New Choke Controller for Managed Pressure Drilling

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Abstract: Managed Pressure Drilling (MPD) is performed in offshore and onshore oil and gas areas to reduce the risks that may be associated with using conventional drilling hydraulic methods. The aim of MPD is to reliably and precisely control the pressure at the bottom of well within what is known as the 'pressure window'. Manual control of the choke valve was adapted from manual well control methods developed for circulating out an oil or gas influx. There have also been attempts dating back more than 40 years to automate the choke controller for influx circulation, though as of today there is still not a reliable automated system available for this purpose. Over the last ten years, MPD systems with various levels of automation have been developed. The current automated MPD system has been successfully used worldwide to drill hundreds of wells with narrow pressure windows. This paper discusses the development history and the newest developments in automated choke control with a forward-looking view of automated processes to precisely manage well pressure.

1. INTRODUCTION

Managed Pressure Drilling is defined by the IADC (International Association of Drilling Contractors) as "An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the down hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process." Drilling a well typically results in changes in geological, geometric, mechanical, and thermodynamic conditions, which have to be compensated with some form of control. The aim of MPD is to reliably and precisely control the pressure at the bottom of well within what is known as the 'pressure window'. The typical problems that can be mitigated by staying within this 'pressure window' are; the undesirable loss of the drilling fluid into the subsurface strata (losses), the undesirable ingress of formation fluids such as oil and gas (kick / blowout) and lastly, the structural failure of the borehole (collapse/caving). Often these three conditions can occur sequentially and repeatedly sometimes resulting in extreme cost overruns, loss of the well, and health, safety and environmental risks. Mitigating these conditions therefore significantly increases the safety and economics of drilling oil and gas wells, making MPD a compelling application for most wells being drilled today. Improvement of the drilling bit penetration rate can also be realized, further reducing the cost of drilling. Using a choke valve at the well discharge to control the pressure at the bottom of the well is currently the most common MPD method used. Manual control of the choke valve was adapted from manual well control methods developed for circulating out an oil or gas influx. But, as wells become more challenging to drill, manual control does not provide the speed, precision, and reliability necessary to maintain the pressure within the desired pressure window. There have also been attempts to automate the choke dating back more than 40 years as seen in fig 1 which shows an early patent figure to automate the choke controller for influx circulation, though as of today there is still not a reliable automated system available for this purpose.

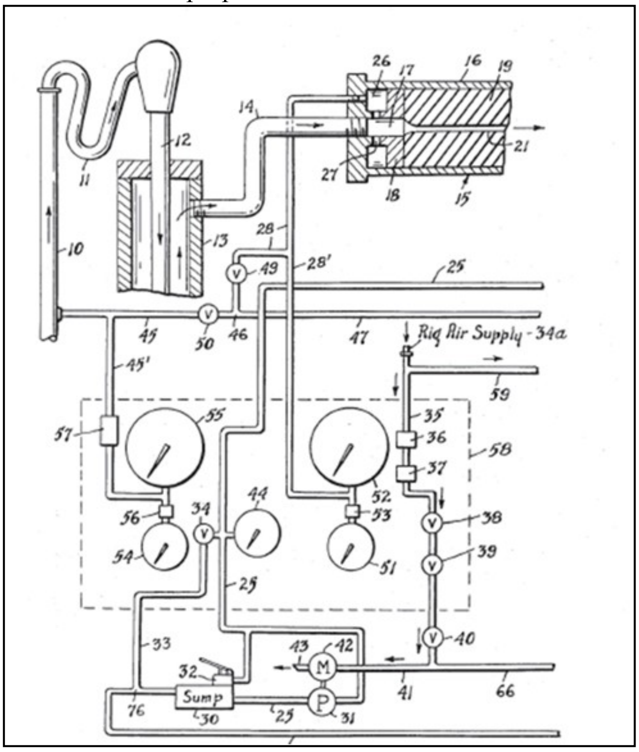

Fig 1: Automated choke control design - 1967

In the last five years, MPD systems with various levels of automation have been developed. Development of a control system to maintain a constant pressure in the well needs to be robust enough to compensate for changes in the process yet stable enough to maintain a constant pressure in the well. This paper will outline the development of an automated system to control the pressure in the well during the well drilling process.

