friction losses on the annular eliminated. In some locations with narrow operating windows, the annular friction losses can be higher than the operational window preventing the continuation of drilling, without the isolation of the previous phases.

MPD technique - managed pressure drilling - allows controlling the pressure in the annular through a counterpressure on the surface. Adequate control of pressure in the annular well for different operational situations in order to compensate friction losses variation can permit drilling in locations with narrow operational windows.

This paper describes the development of a representative hydraulic model of a well that applies to MPD technique to a generic geometry. On the hydraulic model developed different forms of control were applied to evaluate performance.

2. DRILLING

The drilling of oil wells involves the same technology principle since the nineteenth century. The technology consists of a bit attached to a drillpipe (DP) and drilling fluid (mud) being pumped through the interior of the drillpipe, while weight and rotation are transmitted to the drillpipe. The fluid pumped through the interior of the drillpipe has several functions, including: to cool the bit; to carry cutting to the surface; stabilize the walls of the open hole; preventing unwanted inflows of formations exposed in open hole.

The stabilization of the walls of the open hole and prevention of influxes are due to the density of the mud. The fluid density is responsible for the hydrostatic pressure within the wellbore. The pressure within the open hole must prevent unwanted collapse and inflow without extrapolating the resistance of the formations exposed on the openhole.

Being the pressure in the openhole within the operating window, none of the problems mentioned should occur (Note: several other operational problems are possible, but they are not the focus of this work). A further difficulty with respect to maintaining pressure within the operating window in the well is the pressure variation with variation of flow rate. Each drillpipe connection (to be able to deepen the well) the mud pumps are turned off. Because of pressure losses in the well the annular pressure therein varies with the oscillation of the flow rate, this change alone may result in impossibility of continuing drilling in a minimum number of phases, or even the achievement of the objectives. The pressure at the bottom of the well is the sum of hydrostatic pressure with friction losses from the bottom to surface as per eq. 1:

$$P_{bottom} = P_{hydrostatic} + \Delta P_{friction-losses} \quad (1)$$

The extent of the phase of a well is dependent on the operating window and formations in the well trajectory. An oil well consists of several concentric phases. Each new phase of a well is drilled, for deepening the hole, and isolated with a casing (steel pipe that goes to the wellhead) or a liner (steel pipe that goes to the previous casing). The next phase is started with a smaller diameter than the inner diameter of the casing from the previous phase. This process is continued until the objective of the well is reached, or there is any technical infeasibility.

Figure 1 shows a schematic of drilling a new phase of the well. The term ECD corresponding to Equivalent Circulating Density:

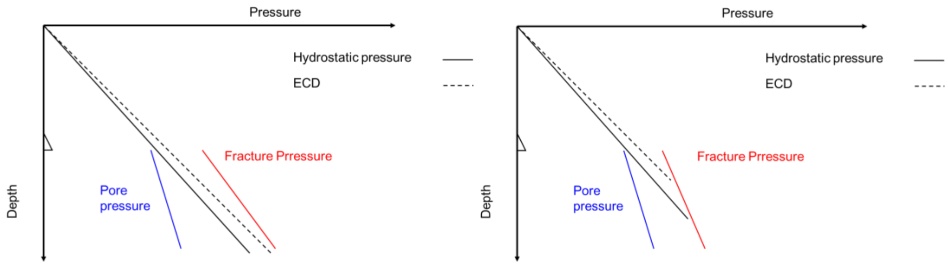

Figure 1: Normal operational window (left), Narrow operational window (right).

2.1 Managed Pressure Drilling

A new drilling possibility is the pressure confinement on surface. Thus, the pressure profile within the well can be manipulated not only by the density and rheology of the mud but with surface pressure also. The example with narrow operating window is repeated in Figure 2, in this case it can be observed that by manipulating the pressure on the surface it is possible to increase the length of the phase when compared to a well using conventional drilling technology.

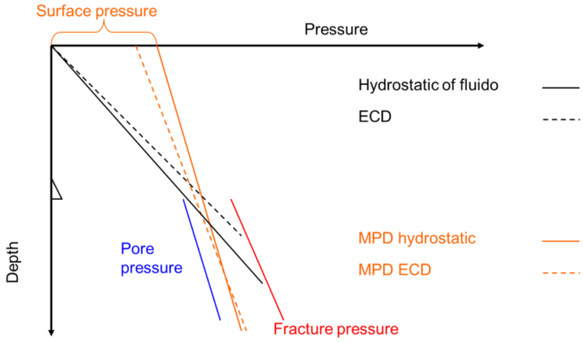

Figure 2 – Narrow operating window drilled with MPD.