2. PROOF OF CONCEPT AND PROTOTYPE (2002)

Conceptual development of an automated system for controlling the pressure while drilling a well was begun as early as 1998. Development plans matured by 2001, and a test system was constructed in 2002 / 2003. Initial tests were conducted in March of 2003 at the Shell research facility in Rijswijk, The Netherlands (van Riet). The equipment consisted of a pump, a drilling choke, pressure sensor and a short flow loop to a liquid holding tank. The trial was successful as a proof of concept that the drilling choke could be automated and sufficiently controlled to maintain a desired pressure upstream of the choke. A prototype system was developed for use in well trials using MATLAB and a PLC. Analog signals for the choke (process) pressure and position sensors were connected to the PLC and processed by the MATLAB program to determine the required well pressure and choke position using a standard PID algorithm (equation 1).

$$Out = Kp\left[\alpha . SP - PV + \int \frac{SP - PV}{Ti} dt - Td\,\frac{d(PV)}{dt}\right] \qquad (1)$$

The last term is filtered with a lowpass filter with timeconstant Td/N

The primary disadvantage of the system was that it required an expert to tune the PID parameters, which could take several hours depending on the characteristics of the well. The aim of the well pressure control system was to maintain a constant pressure at the bottom of the well (Pdownhole) based on equation 2 by changing the discharge pressure (Pback) according to a change in the frictional pressure of the return flow in the well annulus (Pdyn). The static pressure of the fluid (Pstat) remained relatively constant in both cases, except for small increases due to (Pback) and compression.

$$P_{downhole} = P_{stat} + P_{dyn} + P_{back} \qquad (2)$$

The system required two computers, one to run the MATLAB code and provide a control system interface (fig 2) and another to collect rig data via WITS (Well Information Transfer System) and run, near real-time, a hydraulics program to calculate the required bottom hole pressure.

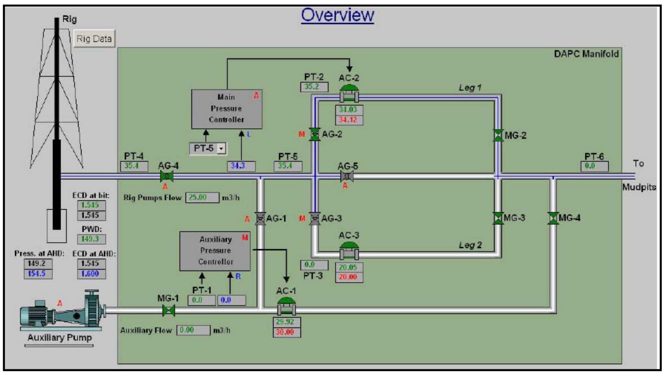

Fig 2. Prototype Control System Interface Overview Screen

The drilling pump flow rate and drill string depth were fed into the hydraulics model to calculate the pressure in the well. In equation 2, the pressure denoted as Pdyn represents the frictional pressure loss in the well annulus when the drilling pumps are on. When the drilling pumps are off, Pdyn is zero and Pdownhole is equal to Pstat, when there is no backpressure (i.e. Pback is zero). The objective was to maintain the difference in pressure required, Pback which would be achieved using the choke. The depth of the drill string changes at a relatively slow rate compared to the drilling pump rate and is not as critical to the computation of well pressure as the drilling pump rate. While drilling with a conventional drilling rig, the pumps are turned off when adding or removing drill pipe. The resulting reduction in frictional pressure in the well is compensated by the pressure control system closing the choke. When the pumps are turned back on the frictional pressure returns and the control system opens the choke to reduce the surface backpressure. There are other planned and unplanned times when the pumps may be stopped or started, often quickly and without notice. To maintain constant pressure, response to an unexpected and sudden pressure change has to be as fast as the event itself and very accurate. The speed and accuracy required is only possible with an automated choke control system.

The time required to identify the change in pump rate and for the system to react to the change in pressure is critical to ensure the required well pressure remains within the specified range. Initial testing of the prototype system took place at the Shell SIMWELL in northern Holland and utilized an OPC connection with a data exchange delay of less than one second. Using a WITS (Well Information Transfer System) connection during later field trials proved to be problematic due to long data exchange delays ranging from 5 to 15 seconds. Improvements were made by the data supplier to transmit data every 1 to 2 seconds. Data quality was also a concern. In some cases the pump rate signal was averaged which added additional delays and errors in the computation of the required pressure. Data accuracy and reliability continued to be challenging due to lost, frozen and erroneous pump rate signals resulting in further calculation errors.

Surface pressure is calculated based on the difference between the required pressure and actual pressure. In some cases the system calculated a negative surface pressure when the drilling pumps were on and the actual pressure exceeded the required well pressure. Since a negative surface pressure is not possible, the system was designed to return a zero pressure requirement.

To apply the required surface pressure, the choke was first positioned according to the discharge flow rate, assumed to be equal to the pump injection rate, after which the system used the KV (CV) of the choke position (fig 3). This was only an approximation which was then corrected based on the difference between the actual and required pressure.

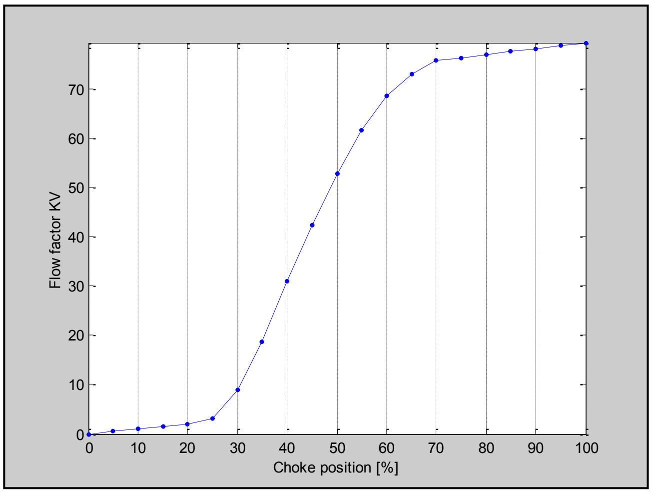

Fig 3: KV (CV) of the Drilling Choke

Using a choke with a large orifice (76.2mm) during low flow proved to be problematic. A solution was devised that involved making a transition from the large choke to a smaller one with an orifice of 38.2 mm. This was still somewhat problematic because the change in flow had to remain relatively constant even though it was manually controlled.

An auxiliary pump with an inlet upstream of the choke was used to maintain a constant flow through the choke, eliminating the need to close the choke fully when the drilling pump was off. The auxiliary pump was started automatically prior to the drilling pump being turned off then stopped after the drilling pump was restarted and the flow was back to the required rate. The auxiliary pump kept the well pressurized, which compensated for any pressure leakage in the well and mitigated the risk of influx into the borehole.

Prototype field testing involved drilling two well sections to test control and reliability. The first well section had a diameter of 311 mm and was drilled with a flow rate of approximately 3400 l/min at a depth of 900 meters. The second had a diameter of 152.4mm and was drilled with a flow rate of 600 l/min at a depth of 3600 meters.

In both sections the system operated reliably but control stability proved problematic when the pump rate was changed too fast compared to the data communication lag time. This had a detrimental effect because the actual flow rate was significantly different than the data provided to the system resulting in a miscalculation of the required choke position and therefore a significant error1. Once the driller was familiar with the new procedure of starting and stopping the pump, the control system was able to accurately control the pressure at the desired value of 350 kPa variance over a range of 3500 kPa in both sections, though it added several minutes more to each drill pipe connection compared to the previous procedure. The optimal rate of change for pump rate was approximately 1 minute per 1000 l/min. Pressure oscillations of approximately 250 kPa were also observed when the auxiliary pump was being used to sustain pressure. These oscillations were caused by the triplex pumps and the inability of the control system to react fast enough to pressure changes that were occurring about once a second.

In spite of these limitations, the system proved capable of automatically controlling relatively constant bottom hole pressure in near real-time with an uptime of over 98%. These encouraging results proved that a commercial automated pressure control system was viable. Two critical improvements were identified, one involved designing the control system hardware to operate in a potentially explosive environment zone and the other involved including a backup power supply.

In early 2004, the prototype hydraulic calculator and PID controller were used to provide pressure and position values to an untested third party choke control system which Shell wanted to use for pressure management on their Mars platform (Roes). The initial objective was to provide the required pressure to the third party system for choke control. But because it used fixed PID values it was not possible to properly tune the choke controller for the well environment. Choke position was sent to the third party control system, which resulted in a level of pressure control similar to the first two field trials. Another well drilled with a similar setup and the same third party choke controller, but with a different pressure calculator, achieved the same results. These applications clearly highlighted the need for a robust PID controller that could be tuned according to different well characteristics.