Adequate control of pressure at the surface is made by the restriction of the flow at the return in surface. The drilling fluid is forced to a choke (flow restrictors), depending on the need for pressure in the well opening of the chokes will be changed. The pressure at the bottom becomes the sum of the hydrostatic pressure, friction losses in the annular and pressure on the surface:

$$P_{bottom} = P_{hydrostatic} + \Delta P_{friction-losses} + \Delta P_{choke} \quad (2)$$

The pressure control process is continuous throughout the drilling operation and critical to the success of the MPD technique. Since the error in the application at the correct pressure on the surface can remove the pressure inside the well from the operational window.

For adequate control of surface pressure, and the resulting pressure profile inside the well, two approaches are made: The first is the manual control of choke, where an operator directly drives the choke valve and thus varies the pressure in the bottom of the hole. This approach is simpler and still used in some onshore wells, but has been abandoned by the industry. The second approach makes use of an automatic controller for the choke position based on the operating situation. This approach is independent of the continuous attention and immediate operator response.

MPD allow the construction of wells with fewer phases, or allow scenarios with narrow or no operating windows to be drilled with fewer operational problems. Despite being a more complex operation, precise control of pressure in the annular allows the reduction and even elimination of time wasted in loss control and well control event.

3. Hydraulic Model

In order to evaluate the dynamics of well with MPD a hydraulic model must be used. As seen on eq. (2) the MPD have a new component when compared to conventional drilling, eq. (1). In order to determine the pressure required at the choke the dynamic of all components from eq. (2) must be known.

3.1 Hydrostatic pressure

The hydrostatic pressure is a direct function of the density of the drilling fluid. H being the vertical depth, g the gravity acceleration and ρ the density of the fluid, the hydrostatic pressure in a vertical depth H is defined as:

$$P_{Hydrostatic} = \rho * g * H \tag{3}$$

3.2 Friction losses

The calculation of friction losses, pressure drop, depends on the fluid characteristics, flow rate, and geometry of the flow path. Several correlations and methods are available in the literature to calculate friction losses. Scheid et al, 2009, indicate which equations better comply for the calculation of friction losses on a well profile.

Drilling mud behavior in most of cases cannot be described as Newtonian fluid. Fluids used in well drilling in many cases are chemical compounds that have different compositions for different wells. It is common the preparation of mud to be done onsite, having different properties for each phase of the well and the exposed formations in each phase. In this way, different fluids used in drilling may have different rheological behavior, and there are several rheological models used to describe the behavior of drilling fluids.

Two drilling fluid models that are vastly used on offshore drilling are the Newtonian fluids (initial phases) and Power law model fluid. To calculate the friction losses of these fluids it is necessary to determine the flow regime.

The flow regime of the fluid can be laminar or turbulent. The determination of the flow regime in the system is done using Reynolds number. The Reynolds number (Re) is a dimensionless number that correlates the viscous forces to inertial forces:

$$Re = \frac{\rho d \bar{v}}{\mu} \tag{4}$$

where ρ is the density of the fluid, d the size of the flow channel, $\bar{v}$ the average flow velocity, and μ the dynamic viscosity. For fluids better described by the Power Law model the calculation of the Reynolds number follows:

$$Re_{POW} = \frac{8 d^{n} v^{(2-n)} \rho}{K\left[\frac{2(3n+1)^{n}}{n}\right]} \tag{5}$$

where K is the flow consistency index and n is the flow behavior index.

In smooth pipes, Bourgoyne et al 1986 states that for flows with a Reynolds numbers lesser or equal to 2100 the flow will be laminar. Values of Reynolds number above 2100 and smaller than 4000 are considered to be in transient flow regime, while values higher than 4000 are considered turbulent flow regime. A simplification considered in the hydraulic modeling is that for Reynolds numbers inferior than 2100 flow will be considered Laminar and for higher values the flow is assumed to be turbulent.