Well pressure was successfully controlled in both cases an order of magnitude better than conventional drilling methods and proved so successful that further redevelopment of platform continued (Malloy).

3. VERSION 1.0 (2004)

To improve accuracy and reliability, the MATLAB program was converted to reside on a commercial PLC that supported floating point operation, resulting in much faster and accurate execution. The PLC and controls were also mounted on the choke manifold which had an ATEX Zone 2 rating. The hydraulic model, control system interface and the rig data communicator continued to reside on a PC, which remained somewhat problematic due to compatibility issues with Microsoft WINDOWS™. However, in the event of a PC failure, the last best value was retained in the PLC and procedures were established to restore the system in a smooth manner. This version maintained the two choke transition, which required an expert operator to tune the chokes and supervise the transition process. The PID loop was changed to one of the proprietary blocks from the PLC manufacturer, but no significant improvement in control stability was observed mainly due to the sequencing process. To improve calculations, high speed counters were added for direct measurement of the drilling pump speed rather than relying on WITS data. That significantly improved the speed and reliability of the control system.

The earliest application of the first commercial version was used by Shell on their Gannett platform in the U.K. North Sea (Laird) to access stranded oil reserves. Shells's objective was to avoid formation damage by reducing the amount of weighting solids in the fluid and the differential pressure at the reservoir. Surface control pressures were approximately 7000 kPa which significantly eclipsed previous maximum control pressures of approximately 2000 kPa.

A Coiled-Tubing drilling unit was used which as its name suggests, is a continuous length of pipe of several thousand meters which is rolled onto a reel rather than using jointed drill pipe. This type of drilling unit was used due to the relatively small available space on the rig and its ability to provide a relatively constant pump rate, which is inherently unachievable with jointed drill pipe. There were however several sudden and unexpected transient events due to the drilling motor abruptly stalling, which flow out of the well suddenly stop. These transients required rapid choke closure and backpressure pump operation to maintain constant well pressure and resulted in brief pressure spikes due the rapid actuation of the choke followed by the pressure stabilizing within an acceptable error of the required value. Had the system been manually controlled it would not have been possible to manage these abrupt changes and re-establish the correct well pressure.

Uptime for the system was 98.8% or a total of 10.25 hrs downtime and no significant pressure losses occurred due to employing contingency measures. By employing the automated pressure control system and utilizing a reduced density, solids free drilling fluid, Shell realized nearly a threefold increase in expected well productivity and an order of magnitude lower water production.

An onshore location that had a higher pressure tolerance was used for the next test of the system. For this application the system was found to take too long due transport and rig up which included a generator for the auxiliary pump. Tuning the choke still took several hours which added to the rig time for a marginal application which was previously done using manual choke control by the senior rig supervisor. The drillers were also not accustomed to starting and stopping the pumps slow enough for the system to react since the manual method had been to stop the pumps rapidly, close the choke and then apply additional pressure as required. This resulted in significantly higher and lower pressures being applied compared to the manual method. The system did perform well when the drillers were properly trained to slowly start and stop the pumps but they typically required constant supervision, again adding to the cost of the operation. The system was partially used in manual mode to ensure the correct pressure was applied by using the real time hydraulic model. Although the well reached the planned depth, the system was not considered economically viable unless transportation costs could be lowered, rig up time reduced and system performance improved.

4. VERSION 1.2 (2006)

The primary change to the system was the removal of the transition sequence for the small bore. This eliminated transition tuning which significantly improved pressure stability and reduced control complexity. However, this required a 75% increase in the backpressure pump flow rate, which allowed the system to operate the choke at an optimal position and in turn manage the pressure with small choke movements, shown in fig 1 between 20 and 60 on the CV curve. Without this feature the choke would have to operate at a CV value below 20, where it would have little effect on pressure. At that position the choke would have to move rapidly, which could cause it to become unstable. Also, different PID parameters would have been required to maintain stability across the entire choke position range which would have led to increased system complexity, greater operator expertise, and a significantly longer time to tune the system.

A number of land and offshore wells with specific safety and redundancy requirements were drilled with constant well pressure (Reitsma). The purpose was either to maintain a stable borehole or prevent fluid losses. Of paramount importance was to avoid an influx of reservoir fluids and to detect it at the earliest possible movement if such an event did occur (Montilva).

Although not strictly part of the automated pressure control system, a Coriolis flow meter was incorporated into the system to detect fluid kicks and losses. The meter is located on the discharge line of the choke manifold and is used to compare flow into the well with flow out of the well. A kick is identified by an increase in flow out of the well compared to flow in and a loss is identified by a decrease in flow out of the well compared to flow int. The Coriolis flow meter is highly sensitive to changes in flow and was instrumental in aiding in detecting kicks and losses for two reasons, 1. Managed Pressure Drilling Operations typically have a reduced pressure margin between pore pressure and fracture pressure, and 2. The driller is unable to observe potential flow during static conditions except at the discharge into the fluid holding tanks which may be some distance from his station.

5. VERSION 2.0 (2008)

This version was entirely rewritten onto a new platform based on the need for increased spare capacity and more precise pressure control using a smaller auxiliary pump. Also, version 1 had been built off of the prototype version which still retained some of the native MATLAB code. Fixed values that were embedded in the code were removed to allow for easier customization at each new well location. The system was also able to now control up to three chokes simultaneously, have redundant pressure sensors, remotely control several valves and monitor up to six drilling pumps. The new platform was also designed to have a 50 – 100 millisecond refresh rate to ensure updates could be made at least every 250 milliseconds.

Development included a new interface that was more intuitive and included a monitor for the driller which provided pressure feedback as the pump speed was altered rather than requiring supervision by an MPD specialist to not change the pump rate faster than the choke could control the well pressure. The feedback system displays a green (normal), amber (reduce change of pump rate) or red light (stop changing pump rate) so the driller can adjust pump speed accordingly to maintain the green light. Some drillers adapted well to this method and others still required supervision, or due to space constraints it was not possible to place the monitor where the driller could observe it.

A new PI controller was implemented for the mechanical choke that did require CV measurements. Instead, course positioning of the choke using an outer loop and a finer inner control loop was developed. The inner loop is activated when the actual well pressure approaches the required pressure and switches back to coarse position if the actual well pressure is significantly different than the required well pressure. This method significantly improved the speed and stability of the system since a large change in choke position could be made. Operators were still required to tune the system by adjusting the gain and integral values. For even the most experienced operators this takes at least two hours and sometimes substantially longer if conditions such as the bulk modulus of the well changed. However, the advantage was that a smaller pump could theoretically be used since the choke could operate over a greater range.

The use of the system has been instrumental in providing precise control of the well pressure primarily in offshore operations. There are numerous references available but most notable have been the contribution to full field offshore redevelopment projects such as Shell Auger (Chustz) and Talisman Malaysia (Fredericks).

6. VERSION 3.0 (2011)

The requirement for an operator to remain on the well location in order to tune the choke controller, while greatly improved from the original version still challenged consistent service delivery because the skill set of the operator was instrumental in determining how well the choke controlled pressure. In fact, on the same project the day Operator might apply different settings than the night Operator (Reitsma). The training of operators also adds significantly to overhead costs. As well it would not be possible to reduce personnel on location and thus limited the deployment of the system based on economics and / or accommodation space. Tuning of the PI loop could also take several hours and would have to be corrected as drilling conditions changed.

Methods such as neural networks, expert systems, commercially available self-tuning systems, choke position versus pressure tables, and fixing the integral time so that the operator would only need to change the gain were investigated as possible solutions but unfortunately all of them provided a lesser degree of control and stability than currently available, so did not offer the potential for reducing training and personnel on location.

As a result, a project was undertaken to develop a proprietary non-linear solution that would self adapt to the changing bulk modulus which commonly occurs when drilling oil and gas wells. Mechanical modifications were also made to the choke actuator and hydraulic control system to increase the speed and accuracy of the choke movement. As a result, the choke actuator moves more than three times faster than the previous choke actuator and with an order of magnitude greater pressure control precision.

The new solution constructs the necessary algorithm based on initial pressure and choke position feedback during an initial calibration process that takes approximately two minutes. After calibration, the system is capable of automatically controlling the choke position based on the difference between the required and actual well pressure. Minor corrections to the algorithm are automatically made based on pressure response during the normal drilling process.

Testing of the new controller was performed at the Louisiana State University PERTT (Petroleum Engineering Research Technology Transfer facility) well number 2 in Baton Rouge Louisiana, which is used extensively for testing managed pressure drilling systems and conducting full scale well control training. While the system is designed for controlling the well pressure during the sequence of starting and stopping the drilling pumps, several other tests were also conducted to test the overall stability. Testing was conducted over several months but only the relevant results are presented.