The determination of the flow regime is important for determining the friction factor and the calculation of the pressure drop in the well pipes. Assuming a model without loss of fluid along the flow path, the flow rate in all sessions will be the same. The variation of the dimensions on the flow path will change the average speeds of each session. Consequently, the Reynolds number of each session can also differ generating different linear friction losses for each session.

To the interior of the drillpipe and BHA (Bottom Hole Assembly) the main dimension is the inner diameter of the pipe. In the annular the calculation of the hydraulic diameter is based on the outer diameter of the pipe and BHA and the inner diameter of the open hole, casing or drilling riser,

$$d_H = 0{,}816 * (d_{int} - d_{out}) \tag{6}$$

where d_h is the hydraulic diameter, the outer diameter of the drillpipe or the bottom hole assembly (BHA) is d_{out} ,in the section and d_{int} is the internal diameter of the casing, open hole or riser of the section.

With the Reynolds number defined for each section it is possible to define the flow regime and the calculation method for the friction factor that is dependent on the type of fluid.

For a laminar flow the friction factor is given by eq. (7) for the Newtonian and Power Law models.

$$f = \frac{16}{Re} \tag{7}$$

For turbulent flow regime the friction factor for the fluid power law considers the eq. (8):

$$f = 0{,}069 n^{2/3} Re^{-0{,}235} \tag{8}$$

To calculate the friction factor to the Newtonian fluid type in turbulent flow, it is used a recursive model based on the Colebrook equation. It is necessary a few iterations to determine the value of friction factor as per eq. (9),

$$\frac{1}{\sqrt{f}} = -1{,}73716 log\left(\frac{\frac{\varepsilon}{d_h}}{3{,}7} + \frac{1{,}255}{Re\sqrt{f}}\right) \tag{9}$$

whereε is the roughness of the pipe / casing and d_H the hydraulic diameter of the pipe, as shown in eq. (6). For the fluid models analyzed the calculation of pressure drop (Δp) is determined by eq. (10), interior of the drill string and (11) annular:

$$\Delta p = 2f\rho v^2 \frac{l}{d} \tag{10}$$

$$\Delta p = 2f\rho v^2 l/d_H \tag{11}$$

The fluid pumped inside the column passes through the bit nozzles before heading to the annular of well. As the nozzles produce an abrupt change in the cross section of flow, that ends up generating a localized pressure drop. The pressure drop calculation in bit nozzles is given by the eq. (12a):

$$P_b = \frac{MW * Q^2}{12032 * (A_n)^2} \tag{12a}$$

where P_b corresponds to pressure drop in the bit nozzles (MW) corresponds to the fluid density (Q) by the flow jets and the drill (A_n) the passage area of the drill jets. It is worth noting that the units considered in the formula are English units (psi, ppg, gpm and in² respectively) units used by most of the oil industry. For its application with SI units, the correction factor needs to be adjusted.

$$P_b = \frac{0.501 * MW * Q^2}{{A_n}^2} \tag{12b}$$

The choke for the MPD system is a variable flow restrictor installed downstream the flowline. The function of the MPD choke is to generate a pressure drop in the return from the well with the objective of changing the pressure profile of the annular.

The flow restrictor considered as a reference for modeling the choke is the pressure loss model for flow through orifices on a short tube, Jelali and Kroll 2003. Another model for choke, which would require no adjustment, would be a butterfly valve. The problem of butterfly valve is the accumulation of cuttings at the valve when it is used a MPD choke, Sharma et al, 2015. The accumulation of cuttings bring operational problems and difficulties on the proper pressure control. In this way, the butterfly valve is not being used as a choke for MPD applications.

In general, a choke flow will follow:

$$Q = \alpha_d A \sqrt{\frac{2}{\rho}\Delta p} \tag{13}$$

where Q is the flow by choke, α_d is the discharge coefficient, A is the area of passage of the choke, ρ is the density of the fluid and Δp pressure drop located in the choke. Rearranging eq. (13):

$$\Delta p = \frac{Q^2 \rho}{2\alpha_d^2 A^2} \tag{14}$$

The defining characteristic of a choke is the reaction of the discharge coefficient with the flow. Equation (15) describes the discharge coefficient for orifices on a short tube with the dimensions of a MPD choke.

$$\alpha_d = \left(2{,}28 + 64\frac{2L}{d_0 d}\right)^{-1/2} for\ \frac{d_0 d}{2L} \leq 50 \tag{15}$$

Where d is the pipe diameter, d_0 orifice diameter and L is the length of the orifice in the flow direction. The choke considered for the inner diameter, d, of 4 inches and thickness of 0.5 inch. Even in the fully open choke condition the relationship between $\frac{d_0 d}{2L}$ always remain below 50. It is worth noting that eq. (15) is indicated for Reynolds number greater than 80. As the drilling flow rates do not usually operate below this Reynolds number range (except during transient stop and acceleration bombs) the choke will only consider the discharge coefficient described by equation (15).

Another option would be to arrange the curve of the flow coefficient of the valve. Ideally, when considering the application of a MPD choke, the knowledge of the choke discharge coefficient or flow coefficient would be beneficial to the control strategy. As it can be seen on figure (3) the pressure drop for a fixed flow rate on a choke is not linear with the opening of the choke.

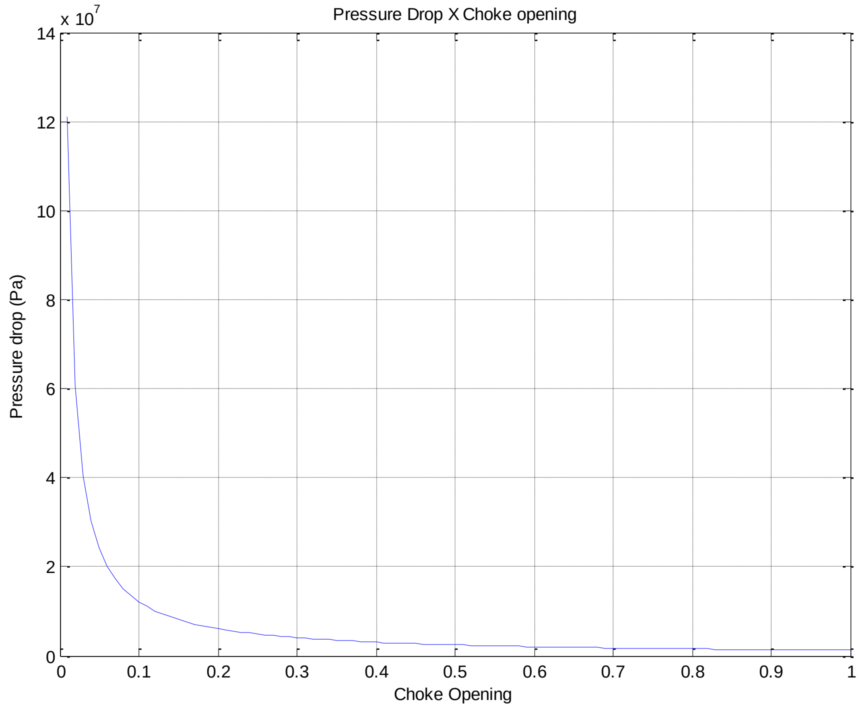

Figure (3) - pressure drop for various openings of the modeled choke with fixed flow rate.

3.3 Simplified hydraulic model

Known the factors necessary to calculate the pressure at any well depth it is possible to mount a simplified model of MPD control. Based on the desired pressure in the chosen depth, the controller must adjust the opening of the choke so that the surface pressure reaches the required pressure. Equation (16) shows how to obtain the required pressure on the surface.

$$P_{surface} = P_{required\ pressure@depth} - P_{hydrostatic} - \Delta P_{friction\ depth-Surface} \quad (16)$$

For this model the adjustment of the choke depends on the rheology of the fluid and the flow rate. Considering no variation on the rheology of the fluid, the friction losses will be function of the flow rate and choke position.

As the compressibility phenomenon is ignored, flow rate variation at the input is propagated instantaneously throughout the system and the pressure drop at is propagated directly to the variation of the input flow. For this scenario, a variation of the choke position cause a localized pressure drop change and a variation on the pressure at the fluid from the system at the same time. These considerations leads to the assumption that the responses in the model are instantaneous with the variation of the choke and the change in flow rate.