Test #1 involved manually increasing the well pressure in 350 kPa increments at a constant pump rate to test the ability of the system to match the actual well pressure. Total system reaction time which includes signal reception, processing and the mechanical action of the choke hydraulics was approximately one second. Fig 4 is a plot of test #1 showing only a minor pressure overshoot before stabilizing at +/- 15 kPa of the required pressure. What is significant is that there is no characteristic pressure oscillations normally associated with a PI control as evident in the references mentioned. Rather than step down the pressure in 350 kPa increments, the pressure was decreased in a single 2100 kPa step to test the stability of the system to correct for significant pressure changes. The result was a relatively minor undershoot of pressure and then pressure stabilized at +/- 15 kPa. This is a significant improvement over PI controllers which can usually provide +/- 250 kPa under ideal conditions.

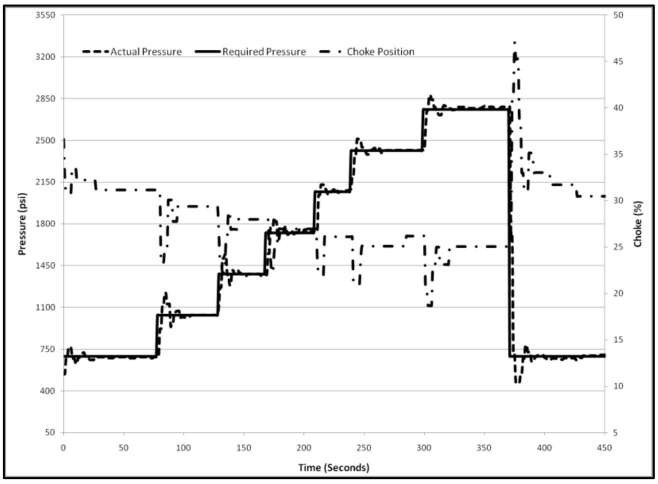

Fig 4: Test #1 – Manual Set Point Pressure Changes

Test #2 was a typical sequence of stopping and starting the drilling pump shown in Fig 5 where the drilling choke pressure is altered automatically to compensate for the loss of frictional pressure in the well. A second smaller triplex pump was used to maintain flow through the choke as the primary pump rate was altered. The PV pressure tracks closely to the set point pressure while the pump rate is reduced with only minor differences due to inconsistent changes in pump rate. The variation in pressure and minor changes in choke position from time 100 – 180 is characteristic of the inefficient nature of the auxiliary triplex pump resulting in a variable flow rate which is partially compensated by the choke controller. After stopping the pump, the operator was then instructed to start the main pump as quickly as possible. This was to test the system reaction to prevent a pressure overshoot. A minor pressure overshoot was observed when the pump was initially started followed by the minor fluctuations in actual pressure compared to required pressure. The actual pressure then tracked precisely to the required pressure which is significantly better than PI controlled mechanical and pressure balanced chokes.

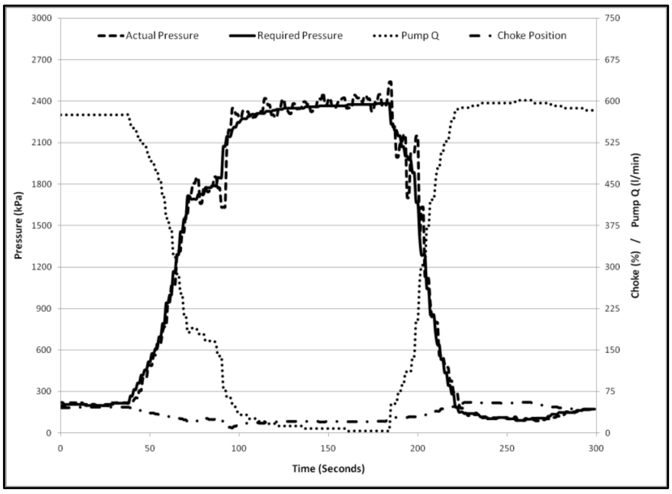

Fig 5: test #2 – Pump Stop / Start Sequence

Test #3 was designed to identify an influx with the choke closed at required pressure. If the pressure exceeded the required pressure, the choke would open which would indicate flow coming from the well. This also provided a good test of the reaction time and ability to manage pressure at very low flow rates. Fig 6a shows the choke pressure below the required pressure when gas was initially injected into the well at an instantaneous surface flow rate of approximately 680 l/min and then reduced to 11 l/min. The choke immediately opens to relieve the pressure resulting in a pressure overshoot of approximately 270 kPa above the required pressure followed by an undershoot of 200 kPa. Pressure then stabilized with less than a 35 kPa difference compared to the required pressure and was continuing to reduce. Fig 6b shows the choke position response, which is controlling at less than 20% through the entire event. At 11 l/min the choke is stable at less than 0.2% open. Other kick detection tests were also carried out and found to be comparable or better than using a Coriolis flow meter. These tests will be discussed in detail in future publications. The ability to control flow at such low rates and choke positions clearly supports that an auxiliary pump to provide flow through the choke can be significantly reduced or eliminated.

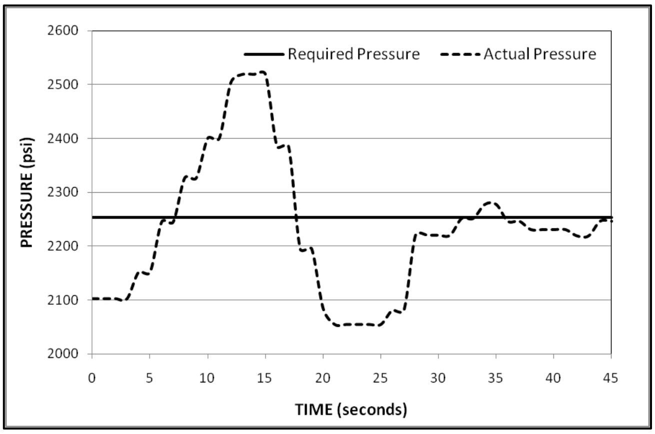

Fig 6a: Test #3 Pressure Response

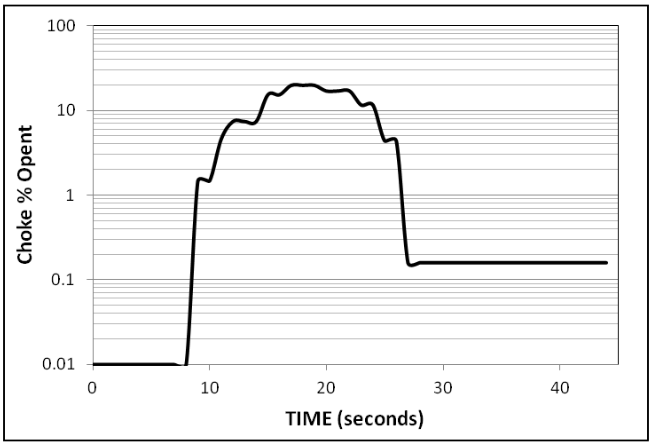

Fig 6b: Test #3 Choke position response to a gas kick

Test #4 was conducted to evaluate the stability of the controller to changes in fluid through the choke; particularly a large volume of gas which can occur after a well control event. This would not normally be the case when performing a managed pressure drilling operation but was a rigorous test to confirm the stability and adaptive capability of the controller. A similar test was not done with the PI controller since it is well known that the choke becomes unstable due under similar conditions. Gas was routed directly from the gas supply well across the wellhead of the test well and through the choke. As shown in Fig 7, flow of approximately 450 l/min and 5500 l/min pressure was stabilized at the choke. The gas supply was opened 2 minutes into the test which can be seen by as an increase in choke position. Gas begins flowing through the choke at approximately 3.5 minutes into the test which is characterized by the minor pressure and choke position changes. The pressure and position then begin to stabilize as the controller adapts. In an attempt to destabilize the controller, pressure was reduced by 2100 kPa at approximately 8.5 minutes into the test. This caused the choke to immediately open causing a pressure undershoot of approximately 1030 kPa lasting approximately 2 seconds. The controller then closes the choke and begins to stabilize the pressure within 6 pressure cycles. Additional pressure reductions are made without allowing the choke to fully compensate for the previous change in pressure with continually improving pressure stabilization.