3.4 Dynamic Hydraulic Model

Landet et al 2012, described a discretized simulation model for a hydraulic transmission line, where the dynamics on the fluid due to the compressibility are considered. For every control volume it is considered the flow in, flow out and the average pressure inside. Two differential equations are obtained for every control volume:

$$\dot{p}_i = \frac{\beta_i}{A_i l_i}(q_{i-1} - q_i) \quad (17)$$

$$\dot{q}_i = \frac{A_i}{l_i \rho_i}(p_i - p_{i+1}) - \frac{F_i A_i}{\rho_i l_i} + A_i g \frac{\Delta h_i}{l_i} \quad (18)$$

where *i* is the index regarding the control volume number *i*, $\dot{p}_i$ is the pressure variation with time, β_i is the bulk modulus, *q* is the flow rate, A_i is the area of the section, l_i the length, ρ_i is the density, F_i are the friction losses in the control volume, *g* gravity acceleration, Δh_i is variation of vertical depth of the control section and $\dot{q}_i$ the flow rate variation with time.

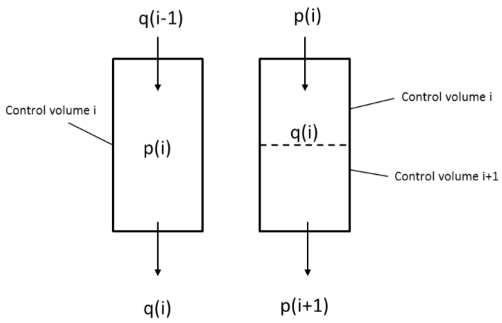

Figure (4) – Control volumes.

4. Control and Results

Before applying a controller on the hydraulic model it is interesting to analyze the model behavior for different stimulations. The inputs of the hydraulic model are the flow rate from the mud pumps and the choke opening position. The mud pumps of an offshore drilling rig can reach 1600 kW in power, requiring large spaces and energy supply. To control the pressure of the annular with the use of an additional control pump brings the inconvenient of limited variation of pressure due to friction losses and the limitation of BHA tools. An alternative to change the flow through the MPD choke would be an auxiliary pump, smaller than the mud pumps, which could pump to a surface circuit intended to change the flow at the system output and consequently change the pressure drop located in the choke. This option is used in some onshore wells with MPD, but in offshore rigs this option is not applied, as the booster line can replace the control pup, without the need of changes to the layout and rig equipment. The skid of the MPD choke already contains the hydraulic actuators, not requiring additional space for system installation. By generating a localized pressure drop, a small change in the opening of the choke impacts the whole pressure profile of the well.

With that considered, the control of the annular pressure from the well is concentrated on the opening and closing of the MPD choke. The first stimulus simulated was a step input on the choke position from open position 100% to half its stroke (50%). As it can be seen on figure (5) the pressure from the control point (first control volume of the annular, BHA-CASING) does not rise immediately. It can also be noted that the flow is momentarily reduced, in particular in the riser annular, last control volume of the annular (DP-RISER). This fact is explained by the compressibility of the fluid as the pressure generated in the choke is not immediately transmitted to the rest of the system.