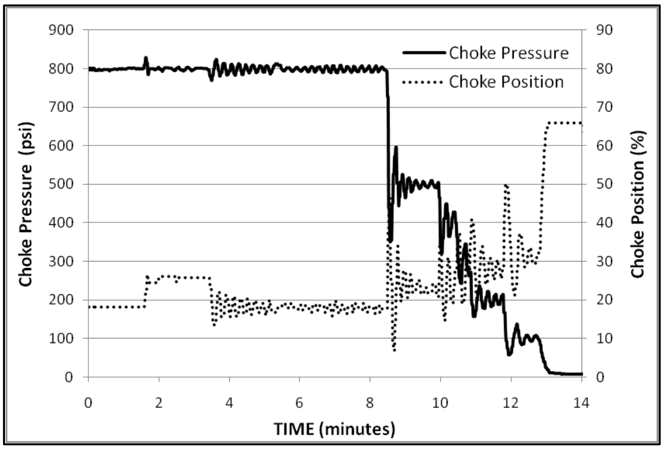

Fig 7: New Controller Test 4 – Gas Flow Stability Test

Test #5 was to determine system stability with the driller making erratic changes to the drilling pump rate in an attempt to destabilize the choke controller below the 20% operating range of the choke which is historically considered to be an unstable region for choke performance (Reitsma). As shown in fig 8a and fig 8b the pressure set point was automatically varied according to the change in pump rate as would be the case in a typical field application as the friction pressure in the well also changed. Several times the choke almost closes fully and in another case it closes fully due to the rapid change in pump rate and resulting error between SP and PV. The choke then reopens due to pump rate changes and remains stable throughout the test as other pump rate changes are made. There were several other tests conducted in order to attempt to destabilize the choke but the choke remained stable.

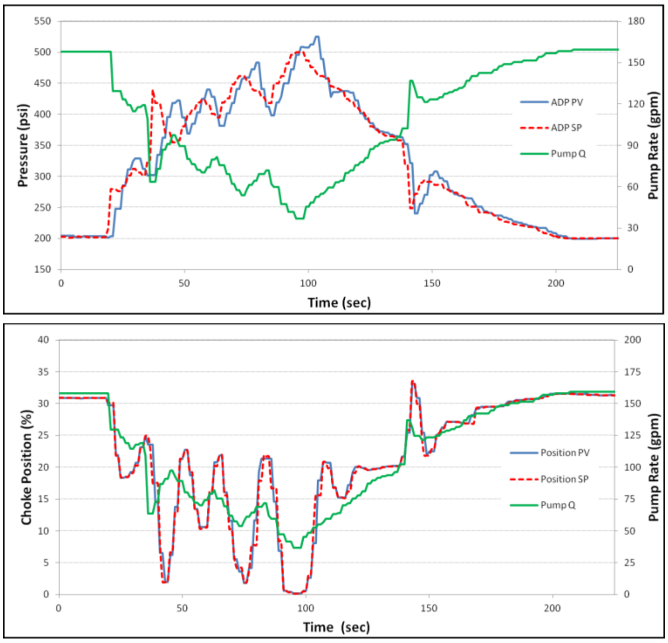

Fig 8a and 8b: Attempt to Destabilize Choke Controller

7. FUTURE PRESSURE CONTROL DEVELOPMENT

The choke controller in its present state has been developed as purely reactionary to the change in rig and well conditions without the benefit of using a feed forward controller. Future development will be to coordinate pump speed, hoisting, rotary control and vessel movement in floating rig applications with the choke controller. Changes in well conditions such as gas content, geometry and fluid properties also need to be included in the control system process.

8. CONCLUSIONS

- The choke control system to control well pressure has been under continuous development for more than 10 years, progressing from prototype to the current system with discreet development objectives.
- Removing the variables from the source code enabled the operators to configure the system on location without assistance from the support group.
- The PI choke controller was improved with the removal of the choke transition but still requires a trained operator to perform the tuning and a larger pump.
- Improvements in the performance of the system were significant in reducing the pump size, reducing training and improving stability, however removal of the PI control loop was seen as a requirement in order to further reduce training and improve service quality.
- The newly developed non-linear controller has proven to be stable, fast and reliable in testing compared to using the current PI control system, requires practically no training and provides a higher level of service quality.
- Throughout the development of the system it has been successfully used to drill offshore and onshore resulting in significant cost savings and additional reserves. In some cases it would not have been technically impossible to drill the wells resulting in the stranding of the reserves.

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