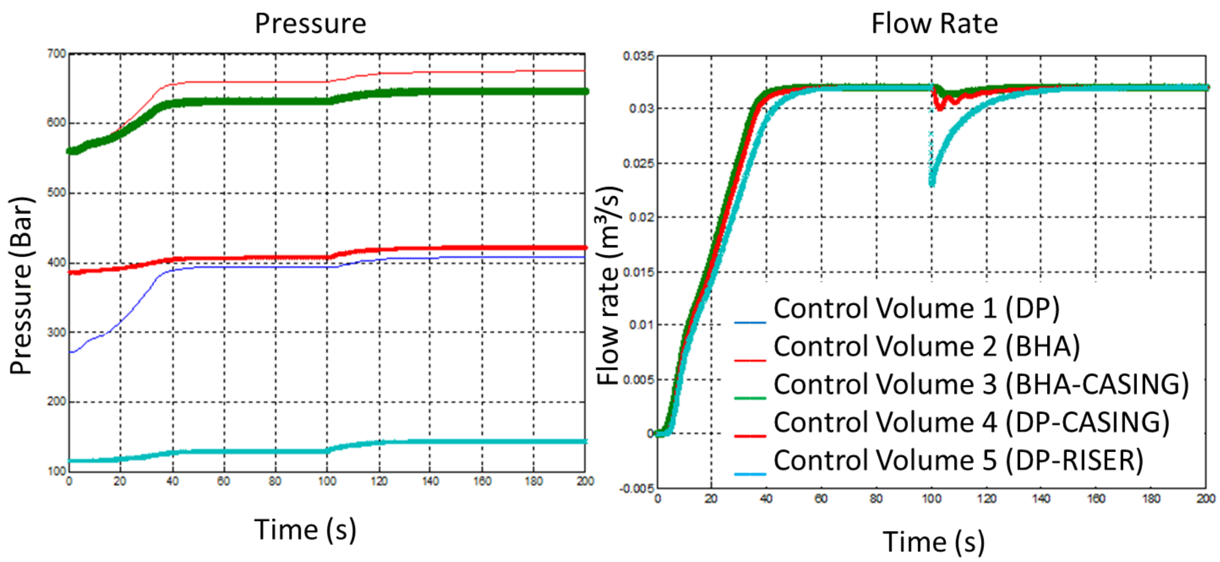

Figure (5) – System pressure (left) and flow (right) reaction to step input on choke position.

The second step in the system observation in open loop was applying a stimulus in form of sinusoidal wave for various frequencies. The range of frequency analyzed considered the practical operating range of a choke. A hydraulic choke cannot provide stimulation at high frequencies, then frequencies higher than 1 Hz were not analyzed. Frequencies lower than 0,001 Hz were not analyzed because of reaction time required for a drilling operation. 3 choke variation amplitudes were simulated for observation of the response, in order to check the impact of the non-linearity of the opening of the choke with localized pressure drop. Through the data it is possible to make a frequency analysis of the phase and amplitude of the system response.

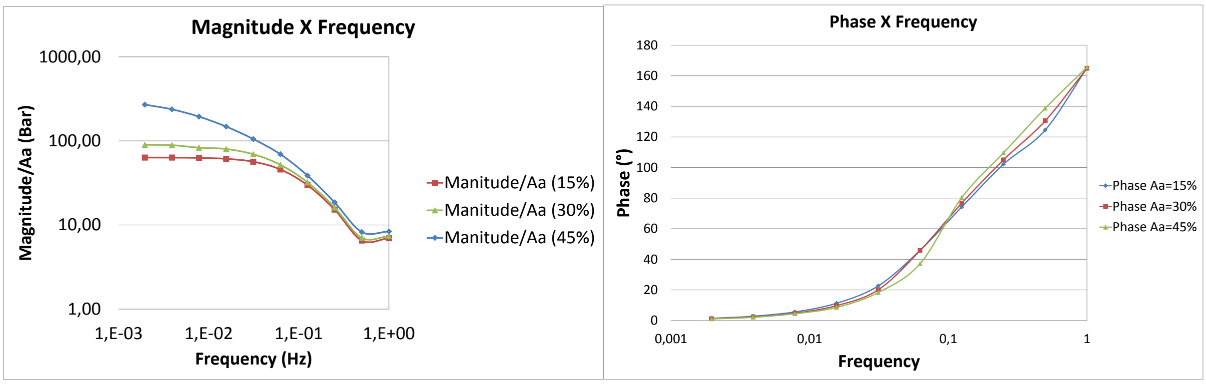

Figure (6) – Frequency amplitude response (left) and frequency phase response (right).

As seen on figure (6), where A is the percent choke variation around 50% of opening, the system does not present a linear response. Even with small amplitudes variations on the choke (linear range from choke actuation to pressure drop), the system does not present a first order behavior.

A PD controller was applied to the choke to verify its performance in controlling the bottom hole pressure. It is worth noting that although not a linear system, the PI controller or PID controllers are the most used among the MPD choke service providers. As the control progressively actuates in the opening and closing of the choke, the controller have an integrative effect on the response. If this was not the case, the moment the choke pressure reached the setpoint pressure the error would be zero, and the choke would shut or open entirely, changing the operational status and diverting the pressure at the bottom hole from the reference pressure.

Two sets of simulations were performed with the PD controller. The first simulation considered friction losses calculated based on the dynamics of the well and changes in flow due to choke actuation. The second simulation considers the calculation of the friction losses in the system based on the flow rate of the pump, disregarding the system dynamics. The change in the calculated friction losses affects the calculation of the surface pressure required to the bottom hole pressure achieve reference pressure. The simulations consists in an increase in the reference pressure (23 bar) at time 100s in an offshore well with the following characteristics: 4700m of drillpipe (ID = 4.63 "/ OD = 5.5"), 300m BHA (ID = 3 "/ OD = 8"), water depth of 2000m (riser with ID = 19.25 ") and 3000m casing 9-7 / 8" (ID = 8.6 "), using an Oil base mud (Power Law Model).

As seen in figures (7A) and (7B) the disregard of the flow dynamics in the system causes a delay in the controller response and consequently a worse performance of the same, as the pressure at the bottom takes longer to reach its reference pressure, using the same gains for the controller. One way to mitigate this delay would be to change the variation of the set point more slowly reducing the impact on the flow rate, resulting in a smaller variation of the pressure drop along the well. The other way to mitigate the problem would be to set more aggressive gains for the controller, but that may cause other operational problems as instability on normal operation. Both options are not always viable during critical operational situations and are time consuming.

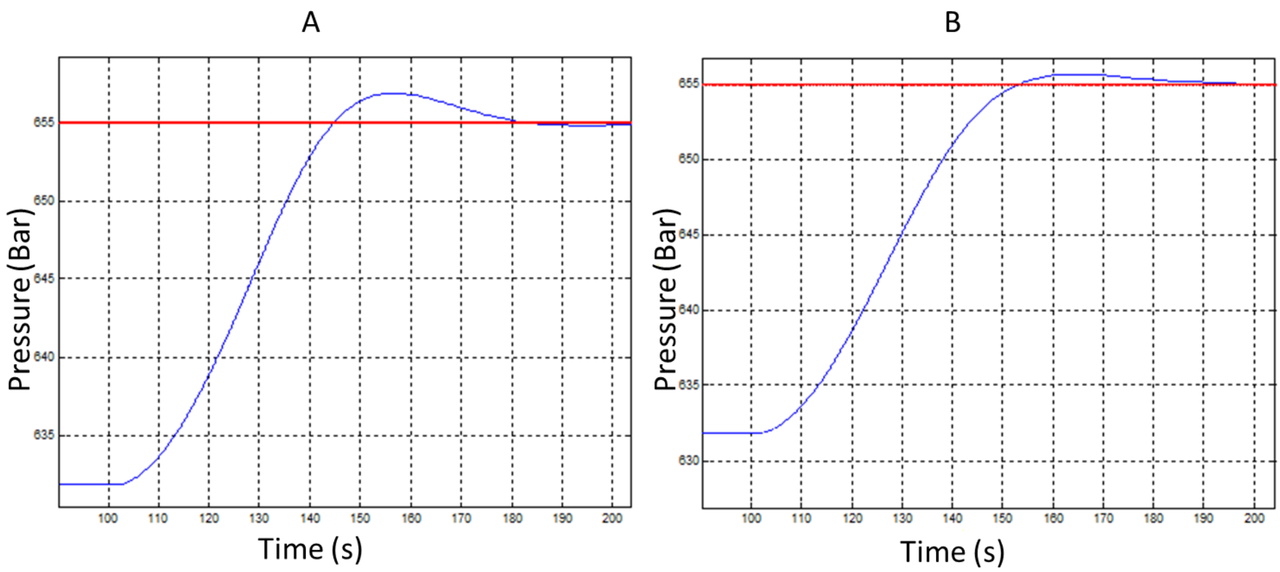

Figure (7) – Pressure at bottom hole for PD controller considering system dynamics (A); Pressure at bottom hole for PD controller based on static conditions (B)

5. Conclusions

The hydraulic model developed in this study shows the importance of considering different fluid rheologies in the distribution of pressure in a well, as well as the non-linear behavior of the pressure components. The simplified hydraulic model for an ideal incompressible fluid demonstrates significant errors in estimating the well pressure compared to other types of fluid. In addition to the rheology, it can be seen that the choke actuation cause dynamic pressure variations which are not considered in a quasi-static modeling

Given the multiple system operating ranges (flow and opening the choke), it is concluded that it is not efficient to implement a linearized system, because it would generate a considerable error in estimating system conditions. Although the control objectives are met with PID controllers, and its derivations (PD and PI), it should be noted that in some operational situations during drilling of wells a delay controller to achieve a new reference pressure can lead to problems that carry to non-productive time, as inflows or losses to formation due to fracture. A controller based on a model that includes the non-linearities of the system, and internal dynamics can provide better performance than a controller based only on static conditions as the pressure is not transmitted immediately.

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